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PUBLIC SERVICE COMMISSION

January 23, 2014

Via Personal Delivery

Mr. Jeff Derouen, Executive Director
Case No. 2013-00259
Kentucky Public Service Commission
211 Sower Blvd.
Frankfort, KY 40601

Re: Case No. 2013-00259 Sonia McElroy and Sierra Club's Responses to East Kentucky Power Cooperative, Inc.'s Request for Information from the Hearing of January 14, 2014 through January 15, 2014

Dear Mr. Derouen,

Enclosed please find one original and ten (10) copies of Sonia McElroy and Sierra Club's Responses to East Kentucky Power Cooperative, Inc.'s Request for Information from the Hearing of January 14, 2014 through January 15, 2014, filed today in the above-referenced matter via personal delivery. By copy of this letter, all parties listed on the Certificate of Service have been served via USPS and e-mail. Please place this document of file.

Sincerely,

Kristin A. Henry

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Senior Attorney
Sierra Club
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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
AN APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR ALTERATION OF CERTAIN EQUIPMENT AT THE COOPER STATION AND APPROVAL OF A COMPLIANCE PLAN AMENDMENT FOR ENVIRONMENTAL SURCHARGE COST RECOVERY	)	**CASE NO. 2013-00259**

SONIA MCELROY AND SIERRA CLUB'S RESPONSES TO EAST KENTUCKY POWER COOPERATIVE, INC.'S REQUEST FOR INFORMATION FROM THE HEARING OF JANUARY 14, 2014 THROUGH JANUARY 15, 2014

Intervenors Sonia McElroy and Sierra Club (collectively "Environmental Intervenors") hereby submit their response to East Kentucky Power Cooperative, Inc.'s ("EKPC") Information Requests made during the hearing of January 14, 2014 and January 15, 2014.

Request No. 1: I would like a post-hearing data request to ask the witness and the Sierra Club for each and every case and situation where Wood Mackenzie has provided Synapse Energy Economics with their methodology and proprietary work product.

Response No. 1:

In Indiana Utility Regulatory Commission ("IURC") Cause 44217, Duke Energy Indiana provided Synapse Energy Economics ("Synapse") with energy price forecasts from Wood Mackenzie. As part of confidential material in the filing and in response to data requests, Duke Energy Indiana provided Synapse with detailed inputs and assumptions underlying the Wood Mackenzie forecasts, including: hourly energy prices, load forecasts, coal prices, natural gas prices, carbon prices, coal plant retirements (by plant), fuel supply and demand balance, economic outlook, and environmental regulation assumptions. Duke Energy Indiana also provided a witness from Wood Mackenzie who testified to the methodology and aforementioned inputs for its forecasts.

For reference, public testimony in IURC Cause 44217 from Robert Fleck (Wood Mackenzie) and Rachel Wilson (Synapse Energy Economics) is attached with this response.

In KPSC Case No. 2013-00199, Big Rivers Electric Corporation provided Synapse with energy forecasts from Wood Mackenzie, but did not provide detailed inputs or assumptions used in generating the forecasts. Another utility provided Synapse with a Wood Mackenzie energy price forecast in another case, but the terms of a non-disclosure agreement prevent me from disclosing the name of the utility or the case.

Additionally, in IURC Cause 44242, Indianapolis Power & Light Co. ("IPL") provided Synapse with detailed assumptions used by Ventyx to generate the energy price forecast.

Respectfully submitted,

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Dated: January 23, 2014

CERTIFICATE OF SERVICE

I certify that I had filed with the Commission and served via U.S. Mail and electronic mail the foregoing Intervenors' Responses to East Kentucky Power Cooperative, Inc.'s Requests for Information on January 23, 2014 to the following:

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Anthony Raduazo

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC., FOR APPROVAL OF (1) A PHASE 2 COMPLIANCE PLAN REGARDING EMISSIONS REDUCTION REQUIREMENTS; (2) THE USE OF CERTAIN QUALIFIED POLLUTION CONTROL PROPERTY AND CLEAN ENERGY PROJECTS; (3) CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSITY FOR CLEAN COAL TECHNOLOGY; (4) THE USE OF CONSTRUCTION WORK IN PROGRESS RATEMAKING TREATMENT; (5) CERTAIN FINANCIAL INCENTIVES IN CONNECTION WITH PETITIONER'S COMPLIANCE PLAN, INCLUDING THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF THE CLEAN COAL TECHNOLOGY PROJECTS VIA DUKE ENERGY INDIANA'S RIDER NOS. 62 AND 71, AND THE USE OF ACCELERATED DEPRECIATION; (6) THE AUTHORITY TO DEFER POST-IN-SERVICE CARRYING COSTS, DEPRECIATION COSTS, AND OPERATION AND MAINTENANCE COSTS ON AN INTERIM BASIS UNTIL THE APPLICABLE COSTS ARE REFLECTED IN PETITIONER'S RATES; (7) CONDUCTING ONGOING REVIEWS OF THE IMPLEMENTATION OF PETITIONER'S COMPLIANCE PLAN; (8) THE TIMELY RECOVERY OF EMISSION ALLOWANCE COSTS IN DUKE ENERGY'S RIDER NO. 63; AND (9) DEFERRAL AND RECOVER THE PHASE 3 PLAN DEVELOPMENT, ENGINEERING AND PRE-CONSTRUCTION COSTS	CAUSE NO. 44217

Direct Testimony of
Rachel S. Wilson

PUBLIC VERSION

On Behalf of
Citizens Action Coalition, Sierra Club, Save the Valley, and Valley Watch

November 29, 2012

Table of Contents

1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and position.

A. My name is Rachel Wilson and I am an Associate with Synapse Energy Economics, Incorporated (Synapse). My business address is 485 Massachusetts Avenue, Suite 2, Cambridge, Massachusetts 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government and utilities.

Q. Please summarize your work experience and educational background.

A. At Synapse, I conduct research and write testimony and publications that focus on a variety of issues relating to electric utilities, including: integrated resource planning; federal and state clean air policies; emissions from electricity generation; environmental compliance technologies, strategies, and costs; electrical system dispatch; and valuation of environmental externalities from power plants.

I also perform modeling analyses of electric power systems. I am proficient in the use of spreadsheet analysis tools, as well as optimization and electricity dispatch models to conduct analyses of utility service territories and regional energy markets. I have direct experience running the Strategist, PROMOD, PROSYM/Market Analytics, and PLEXOS models, and have reviewed input and output data for a number of other industry models.

Prior to joining Synapse in 2008, I worked for the Analysis Group, Inc., an economic and business consulting firm, where I provided litigation support in the form of research and quantitative analyses on a variety of issues relating to the electric industry.

I hold a Master of Environmental Management from Yale University and a Bachelor of Arts in Environment, Economics, and Politics from Claremont McKenna College in Claremont, California.

A copy of my current resume is attached as Exhibit RW-1.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Citizens Action Coalition of Indiana, Sierra Club, Save the Valley, and Valley Watch (the Joint Intervenors).

Q. Have you testified previously before the Indiana Utility Regulatory Commission?

A. No.

Q. What is the purpose of your testimony?

A. My testimony details and evaluates specific components of Duke Energy Indiana's ("the Company" or "Duke") analysis supporting this certificate of public convenience and necessity ("CPCN") application. I evaluate the Market Analytics/PROSYM ("PROSYM") modeling performed by the Company, as well as certain inputs to the PROSYM model. I also describe my own PROSYM modeling efforts using the Company's input data and present the results of that analysis.

Finally, I discuss some of the current and likely upcoming federal environmental regulations that are likely to affect the operations and economics of the fleet of Indiana coal plants owned by the Company and identify shortcomings in the Company's assumptions about those regulations.

Q. Please identify the documents and filings on which you base your opinion regarding the Company's analysis of the environmental compliance costs affecting its fleet of coal plants.

A. In addition to the application, testimony from Company witnesses, and discovery responses in this case, I have reviewed the Company's Market Analytics/PROSYM modeling input and output files.

2. Overview of Testimony and Conclusions

Q. In your opinion, do the modeling assumptions and the Market Analytics/PROSYM modeling performed by Duke support the decision to install the proposed pollution control retrofits on its coal fleet?

A. The modeling performed by Duke and the underlying assumptions do not appear to support the installation of pollution controls on Gallagher Units 2 and 4 and Cayuga Units 1 and 2.

The Company committed a critical modeling error in its analysis of the benefits of the installation of pollution controls at its Gallagher units by failing to actually retire Gallagher Units 2 and 4 in the retirement scenarios, thereby charging those scenarios with both the cost of operating those units and the cost of replacing them. Duke also makes several assumptions that are incorrect, including: 1) inconsistency with respect to the retirement dates of Gallagher 2 and 4; 2) the assumption that energy efficiency savings will decline sharply after 2019; and 3) the use of a CO_2 allowance price projection at the low end of the range of utility forecasts. I was able to use PROSYM to correct the modeling error and update the results with more reasonable assumptions about extended energy efficiency and CO_2 price (the "Synapse Base Case"). Those results are shown in Table 1.

Table 1. Net Benefit of Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4	Cayuga 1	Cayuga 2
Duke Base Case	[redacted]	[redacted]	[redacted]	[redacted]
Duke Base Case (Corrected)	[redacted]	[redacted]	[redacted]	[redacted]
Synapse Base Case (Extended EE + Mid CO_2)	[redacted]	[redacted]	[redacted]	[redacted]

There were two additional errors regarding the analysis of the Gallagher units that can be corrected outside of PROSYM. The first is the retirement of Gallagher 2 on [redacted] and Gallagher 4 on [redacted] These units are retired in PROSYM after being controlled in the Company's Base Case retrofit scenario. However, no additional capacity is added to maintain the Company's reserve margin when these retirements occur. A calculation done outside the modeling shows that correction of this error would lead to an additional capital cost of [redacted] for Gallagher 2 and [redacted] for Gallagher 4 in the retrofit scenario. This adjustment would lower the net benefit of control retrofits by the same dollar amounts. Additional production costs associated with the operation of replacement capacity would lower the net benefits by even more. [redacted] Corrections for these errors are shown in Table 2.

Table 2. Net Benefit of Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4
2032-2033 Replacement Cost Adjustment	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
With Adjustments Shown Above:		
Duke Base Case (Corrected)	[redacted]	[redacted]
Synapse Base Case (Extended EE + Mid CO_2)	[redacted]	[redacted]

I have additional concerns about: 1) the transparency of the modeling performed by Duke in this analysis; 2) the exclusion of any capacity and energy associated with the potential Wabash River Unit 6 natural gas conversion or replacement RFP; 3) the failure to consider additional demand response in the analysis period, 4) the difference in the dispatch methodology between the Company's Engineering Screening Model and the PROSYM model; and 5) the energy market price forecast.

The next sections of my testimony describe in more detail the errors and flawed assumptions that are included in Duke's modeling analysis, as well as the scenarios that were modeled by Synapse in our Market Analytics/PROSYM analysis.

3. Description of Company Modeling

Q. Please describe the modeling methods used by Duke in this docket.

A. It is my understanding that four different modeling methodologies were used by Duke in this docket. First, Wood Mackenzie used the Aurora XMP model to determine an hourly energy price forecast using its forecasts for coal and natural gas prices, a carbon dioxide ("CO_2") pricing regime, and coal retirements associated with national environmental regulations. These environmental regulations include the Cross States Air Pollution Rule ("CSAPR"); the Mercury and Air Toxics Standards ("MATS"); Coal Combustion Residuals ("CCR"); Clean Water Act 316(b) ("316(b)"); and the National Ambient Air Quality Standards ("NAAQS") for 8 hour ozone, $PM_{2.5}$, and sulfur dioxide ("SO_2"). This hourly energy price forecast is referred to as the Duke Fundamental Forecast.

Price forecasts for coal and natural gas, as well as the hourly energy price forecast, were then transferred to Duke for use in the Company's proprietary Engineering Screening Model. The Engineering Screening model evaluates various pollution control retrofit installations at each of the Duke units. Using unit specific information about such factors as capacity, emissions rate, heat rate, fixed costs, variable costs, etc., the Duke units are dispatched individually against an energy market price curve (in this case, the energy price curve provided by Wood Mackenzie in the Duke Fundamental Forecast). Model outputs are based on this unit dispatch, and include unit generation, capacity factor, fuel cost, operations and maintenance ("O&M") cost, emissions allowance cost, etc. These operating costs are combined with the capital costs associated with the particular pollution control retrofit technologies installed at a unit to arrive at a cash flow stream for each unit, and the net present value ("NPV") of this stream is calculated. Retrofit options are then selected based on a combination of NPV and whether or not required emission reductions are likely to be achieved by a given suite of controls.

Results from the Engineering Screening Model are then used in the Company's proprietary Integrated Resource Planning Model. This model analyzes the economics of installing pollution controls at each of the units compared to retirement scenarios that replace the retired units with natural gas combustion turbine or combined cycle options. A build-out schedule is generated for each scenario, showing the new capacity added (both type and size) in a given year for the simulation period.

These build-out schedules, as well as individual unit data from both of the Duke proprietary models are passed to the PROSYM model. PROSYM dispatches the Duke units in each scenario against the Company's load forecast in order to arrive at total production costs for the system on an annual basis.

For each scenario, production costs from PROSYM are combined with the stream of capital costs for the pollution controls and new capacity. These streams are discounted to calculate the total present value of revenue requirements ("PVRR") for each control option. Those PVRRs are presented in the exhibits of Company Witness Robert A. McMurry.

4. Description of Synapse Modeling

Q. Did you utilize any of the models used by Wood Mackenzie or Duke when conducting your review of the Company's analysis?

A. Only one – the PROSYM model. I was not given access to the Wood Mackenzie input and output files used in its Aurora XMP analysis, nor to the Company's proprietary Engineering Screening Model and Integrated Resource Planning Model. I did, however, receive the PROSYM input and output files from the Company and was able to use this model to review the Duke analysis.

Q. Please describe the modeling you performed in this docket.

A. First, I took the Company's PROSYM input files and re-ran the retrofit and retire scenarios for the Gallagher and Cayuga units (together the "Base Case") in order to confirm that the output results from my modeling were the same as the Company's results. For those scenarios that I ran, the output results were indeed the same. I then proceeded to conduct my own modeling analysis in order to correct a subset of the errors and erroneous assumptions that I believe are contained in the Company's analysis. There are additional erroneous assumptions that I did not correct for, which I will describe in Section 5.

Q. What are the errors and mistaken assumptions that you believe exist in the Duke analysis that you have corrected?

A. There is one error, and two flawed assumptions that I believe exist in the Duke analysis that I was able to correct in the PROSYM model:

A. A failure to actually retire Gallagher Units 2 and 4 in the Duke Base Case, resulting in a double counting of the production of both the replacement CT unit and the existing Gallagher Unit.
B. The assumption that the Company's efforts at energy efficiency and the resulting peak and energy savings will decline steeply at the end of 2019.
C. The use of a CO_2 emissions allowance price forecast that is at the low-end of the range of utility price projections.

The failure to actually retire the Gallagher units represents the error, and the points about energy efficiency and CO_2 are Duke's flawed assumptions. I will describe each of these in turn.

A. Duke's Failure to Actually Retire Gallagher Units 2 and 4 in Duke Base Case

Q. What do you mean when you say that the Company failed to retire Gallagher Units 2 and 4 in the Company Base Case?

In running the Base Case scenarios for the Gallagher units, I discovered an error in the Company modeling. The Base Case for each unit compares two scenarios: installing environmental controls at that unit (retrofit) to retiring the unit and replacing it (retire) with either a combustion turbine (in the case of Gallagher and Wabash) or a combined cycle unit (in the case of Cayuga and Gibson). However, in the Base Case scenario that retires Gallagher Unit 2, the replacement combustion turbine (CT) is added to the production cost simulation in PROSYM **without** actually retiring Gallagher 2. This is clear by reviewing the PROSYM output files in which Gallagher 2, with installed pollution controls, continues to operate throughout the planning period. Production costs are thus much higher than they should be with an extraneous unit in the analysis. The same error is made for the Gallagher Unit 4 retirement scenario.

When I corrected this error, the benefit of controlling the Gallagher units decreases substantially. Those results are shown in Table 3, below.

Table 3. Net Benefit of Gallagher Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4
Duke Base Case	[redacted]	[redacted]
Synapse Corrected Case	[redacted]	[redacted]

[redacted]

[redacted]

Table 4. Net Benefit of Gallagher Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4
Synapse Corrected Case	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]

Note that all of the Synapse modeling results that follow include the retirement of Gallagher 2 and 4, as well as the [redacted]

Q. Did the sensitivity scenarios modeled by Duke for Gallagher Units 2 and 4 contain the same error?

A. Yes, the PROSYM output files for the sensitivity scenarios show that the same error was made for Gallagher Units 2 and 4.

Q. Did you run the PROSYM model to correct these errors?

A. No. Time constraints did not allow for me to run PROSYM to correct this error in each of the Gallagher sensitivities.

[1] Confidential Data Response CAC 2.2

B. New Energy Efficiency Savings Drop Significantly after 2019

Q. What do you mean when you say that new energy efficiency savings drop significantly after 2019 in the Company's analysis?

A. In its analysis, Duke assumes no new energy efficiency (EE) savings after 2019. Beginning in 2012, the Company's incremental energy efficiency rises from about 1.0% per year to approximately 1.4% in 2019. After 2020, however, the energy efficiency savings drop to 0.1% per year, as no new EE measures are introduced. My colleague, Dr. Frank Ackerman, describes in more detail the ways in which this assumption is erroneous.

In order to correct for this in the PROSYM modeling runs, we modified the Company's load forecast. We also had to modify the new capacity build-out, as smaller amounts of capacity were needed to maintain the Company's reserve margin. I call this case the "Extended EE Case." Note that this case corrects the Company's error of continuing to run the Gallagher units in the scenarios that should retire them.

Q. How did you adjust the Company's peak load in the Extended EE Case?

A. Duke's load forecasts were provided as part of Data Response 1.79A. In order to arrive at a case with the possibility for slower peak load growth, Synapse assumed half of the annual growth of the Company's peak load (0.6% compared to 1.2% annual growth), which is a conservative assumption. The net peak load matches the Company's net peak load through 2019, but we reasonably assume that peak load growth can be mitigated or grow more slowly after that period. The projections of peak load used in the Extended EE Case are shown in Figure 1, below.

[redacted]

[redacted]

[redacted]

We also adjusted annual energy requirement (MWh) to grow at 0.6 percent per year as a result of new efficiency measures. The forecast of the resulting native load used in the Extended EE Case is shown in Figure 2, below.

[redacted]

Q. How did you revise the Company's capacity build-out for the Synapse Extended EE Case?

A. Confidential Attachment CAC 1.89A contain the assumptions regarding the new capacity that Duke would need to replace retiring units and also to meet future load requirements. We incorporated the load forecast from the Synapse Extended EE Case (shown above) into this analysis and recalculated the capacity that would be necessary under this forecast to maintain the Company's planning reserve margin; the Synapse Extended EE Case maintains the Company's 15% minimum reserve margin in all planning years. These reconstructions of the Company's build-out were done for both the retrofit and retire scenarios for the Gallagher and Cayuga units.

The Extended EE Case resulted in a reduction of between [redacted] and [redacted] MW of new capacity compared to the Company's base case for all scenarios of retrofitting or retiring the Gallagher and Cayuga units. Thus the Company would not need as many new gas CC's and CT's to maintain reserves. The summary of these results is shown below in Table 5.

Table 5. New Capacity (MW) for Duke and Extended EE Cases.

Company scenario	Duke Base	Synapse Base	New Capacity Saved
Control Cayuga 1&2	[redacted]	[redacted]	[redacted]
Retire Cayuga 1	[redacted]	[redacted]	[redacted]
Retire Cayuga 2	[redacted]	[redacted]	[redacted]
Control Gallagher 2&4	[redacted]	[redacted]	[redacted]
Retire Gallagher 2	[redacted]	[redacted]	[redacted]
Retire Gallagher 4	[redacted]	[redacted]	[redacted]

Source: Data Response 1.89A, Synapse

In the Extended EE Case as modeled, the benefits of installing the retrofits at Gallagher 2 drop by [redacted]. The benefits of controlling Gallagher 4 drop by a little less than one-third. The benefits of controlling Cayuga 1 are cut in half, while the benefits of controlling Cayuga 2 decline by about 25 percent. These results are shown in Table 6.

Table 6. Net Benefit of Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4	Cayuga 1	Cayuga 2
Duke Base Case	[redacted]	[redacted]	[redacted]	[redacted]
Corrected Case	[redacted]	[redacted]	[redacted]	[redacted]
Extended EE Case	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

C. Use of a CO_2 Price Forecast on the Low-End of the Utility Range

Q. What do you mean when you say that the Company uses a CO_2 price forecast that is on the low-end of the utility range?

A. Many utilities include forecasts of future CO_2 allowance prices in their forward planning analyses. Synapse has collected utility forecasts from the last two years, and when compared to these other forecasts, the Duke forecast falls into the lower part of the range. Dr. Ackerman provides a more in-depth discussion of Duke's CO_2 allowance price forecast, and provides a graph of the other, publicly available utility price forecasts.

In order to correct for this in the PROSYM modeling runs, we modified the Company's CO_2 price forecast input to use the Synapse Mid CO_2 Forecast. When incorporating this new CO_2 forecast, we also had to modify the market price forecast to reflect the additional CO_2 costs. I call this case the "Mid CO_2 Case."

Q. How did you incorporate higher carbon prices into the market price in the Mid CO_2 Case?

A. Data Response 1.79A contained the market price forecast used by Duke in both its Base Case and its No Carbon Case. We were able to compare the market prices in these two cases, and impute the effect of the Company's carbon prices on its energy market. We then applied the hourly marginal emission rate (in tons of CO_2 per MWh) to the Synapse Mid CO_2 price ($/ton) in a given year in order to arrive at the new energy market prices for the Mid CO_2 Case ($/MWh).

The resulting average annual energy market prices are shown below in Figure 3 (nominal $/MWh). The prices are identical from 2012 through 2019 because there was no assumed carbon price for these years in either case. Market prices are higher in the Synapse Mid CO_2 Case as a result of the increased price of CO_2 allowances in each year.

[redacted]

[redacted]

[redacted]

In the Mid CO_2 Case as modeled, the benefits of installing the retrofits at Gallagher 2 drop by [redacted]. The benefits of controlling Gallagher 4 drop by a little less than one-third. These results are shown in Table 5.

In the Mid CO_2 Case as modeled, the benefits of installing the retrofits at Gallagher 2 drop by [redacted] from the Synapse Corrected Case. The benefits of controlling Gallagher 4 also drop by [redacted] from the Corrected Case. The benefits of controlling Cayuga 1 and 2 tum negative, meaning that it would be a liability to control these units, and that a combined cycle replacement would be more economic. These results are shown in Table 7.

Table 7. Net Benefit of Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4	Cayuga 1	Cayuga 2
Duke Base Case	[redacted]	[redacted]	[redacted]	[redacted]
Synapse Corrected Case	[redacted]	[redacted]	[redacted]	[redacted]
Extended EE Case	[redacted]	[redacted]	[redacted]	[redacted]
Mid CO_2 Case	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

Q. Did you do any additional model runs?

A. Yes. For each of the retrofit and retire scenarios for Gallagher 2 and 4 and Cayuga 1 and 2, I executed model runs using a combination of the Extended EE Case and the Mid CO_2 Case. We believe this combination is a more likely future than the Duke Base Case, and call it the "Synapse Base Case." Those results are shown in Table 8.

Table 8. Net Benefit of Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4	Cayuga 1	Cayuga 2
Duke Base Case	[redacted]	[redacted]	[redacted]	[redacted]
Synapse Corrected Case	[redacted]	[redacted]	[redacted]	[redacted]
Extended EE Case	[redacted]	[redacted]	[redacted]	[redacted]
Mid CO_2 Case	[redacted]	[redacted]	[redacted]	[redacted]
Synapse Base Case (Extended EE + Mid CO_2)	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

5. Concerns with the Duke Modeling Input Assumptions

Q. Did you identify anything in the Company's analysis that you were concerned with but did not correct?

A. Yes, I have several areas of concern with regard to Duke's modeling that I was unable to or did not correct, including:

A. Lack of transparency in the first three pieces of the Duke modeling analysis: the Wood Mackenzie hourly energy price forecast, the proprietary Engineering Screening Model, and the proprietary Integrated Resource Planning Model.

B. A failure to include the capacity associated with the Wabash River Unit 6 natural gas conversion and/or the replacement capacity associated with the RFP for purchased power issued by Duke in February 2012.[2]

C. The retirement dates for Gallagher 2 and 4 in PROSYM for the Base Case retrofit scenario are [redacted] and [redacted], respectively. However, the Company does not include these retirements in its build-out plan.[3] As a result, the necessary replacement capacity does not get added to the calculations of PVRR, nor do the production costs associated with that replacement capacity.

D. The failure to incorporate any additional demand response in the Duke peak load forecast.

E. Difference in dispatch methodology between the Engineering Screening Model and the PROSYM model.

F. The use of an energy price forecast that appears to be too high.

A. Lack of Transparency in Duke Modeling Analysis

Q. Please describe what you mean when you say there was a "lack of transparency in the first three pieces of the Duke modeling analysis."

A. Company Witness Douglas F. Esamann states that Duke's Phase 2 compliance plan is estimated to require a capital investment of $450 million, plus AFUDC

[2] Page 11, lines 1-11 of the Direct Testimony of Robert A. McMurry.
[3] "Prosym Portfolios.xlsx," provided as Confidential Attachment CAC 1.89-A.

estimated at $19 million.[4] The Company is also forecasting future investments of $945 million without AFUDC. Though not seeking recovery for it at this time, this additional $945 million is taken into account in the Company's assessment of the economics of the retrofit of its units compared to their retirement. With almost $1.5 billion in investment capital going into the continued operation of the Duke units, it is critical that any analysis of the economics of this decision be executed thoughtfully and carefully, and that it is subject to check by intervenors and the Commission.

There were four pieces to the Duke modeling analysis, which I have described above. We were given access to only one of the four pieces – the PROSYM modeling – and found one crucial error, several important omissions, and a number of flawed assumptions. Without access to the remaining three pieces of the analysis, neither the Commission nor any intervenors can be confident that there are no other errors that would significantly impact the results of this analysis.

B. Wabash River Replacement

Q. How did the Duke modeling runs fail to include possible capacity from the Wabash River 6 natural gas conversion, and/or from the replacement capacity associated with the RFP?

A. The Company's analysis of the economics of the Wabash River units led to a decision to retire Units 2-5, and the possibility of converting the 318 MW Wabash River Unit 6 to natural gas. Though Duke has not yet made a decision about Wabash River 6, the Duke analysis indicates that the economics of the natural gas conversion are positive. However, in the PROSYM model runs, Wabash Units 2-6 are all retired at the end of 2014, totaling 668 MW of retired capacity. No replacement capacity is added to the Company's generation mix as a result of

[4] Page 19, lines17-19 of the Direct Testimony of Douglas F. Esamann.

these retirements, nor is the gas conversion included in any of the modeling scenarios or sensitivities. Consequently the reserve margin drops from 26.1% in 2014 to 15.2% in 2015. Any retirement that occurs in 2015, then, Duke would need to offset with the addition of new capacity in order to maintain the reserve margin. An analysis of the retirement of the Gallagher or Cayuga units will thus have to include replacement capacity on a MW-for-MW basis. Inclusion of any replacement capacity for Wabash 2-5, or with the natural gas conversion of Wabash Unit 6, Duke could retire both Gallagher 2 and 4 or a portion of the Cayuga unit without the addition of new capacity. Also, because of their low capacity ratings, it might be better for Duke to evaluate the Wabash and Gallagher units in tandem, with their retirement considered together against a larger replacement combined cycle unit, rather than comparing each unit to a combustion turbine on a stand-alone basis.

Similarly, the Company issued an RFP for purchased power for a period of one to three years, largely as a result of the decision to retire Wabash 2-6.[5] According to Mr. McMurry, five bids were received and three are being evaluated further. None of the capacity and energy associated with any of these bids was included in any base or sensitivity analysis evaluating coal unit retrofits/retirements done by the Company.

Had any replacement capacity been included, it very likely would have changed both the capital and production cost components of the Company's analysis, changing the PVRRs for both the retrofit and retire scenarios for the Gallagher and Cayuga units.

[5] Page 11, lines 1-11 of the Direct Testimony of Robert A. McMurry.

C. Gallagher Retirement Dates in the Retrofit Scenario

Q. Please explain what you mean when you say that Duke does not include the retirements of Gallagher 2 and 4 on January 1, 2033 and January 1, 2032, respectively, in its retrofit scenario.

A. The retirement dates for Gallagher 2 and 4 in PROSYM for the Base Case retrofit scenario are [redacted] and [redacted], respectively. This is the case in which both units receive the recommended pollution controls, and is compared against each of the retirement scenarios for the standalone units. However, the Company does not include these retirements in its build-out plan.[6] In order to maintain the appropriate reserve margin, capacity would need to be added as the Gallagher units retire. However, because the retirements are not included in the build-out, the necessary replacement capacity does not get added to the calculations of PVRR, nor do the production costs associated with that replacement capacity.

A natural gas combustion turbine added in 2032 to replace Gallagher 4 would have a net present value of approximately [redacted]. A natural gas combustion turbine added in 2033 to replace Gallagher 2 would have a NPV of approximately [redacted]. Both of these retirements occur in the Duke Base Case retrofit scenario, and should be added to the total capital cost associated with that scenario. Doing so would lead to a decrease in the benefits associated with controlling the Gallagher units. Those results are shown in Table 9.

[6] "Prosym Portfolios.xlsx," provided as Confidential Attachment CAC 1.89-A.

Table 9. Net Benefit of Retrofits (millions of dollars).

	Gallagher 2	Gallagher 4	Cayuga 1	Cayuga 2
Duke Base Case	[redacted]	[redacted]	[redacted]	[redacted]
Synapse Corrected Case	[redacted]	[redacted]	[redacted]	[redacted]
Extended EE Case	[redacted]	[redacted]	[redacted]	[redacted]
Mid CO_2 Case	[redacted]	[redacted]	[redacted]	[redacted]
Synapse Base Case (Extended EE + Mid CO_2)	[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

The Company's PROSYM model runs simulate the period from 2012 to 2032. The study period for the analysis, however, is 2012 to 2034. In the final two years, Duke applies an inflation rate to grow the production costs. This may not accurately represent what the production costs would have been if the PROSYM period had been extended by two years. This is especially true when changes are being made to Duke's capacity mix. Adding in the production costs associated with the new CT replacement capacity would likely lead to an even greater decline in the benefits associated with controlling the Gallagher units.

D. Failure to Include Additional Demand Response

Q. How does the Duke analysis fail to consider additional demand response?

A. As discussed by Dr. Ackerman in his testimony, the estimated potential for demand response is much greater than what is assumed in the Duke analysis. This is important due to the fact that the utility is capacity short but energy long. In any given year in the retirement scenarios, Duke maintains thousands of GWh of market sales and seems to have no issues meeting its native load. Duke does have excess capacity in 2014, with a reserve margin greater than 26%. However, after the retirement of the Wabash units, that excess capacity disappears, and the Company must add additional combined cycle units over the planning period in order to meet peak load. Additional demand response would serve to lower that peak load, and could perhaps offset some of those capacity additions in later years, lowering the total cost to the utility and to consumers.

E. Difference in Dispatch Methodology between Models

Q. How is there a difference in dispatch methodology between the models used by the Company?

A. As described above, Duke's proprietary Engineering Screening Model dispatches the Company's units against the set of market energy prices created by Wood Mackenzie. PROSYM, however, has been set to dispatch the Duke units against the utility's load. The PROSYM simulation is thus just the Duke system, and represents neighboring utilities in an oversimplified way.

Thermal stations are dispatched against load based on their fuel prices and heat rates. This may cause an unrealistic increase in the generation from some of the Duke units, specifically Gallagher 2 and 4. When thermal stations are dispatched against the market, they do not generate electricity in hours when their running costs are higher than the market price, subject to ramping constraints, minimum up and down times, etc. When thermal stations are dispatched against load, they are stacked according to their running costs from low-to-high, and the least-cost generators are dispatched first. Generators in the stack are dispatched, subject to the same operating constraints mentioned above, until the load in a given hour is met. While certainly not the lowest-cost generator in the Duke fleet, the Gallagher units are less expensive to operate than older peaking units in Duke's fleet. When dispatched against load, they would likely generate more than when dispatched against market prices, especially when more efficient units in neighboring utility service territories are bidding in their generation.

Figure 4, below, shows historic capacity factors for the Gallagher units, as well as those capacity factors projected by the PROSYM model.

[redacted]

[redacted]

[redacted]

Gallagher capacity factors are expected to rise slightly in 2013, and then to continue to grow through 2019, when they begin to decline again. These units are aging, and will experience greater operating costs with the installation of pollution control equipment. It seems highly unusual that, absent a spike in natural gas prices, the capacity factors of these units should rise from 5 percent or less in 2012 to 30-35 percent between 2017 and 2019.

Market purchases and sales in PROSYM are assigned a maximum capacity value, designated as "must run," and dispatched against load using the input market energy price forecast provided by Wood Mackenzie to calculate their running cost. When market sales are compared across the retrofit and retirement scenarios for both Cayuga 1 and 2, and Gallagher 2 and 4, we see that volume of sales (in GWh) stays relatively constant across scenarios. These outputs can be seen in Figures 5 and 6, below.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

In the energy market, one might expect that energy sales would adjust as the mix of capacity and fuel in a region changes. It seems possible that in each of these sets of scenarios, as units retire, the more expensive replacement capacity has to generate more than it otherwise would in order to maintain the same sales volume. This would lead to a higher total production cost in the retirement scenarios than would otherwise occur, and bias the output results in favor of the retrofit scenarios. In the real-world energy market, I believe that volume of sales would adjust downward as more expensive gas peaking capacity is added to the generation mix.

F. Wood Mackenzie Market Price Forecast

Q. How was the market energy price forecast developed for the purposes of the Duke analysis?

A. Wood Mackenzie used the Aurora XMP model in a deterministic manner to derive its market energy price forecast, as confirmed in Data Response CAC 2.23. That is, Wood Mackenzie developed base forecasts for a variety of input assumptions, including (but not limited to) fuel prices, potential carbon prices, environmental regulations, load growth, capacity additions and retirements, and economic growth. Wood Mackenzie then estimated a single set of future market prices based on these static assumptions. Deterministic models thus allow for no amount of randomness in their output when using a given set of input values.

Q. Do you agree with this methodology?

A. No. All of the input assumptions listed above are drivers of future energy market prices, and each one is subject to some amount of uncertainty and risk. To use a single forecast for each of these variables to generate a single market price forecast is erroneous.

Q. How would you recommend that energy market prices be determined?

A. The Aurora XMP model has the capability to operate stochastically, meaning that it can incorporate a range of uncertainties and risks and produce a range of potential outcomes. It is, in fact, my understanding that entities obtain and use the Aurora model specifically because it has this capability. Duke should develop reference cases for important input variables like natural gas or CO_2 allowance prices, but the Company should also develop some number of iterations of these forecasts (e.g. 200 iterations). Duke should then run the same number of model iterations in order to determine the energy market price forecast. The Company can then develop a reference case for energy market prices by taking the mean outcome of the distribution of the model iterations.

Q. What is your impression of the Company's market price forecast?

A. The Duke market price forecast seems high when compared to historic market prices and MISO market forward energy prices.

Q. How do recent MISO market prices compare to the cost of running the Company's fleet?

A. In recent years, the MISO market prices have been lower than the running costs for the Gallagher units for a majority of hours, and have been lower than the operating and fuel costs of the Cayuga units in many hours. Figure 7 below shows the operating and fuel costs for the Gallagher and Cayuga units compared to the most recent MISO market prices for the Cinergy Hub. Note that the 2011 increase in the running costs of the Gallagher units is due to the use of low sulfur coal. The units are expected to continue burning low sulfur coal during the study period in the Company's analysis.

[redacted]

[redacted]

Figure 7. Cinergy Hub Forwards Compared to Gallagher and Cayuga Operating and Fuel Costs
(MISO, Confidential Attachment CAC 1.77A)

Because the decision to generate or not is based largely on whether or not the market price (and thus the revenue that can be earned) is higher than a unit's running cost, this indicates that the Gallagher units would not generate for the majority of the year. The Cayuga units would generate more often, but not as much as one might expected from a baseload coal plant. The costs above do not account for capital expenditures (including costs of environmental controls) which would drive running costs even higher.

Q. What are the expectations for MISO market prices in the near future?

A. The NYMEX forward energy prices for the MISO region have the prices remaining low through 2015. Figure 8 below shows recent NYMEX futures for the Cinergy Hub as compared to the Wood Mackenzie market price projection.

[redacted]

[redacted]

Q. Do you have an opinion about the possible drivers of an inflated Wood Mackenzie energy market price forecast?

A. Yes. Projections of the rate of coal capacity retirements in the near term as a result of EPA regulations are greater in the Wood Mackenzie forecast than might actually be expected. Mr. Robert W. Fleck states that the Wood Mackenzie expectation in the Duke Fundamental Forecast is that 49.3 gigawatts (GW) of coal-fired capacity will retire in the United States by 2016, and 57.9 GW will retire by 2030.[7] A comparison of these projections to those from Ventyx, the PROSYM model vendor, shows that the Wood Mackenzie projected retirements are higher by approximately [redacted] in [redacted], as shown in Figure 9, below. While the Wood Mackenzie forecast shows a dramatic spike in number of GW of coal

[7] Page 20, lines 8-10 of the Direct Testimony of Robert W. Fleck.

retired in 2015, and then a very gradual rise through 2030, [redacted]. These forecasts converge around [redacted]. In contrast to the Wood Mackenzie forecast of coal retirements, the Ventyx schedule would likely have a more favorable effect on the upward trajectory of market prices. [redacted].

[redacted]

[redacted]

As mentioned above, Mr. Fleck states that the projected retirements in the Wood Mackenzie price forecast are determined by taking into consideration the CSAPR, MATS, CCR, and 316(b) rules, as well as revisions to the NAAQS.[8] On August 21, 2012, U.S. District of Columbia Circuit Court vacated CSAPR. It is reasonable to assume that a portion of coal capacity retirements were being driven

[8] Page 14, lines 1-23 of the Direct Testimony of Robert W. Fleck.

by CSAPR and the need to install emission control retrofits to lower emissions of SO_2 and NO_x. Because these controls are no longer required due to the vacatur of CSAPR, it is reasonable to assume that a portion of the retirements projected by Wood Mackenzie may not occur.

Assumptions about replacement capacity for retired coal units are significant to an hourly energy market price forecast. Renewable resources operating at variable costs of zero, or close to zero, would lower energy market prices in the hours in which they are operating. Assuming more renewable capacity could displace certain peaking and intermediate units, and thus lead to lower market prices. The assumption that all or most coal-fired generation that retires is replaced with natural gas would not lead to a similar decline in market prices.

6. Evaluation of Duke Environmental Compliance Assumptions

Q. Were you able to review the Company's assumptions about environmental compliance?

A. Yes.

Q. Do you believe that the Company's proposed retrofits for which it is seeking recovery will bring its units into compliance with current pending EPA regulations?

A. Not necessarily. The revised NAAQS for the 8-hour ozone standard are still in flux. In March 2008, EPA strengthened the 8-hour ozone standard from 84 ppb to 75 ppb. On September 16, 2009, EPA announced that because the 2008 standard was not as protective as recommended by EPA's panel of science advisors, it would reconsider the 75 ppb standard. In 2010, EPA proposed lowering the 8-hour ozone standard from 75 ppb to between 60 and 70 ppb. As acknowledged by Company witness Geers, this range is significantly more stringent than the 2008 standard and "would likely drive additional NOx emission reductions."[9] However,

[9] Page 16, lines 17-22 of the Direct Testimony of Michael Geers.

on September 2, 2011, the Administration announced that EPA would not finalize its proposed reconsideration of the 75 ppb standard ahead of the regular 5-year NAAQS review cycle. The next 5-year review for 8-hour ozone is expected in 2013. Compliance with the upcoming standard would likely be required in the 2019-2020 timeframe.

Mr. Geers states that "The vast majority of Indiana...is in attainment with the [current] 75 ppb standard. The potential for EPA to issue a lower standard, possibly in the 60 to 70 ppb range, is still a risk..."[10] If the EPA does in fact issue a standard in the 60 to 70 ppb range, or an even lower standard (in its 2010 proposal, EPA also evaluated a 55 ppb standard[11]), many Indiana counties may be out of attainment with the 8-hour ozone standard, including Floyd County, where the Gallagher Plant is located. If this were to occur, the proposed SNCR retrofits at Gallagher might be insufficient to meet the standard. Some other form of control technology could be required at the units, and would most likely be more expensive from a capital cost perspective than the SNCR. This would negatively affect the economics of controlling Gallagher 2 and 4. The magnitude of that effect would be dependent on the control technology, but it would likely push the analysis in favor of retirement.

The Company also used the Engineering Screening Model to evaluate a "Strict Scenario" that assumes the most stringent combination of potential outcomes of the various EPA regulations.[12] No additional analysis of this scenario was performed. Nonetheless, Mr. Miller states that the retrofit economics would be highly stressed for Cayuga 1 and 2, Gallagher 2 and 4, and Gibson 5. The retrofit economics would be marginal for Gibson 1-4.[13] I believe this Strict Scenario

[10] Page 17, lines 9-11 of the Direct Testimony of Michael Geers.
[11] 75 Fed. Reg. 2938 (January 19, 2010)
[12] Page 22, lines 16-21 of the Direct Testimony of Joseph. A. Miller, Jr.
[13] Page 23, lines 1-3 of the Direct Testimony of Joseph. A. Miller, Jr.

should have been run through all of the steps in the Company's modeling process to properly evaluate, and present, the risks associated with this scenario.

Q. Do you believe that costs of all necessary environmental compliance technologies were included in the Company's analysis, based on the Company's understanding of the current and pending EPA regulations?

A. No, I do not. Two pieces of cost information are missing from the Company's economic analysis – capital and operating costs associated with upgrades of electrostatic precipitators, and capital and operating costs associated with the entrainment provision of the 316(b) cooling water rule. While the Company admits that these control retrofits will likely be necessary, it has left the capital and operating costs out of its analysis.

Installation of activated carbon injection ("ACI") and/or dry sorbent injection ("DSI") for compliance with the MATS rule can lead to additional loading of particulate matter and may necessitate upgrades to existing electrostatic precipitators ("ESPs") at the Duke units. Under the Company's Phase 2 Compliance Plan, the Gallagher and Gibson units will be retrofit with ACI technologies, while the Cayuga units will receive both ACI and DSI systems. Mr. Joseph A. Miller states that current precipitators installed at the units were not designed for the addition of carbon for mercury removal, and "increased particulate loading will most likely require some precipitator enhancement to prevent too much particulate breakthrough to the FGDs."[14] Mr. Miller also states that Duke has not yet had the proper time to fully develop and evaluate the potential ESP improvement alternatives. Thus, any capital and operating costs associated with ESP upgrades that might be needed at any of the units are not included in the Company's economic analysis. Had they been included, it would most likely increase the total PVRR associated with Duke's Base Case retrofit scenarios for each of the units requiring the upgrades.

[14] Page 38, lines 8-10 of the Direct Testimony of Joseph A. Miller, Jr.

EPA's proposed 316(b) cooling water rule has provisions to mitigate the impingement and entrainment of aquatic organisms. In its economic analysis, the Company has included costs associated with the impingement provisions of the rule. These include capital costs for upgrades of fine mesh screens and the installation of fish return systems, as well as O&M for impingement mortality monitoring. According to Mr. Miller, however, Duke has "not included in our analysis any costs for implementing the entrainment provisions of the rule."[15] Mr. Miller states that the "primary risk associated with compliance would be the installation of closed cycle cooling towers." [16] Closed cycle cooling towers are one method of achieving compliance with the entrainment portion of the rule, however, many utilities are claiming that compliance can be achieved through the use of traveling screens and other lower cost, less effective technologies. Duke makes no mention of having evaluated any of these technologies for compliance with the entrainment provision, nor has any capital or operating cost for entrainment compliance been included in the economic analysis. Had these costs been included, it would most likely lead to an increase in the total PVRR associated with Duke's Base Case retrofit scenarios for each of the units requiring the technologies.

Q. Are there any other issues with the Company's environmental compliance that you would like to raise at this time?

A. Yes. Under EPA's Final Tailoring Rule, the largest sources of greenhouse gas emissions are subject to permitting requirements. A "large source" is a new facility with GHG emissions of at least 100,000 tons per year of carbon dioxide equivalent (CO_2e) or an existing facility with at least 100,000 tons per year CO_2e making changes that would increase GHG emissions by at least 75,000 tons per year CO_2e. These sources are required to obtain permits under the New Source

[15] Page 11, lines 1-2 of the Direct Testimony of Joseph A. Miller, Jr.
[16] Page 11, lines 4-5 of the Direct Testimony of Joseph A. Miller, Jr.

Review Prevention of Significant Deterioration and title V Operating Permit programs.

In response to discovery request CAC 2.10, the Company provided Attachment CAC 2.10A, which is the approval of a significant source modification to the Part 70 Operating Permit Renewal for Cayuga Generating Station dated September 5, 2012. This permit authorizes the construction of the Company's Phase 2 SCR, DSI, and ACI projects at the Cayuga Generating Station. The Company indicates that the past actual emissions of CO_2e at the facility are 6,280,278 tons per year.[17] The future projected actual emissions of CO_2e after the installation of the Phase 2 projects at the Cayuga plant will be 7,662,250 tons per year. The Company indicates that this is a net increase in CO2e of 1,582,414 tons per year, or, a 25 percent increase. This significant increase in CO_2e is attributed entirely to "demand growth," with none of the increase attributed to the projects, and so the Company determined that the modification would not trigger PSD compliance. "Demand growth" is not defined in Attachment CAC 2.10 and IDEM did not review this determination.

A nearly 1.6 million ton per year increase in CO_2e is considered significant under the Tailoring Rule and should trigger PSD permitting. The Company's determination that the 25 percent increase in CO_2e emissions is due entirely to demand growth is difficult to understand, especially in light of Duke Energy Indiana's very weak growth forecast. In his testimony, Witness Merino explains that:

> The latest forecast for Duke Energy Indiana points to negative growth between 2012 and 2017 for MWH sales and no growth for MW peaks. The weak outlook in sales is attributable to a slow economic recovery, low levels of new customer additions, the impact of energy efficiency programs, and the

[17] Attachment CAC 2.10, page 090004112-004284 (page 196 of the .pdf file).

expiration of wholesale backstand contracts associated with the Gibson 5 ownership.[18]

PROSYM results for the Company's Base Case retrofit scenario for the Cayuga units do not indicate a sustained increase in the capacity factors of the units subsequent to the retrofit projects. The projected capacity factors of the units are shown in Figure 10, below.

[redacted]

[redacted]

[redacted]

The Cayuga capacity factors do increase early in the planning period, but begin to decline beginning 2017. It does not appear as though load growth is in fact leading to a sustained increase in the energy output of the Cayuga units, nor to the increase in CO_2e emissions that is projected in the Operating Permit.

The use of Trona as a sorbent in DSI systems, on the other hand, can lead to significant increases in CO_2 emissions. The additional energy requirements of the

[18] Page 7, lines 5-9 of the Direct Testimony of Jose I. Merino.

new controls can also lead to increased CO_2e emissions, though on a smaller scale.

I believe that the Company should provide justification for the decision not to obtain a PSD permit for GHGs as required by the Tailoring Rule. The increase in CO_2e emissions that is projected in the Operating Permit is not reflected in the PROSYM output associated with the retrofit of the units. If these increases are truly expected to occur, they will cause a significant rise in the production cost between 2020 and 2034, when the CO_2 emissions allowance pricing regime is expected to be in effect.

7. Conclusions

Q. Please summarize your conclusions.

A. Based on my review, I conclude that the errors and flawed assumptions present in the Duke modeling analysis causes the Company to overstate the benefits associated with the continued operations of Cayuga 1 and 2 and Gallagher 2 and 4. After correcting for the modeling errors and updating the input assumptions, we see that the net benefits of installing emission controls at these units decline dramatically, and disappear entirely under many scenarios. Thus, I conclude that the modeling performed by Duke and the underlying assumptions, when corrected, do not appear to support the installation of pollution controls on Gallagher Units 2 and 4 and Cayuga Units 1 and 2.

Q. Does this conclude your direct testimony?

A. Yes.

VERIFICATION

I, Rachel S. Wilson, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Rachel Wilson ______________________ 11/29/12 ______________________

Rachel S. Wilson   Date

EXHIBIT RW-1

Rachel Wilson

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. Associate, 2010 – present, Research Associate, 2008 – 2010.

- Performs consulting, conducts research, and assists in writing testimony and reports on a wide range of issues relating to electric utilities, including: federal and state clean air policies; emissions from electricity generation; environmental compliance technologies, strategies, and costs; integrated resource planning; valuation of environmental externalities from power plants; and the nexus between water and energy.
- Uses optimization and electricity dispatch models, including Strategist, PROMOD, PROSYM/Market Analytics, and PLEXOS to conduct analyses of utility service territories and regional energy markets.

Analysis Group, Inc., Boston, MA. Associate, Energy Practice, 2007 - 2008.

- Supported an expert witness asked to opine on various topics in the electric industry as they applied to merchant generators and provided incentives for their behavior in the late 1990s and early 2000s.
- Analyzed data related to coal production on Indian land and contractual royalties paid to the tribe over a 25 year period to determine if discrepancies exist between these values for the purposes of potential litigation.
- Examined Canadian policies relating to carbon dioxide, and assisted with research on linkage of international tradable permit systems.
- Managed analysts' work processes and evaluated work products.

Senior Analyst Intern, Energy Practice, 2006 - 2007.

- Supported an expert witness in litigation involving whether a defendant power company could financially absorb a greater investment in pollution control under its debt structure while still offering competitive rates. Analyzed impacts of federal and state clean air laws on energy generators and providers. Built a quantitative model showing the costs of these clean air policies to the defendant over a 30 year period. Built a financial model calculating impacts of various pollution control investment requirements.
- Researched the economics of art; assisted in damage calculations in arbitration between an artist and his publisher.

Yale Center for Environmental Law and Policy, New Haven, CT. Research Assistant, 2005 – 2007.

- Gathered and managed data for the Environmental Performance Index, presented at the 2006 World Economic Forum. Interpreted statistical output, wrote critical analyses of results, and edited report drafts.
- Part of the team that produced *Green to Gold*, an award-winning book on corporate environmental management and strategy. Managed data, conducted research, and implemented marketing strategy.

CERES, Boston, MA. Student Consultant, Spring 2006.

- As part of a four-person team, made strategic recommendations on all aspects of messaging and engagement to encourage corporate directors to act on the issue of climate change. First strategic recommendation was sustainable governance forums, which were profiled in New York Times article "Global Warming Subject for Directors at Big Companies" on September 21, 2006.

Marsh Risk and Insurance Services, Inc., Los Angeles, CA. Risk Analyst, Casualty Department, 2003 – 2005.

- Evaluated Fortune 500 clients' risk management programs/requirements and formulated strategic plans and recommendations for customized risk solutions.
- Supported the placement of $2 million in insurance premiums in the first year and $3 million in the second year.
- Utilized quantitative models to create loss forecasts, cash flow analyses and benchmarking reports.
- Completed a year-long Graduate Training Program in risk management; ranked #1 in the western region of the US and shared #1 national ranking in a class of 200 young professionals.

EDUCATION

Yale School of Forestry & Environmental Studies, Master of Environmental Management, New Haven, Connecticut, 2007.
Concentration in Law, Economics, and Policy with a focus on energy issues and markets.

Claremont McKenna College, Bachelor of Arts in Environment, Economics, Politics (EEP) Claremont, California, 2003.
cum laude and EEP departmental honors.

School for International Training Quito, Ecuador. Spring 2002.
Semester abroad studying Comparative Ecology. Microfinance Intern – Viviendas del Hogar de Cristo in Guayaquil, Ecuador.

SKILLS AND ACCOMPLISHMENTS

Microsoft Office Suite, Lexis-Nexis, Platts Energy Database, Strategist, PROMOD, PROSYM/Market Analytics, and PLEXOS, some SAS and STATA.
Competent in oral and written Spanish.
Hold the Associate in Risk Management (ARM) professional designation.

PUBLICATIONS AND PRESENTATIONS

Wilson R., P. Luckow, B. Biewald, F. Ackerman, and E.D. Hausman. *2012 Carbon Dioxide Price Forecast.* Prepared by Synapse Energy Economics, October 4, 2012.

Hornby, R., R. Fagan, D. White, J. Rosenkranz, P. Knight, and R. Wilson. *Potential Impacts of Replacing Retiring Coal Capacity in the Midwest Independent System Operator (MISO) Region with Natural Gas or Wind Capacity.* Prepared for the Iowa Utilities Board. September 14, 2012.

Fagan, R., M. Chang, P. Knight, M. Schultz, T. Comings, E. Hausman, and R. Wilson. *The Potential Rate Effects of Wind Energy and Transmission in the Midwest ISO Region.* Prepared for the Energy Future Coalition. May 22, 2012.

Wilson, R. *Comments Regarding MidAmerican Energy Company Filing on Coal-Fired Generation in Iowa.* Prepared for the Iowa Office of the Consumer Advocate. December 15, 2011.

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Johnston, L., E. Hausman., B. Biewald, R. Wilson, and D. White. *2011 Carbon Dioxide Price Forecast.* February 11, 2011.

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Peterson, P., V. Sabodash, R. Wilson, and D. Hurley. *Public Policy Impacts on Transmission Planning.* Prepared for Earthjustice, December 21, 2010.

Fisher, J., S. Levy, Y. Nishioka, P. Kirshen, R. Wilson, M. Chang, J. Kallay, and C. James. *Co-Benefits of Energy Efficiency and Renewable Energy in Utah.* Prepared for the State Energy Office of Utah, March 2010.

Wilson, R. "The Energy-Water Nexus: Interactions, Challenges, and Policy Solutions." Presented at the National Drinking Water Symposium 2009, October 2009.

Fisher, J., C. James, L. Johnston, D. Schlissel, R. Wilson, *Energy Future: A Green Alternative for Michigan.* Prepared for Natural Resources Defense Council and Energy Foundation, August 2009.

Schlissel, D., R. Wilson, L. Johnston, D. White, *An Assessment of Santee Cooper's 2008 Resource Planning.* April 2009.

Schlissel, D., A. Smith, R. Wilson, *Coal-Fired Power Plant Construction Costs.* July 2008.

TESTIMONY

Kentucky Public Service Commission. Direct testimony before the Commission on behalf of the Sierra Club. Testimony included discussion of STRATEGIST modeling relating to the application of Kentucky Power Company for a Certificate of Public Convenience and Necessity, and for approval of its 2011 environmental compliance plan and amended environmental cost recovery surcharge. March 12, 2012.

Kentucky Public Service Commission. Direct testimony before the Commission on behalf of Sierra Club and Natural Resources Defense Council. Testimony included discussion of STRATEGIST modeling relating to the applications of Kentucky Utilities Company, and Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity, and approval of its 2011 compliance plan for recovery by environmental surcharge. September 16, 2011.

Minnesota Public Utilities Commission. Rebuttal testimony before the Commission on behalf of Izaak Walton League of America, Fresh Energy, Sierra Club, and Minnesota Center for Environmental Advocacy. Testimony described STRATEGIST modeling performed in the docket considering Otter Tail Power's application for an Advanced Determination of Prudence for BART retrofits at its Big Stone plant. September 7, 2011.

EXHIBIT RW-2

CAC
IURC Cause No. 44217
Data Request Set No. 2
Received: October 29, 2012

CAC 2.3

Request:

Please refer to data response OUCC 7.2.

a. Please confirm the retirement dates for all units.
b. Given that the "environmental control equipment proposed in this proceeding is expected to last until the units are retired," please explain why the Company used a study period of 2012 through 2034 for its Economic Analysis.

Objection:

Duke Energy Indiana objects to subpart (a) as vague and ambiguous, particularly as to its use of the word "confirm."

Response:

Subject to and without waiving its objections, Duke Energy Indiana responds as follows:

a. Duke Energy Indiana hereby confirms the retirement dates contained in the Company's response to OUCC 7.2. As noted in that response, these are the dates contained in the most recent depreciation study filed in Cause No. 43114 IGCC 4S1.
b. For its proposed Phase 2 plan equipment, Duke Energy Indiana used a 20-year planning period from the final MATS rule compliance year of 2015. Using a 20-year period for such economic analysis is routine, and consistent with capital project planning.

Witness: Kent Freeman / Robert A. McMurry

CAC
IURC Cause No. 44217
Data Request Set No. 2
Received: October 29, 2012

CAC 2.4

Request:

Please refer to data response CAC 1.21. Please provide the Company's calculations and workpapers supporting the undepreciated book value by unit.

Response:

See Attachment CAC 2.4-A.

Witness: Kent K. Freeman

Duke Energy
US FE&G NBV/Retirement Analysis Summary
As of 6/30/2012

ATTACHMENT CAG-2-A

Unit	In-Service Date	Estimated Retirement	Gross Cost (millions)	COR Reserve	Allocated Total Accumulated Depreciation (millions)	Estimated Net Book Value (millions)	Allocated Net Book Value (Grossed up for COR)
			ESTIMATED NET BOOK VALUE				
	A	B	C (Note 1)	C1	D (Note 1)	E = C - D	E1 = C1 + E
Cayuga 1	10/4/1970	6/30/2030	217 0	4 2	46 3	170 7	174 9
Cayuga 2	6/22/1972	6/30/2032	225 6	6.5	51 8	173 8	179 3
Cayuga Common	10/4/1978	6/30/2032	357 4	23 0	192 5	164 9	187 6
			800 9	32 8	290 6	509 5	542 1
Edwardsport 6	7/18/1944	6/30/2012	0 3	3 9	3 4	(3 1)	(0 1)
Edwardsport 7	1/30/1949	6/30/2012	0 3	3 4	3 6	(3 5)	(0 1)
Edwardsport 8	12/9/1851	6/30/2012	0 6	5 6	8 4	(5 9)	(0 2)
			1 2	12 0	13 7	(12 5)	(0 5)
Gallagher 1	6/15/1959	6/30/2018	0 0	0.0	0 0	0 0	0 0
Gallagher 2	12/1/1958	6/30/2016	23 0	0 9	6 1	14 9	15 6
Gallagher 3	4/15/1960	6/30/2020	8 0	0 8	0 0	8 0	0 0
Gallagher 4	3/1/1961	6/30/2021	29 5	0 9	7 1	22 4	23 3
Gallagher Common	12/1/1958	6/30/2019	150 2	16 3	94 0	56 2	72 5
			202 2	18.2	109 3	03 5	111 6
Gibson 1	5/3/1976	6/30/2036	269 4	12 9	86 8	182 8	185.5
Gibson 2	4/16/1975	6/30/2035	280.0	18.1	118.1	169 9	186 0
Gibson 3	3/28/1978	6/30/2038	340 6	19 3	133 5	297 3	226 6
Gibson 4	3/27/1979	6/30/2039	130.5	11.6	63 6	66 7	78 3
Gibson 5	10/1/1982	6/30/2042	311 6	30 6	150 7	160 9	191.8
Gibson Common	4/18/1975	6/30/2038	1,345 9	131 7	720 7	825 3	757 0
			2,678 3	222 5	1,265 6	1,412 7	1,635 2
Wabash River 2	8/1/1953	6/30/2013	12 8	2 6	11 7	1 1	3 7
Wabash River 3	9/1/1954	6/30/2014	1 6	8 1	0 4	1.2	1.3
Wabash River 4	1/1/1955	6/30/2015	155 6	20 3	126 2	29 3	49 6
Wabash River 5	5/1/1956	6/30/2016	1 6	0 1	0 6	1 0	1 1
Wabash River 6	0/1/1968	6/30/2028	115.2	12.9	61 1	34 1	47 1
Wabash River Common 2-5	8/1/1953	6/30/2016	104 8	10 4	64 7	20 0	30 4
Wabash River Common 2-6	9/1/1954	6/30/2015	5 6	9 3	1 7	3 9	4 2
			397 1	40 7	306 4	89 7	137 4
Total Steam Production			4,079.2	332 0	1,995.5	2,093 6	2,425 6
Not Station Specific			0 0	0 9	0 8	0 0	8 8
Total Steam Production			4,879 2	332 0	1,985 5	2,093 8	2,425 6
ARO's			24 9	0 0	13 8	11 0	N/A
Total Indiana Steam			4,104.1	332.0	1,999 4	2,194.7	2,425.8
Connersville Common	1972	6/30/2012	12 6	0 7	10 5	2 1	2 7
Cayuga Diesel 3	1672	6/30/2012	1 8	(0 1)	1 4	6 4	0 3
Cayuga CT 4	1993	6/30/2028	51 6	3 5	36 2	15 4	18 9
Henry County CT 1 (Cadiz)	2001	6/30/2041	75 0	(0 1)	23 1	51 6	51 7
Henry County CT 2 (Cadiz)	2001	6/30/2041	0 0	0 0	0 0	0 0	0 9
Henry County CT 3 (Cadiz)	2001	6/30/2041	0 0	0 0	0 0	8 0	0 0
Henry County CT 1-3 (Cadiz)	2001	6/30/2041	6.8	0 0	0 2	0 6	0.6
Madison CT 1	2000	6/30/2040	314 7	1.4	116 0	195 6	197 1
Madison CT 1-8	2000	6/30/2040	6 3	(0 0)	(0.2)	8 5	8.5
Miami Wabash Peak Station	1968	6/30/2012	14 6	1.2	13 7	6 9	2 1
Noblesville CT Common	2003	6/30/2038	234.3	(1.5)	79.2	155 0	153 8
Vermilion CT 1-8	2000	6/30/2031	158.2	(0.1)	55.8	103 4	103 3
Wheatland CT Common 1-4	2000	6/30/2040	93 3	(0 1)	17 7	75 6	76 5
Wabash River Diesel 7	1967	6/30/2015	0 6	0 0	8 6	(0 0)	(0 0)
Total Other Production			956 9	4.9	357 5	601 8	606 4
Not Station Specific			0 0	0 0	0 0	6.0	0 9
Total Other Production			956 0	4 9	357 5	601.5	606 4
ARO's			0 6	0 0	0 3	0 3	N/A
Total Indiana Other			858 6	4.8	357.8	601.7	606 4

Note 1.	Cost, CWIP, Depreciation, and Reserve amounts for the Carolinas and Edwardsport are maintained at the Station level, rather than the Unit level. As such, Cost, CWIP, and Depreciation Expense are allocated to the individual units based on their proportion of MW output. Reserve is allocated based on Theoretical Reserve (column N) All Midwest data except Edwardsport is maintained at the Unit level, so no allocation is necessary.
Note 2.	Analysis does not include non-utility assets (such as non-utility land, DFD profit, Gallagher baghouse amounts over regulatory threshold, etc.) or ARO assets/accumulated depreciation.

IDEM

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 5, 2012

RE: Duke Energy Indiana / 165-32045-00001

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

Notice of Decision: Approval - Effective Immediately

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 13-15-5-3, this permit 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.

If you wish to challenge this decision, IC 4-21.5-3 and IC 13-15-6-1 require 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
FNPER.dot12/03/07

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Mitchell E. Daniels, Jr.
Governor

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Mr. Patrick Coughlin
Duke Energy Indiana - Gallagher Generating Station
1000 East Main Street
Plainfield, IN 46168

September 5, 2012

Re: 165-32045-00001
Significant Source Modification to
Part 70 Renewal No.: T 165-27260-00001

Dear Mr. Coughlin:

Duke Energy Indiana - Cayuga Generating Station was issued a Part 70 Operating Permit Renewal on August 20, 2012 for an electric utility generating station. A letter requesting changes to this permit was received on June 26, 2012. Pursuant to 326 IAC 2-7-10.5 the following emission units are approved for construction at the source:

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boilar No. 1, installed in 1967, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Boiler No. 1 was configured with a low NO_X burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activatad Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boilar No. 2, installed in 1968, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) and sulfur dioxida (SO_2) end a continuous opacity monitor (COM). Boiler No. 2 was configured with a low NO_X burner in 1993.Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg amissions scheduled to be installed by 2015

(c) One (1) Arsenic Mitigation System consisting of (1) 700 ton Limestone Storage Silo and (1) 300 ton Limestone Surge Bin, scheduled to be installed by 2015. Limestona is pneumatically conveyed from delivery trucks to the Limastone Storage Silo end from the Limestone Storage Silo to the Limestone Surge Bin. Limastona in the Surge Bin is dropped on to the C-1 and C-2 coal convayors. PM emissions generated during pnaumatic conveying and trensfer points to the C-1 and C-2 conveyor will be controllad by tha bin vent filters. The Limestone Storage Silo and Limestona Surga Bin are identifiad as emissions points EP-01(LS) and EP-02(LS).

(d) Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of (2) two Sorbent Storage Silos with a storage capacity of 120 tons and system to inject the sorbent material into the flue gas, scheduled to be installed by 2015. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo. The four (4) Sorbent Silos are identified as emission points EP-01(DSI), EP-02(DSI, EP-03(DSI), and EP-04(DSI).

(e) Two (2) Activated Carbon Injection (ACI) Systems, one for each Unit. Each ACI system consists of one (1) storage silo with a 80 ton storage capacity and system for injecting the Activated Carbon into the flue gas, scheduled to be installed by 2015. PM emissions during the silo loading operation are controlled by the bin vent filters located on top of the silos. The two (2) Activated Carbon Storage Silos are identified as emission points EP-01(ACI) and EP-02(ACI).

(f) Two (2) Dry Ash Handling Systems, one for each Unit. The dry ash handling system consists of a pneumatic conveying system, four (4) baghouse separators, two (2) ash silos with a storage capacity of 3,500 each and an ash unloading system, scheduled to be installed by 2015.

(i) Baghouse Separators - Fly ash from the ESP Ash Hoppers, Air Heater Ash Hoppers, Economizer Ash Hoppers and SCR Large Particle Screen Ash Hopper will be pneumatically conveyed to one of four (4) baghouse separators. There will be two (2) baghouse separators for each unit. The dry fly ash is separated from the air stream in a baghouse separator. Each baghouse separator are identified as emissions points EP-01(DFA), EP--02(DFA), EP-03(DFA), and EP-04(DFA). The system is equipped with a spare exhauster identified as emissions point EP-05(DFA).

(ii) Ash Silos - Fly ash collected in the baghouse separators is dropped into a feeder and pneumatically conveyed to one of two (2) ash silos. Each ash silo is equipped with a bin vent filter to control particulate matter emissions from pneumatic conveying. The Ash Silos are identified as emission point EP-06(DFA) and EP-07(DFA).

(iii) Ash Unloading Operation - Fly ash collected in the silos can be unloaded into trucks or pneumatically conveyed to the ash fixation process. Fly ash unloaded into trucks can be unloaded dry or wet. Fly ash unloaded dry is gravity feed to a chute and unloaded into enclosed trucks. The emissions generated from unloading the ash dry are vented back to the silo and controlled by the silo bin vent filter. Ash unloaded wet is feed into a pin mixer where the ash is mixed with water and unloaded into open trucks

(g) One (1) Ash Fixation Process consisting of a pneumatic conveying system, one (1) ash day bin, one (1) lime silo, conveyors, and two (2) pin mixers, scheduled to be installed by 2015.

(i) Fly Ash Day Bin - Fly ash from the ash silos can be pneumatically conveyed to the day bin. The storage capacity of the day bin is 500 tons. The emissions generated from pneumatic conveyance will be controlled by a bin vent filter located on top of the fly ash day bin. The Fly Ash Day Bin is identified as emissions point EP-01(FIX).

(ii) Lime Silo – Lime will be delivered by truck and will pneumatically loaded into the silo. The storage capacity of the silo is 300 tons. The emissions generated by the pneumatic conveying will be controlled by a bin vent filter located on top of the lime silo. The Lime Silo is identified as emissions point EP-02(FIX).

(iii) Conveyor and Transfer Points – Fty ash, Lime and Gypsum will be conveyed to one of two (2) pin mixers where this material will be mixed with water to make the fixated ash. The fixated ash will be unloaded to a storage pile, and then loaded into trucks using front end loaders

The following construction conditions are applicable to the proposed project:

General Construction Conditions

1. The data and information supplied with the application shall be considered part of this source modification approval Prior to any proposed change in construction which may affect the potential to emit (PTE) of the proposed project, the change must be approved by the Office of Air Quality (OAQ)

2. This approval to construct does not relieve the permittee of the responsibility to comply with the provisions of the Indiana Environmental Management Law (IC 13-11 through 13-20; 13-22 through 13-25; and 13-30), the Air Pollution Control Law (IC 13 17) and the rules promulgated thereunder, as well as other applicable local, state, and federal requirements

3. Effective Date of the Permit
Pursuant to IC 13-15-5-3, this approval becomes effective upon its issuance.

4. Pursuant to 326 IAC 2-1.1-9 and 326 IAC 2-7-10.5(i), the Commissioner may revoke this approval if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is suspended for a continuous period of one (1) year or more.

5. All requirements and conditions of this construction approval shall remain in effect unless modified in a manner consistent with procedures established pursuant to 326 IAC 2.

6. Pursuant to 326 IAC 2-7-10 5(l) the emission units constructed under this approval shall not be placed into operation prior to revision of the source's Part 70 Operating Permit to incorporate the required operation conditions

This significant source modification authorizes construction of the new emission units. Operating conditions shall be incorporated into the Part 70 operating permit as a significant permit modification in accordance with 326 IAC 2-7-10.5(l)(2) and 326 IAC 2-7-12. Operation is not approved until the significant permit modification has been issued.

All other conditions of the permit shall remain unchanged and in effect. For your convenience, the entire Part 70 Operating Permit as modified will be provided at issuance.

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 Josiah Balogun, OAQ, 100 North Senate Avenue, MC 61-53, Room 1003, Indianapolis, Indiana, 46204-2251, or call at (800) 451-6027, and ask for Josiah Balogun or extension (4-5257), or dial (317) 234-5257.

Sincerely,

Tripurari Sinha

Tripurari P. Sinha, Ph.D., Section Chief
Permits Branch
Office of Air Quality

Attachments:
Updated Permit
Technical Support Document
PTE Calculetions

JB

cc: File – Vermillion County
Vermillion County Health Department
U.S. EPA, Region V
Compliance and Enforcement Branch

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Significant Source Modification to a Part 70 Operating Permit
OFFICE OF AIR QUALITY

Duke Energy, Inc. - Cayuga Generating Station
State Road 63
Cayuga, Indiana 47928

(herein known as the Permittee) is hereby authorized to construct subject to the conditions contained herein, the source described in Section A (Source Summary) of this permit.

This permit is issued in accordance with 326 IAC 2 and 40 CFR Part 70 Appendix A and contains the conditions and provisions specified in 326 IAC 2-7 as required by 42 U S C 7401, et. seq (Clean Air Act as amended by the 1990 Clean Air Act Amendments), 40 CFR Part 70 6, IC 13-15 and IC 13-17. This permit also addresses certain new source review requirements for existing equipment and is intended to fulfill the new source review procedures pursuant to 326 IAC 2-7-10 5, applicable to those conditions.

Significant Source Modification No.: 165-32045-00001	
Original signed by: Tripurari Sinha Tripurari P. Sinha, Ph. D., Section Chief Permits Branch Office of Air Quality	Issuance Date. September 5, 2012

TABLE OF CONTENTS

SECTION A SOURCE SUMMARY

This permit 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 through A.3 is descriptive information and does not constitute enforceable conditions. However, the Permittee 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 Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary electric utility generating station.

Source Address:	State Road 63, Cayuga, Indiana 47928
General Source Phone Number:	(317) 838-2108
SIC Code:	4911
County Location:	Vermillion
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(14)]

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

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Boiler No. 1 was configured with a low NO_X burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Boiler No. 2 was configured with a low NO_X burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

(c) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3A, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3A.

(d) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3B, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3B.

(e) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3C, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3C.

(f) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3D, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3D.

(g) A dual conveyor coal processing system, with a nominal throughput of 1900 tons of coal per hour (950 tons of coal per hour each side), consisting of the following equipment:

(1) One (1) railcar unloading station, with a drop point to two (2) hoppers identified as DP-1, with the drop point enclosed with emissions uncontrolled, and exhausting to the ambient air.

(2) One (1) storage area, having a nominal storage capacity including the active piles of 982,800 tons, with fugitive emissions controlled as needed by a watering truck.

(3) One (1) enclosed hopper, with a drop point to a conveyor identified as DP-2, with the drop point enclosed with emissions controlled by a water spray dust suppression system as needed, and exhausting to the ambient air.

(4) One (1) enclosed hopper and two (2) reclaim feeders, with an underground drop points identified as DP-11 and DP-12, with emissions controlled by the underground enclosure, and routed to the conveyor system.

(5) An enclosed dual conveyor system, with 6 drop points identified as DP-3 through DP-6, DP-8, and DP-13, with each drop point enclosed with emissions controlled by the enclosure. Drop points DP-3 through DP-5, DP-8, and DP-13 are controlled as needed by a water spray dust suppression system, and DP-6 is controlled by rotoclones.

(6) An enclosed conveyor system with drop point identified as DP-9, controlled by a telescoping chute.

(7) Coal bunker and coal scale exhausts and associated dust collector vents.

(h) One (1) limestone handling and storage system for the flue gas desulfurization system, constructed in 2006, with a maximum throughput rate of 1,000 tons per hour, consisting of the following:

(1) One (1) railcar/truck unloading operation, with a maximum capacity of 1,000 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L1.

(2) Two (2) hoppers, each with a maximum capacity of 500 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L2.

(3) Two (2) belt feeders, identified as LHBF-1 and LHBF-2, each with a maximum capacity of 500 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L2.

(4) One (1) conveyor, identified as LH-1, controlled by a telescopic chute, and exhausting to emission point EP-L3. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(5) One (1) active limestone stockout pile, with a maximum capacity of 7,700 tons.

(6) One (1) inactive limestone storage pile, with a maximum capacity of 45,000 tons.

(7) Two (2) reclaim hoppers, each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.

(8) Two (2) belt feeders, identified as LHBF-3 and LHBF-4, each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.

(9) One (1) conveyor, identified as LH-2, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission point EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(10) One (1) reversible conveyor, identified as LH-3, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression. The emissions exhaust out the general building vents, identified as emission points EP-L18a and EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(11) Two (2) day bins, each with a maximum throughput rate of 400 tons per hour. Each bin is equipped with a Baghouse to control particulate emissions. Baghouses BH-L1 and BH-L2 exhaust to EP-L16 and EP-L17, respectively. Under NSPS, Subpart OOO, these units considered storage bins.

(12) Two (2) wet ball mills, each with a maximum capacity of 51 tons of limestone slurry per hour. Under NSPS, Subpart OOO, these units are considered grinding mills.

(i) One (1) gypsum handling and storage system, constructed in 2006, consisting of the following:

(1) One (1) wet gypsum conveying system, with a maximum throughput rate of 150 tons per hour.

(2) Two (2) gypsum stock out piles. Gypsum can be stocked out to an outside pile or a pile located in the gypsum stock out building. The maximum gypsum storage capacity is 10,400 tons.

(3) One (1) emergency gypsum stockout pile, with a maximum capacity of 2,600 tons.

(4) One (1) dry gypsum transferring operation, transferring gypsum to landfills by trucks on paved roads.

(j) Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968.

(k) One (1) Arsenic Mitigation System consisting of (1) 700 ton Limestone Storage Silo and (1) 300 ton Limestone Surge Bin, scheduled to be installed by 2015. Limestone is pneumatically conveyed from delivery trucks to the Limestone Storage Silo and from the Limestone Storage Silo to the Limestone Surge Bin. Limestone in the Surge Bin is dropped on to the C-1 and C-2 coal conveyors. PM emissions generated during pneumatic conveying and transfer points to the C-1 and C-2 conveyor will be controlled by the bin vent filters. The Limestone Storage Silo and Limestone Surge Bin are identified as emissions points EP-01(LS) and EP-02(LS).

(l) Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of (2) two Sorbent Storage Silos with a storage capacity of 120 tons and system to inject the sorbent material into the flue gas, scheduled to be installed by 2015. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo. The four (4) Sorbent Silos are identified as emission points EP-01(DSI), EP-02(DSI, EP-03(DSI), and EP-04(DSI).

(m) Two (2) Activated Carbon Injection (ACI) Systems, one for each Unit. Each ACI system consists of one (1) storage silo with a 80 ton storage capacity and system for injecting the Activated Carbon into the flue gas, scheduled to be installed by 2015. PM emissions during the silo loading operation are controlled by the bin vent filters located on top of the silos. The two (2) Activated Carbon Storage Silos are identified as emission points EP-01(ACI) and EP-02(ACI).

(n) Two (2) Dry Ash Handling Systems, one for each Unit. The dry ash handling system consists of a pneumatic conveying system, four (4) baghouse separators, two (2) ash silos with a storage capacity of 3,500 each and an ash unloading system, scheduled to be installed by 2015.

(i) Baghouse Separators - Fly ash from the ESP Ash Hoppers, Air Heater Ash Hoppers, Economizer Ash Hoppers and SCR Large Particle Screen Ash Hopper will be pneumatically conveyed to one of four (4) baghouse separators. There will be two (2) baghouse separators for each unit. The dry fly ash is separated from the air stream in a baghouse separator. Each baghouse separator are identified as emissions points EP-01(DFA), EP--02(DFA), EP-03(DFA), and EP-04(DFA). The system is equipped with a spare exhauster identified as emissions point EP-05(DFA).

(ii) Ash Silos - Fly ash collected in the baghouse separators is dropped into a feeder and pneumatically conveyed to one of two (2) ash silos. Each ash silo is equipped with a bin vent filter to control particulate matter emissions from pneumatic conveying. The Ash Silos are identified as emission point EP-06(DFA) and EP-07(DFA).

(iii) Ash Unloading Operation - Fly ash collected in the silos can be unloaded into trucks or pneumatically conveyed to the ash fixation process. Fly ash unloaded into trucks can be unloaded dry or wet. Fly ash unloaded dry is gravity feed to a chute and unloaded into enclosed trucks. The emissions generated from unloading the ash dry are vented back to the silo and controlled by the silo bin vent filter. Ash unloaded wet is feed into a pin mixer where the ash is mixed with water and unloaded into open trucks

(o) One (1) Ash Fixation Process consisting of a pneumatic conveying system, one (1) ash day bin, one (1) lime silo, conveyors, and two (2) pin mixers, scheduled to be installed by 2015.

(i) Fly Ash Day Bin - Fly ash from the ash silos can be pneumatically conveyed to the day bin. The storage capacity of the day bin is 500 tons. The emissions generated from pneumatic conveyance will be controlled by a bin vent filter located on top of the fly ash day bin. The Fly Ash Day Bin is identified as emissions point EP-01(FIX).

(ii) Lime Silo – Lime will be delivered by truck and will pneumatically loaded into the silo. The storage capacity of the silo is 300 tons. The emissions generated by the pneumatic conveying will be controlled by a bin vent filter located on top of the lime silo. The Lime Silo is identified as emissions point EP-02(FIX).

(iii) Conveyor and Transfer Points – Fly ash, Lime and Gypsum will be conveyed to one of two (2) pin mixers where this material will be mixed with water to make the fixated ash. The fixated ash will be unloaded to a storage pile, and then loaded into trucks using front end loaders.

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)] [326 IAC 2-7-4(c)] [326 IAC 2-7-5(14)]

This stationary source also includes the following insignificant activities which are specifically regulated, as defined in 326 IAC 2-7-1(21):

(a) Degreasing operations that do not exceed one hundred forty-five (145) gallons per twelve months, except if subject to 326 IAC 20-6.

(b) One 156.9 HP (100 kW), CI ICE with a displacement 4.4 liters, Diesel Fired Emergency Generator, Manufactured by Caterpillar Model Year 2007, Model D100-6, constructed in 2007, identified as ENG-1. This generator is located in the switch yard and is operated as backup for the black start diesel aux feed.

(c) One 713 Hp (450 kW), CI ICE with a displacement 15.2 liters, Diesel Fired Emergency Engine, Manufactured by Caterpillar, Model Year 2007, Model C15DITA, constructed in 2007, identified as ENG-2. This engine is use to quench the flue gas if the scrubber should fail.

A.4 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

(c) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3);

SECTION B GENERAL CONDITIONS

B.1 Definitions [326 IAC 2-7-1]

Terms in this permit 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 2-7) shall prevail.

B.2 Permit Term [326 IAC 2-7-5(2)][326 IAC 2-1.1-9.5][326 IAC 2-7-4(a)(1)(D)][IC 13-15-3-6(a)]

(a) The Part 70 Operating Permit, T 165-27260-00001, is issued for a fixed term of five (5) years, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

(b) If IDEM, OAQ, upon receiving a timely and complete renewal permit application, fails to issue or deny the permit renewal prior to the expiration date of this permit, this existing permit shall not expire and all terms and conditions shall continue in effect, including any permit shield provided in 326 IAC 2-7-15, until the renewal permit has been issued or denied.

B.3 Term of Conditions [326 IAC 2-1.1-9.5]

Notwithstanding the permit term of a permit to construct, a permit to operate, or a permit modification, any condition established in a permit issued pursuant to a permitting program approved in the state implementation plan shall remain in effect until:

(a) the condition is modified in a subsequent permit action pursuant to Title I of the Clean Air Act; or

(b) the emission unit to which the condition pertains permanently ceases operation.

B.4 Enforceability [326 IAC 2-7-7] [IC 13-17-12]

Unless otherwise stated, all terms and conditions in this permit, including any provisions designed to limit the source's potential to emit, are enforceable by IDEM, the United States Environmental Protection Agency (U.S. EPA) and by citizens in accordance with the Clean Air Act.

B.5 Severability [326 IAC 2-7-5(5)]

The provisions of this permit are severable; a determination that any portion of this permit is invalid shall not affect the validity of the remainder of the permit.

B.6 Property Rights or Exclusive Privilege [326 IAC 2-7-5(6)(D)]

This permit does not convey any property rights of any sort or any exclusive privilege.

B.7 Duty to Provide Information [326 IAC 2-7-5(6)(E)]

(a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. Upon request, the Permittee shall also furnish to IDEM, OAQ copies of records required to be kept by this permit.

(b) For information furnished by the Permittee to IDEM, OAQ, the Permittee may include a claim of confidentiality in accordance with 326 IAC 17.1. When furnishing copies of requested records directly to U. S. EPA, the Permittee may assert a claim of confidentiality in accordance with 40 CFR 2, Subpart B.

B.8 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]

(a) A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:

(i) it contains a certification by a "responsible official", as defined by 326 IAC 2-7-1 (34), and

(ii) the certification is based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) The Permittee may use the attached Certification Form, or its equivalent with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.

(c) A "responsible official" is defined at 326 IAC 2-7-1(34).

B.9 Annual Compliance Certification [326 IAC 2-7-6(5)]

(a) The Permittee shall annually submit a compliance certification report which addresses the status of the source's compliance with the terms and conditions contained in this permit, including emission limitations, standards, or work practices. All certifications shall cover the time period from January 1 to December 31 of the previous year, and shall be submitted no later than July 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, Indiana 46204-2251

and

United States Environmental Protection Agency, Region V
Air and Radiation Division, Air Enforcement Branch - Indiana (AE-17J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

(b) The annual compliance certification report required by this permit 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.

(c) The annual compliance certification report shall include the following:

(1) The appropriate identification of each term or condition of this permit that is the basis of the certification;

(2) The compliance status;

(3) Whether compliance was continuous or intermittent;

(4) The methods used for determining the compliance status of the source, currently and over the reporting period consistent with 326 IAC 2-7-5(3); and

(5) Such other facts, as specified in Sections D of this permit, as IDEM, OAQ may require to determine the compliance status of the source.

The submittal by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(12)][326 IAC 1-6-3]

(a) A Preventive Maintenance Plan meets the requirements of 326 IAC 1-6-3 if it includes, at a minimum:

(1) Identification of the individual(s), by title or classification, responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification end quantification of the replacement parts that will be maintained in inventory for quick replacement.

The Permittee shall implement the PMPs.

(b) If required by specific condition(s) in Section D of this permit where no PMP was previously required, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this permit or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee's control, the PMPs cannot be prepared and maintained within the time frame specified in Section D, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

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

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(d) To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

B.11 Emergency Provisions [326 IAC 2-7-16]

(a) An emergency, as defined in 326 IAC 2-7-1(12), is not an affirmative defense for an action brought for noncompliance with a federal or state health-based emission limitation.

(b) An emergency, as defined in 326 IAC 2-7-1(12), constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the affirmative defense of an emergency is demonstrated through properly signed, contemporaneous operating logs or other relevant evidence that describe the following:

(1) An emergency occurred and the Permittee can, to the extent possible, identify the causes of the emergency;

(2) The permitted facility was at the time being properly operated;

(3) During the period of an emergency, the Permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in this permit;

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, no later than four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or
Telephone Number: 317-233-0178 (ask for Compliance and Enforcement Branch)
Facsimile Number: 317-233-6865

(5) For each emergency lasting one (1) hour or more, the Permittee submitted the attached Emergency Occurrence Report Form or its equivalent, either by mail or facsimile 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

no later than two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-7-5(3)(C)(ii) and must contain the following:

(A) A description of the emergency;

(B) Any steps taken to mitigate the emissions; and

(C) Corrective actions taken.

The notification which shall be submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(6) The Permittee immediately took all reasonable steps to correct the emergency.

(c) In any enforcement proceeding, the Permittee seeking to establish the occurrence of an emergency has the burden of proof.

(d) This emergency provision supersedes 326 IAC 1-6 (Malfunctions). This permit condition is in addition to any emergency or upset provision contained in any applicable requirement.

(e) The Permittee seeking to establish the occurrence of an emergency shall make records available upon request to ensure that failure to implement a PMP did not cause or contribute to an exceedance of any limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4(c)(9) be revised in response to an emergency.

(f) Failure to notify IDEM, OAQ by telephone or facsimile of an emergency lasting more than one (1) hour in accordance with (b)(4) and (5) of this condition shall constitute a violation of 326 IAC 2-7 and any other applicable rules.

(g) If the emergency situation causes a deviation from a technology-based limit, the Permittee may continue to operate the affected emitting facilities during the emergency provided the Permittee immediately takes all reasonable steps to correct the emergency and minimize emissions.

B.12 Permit Shield [326 IAC 2-7-15][326 IAC 2-7-20][326 IAC 2-7-12]

(a) Pursuant to 326 IAC 2-7-15, the Permittee has been granted a permit shield. The permit shield provides that compliance with the conditions of this permit shall be deemed compliance with any applicable requirements as of the date of permit issuance, provided that either the applicable requirements are included and specifically identified in this permit or the permit contains an explicit determination or concise summary of a determination that other specifically identified requirements are not applicable. The Indiana statutes from IC 13 and rules from 326 IAC, referenced in conditions in this permit, are those applicable at the time the permit was issued. The issuance or possession of this permit shall not alone constitute a defense against an alleged violation of any law, regulation or standard, except for the requirement to obtain a Part 70 permit under 326 IAC 2-7 or for applicable requirements for which a permit shield has been granted.

This permit shield does not extend to applicable requirements which are promulgated after the date of issuance of this permit unless this permit has been modified to reflect such new requirements.

(b) If, after issuance of this permit, it is determined that the permit is in nonconformance with an applicable requirement that applied to the source on the date of permit issuance, IDEM, OAQ, shall immediately take steps to reopen and revise this permit and issue a compliance order to the Permittee to ensure expeditious compliance with the applicable requirement until the permit is reissued. The permit shield shall continue in effect so long as the Permittee is in compliance with the compliance order.

(c) No permit shield shall apply to any permit term or condition that is determined after issuance of this permit to have been based on erroneous information supplied in the permit application. Erroneous information means information that the Permittee knew to be false, or in the exercise of reasonable care should have been known to be false, at the time the information was submitted.

(d) Nothing in 326 IAC 2-7-15 or in this permit shall alter or affect the following:

(1) The provisions of Section 303 of the Clean Air Act (emergency orders), including the authority of the U.S. EPA under Section 303 of the Clean Air Act;

(2) The liability of the Permittee for any violation of applicable requirements prior to or at the time of this permit's issuance;

(3) The applicable requirements of the acid rain program, consistent with Section 408(a) of the Clean Air Act; and

(4) The ability of U.S. EPA to obtain information from the Permittee under Section 114 of the Clean Air Act.

(e) This permit shield is not applicable to any change made under 326 IAC 2-7-20(b)(2) (Sections 502(b)(10) of the Clean Air Act changes) and 326 IAC 2-7-20(c)(2) (trading based on State Implementation Plan (SIP) provisions).

(f) This permit shield is not applicable to modifications eligible for group processing until after IDEM, OAQ, has issued the modifications. [326 IAC 2-7-12(c)(7)]

(g) This permit shield is not applicable to minor Part 70 permit modifications until after IDEM, OAQ, has issued the modification. [326 IAC 2-7-12(b)(8)]

B.13 Prior Permits Superseded [326 IAC 2-1.1-9.5][326 IAC 2-7-10.5]

(a) All terms and conditions of permits established prior to T 165-27260-00001 and issued pursuant to permitting programs approved into the state implementation plan have been either:

(1) incorporated as originally stated,

(2) revised under 326 IAC 2-7-10.5, or

(3) deleted under 326 IAC 2-7-10.5.

(b) Provided that all terms and conditions are accurately reflected in this permit, all previous registrations and permits are superseded by this Part 70 operating permit, except for permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control)

B.14 Termination of Right to Operate [326 IAC 2-7-10][326 IAC 2-7-4(a)]

The Permittee's right to operate this source terminates with the expiration of this permit unless a timely and complete renewal application is submitted at least nine (9) months prior to the date of expiration of the source's existing permit, consistent with 326 IAC 2-7-3 and 326 IAC 2-7-4(a).

B.15 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification,

revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit.
[326 IAC 2-7-5(6)(C)] The notification by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(b) This permit shall be reopened and revised under any of the circumstances listed in IC 13-15-7-2 or if IDEM, OAQ determines any of the following:

(1) That this permit contains a material mistake.

(2) That inaccurate statements were made in establishing the emissions standards or other terms or conditions.

(3) That this permit must be revised or revoked to assure compliance with an applicable requirement. [326 IAC 2-7-9(a)(3)]

(c) Proceedings by IDEM, OAQ to reopen and revise this permit shall follow the same procedures as apply to initial permit issuance and shall affect only those parts of this permit for which cause to reopen exists. Such reopening and revision shall be made as expeditiously as practicable. [326 IAC 2-7-9(b)]

(d) The reopening and revision of this permit, under 326 IAC 2-7-9(a), shall not be initiated before notice of such intent is provided to the Permittee by IDEM, OAQ at least thirty (30) days in advance of the date this permit is to be reopened, except that IDEM, OAQ may provide a shorter time period in the case of an emergency. [326 IAC 2-7-9(c)]

B.16 Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

(b) A timely renewal application is one that is:

(1) Submitted at least nine (9) months prior to the date of the expiration of this permit; and

(2) 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.

(c) If the Permittee submits a timely and complete application for renewal of this permit, the source's failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ takes final action on the renewal application, except that this protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit by the deadline specified, pursuant to 326 IAC 2-7-4(a)(2)(D), in writing by IDEM, OAQ any additional information identified as being needed to process the application.

B.17 Permit Amendment or Modification [326 IAC 2-7-11][326 IAC 2-7-12] [40 CFR 72]

(a) Permit amendments and modifications are governed by the requirements of 326 IAC 2-7-11 or 326 IAC 2-7-12 whenever the Permittee seeks to amend or modify this permit.

(b) Pursuant to 326 IAC 2-7-11(b) and 326 IAC 2-7-12(a), administrative Part 70 operating permit amendments and permit modifications for purposes of the acid rain portion of a Part 70 permit shall be governed by regulations promulgated under Title IV of the Clean Air Act. [40 CFR 72]

(c) Any application requesting an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application shall be certified by the "responsible official" as defined by 326 IAC 2-7-1(34).

(d) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.18 Permit Revision Under Economic Incentives and Other Programs [326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]

(a) No Part 70 permit revision or notice shall be required under any approved economic incentives, marketable Part 70 permits, emissions trading, and other similar programs or processes for changes that are provided for in a Part 70 permit.

(b) Notwithstanding 326 IAC 2-7-12(b)(1) and 326 IAC 2-7-12(c)(1), minor Part 70 permit modification procedures may be used for Part 70 modifications involving the use of economic incentives, marketable Part 70 permits, emissions trading, and other similar approaches to the extent that such minor Part 70 permit modification procedures are explicitly provided for in the applicable State Implementation Plan (SIP) or in applicable requirements promulgated or approved by the U.S. EPA.

B.19 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b) or (c) without a prior permit revision, if each of the following conditions is met:

(1) The changes are not modifications under any provision of Title I of the Clean Air Act;

(2) Any preconstruction approval required by 326 IAC 2-7-10.5 has been obtained;

(3) The changes do not result in emissions which exceed the limitations provided in this permit (whether expressed herein as a rate of emissions or in terms of total emissions);

(4) The Permittee notifies the:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

United States Environmental Protection Agency, Region V
Air and Radiation Division, Regulation Development Branch - Indiana (AR-18J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

in advance of the change by written notification at least ten (10) days in advance of the proposed change. The Permittee shall attach every such notice to the Permittee's copy of this permit; and

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-7-20(b) or (c). The Permittee shall make such records available, upon reasonable request, for public review.

Such records shall consist of all information required to be submitted to IDEM, OAQ in the notices specified in 326 IAC 2-7-20(b)(1), (c)(1), and (e)(2).

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(36)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

(1) A brief description of the change within the source;

(2) The date on which the change will occur;

(3) Any change in emissions; and

(4) Any permit term or condition that is no longer applicable as a result of the change.

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(c) Emission Trades [326 IAC 2-7-20(c)]
The Permittee may trade emissions increases and decreases at the source, where the applicable SIP provides for such emission trades without requiring a permit revision, subject to the constraints of Section (a) of this condition and those in 326 IAC 2-7-20(c).

(d) Alternative Operating Scenarios [326 IAC 2-7-20(d)]
The Permittee may make changes at the source within the range of alternative operating scenarios that ere described in the terms and conditions of this permit in accordance with 326 IAC 2-7-5(9). No prior notification of IDEM, OAQ, or U.S. EPA is required.

(e) Backup fuel switches specifically addressed in, and limited under, Section D of this permit shall not be considered alternative operating scenarios. Therefore, the notification requirements of part (a) of this condition do not apply.

(f) This condition does not apply to emission trades of SO_2 or NO_X under 326 IAC 21.

B.20 Source Modification Requirement [326 IAC 2-7-10.5]

A modification, construction, or reconstruction is governed by the requirements of 326 IAC 2.

B.21 Inspection and Entry [326 IAC 2-7-6][IC 13-14-2-2][IC 13-30-3-1][IC 13-17-3-2]

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a Part 70 source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

(b) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, have access to and copy any records that must be kept under the conditions of this permit;

(c) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, inspect any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;

(d) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, sample or monitor substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) As authorized by the Clean Air Act, IC 13-14-2-2, IC 13-17-3-2, and IC 13-30-3-1, utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

B.22 Transfer of Ownership or Operational Control [326 IAC 2-7-11]

(a) The Permittee must comply with the requirements of 326 IAC 2-7-11 whenever the Permittee seeks to change the ownership or operational control of the source and no other change in the permit is necessary.

(b) Any application requesting a change in the ownership or operational control of the source shall contain a written agreement containing a specific date for transfer of permit responsibility, coverage and liability between the current and new Permittee. The application shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

The application which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(c) The Permittee may implement administrative amendment changes addressed in the request for an administrative amendment immediately upon submittal of the request. [326 IAC 2-7-11(c)(3)]

B.23 Annual Fee Payment [326 IAC 2-7-19] [326 IAC 2-7-5(7)][326 IAC 2-1.1-7]

(a) The Permittee shall pay annual fees to IDEM, OAQ within thirty (30) calendar days of receipt of a billing. Pursuant to 326 IAC 2-7-19(b), if the Permittee does not receive a bill from IDEM, OAQ the applicable fee is due April 1 of each year.

(b) Except as provided in 326 IAC 2-7-19(e), failure to pay may result in administrative enforcement action or revocation of this permit.

(c) The Permittee may call the following telephone numbers: 1-800-451-6027 or 317-233-4230 (ask for OAQ, Billing, Licensing, and Training Section), to determine the appropriate permit fee.

B.24 Credible Evidence [326 IAC 2-7-5(3)][326 IAC 2-7-6][62 FR 8314] [326 IAC 1-1-6]

For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any emission limitation, standard or rule, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether the Permittee would have been in compliance with the condition of this permit if the appropriate performance or compliance test or procedure had been performed.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

Emission Limitations and Standards [326 IAC 2-7-5(1)]

C.1 Particulate Emission Limitations For Processes with Process Weight Rates Less Than One Hundred (100) Pounds per Hour [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2(e)(2), particulate emissions from any process not exempt under 326 IAC 6-3-1(b) or (c) which has a maximum process weight rate less than 100 pounds per hour and the methods in 326 IAC 6-3-2(b) through (d) do not apply shall not exceed 0.551 pounds per hour.

C.2 Opacity [326 IAC 5-1]

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

(a) Opacity shall not exceed an average of forty percent (40%) 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.3 Open Burning [326 IAC 4-1] [IC 13-17-9]

The Permittee shall not open burn any material except as provided in 326 IAC 4-1-3, 326 IAC 4-1-4 or 326 IAC 4-1-6. The previous sentence notwithstanding, the Permittee may open burn in accordance with an open burning approval issued by the Commissioner under 326 IAC 4-1-4.1.

C.4 Incineration [326 IAC 4-2] [326 IAC 9-1-2]

The Permittee shall not operate an incinerator except as provided in 326 IAC 4-2 or in this permit. The Permittee shall not operate a refuse incinerator or refuse burning equipment except as provided in 326 IAC 9-1-2 or in this permit.

C.5 Fugitive Dust Emissions [326 IAC 6-4]

The Permittee 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). 326 IAC 6-4-2(4) is not federally enforceable.

C.6 Fugitive Particulate Matter Emission Limitations [326 IAC 6-5]

Pursuant to 326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations), fugitive particulate matter emissions shall be controlled according to the submitted plan. The plan is included as Attachment A.

C.7 Stack Height [326 IAC 1-7]

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted by using ambient air quality modeling pursuant to 326 IAC 1-7-4. The provisions of 326 IAC 1-7-1(3), 326 IAC 1-7-2, 326 IAC 1-7-3(c) and (d), 326 IAC 1-7-4, and 326 IAC 1-7-5(a), (b), and (d) are not federally enforceable.

C.8 Asbestos Abatement Projects [326 IAC 14-10] [326 IAC 18] [40 CFR 61, Subpart M]

The Permittee shall comply with the applicable requirements of 326 IAC 14-10, 326 IAC 18, and 40 CFR 61.140.

Testing Requirements [326 IAC 2-7-6(1)]

C.9 Performance Testing [326 IAC 3-6]

(a) For performance testing required by this permit, a test protocol, except as provided elsewhere in this permit, shall be submitted 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

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ if the Permittee submits to IDEM, OAQ a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period. The extension request submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

Compliance Requirements [326 IAC 2-1.1-11]

C.10 Compliance Requirements [326 IAC 2-1.1-11]

The commissioner may require stack testing, monitoring, or reporting at any time to assure compliance with all applicable requirements by issuing an order under 326 IAC 2-1.1-11. Any monitoring or testing shall be performed in accordance with 326 IAC 3 or other methods approved by the commissioner or the U. S. EPA.

Compliance Monitoring Requirements [326 IAC 2-7-5(1)][326 IAC 2-7-6(1)]

C.11 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)]

(a) Unless otherwise specified in this permit, for all monitoring requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or of initial start-up, whichever is later, to begin such monitoring. If due to circumstances beyond the Permittee's control, any monitoring equipment required by this permit cannot be installed and operated no later than ninety (90) days after permit issuance or the date of initial startup, whichever is later, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:

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

in writing, prior to the end of the initial ninety (90) day compliance schedule, with full justification of the reasons for the inability to meet this date.

The notification which shall be submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a source modification shall be implemented when operation begins.

(b) For monitoring required by CAM, at all times, the Permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(c) For monitoring required by CAM, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

C.12 Instrument Specifications [326 IAC 2-1.1-11] [326 IAC 2-7-5(3)] [326 IAC 2-7-6(1)]

(a) When required by any condition of this permit, an analog instrument used to measure a parameter related to the operation of an air pollution control device shall have a scale such that the expected maximum reading for the normal range shall be no less than twenty percent (20%) of full scale.

(b) The Permittee may request that the IDEM, OAQ approve the use of an instrument that does not meet the above specifications provided the Permittee can demonstrate that an alternative instrument specification will adequately ensure compliance with permit conditions requiring the measurement of the parameters.

Corrective Actions and Response Steps [326 IAC 2-7-5][326 IAC 2-7-6]

C.13 Emergency Reduction Plans [326 IAC 1-5-2] [326 IAC 1-5-3]

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee shall maintain the most recently submitted written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) Upon direct notification by IDEM, OAQ that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

C.14 Risk Management Plan [326 IAC 2-7-5(11)] [40 CFR 68]

If a regulated substance, as defined in 40 CFR 68, is present at a source in more than a threshold quantity, the Permittee must comply with the applicable requirements of 40 CFR 68.

C.15 Response to Excursions or Exceedances [326 IAC 2-7-5] [326 IAC 2-7-6]

Upon detecting an excursion where a response step is required by the D Section or an exceedance of a limitation in this permit:

(a) The Permittee shall take reasonable response steps to restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing excess emissions.

(b) The response shall include minimizing the period of any startup, shutdown or malfunction The response may include, but is not limited to, the following:

(1) initial inspection and evaluation;

(2) recording that operations returned to normal without operator action (such as through response by a computerized distribution control system); or

(3) any necessary follow-up actions to return operation to normal or usual manner of operation.

(c) A determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include, but is not necessarily limited to, the following:

(1) monitoring results;

(2) review of operation and maintenance procedures and records; and/or

(3) inspection of the control device, associated capture system, and the process.

(d) Failure to take reasonable response steps shall be considered a deviation from the permit.

(e) The Permittee shall record the reasonable response steps taken.

(II)

(a) CAM *Response to excursions or exceedances.*

(1) Upon detecting an excursion or exceedance, subject to CAM, the Permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by

excused startup or shutdown conditions). Such actions may include initial inspection end evaluation, recording that operations retumed to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(2) Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

(b) If the Permittee identifies a failure to achieve compliance with an emission limitation, subject to CAM, or standard, subject to CAM, for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the IDEM, OAQ and, if necessary, submit a proposed significant permit modification to this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

(c) Based on the results of a determination made under paragraph (II)(a)(2) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a QIP. The Permittee shall develop and implement a QIP if notified to in writing by the EPA or IDEM, OAQ.

(d) Elements of a QIP:
The Permittee shall maintain a written QIP, if required, and have it available for inspection. The plan shall conform to 40 CFR 64.8 b (2).

(e) If a QIP is required, the Permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the IDEM, OAQ if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(f) Following implementation of a QIP, upon any subsequent determination pursuant to paragraph (II)(a)(2) of this condition the EPA or the IDEM, OAQ may require that the Permittee make reasonable changes to the QIP if the QIP is found to have:

(1) Failed to address the cause of the control device performance problems; or

(2) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(g) Implementation of a QIP shall not excuse the Permittee from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(h) *CAM recordkeeping requirements.*

(1) The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to paragraph (II)(a)(2) of this condition and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this condition (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions). Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

(2) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such altemative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements.

C.16 Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall submit a description of its response actions to IDEM, OAQ, no later than seventy-five (75) days after the date of the test.

(b) A retest to demonstrate compliance shall be performed no later than one hundred eighty (180) days after the date of the test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred eighty (180) days is not practicable, IDEM, OAQ may extend the retesting deadline.

(c) IDEM, OAQ reserves the authority to take any actions allowed under law in response to noncompliant stack tests.

The response action documents submitted pursuant to this condition do require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

C.17 Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit **no later than** July 1 of each year an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

(a) Indicate estimated actual emissions of all pollutants listed in 326 IAC 2-6-4(a);

(b) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(32) ("Regulated pollutant, which is used only for purposes of Section 19 of this rule") from the source, for purpose of fee assessment.

The statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue

MC 61-50 IGCN 1003
Indianapolis, Indiana 46204-2251

The emission statement does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

C.18 General Record Keeping Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-6] [326 IAC 2-2][326 IAC 2-3]

(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following:

(AA) All calibration and maintenance records.

(BB) All original strip chart recordings for continuous monitoring instrumentation.

(CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following:

(AA) The date, place, as defined in this permit, and time of sampling or measurements.

(BB) The dates analyses were performed.

(CC) The company or entity that performed the analyses.

(DD) The analytical techniques or methods used.

(EE) The results of such analyses.

(FF) The operating conditions as existing at the time of sampling or measurement.

These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Unless otherwise specified in this permit, for all record keeping requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or the date of initial start-up, whichever is later, to begin such record keeping.

(c) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A), 326 IAC 2-2-8 (b)(6)(B), 326 IAC 2-3-2 (l)(6)(A), and/or 326 IAC 2-3-2 (l)(6)(B)) that a "project" (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Before beginning actual construction of the "project" (as defined in

326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, document and maintain the following records:

(A) A description of the project.

(B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project.

(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:

(i) Baseline actual emissions;

(ii) Projected actual emissions;

(iii) Amount of emissions excluded under section 326 IAC 2-2-1(pp)(2)(A)(iii) and/or 326 IAC 2-3-1 (kk)(2)(A)(iii): and

(iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.

(d) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A) and/or 326 IAC 2-3-2 (l)(6)(A)) that a "project" (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (1)(B) above; and

(2) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) years following resumption of regular operations after the change if the project increases the design capacity of or the potential to emit that regulated NSR pollutant at the emissions unit.

C.19 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2] [40 CFR 64][326 IAC 3-8]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B –Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

On and after the date by which the Permittee must use monitoring that meets the requirements of 40 CFR Part 64 and 326 IAC 3-8, the Permittee shall submit CAM reports to the IDEM, OAQ.

A report for monitoring under 40 CFR Part 64 and 326 IAC 3-8 shall include, at a minimum, the information required under paragraph (a) of this condition and the following information, as applicable:

(1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(3) A description of the actions taken to implement a QIP during the reporting period as specified in Section C-Response to Excursions or Exceedances. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

The Permittee may combine the Quarterly Deviation and Compliance Monitoring Report and a report pursuant to 40 CFR 64 and 326 IAC 3-8.

(b) The address for report submittal is:

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

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit 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.

(d) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.

(e) If the Permittee is required to comply with the recordkeeping provisions of (d) in Section C - General Record Keeping Requirements for any "project" (as defined in 326 IAC 2-2-1 (oo) and/or 326 IAC 2-3-1 (jj)) at an existing emissions unit, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:

(1) The annual emissions, in tons per year, from the project identified in (c)(1) in Section C- General Record Keeping Requirements exceed the baseline actual emissions, as documented and maintained under Section C- General Record Keeping Requirements (c)(1)(C)(i), by a significant amount, as defined in

326 IAC 2-2-1 (ww) and/or 326 IAC 2-3-1 (pp), for that regulated NSR pollutant, and

(2) The emissions differ from the preconstruction projection as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(ii).

(f) The report for project at an existing emissions unit shall be submitted no later than sixty (60) days after the end of the year and contain the following:

(1) The name, address, and telephone number of the major stationary source.

(2) The annual emissions calculated in accordance with (d)(1) and (2) in Section C - General Record Keeping Requirements.

(3) The emissions calculated under the actual-to-projected actual test stated in 326 IAC 2-2-2(d)(3) and/or 326 IAC 2-3-2(c)(3).

(4) Any other information that the Permittee wishes to include in this report such as an explanation as to why the emissions differ from the preconstruction projection.

Reports required in this part shall be submitted 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

(g) The Permittee shall make the information required to be documented and maintained in accordance with (c) in Section C- General Record Keeping Requirements available for review upon a request for inspection by IDEM, OAQ. The general public may request this information from the IDEM, OAQ under 326 IAC 17.1.

Stratospheric Ozone Protection

C.20 Compliance with 40 CFR 82 and 326 IAC 22-1

Pursuant to 40 CFR 82 (Protection of Stratospheric Ozone), Subpart F, except as provided for motor vehicle air conditioners in Subpart B, the Permittee shall comply with the standards for recycling and emissions reduction.

Ambient Monitoring Requirements [326 IAC 7-3]

C.21 Ambient Monitoring [326 IAC 7-3]

(a) The Permittee shall operate continuous ambient sulfur dioxide air quality monitors and a meteorological data acquisition system according to a monitoring plan submitted to the commissioner for approval. The monitoring plan shall include requirements listed in 326 IAC 7-3-2(a)(1), 326 IAC 7-3-2(a)(2) and 326 IAC 7-3-2(a)(3).

(b) The Permittee and other operators subject to the requirements of this rule, located in the same county, may submit a joint monitoring plan to satisfy the requirements of this rule. [326 IAC 7-3-2(c)]

(c) The Permittee may petition the commissioner for an administrative waiver of all or some of the requirements of 326 IAC 7-3 if such owner or operator can demonstrate that ambient monitoring is unnecessary to determine continued maintenance of the sulfur dioxide ambient air quality standards in the vicinity of the source. [326 IAC 7-3-2(d)]

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Boiler No. 1 was configured with a low NO_X burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

(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 2-7-5(1)]

D.1.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

The Particulate Matter emissions from Boiler #1 shall be limited to 0.227 lbs/MMBtu. Compliance with this limit satisfies the requirements of 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating). This emissions limit is based on the historic Particulate Matter emission limit established under 326 IAC 6-2-3.

D.1.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3(e) (Temporary Alternative Opacity Limitations), the following applies:

(1) When building a new fire in Boiler No. 1, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed three (3) hours (30 six minute-averaged periods) or until the flue gas temperature entering the electrostatic precipitator (ESP) reaches 250 degrees Fahrenheit, whichever occurs first.

(2) When shutting down a boiler, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed three (3) hours (30 six minute-averaged periods) or until the flue gas temperature entering the electrostatic precipitator (ESP) has dropped below 250 degrees Fahrenheit.

(3) Operation of the electrostatic precipitator is not required during these times.

(b) Firing a boiler as part of the chemical cleaning operations of the boiler and its associated tubes is considered a "startup condition" pursuant to 326 IAC 1-2-76 and subject to the exemptions as set forth in D.1.2(a).

(c) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed the applicable limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of the applicable limit shall not continue for more than one (1) six (6)-minute averaging periods in any sixty (60) minute period. The averaging periods shall not be permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period.

(d) Permittee is also allowed one start up and one shut down per calendar year as follows:

(i) When building a new fire in a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed a total of seven (7) hours (seventy (70) six (6)-minute averaging periods, consecutive or non-consecutive) or until the flue gas temperature reaches two hundred fifty (250) degrees Fahrenheit, whichever occurs first.

(ii) When shutting down a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed a total of five (5) hours (fifty (50) six (6)-minute averaging periods, consecutive or non-consecutive).

D.1.3 Sulfur Dioxide (SO_2) [326 IAC 7-4-8] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-4-8 (Vermillion County Sulfur Dioxide Emission Limitations), the SO_2 emissions from Boiler No. 1 shall not exceed 4.40 pounds per million Btu (lbs/MMBtu), demonstrated using a thirty (30) day weighted rolling average. This limitation will ensure that SO_2 emissions do not exceed the amount assumed in the modeling analysis performed for the Vermillion County SO_2 SIP limits.

D.1.4 Operational Standards [326 IAC 2-1.1-5(a)(4)]

(a) All coal burned, including coal treated with any additive, shall meet the ASTM definition of coal.

(b) Any boiler or condenser tube chemical cleaning waste liguids fired in the boiler shall only contain the cleaning solution and two full volume boiler rinses.,

D.1.5 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.1.6 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

In order to determine compliance with the PM limitation, the Permittee shall perform PM testing for the pulverized coal-fired boiler, identified as Boiler No. 1, any time during calendar year 2011 utilizing methods as approved by the Commissioner. This test shall be repeated at least once every two (2) calendar years following this valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

D.1.7 Operation of Electrostatic Precipitator and Flue Gas Desulfurization (FGD) [326 IAC 2-7-6(6)]

(a) Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator shall be operated at all times that Boiler No. 1 is in operation and combusting solid fuel or any combination of solid fuels or other fuels.

(b) Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system shall be operated as needed to maintain compliance with applicable SO_2 emission limits.

D.1.8 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)] [40 CFR 64]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment. For a boiler, the COMS shall be in operation at all times that the induced draft fan is in operation.

(b) All COMS shall meet the performance specifications of 40 CFR 60, Appendix B, Performance Specification No. 1, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5.

(c) In the event that a breakdown of a COMS occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(d) Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS, the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to self-monitor the emissions from the emission unit stack.

(1) Visible emission readings shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, for a minimum of five (5) consecutive six (6) minute averaging periods beginning not more than twenty-four (24) hours after the start of the malfunction or down time.

(2) Method 9 opacity readings shall be repeated for a minimum of five (5) consecutive six (6) minute averaging periods at least twice per day during daylight operations, with at least four (4) hours between each set of readings, until a COMS is online.

(3) Method 9 readings may be discontinued once a COMS is online.

(4) Any opacity exceedances determined by Method 9 readings shall be reported with the Quarterly Opacity Exceedances Reports.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous opacity monitoring system pursuant to 326 IAC 3-5, (and 40 CFR 60 and/or 40 CFR 63).

D.1.9 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)] [40 CFR 64]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment as specified in Section D.

(b) All continuous emission monitoring systems shall meet all applicable performance specifications of 40 CFR 60, 40 CFR 75 or any other performance specification, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(d) Whenever a continuous emission monitor other than an opacity monitor is malfunctioning or will be down for calibration, maintenance, or repairs, the following shall be used as an alternative to continuous data collection:

(1) If the CEM is required for monitoring NO_x or SO_2 emissions pursuant to 40 CFR 75 (Title IV Acid Rain program) or 326 IAC 24 (SO_2 and NO_x Trading Program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D- Missing Data Substitution Procedures.

(2) If the CEM is not used to monitor NO_x or SO_2 emissions pursuant to 40 CFR 75 or 326 IAC 24 (SO_2 and NO_x Trading Program), then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 40 CFR 60, Subpart GG 326 IAC 3-5, 40 CFR 60 or 40 CFR 75.

D.1.10 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 2-7-5(A)] [326 IAC 2-7-6] [326 IAC 7-2]

(a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions from Unit 1 do not exceed the equivalents of the limits specified in Conditions D.1.3 (Sulfur Dioxide (SO_2)) using a thirty (30) day rolling weighted average.

(b) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7, coal sampling and analysis data shall be collected as follows:

(1) Coal sampling shall be performed using the methods specified in 326 IAC 3-7-2(a), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e); or

(2) Pursuant to 326 IAC 3-7-3, manual or other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring.

(c) If using CEMS, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 shall be used as the means for determining compliance with the emission limitations in 326 IAC 7.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.1.11 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

(a) The ability of the ESP to control particulate emissions shall be monitored once per day, when the unit is in operation, by measuring and recording the number of T-R sets in service and the primary and secondary voltages and the currents of the T-R sets.

(b) Reasonable response steps shall be taken in accordance with Section C - Response to Excursions or Exceedances whenever the percentage of T-R sets in service falls below ninety percent (90%). T-R set failure resulting in less than ninety percent (90%) availability is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

D.1.12 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Appropriate response steps shall be taken in accordance with Section C - Response to Excursions or Exceedances whenever the opacity exceeds twenty-five percent (25%) for three (3) consecutive six (6) minute averaging periods. In the event of opacity exceeding twenty-five percent (25%), response steps will be taken such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty-five percent (25%). Examples of expected response steps include, but are not limited to, boiler loads being reduced and ESP T-R sets being returned to service.

(b) Opacity readings in excess of twenty-five percent (25%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

(c) The requirements of (a) and (b), do not apply to Boiler No. 1 during startup and shutdown of Boiler No. 1 and do not apply when Boiler No. 1 is being controlled by the flue gas desulfurization (FGD) system.

D.1.13 SO_2 Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

Whenever the SO_2 continuous emission monitoring system (CEMS) is malfunctioning or down for repairs or adjustments for twenty-four (24) hours or more, the Permittee shall monitor and record the boiler load, recirculation pH, slurry feed rate, and number of recirculation pumps in service, to demonstrate that the operation of the scrubber continues in a manner typical for the boiler load and sulfur content of the coal fired. Scrubber parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a backup CEMS is brought online.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.1.14 Record Keeping Requirements

(a) To document the compliance status with Section C - Opacity and Conditions D.1.1, D.1.2, D.1.9, D.1.11 and D.1.12, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.1.1 and D.1.2.

(1) Data and results from the most recent stack test.

(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5-6.

(3) The results of all Method 9 visible emission readings taken during any periods of COMS downtime.

(4) All ESP parametric monitoring readings.

(b) To document the compliance status with Conditions D.1.3, D.1.10 and D.1.13, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the SO_2 limits as required in Conditions D.1.3 and D.1.10. The Permittee shall maintain records in accordance with (2) and (3) below during SO_2 CEM system downtime if a backup CEM is not used.

The Permittee shall maintain the following records:

(1) All SO_2 continuous emissions monitoring data pursuant to 326 IAC 3-5-6.

(2) All scrubber parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.1.13.

(3) Actual fuel usage during each SO_2 CEMS downtime.

(c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.1.15 Reporting Requirements

(a) Pursuant to 326 IAC 3-5-7, a quarterly report of opacity exceedances and a quarterly summary of the information to document compliance with Condition D.1.8 shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(b) Pursuant to 326 IAC 3-5-7, a quarterly report of SO_2 exceedances shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(c) Pursuant to 326 IAC 3-5-5(e), a quarterly report of the continuous emissions monitoring system performance audits shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(d) Pursuant to 326 IAC 3-5-7(5), a quarterly report of the continuous monitoring system instrument downtime shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.2 **EMISSIONS UNIT OPERATION CONDITIONS**

Emissions Unit Description [326 IAC 2-7-5(15)]

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Boiler No. 2 was configured with a low NO_X burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

(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 2-7-5(1)]

D.2.1 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

The Particulate Matter emissions from Boiler #2 shall be limited to 0.227 lbs/MMBtu. Compliance with this limit satisfies the requirements of 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating). This limit is based on the historic particulate matter emissions limit established under 326 IAC 6-2-3.

D.2.2 Temporary Alternative Opacity Limitations [326 IAC 5-1-3]

(a) Pursuant to 326 IAC 5-1-3(e) (Temporary Alternative Opacity Limitations), the following applies:

(1) When building a new fire in Boiler No. 2, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed three (3) hours (30 six minute-averaged periods) or until the flue gas temperature entering the electrostatic precipitator (ESP) reaches 250 degrees Fahrenheit, whichever occurs first.

(2) When shutting down a boiler, opacity may exceed the applicable limitation established in 326 IAC 5-1-2 for a period not to exceed three (3) hours (30 six minute-averaged periods) or until the flue gas temperature entering the electrostatic precipitator (ESP) has dropped below 250 degrees Fahrenheit, whichever occurs first.

(3) Operation of the electrostatic precipitator is not required during these times.

(b) Firing a boiler as part of the chemical cleaning operations of the boiler and its associated tubes is considered a "startup condition" pursuant to 326 IAC 1-2-76 and subject to the exemptions as set forth in D.2.2(a).

(c) When removing ashes from the fuel bed or furnace in a boiler or blowing tubes, opacity may exceed the applicable limit established in 326 IAC 5-1-2. However, opacity levels shall not exceed sixty percent (60%) for any six (6)-minute averaging period and opacity in excess of the applicable limit shall not continue for more than one (1) six (6)-minute averaging periods in any sixty (60) minute period. The averaging periods shall not be permitted for more than three (3) six (6)-minute averaging periods in a twelve (12) hour period.

(d) Permittee is also allowed one start up and one shut down per calendar year as follows:

(i) When building a new fire in a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed a total of seven (7) hours (seventy (70) six (6)-minute averaging periods, consecutive or non-consecutive) or until the flue gas temperature reaches two hundred fifty (250) degrees Fahrenheit, whichever occurs first.

(ii) When shutting down a boiler, opacity may exceed the 40% opacity limitation established in 326 IAC 5-1-2 for a period not to exceed a total of five (5) hours (fifty (50) six (6)-minute averaging periods, consecutive or non-consecutive).

D.2.3 Sulfur Dioxide (SO_2) [326 IAC 7-4-8] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-4-8 (Vermillion County Sulfur Dioxide Emission Limitations), the SO_2 emissions from Boiler No. 2 shall not exceed 4.40 pounds per million Btu (lbs/MMBtu), demonstrated using a thirty (30) day rolling weighted average. This limitation will ensure that SO_2 emissions do not exceed the amount assumed in the modeling analysis performed for the Vermillion County SO_2 SIP limits.

D.2.4 Operational Standards [326 IAC 2-1.1-5(a)(4)]

(a) All coal burned, including coal treated with any additive, shall meet the ASTM definition of coal.

(b) Any boiler or condenser tube chemical cleaning waste liquids fired in the boiler shall only contain the cleaning solution and two full volume boiler rinses.

D.2.5 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.2.6 Testing Requirements [326 IAC 2-7-6(1),(6)] [326 IAC 2-1.1-11]

In order to determine compliance with the PM limitation, the Permittee shall perform PM testing for the pulverized coal-fired boiler, identified as Boiler No. 2, any time during calendar year 2010 utilizing methods as approved by the Commissioner. This test shall be repeated at least once every two (2) calendar years following this valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

D.2.7 Operation of Electrostatic Precipitator and Flue Gas Desulfurization (FGD) [326 IAC 2-7-6(6)]

(a) Except as otherwise provided by statute or rule or in this permit, the electrostatic precipitator shall be operated at all times that Boiler No. 2 is in operation and combusting solid fuel or any combination of solid fuels or other fuels.

(b) Except as otherwise provided by statute or rule or in this permit, the flue gas desulfurization (FGD) system shall be operated as needed to maintain compliance with applicable SO_2 emission limits.

D.2.8 Maintenance of Continuous Opacity Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)] [40 CFR 64]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous opacity monitoring systems (COMS) and related equipment. For a boiler, the COMS shall be in operation at all times that the induced draft fan is in operation.

(b) All COMS shall meet the performance specifications of 40 CFR 60, Appendix B, Performance Specification No. 1, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5.

(c) In the event that a breakdown of a COMS occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(d) Whenever a COMS is malfunctioning or is down for maintenance or repairs for a period of twenty-four (24) hours or more and a backup COMS is not online within twenty-four (24) hours of shutdown or malfunction of the primary COMS, the Permittee shall provide a certified opacity reader, who may be an employee of the Permittee or an independent contractor, to self-monitor the emissions from the emission unit stack.

(1) Visible emission readings shall be performed in accordance with 40 CFR 60, Appendix A, Method 9, for a minimum of five (5) consecutive six (6) minute averaging periods beginning not more than twenty-four (24) hours after the start of the malfunction or down time.

(2) Method 9 opacity readings shall be repeated for a minimum of five (5) consecutive six (6) minute averaging periods at least twice per day during daylight operations, with at least four (4) hours between each set of readings, until a COMS is online.

(3) Method 9 readings may be discontinued once a COMS is online.

(4) Any opacity exceedances determined by Method 9 readings shall be reported with the Quarterly Opacity Exceedances Reports.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous opacity monitoring system pursuant to 326 IAC 3-5, (and 40 CFR 60 and/or 40 CFR 63).

D.2.9 Maintenance of Continuous Emission Monitoring Equipment [326 IAC 2-7-5(3)(A)(iii)] [40 CFR 64]

(a) The Permittee shall install, calibrate, maintain, and operate all necessary continuous emission monitoring systems (CEMS) and related equipment as specified in Section D.

(b) All continuous emission monitoring systems shall meet all applicable performance specifications of 40 CFR 60, 40 CFR 75 or any other performance specification, and are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) In the event that a breakdown of a continuous emission monitoring system occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem.

(d) Whenever a continuous emission monitor other than an opacity monitor is malfunctioning or will be down for calibration, maintenance, or repairs, the following shall be used as an alternative to continuous data collection:

(1) If the CEM is required for monitoring NO_x or SO_2 emissions pursuant to 40

CFR 75 (Title IV Acid Rain program) or 326 IAC 24 (SO_2 and NO_x Trading Program), the Permittee shall comply with the relevant requirements of 40 CFR 75 Subpart D- Missing Data Substitution Procedures.

(2) If the CEM is not used to monitor NO_x or SO_2 emissions pursuant to 40 CFR 75 or 326 IAC 24 (SO_2 and NO_x Trading Program), then supplemental or intermittent monitoring of the parameter shall be implemented as specified in Section D of this permit until such time as the emission monitor system is back in operation.

(e) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 40 CFR 60, Subpart GG 326 IAC 3-5, 40 CFR 60 or 40 CFR 75.

D.2.10 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 2-7-5(A)] [326 IAC 2-7-6] [326 IAC 7-2]

(a) Pursuant to 326 IAC 7-2-1(c), the Permittee shall demonstrate that the sulfur dioxide emissions from Unit 2 do not exceed the equivalents of the limits specified in Conditions D.2.3 (Sulfur Dioxide (SO_2)) using a thirty (30) day rolling weighted average.

(b) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7, coal sampling and analysis data shall be collected as follows:

(1) Coal sampling shall be performed using the methods specified in 326 IAC 3-7-2(a), and sample preparation and analysis shall be performed as specified in 326 IAC 3-7-2(c), (d), and (e); or

(2) Pursuant to 326 IAC 3-7-3, manual or other non-ASTM automatic sampling and analysis procedures may be used upon a demonstration, submitted to the department for approval, that such procedures provide sulfur dioxide emission estimates representative either of estimates based on coal sampling and analysis procedures specified in 326 IAC 3-7-2 or of continuous emissions monitoring.

(c) If using CEMS, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 shall be used as the means for determining compliance with the emission limitations in 326 IAC 7.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.2.11 Transformer-Rectifier (T-R) Sets [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

(a) The ability of the ESP to control particulate emissions shall be monitored once per day, when the unit is in operation, by measuring and recording the number of T-R sets in service and the primary and secondary voltages and the currents of the T-R sets.

(b) Reasonable response steps shall be taken in accordance with Section C - Response to Exceedances or Excursions whenever the percentage of T-R sets in service falls below ninety percent (90%). T-R set failure resulting in less than ninety percent (90%) availability is not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

D.2.12 Opacity Readings [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Appropriate response steps shall be taken in accordance with Section C - Response to Excursions or Exceedances whenever the opacity exceeds twenty-five percent (25%) for three (3) consecutive six (6) minute averaging periods. In the event of opacity exceeding twenty-five percent (25%), response steps will be taken such that the cause(s) of the excursion are identified and corrected and opacity levels are brought back below twenty-five percent (25%). Examples of expected response steps include, but are not limited to, boiler loads being reduced and ESP T-R sets being returned to service.

(b) Opacity readings in excess of twenty-five percent (25%) but not exceeding the opacity limit for the unit are not a deviation from this permit. Failure to take response steps in accordance with Section C - Response to Excursions or Exceedances, shall be considered a deviation from this permit.

(c) The requirements of (a) and (b), do not apply to Boiler No. 2 during startup and shutdown of Boiler No. 2 and do not apply when Boiler No. 2 is being controlled by the flue gas desulfurization (FGD) system.

D.2.13 SO_2 Monitoring System Downtime [326 IAC 2-7-6] [326 IAC 2-7-5(3)]

Whenever the SO_2 continuous emission monitoring system (CEMS) is malfunctioning or down for repairs or adjustments for twenty-four (24) hours or more, the Permittee shall monitor and record the boiler load, recirculation pH, slurry feed rate, and number of recirculation pumps in service, to demonstrate that the operation of the scrubber continues in a manner typical for the boiler load and sulfur content of the coal fired. Scrubber parametric monitoring readings shall be recorded at least twice per day until the primary CEMS or a backup CEMS is brought online.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.2.14 Record Keeping Requirements

(a) To document the compliance status with Section C - Opacity and Conditions D.2.1, D.2.2, D.2.9, D.2.11 and D.2.12, the Permittee shall maintain records in accordance with (1) through (4) below. Records shall be complete and sufficient to establish compliance with the limits established in Section C - Opacity and in Conditions D.2.1 and D.2.2.

(1) Data and results from the most recent stack test.

(2) All continuous opacity monitoring data, pursuant to 326 IAC 3-5-6.

(3) The results of Method 9 visible emission readings taken during any periods of COMS downtime.

(4) All ESP parametric monitoring readings.

(b) To document the compliance status with Conditions D.2.3, D.2.10 and D.2.13, the Permittee shall maintain records in accordance with (1) and (2) below. Records shall be complete and sufficient to establish compliance with the SO_2 limits as required in Conditions D.2.3 end D.2.10. The Permittee shall maintain records in accordance with (2) and (3) below during SO_2 CEM system downtime if a backup CEM is not used.

(1) All SO_2 continuous emissions monitoring data pursuant to 326 IAC 3-5-6.

(2) All scrubber parametric monitoring readings taken during any periods of CEMS downtime, in accordance with Condition D.2.13.

(3) Actual fuel usage during each SO_2 CEMS downtime.

(c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.2.15 Reporting Requirements

(a) Pursuant to 326 IAC 3-5-7, A quarterly report of opacity exceedances shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(b) Pursuant to 326 IAC 3-5-7, a quarterly report of SO_2 exceedances shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(c) Pursuant to 326 IAC 3-5-5(e), a quarterly report of the continuous emissions monitoring system performance audits shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

(d) Pursuant to 326 IAC 3-5-7(5), a quarterly report of the continuous monitoring system instrument downtime shall be submitted not later than thirty (30) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.3 **EMISSIONS UNIT OPERATION CONDITIONS**

Emissions Unit Description [326 IAC 2-7-5(15)]

(d) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3A, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3A.

(e) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3B, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3B.

(f) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3C, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3C.

(g) One (1) no. 2 fuel oil-fired generator, identified as Unit No. 3D, installed in 1972, with a nominal heat input capacity of 30 million Btu per hour (MMBtu/hr), exhausting to stack 3D.

(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 2-7-5(1)]

D.3.1 Sulfur Dioxide (SO_2) [326 IAC 7-1.1-1]

Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations), the SO_2 emissions from each generator shall not exceed five-tenths (0.5) pound per million Btu heat input.

D.3.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.3.3 Sulfur Dioxide Emissions and Sulfur Content [326 IAC 3] [326 IAC 7-2] [326 IAC 7-1.1-2]

(a) Pursuant to 326 IAC 7-2-1(c)(3), the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed the equivalent of 0.5 pounds per MMBtu, using a calendar month average.

(b) Pursuant to 326 IAC 7-2-1(e) and 326 IAC 3-7-4, fuel sampling and analysis data shall be collected as follows:

(1) The Permittee may rely upon vendor analysis of fuel delivered, if accompanied by a vendor certification [326 IAC 3-7-4(b)]; or,

(2) The Permittee shall perform sampling and analysis of fuel oil samples in accordance with 326 IAC 3-7-4(a).

(A) Oil samples shall be collected from the tanker truck load prior to transferring fuel to the storage tank; or

(B) Oil samples shall be collected from the storage tank immediately after each addition of fuel to the tank.

(C) As an alternate to (A) and (B) above, samples may be collected prior to combustion (as burned) on each day fuel is combusted.

(c) Upon written notification to IDEM by a facility owner or operator, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance with the emission limitations in 326 IAC 7. Upon such notification, the other requirements of 326 IAC 7-2 shall not apply. [326 IAC 7-2-1(g)]

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.3.4 Visible Emissions Notations

(a) Visible emission (VE) notations of the generators' stack exhausts shall be performed once per day during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for the generators.

(e) If abnormal emissions are observed at any generators' exhaust, the Permittee shall take reasonable response steps. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps, shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.3.5 Record Keeping Requirements

(a) To document the compliance status with Condition D.3.1, the Permittee shall maintain records in accordance with (1) through (6) below.

(1) Calendar dates covered in the compliance determination period;

(2) Actual fuel oil usage since last compliance determination period and equivalent sulfur dioxide emissions;

(3) A certification, signed by the owner or operator, that the records of the fuel supplier certifications, or the records of fuel sampling and analysis, represent all of the fuel combusted during the period; and

If the fuel supplier certification is used to demonstrate compliance the following, as a minimum, shall be maintained:

(4) Fuel supplier certifications;

(5) The name of the fuel supplier; and

(6) A statement from the fuel supplier that certifies the sulfur content of the fuel oil.

The Permittee shall retain records of all recording/monitoring data and support information for a period of five (5) years, or longer if specified elsewhere in this permit, from the date of the monitoring sample, measurement, or report. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit.

(b) To document the compliance status with Condition D.3.4, the Permittee shall maintain records of visible emission notations of the generators' stack exhausts. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the unit did not operate that day).

(c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description [326 IAC 2-7-5(15)]

(h) A dual conveyor coal processing system, with a nominal throughput of 1900 tons of coal per hour (950 tons of coal per hour each side), consisting of the following equipment:

(1) One (1) railcar unloading station, with a drop point to two (2) hoppers identified as DP-1, with the drop point enclosed with emissions uncontrolled, and exhausting to the ambient air.

(2) One (1) storage area, having a nominal storage capacity including the active piles of 982,800 tons, with fugitive emissions controlled as needed by a watering truck.

(3) One (1) enclosed hopper, with a drop point to a conveyor identified as DP-2, with the drop point enclosed with emissions controlled by a water spray dust suppression system as needed, and exhausting to the ambient air.

(4) One (1) enclosed hopper and two (2) reclaim feeders, with an underground drop points identified as DP-11 and DP-12, with emissions controlled by the underground enclosure, and routed to the conveyor system.

(5) An enclosed dual conveyor system, with 6 drop points identified as DP-3 through DP-6, DP-8, and DP-13, with each drop point enclosed with emissions controlled by the enclosure. Drop points DP-3 through DP-5, DP-8, and DP-13 are controlled as needed by a water spray dust suppression system, and DP-6 is controlled by rotoclones.

(6) An enclosed conveyor system with drop point identified as DP-9, controlled by a telescoping chute.

(7) Coal bunker and coal scale exhausts and associated dust collector vents.

(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 2-7-5(1)]

D.4.1 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), the particulate emission rate from the coal processing drop points, coal scale exhausts, and coal bunkers shall not exceed 86.19 pounds per hour when operating at a process weight rate of 1900 tons per hour. This is determined by the following equation:

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 = 950 (process weight rate in tons per hour)

When the process weight exceeds two hundred (200) tons/hour, the maximum allowable emission may exceed 86.19 pounds per hour, provided the concentration of particulate matter in the discharge gases to the atmosphere is less than 0.10 pounds per one thousand (1,000) pounds of gases.

D.4.2 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.4.3 Particulate Control [326 IAC 2-7-6(6)]

Except as otherwise provided by statute or rule or in this permit, in order to comply with Section C - Opacity and Condition D.4.1, the dust collectors shall be in operation at all times the coal bunker and coal scales are in operation.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.4.4 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of the coal unloading station, coal bunker, coal scale exhausts and associated dust collector vents exhausts shall be performed once per week during normal daylight operations when transferring coal. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

(e) If abnormal emissions are observed from the coal unloading station, coal bunker, coal scale exhausts and associated dust collector vents exhausts, the Permittee shall take reasonable response steps. Observation of abnormal emissions that do not violate 326 IAC 6-4 (Fugitive Dust Emissions) or an applicable opacity limit is not a deviation from this permit. Failure to take response steps, shall be considered a violation of this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.4.5 Record Keeping Requirements

(a) To document the compliance status with Section C - Opacity, Section C -Fugitive Dust Emissions, and Condition D.4.4, the Permittee shall maintain records of visible emission notations of the coal unloading station, coal bunker, coal scale exhausts and associated dust collector vents exhausts. The Permittee shall include in its records when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g. the unit did not operate that day).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.5 **EMISSIONS UNIT OPERATION CONDITIONS**

Emissions Unit Description [326 IAC 2-7-5(15)] Insignificant Activities

(a) Degreasing operations, constructed prior to January 1, 1980, that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6.

(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 2-7-5(1)]

D.5.1 Organic Solvent Degreasing Operations: Cold Cleaner Operation [326 IAC 8-3-2]

Pursuant to 326 IAC 8-3-2 (Cold Cleaner Operations), the owner or operator shall:

(a) Equip the cleaner with a cover;

(b) Equip the cleaner with a facility for draining cleaned parts;

(c) Close the degreaser cover whenever parts are not being handled in the cleaner;

(d) Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases;

(e) Provide a permanent, conspicuous label summarizing the operation requirements;

(f) Store waste solvent only in covered containers and not dispose of waste solvent or transfer it to another party, in such a matter that greater than twenty percent (20%) of the waste solvent (by weight) can evaporate into the atmosphere.

D.5.2 Organic Solvent Degreasing Operations: Cold Cleaner Degreaser Operation and Control [326 IAC 8-3-5]

(a) Pursuant to 326 IAC 8-3-5(a) (Cold Cleaner Degreaser Operation and Control), the owner or operator of a cold cleaner degreaser facility shall ensure that the following control equipment requirements are met:

(1) Equip the degreaser with a cover. The cover must be designed so that it can be easily operated with one (1) hand if:

(A) The solvent volatility is greater than two (2) kiloPascals (fifteen (15) millimeters of mercury or three-tenths (0.3) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F));

(B) The solvent is agitated; or

(C) The solvent is heated.

(2) Equip the degreaser with a facility for draining cleaned articles. If the solvent volatility is greater than four and three-tenths (4.3) kiloPascals (thirty-two (32) millimeters of mercury) or six-tenths (0.6) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F)), then the drainage facility must be internal such that articles are enclosed under the cover while draining. The drainage facility may be external for applications where an internal type cannot fit into the cleaning system.

(3) Provide a permanent, conspicuous label which lists the operating requirements outlined in subsection (b).

(4) The solvent spray, if used, must be a solid, fluid stream and shall be applied at a pressure which does not cause excessive splashing.

(5) Equip the degreaser with one (1) of the following control devices if the solvent volatility is greater than four and three-tenths (4.3) kiloPascals (thirty-two (32) millimeters of mercury) or six-tenths (0.6) pounds per square inch) measured at thirty-eight degrees Celsius (38°C) (one hundred degrees Fahrenheit (100°F)), or if the solvent is heated to a temperature greater than forty-eight and nine-tenths degrees Celsius (48.9°C) (one hundred twenty degrees Fahrenheit (120°F)):

(A) A freeboard that attains a freeboard ratio of seventy-five hundredths (0.75) or greater.

(B) A water cover when solvent is used is insoluble in, and heavier than, water.

(C) Other systems of demonstrated equivalent control such as a refrigerated chiller of carbon adsorption. Such systems shall be submitted to the U.S. EPA as a SIP revision.

(b) Pursuant to 326 IAC 8-3-5(b) (Cold Cleaner Degreaser Operation and Control), the owner or operator of a cold cleaning facility shall ensure that the following operating requirements are met:

(1) Close the cover whenever articles are not being handled in the degreaser.

(2) Drain cleaned articles for at least fifteen (15) seconds or until dripping ceases.

(3) Store waste solvent only in covered containers and prohibit the disposal or transfer of waste solvent in any manner in which greater than twenty percent (20%) of the waste solvent by weight could evaporate.

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description [326 IAC 2-7-5(15)]

(i) One (1) limestone handling and storage system for the flue gas desulfurization system, constructed in 2006, with a maximum throughput rate of 1,000 tons per hour, consisting of the following:

(1) One (1) railcar/truck unloading operation, with a maximum capacity of 1,000 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L1.

(2) Two (2) hoppers, each with a maximum capacity of 500 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L2.

(3) Two (2) belt feeders, identified as LHBF-1 and LHBF-2, each with a maximum capacity of 500 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L2.

(4) One (1) conveyor, identified as LH-1, controlled by a telescopic chute, and exhausting to emission point EP-L3. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(5) One (1) active limestone stockout pile, with a maximum capacity of 7,700 tons.

(6) One (1) inactive limestone storage pile, with a maximum capacity of 45,000 tons.

(7) Two (2) reclaim hoppers, each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.

(8) Two (2) belt feeders, identified as LHBF-3 and LHBF-4, each with a maximum capacity of 200 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L4.

(9) One (1) conveyor, identified as LH-2, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(10) One (1) reversible conveyor, identified as LH-3, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression, and exhausting to emission points EP-L18a and EP-L18c. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(11) Two (2) day bins, each with a maximum throughput rate of 400 tons per hour, and exhausting to EP-L16 and EP-L17, respectively. Under NSPS, Subpart OOO, these units considered storage bins.

(12) Two (2) wet ball mills, each with a maximum capacity of 51 tons of limestone slurry per hour. Under NSPS, Subpart OOO, these units are considered grinding mills.

(j) One (1) gypsum handling and storage system, constructed in 2006, consisting of the following:

(1) One (1) wet gypsum conveying system, with a maximum throughput rate of 150 tons per hour.

(2) One (1) gypsum stockout pile, with a maximum capacity of 10,400 tons.

(3) One (1) emergency gypsum stockout pile, with a maximum capacity of 2,600 tons.

(4) One (1) dry gypsum transferring operation, transferring gypsum to landfills by trucks on paved roads.

(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 2-7-5(1)]

D.6.1 Prevention of Significant Deterioration (PSD) Minor Limits [326 IAC 2-2]

In order to render the requirements of 326 IAC 2-2 (PSD) not applicable, the Permittee shall comply with the following:

(a) The total limestone received shall not exceed 509,000 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(b) The PM/PM_{10} emissions from the lime handling operations shall not exceed the emission limits listed in the table below:

Emission Point	Unit Description	PM Emission Limit (lbs/ton)	PM_{10} Emission Limit (lbs/ton)
EP-L1	Railcar/Truck Unloading	2.50E-05	2.50E-05
EP-L2	Hoppers	7.50E-04	2.75E-04
EP-L2	Belt Feeders	7.50E-04	2.75E-04
EP-L3	Conveyor LH-1	1.50E-03	5.50E-04
EP-L4	Reclaim Hoppers	7.50E-04	2.75E-04
EP-L4	Belt Feeders	7.50E-04	2.75E-04
EP-L18abc	Conveyor LH-2	7.50E-04	2.75E-04
EP-L18abc	Conveyor LH-3	7.50E-04	2.75E-04
EP-L16	Day Bin Unit 1	3.00E-03	1.10E-03
EP-L17	Day Bin Unit 2	3.00E-03	1.10E-03

(c) The emissions from the following units of the limestone handling system shall be controlled by the control method specified in the table below:

Emission Point	Unit	Control Method
EP-L1	Railcar/Truck Unloading Operation	Fog Dust Suppression
EP-L2	Hoppers Belt Feeders LHBF-1 and LHBF-2	Fog Dust Suppression
EP-L3	Conveyor LH-1	Telescoping Chute
EP-L4	Reclaim Hoppers Belt Feeders LHBF-3 and LHBF-4	Fog Dust Suppression
EP-L18a, b, c	Conveyors LH-2 and LH-3	Fog Dust Suppression

(d) The total gypsum processed shall not exceed 900,528 tons per twelve (12) consecutive month period with compliance determined at the end of each month.

(e) The PM/PM_{10} emissions from the gypsum conveying system shall not exceed the emission limits listed in the table below:

Unit Description	PM Emission Limit (lbs/ton)	PM_{10} Emission Limit (lbs/ton)
Gypsum Conveying System	0.00014	0.000046

(f) The limestone and gypsum stockpiles shall be controlled by wet suppression. The suppressant shall be applied in a manner and at a frequency sufficient to ensure compliance with 326 IAC 2-2.

Compliance with these limits will limit the potential to emit of PM and PM_{10} from the limestone handling and the gypsum handling systems to less than 25 tons per year for PM and less than 15 tons per year for PM_{10}, and render the requirements of 326 IAC 2-2 (PSD) not applicable to these units.

D.6.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes), particulate emissions from the following emission units at the limestone handling and storage system, and the gypsum conveying system shall not exceed the emission limits listed in the table below while operating at the maximum throughput rate:

Unit Description	Max. Throughput Rate (tons/hr)	Particulate Emission Limit (lbs/hr)
Railcar/Truck Unloading Operation	1,000	77 6
Each of the Hoppers	500	69 0
Each of the Belt Feeders (LHBF-1 and LHBF-2)	500	69 0
Each of the Reclaim Hoppers	200	58 5
Each of the Belt Feeders (LHBF-3 and LHBF-4)	200	58 5
Gypsum Conveying System	150	55 4

The limitations for these facilities were calculated using the following equations.

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

(b) Pursuant to 326 IAC 6-3-2(e)(3), when the process weight exceeds 200 tons per hour, the maximum allowable emission may exceed that shown in this table, provided the concentration of particulate matter in the gas discharged to the atmosphere is less than 0.10 pounds per 1,000 pounds of gases.

D.6.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.6.4 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

(a) Visible emission notations of the stack exhausts from the conveyors (EP-L3, EP-L18a through c) of the limestone handling and storage system shall be performed once per week during normal daylight operations when transferring limestone. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the eppearance and characteristics of normal visible emissions for that specific process.

(e) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Failure to take response steps, shall be considered a deviation of this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.6.5 Record Keeping Requirements

(a) To document the compliance status with Condition D.6.1(a), the Permittee shall maintain monthly records of the weight of limestone processed.

(b) To document the compliance status with Condition D.6.1(d), the Permittee shall maintain monthly records of the weight of gypsum processed.

(c) To document the compliance status with Condition D.6.4 Visible Emissions Notations, the Permittee shall maintain records of the the weekly visible emission notations of the transfer points, railcar unloading stations and all response steps taken and the outcome for each. The Permittee shall include in its records when a visible emission notation is not taken and the reason for the lack of visible emission notation (e.g., the process did not operate that day).

(d) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

D.6.6 Reporting Requirements

A quarterly summary of the information to document compliance with Conditions D.6.1(a) and (d) shall be submitted, using the reporting forms located at the end of this permit, or their equivalent, not later than thirty (3) days following the end of each calendar quarter. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description [326 IAC 2-7-5(15)]

(k) Auxiliary Boiler, identified as emission unit Aux, with a maximum heat input capacity of 72.76 MMBtu/hr fired with distillate oil and exhausting out one stack identified as stack Aux-1. The Auxiliary boiler was constructed before 1968.

(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 2-7-5(1)]

D.7.1 Sulfur Dioxide (SO_2) [326 IAC 7-1.1-1] [326 IAC 7-2-1]

Pursuant to 326 IAC 7-1.1 (SO_2 Emissions Limitations) the SO_2 emissions from the Auxiliary Boiler shall not exceed five tenths (0.5) pounds per MMBtu heat input when combusting distillate oil.

D.7.2 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(c), the PM emissions from the Auxiliary Boiler stack shall not exceed 0.233 pound per million Btu heat input (lbs/MMBtu).

D.7.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.7.4 Sulfur Dioxide Emissions and Sulfur Content

Compliance shall be determined utilizing one of the following options.

(a) Pursuant to 326 IAC 3-7-4, the Permittee shall demonstrate that the sulfur dioxide emissions do not exceed five-tenths (0.5) pounds per million Btu heat input by:

(1) Providing vendor analysis of fuel delivered, if accompanied by a vendor certification; or

(2) Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR 60, Appendix A, Method 19.

(A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and

(B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling.

(b) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the Auxiliary Boiler, using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6.

(C) As an alternate to (A) and (B) above, samples may be collected prior to combustion (as burned) on each day fuel is combusted.

A determination of noncompliance pursuant to any of the methods specified in (a) or (b) above shall not be refuted by evidence of compliance pursuant to the other method.

Compliance Monitoring Requirements [326 IAC 2-8-4][326 IAC 2-8-5(a)(1)]

D.7.5 Visible Emissions Notations

(a) Visible emission notations of the Auxiliary Boiler stack exhaust (Aux-1) shall be performed once per day during normal daylight operations. A trained employee shall record whether emissions are normal or abnormal.

(b) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(c) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(d) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

(e) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Failure to take response steps, shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

Record Keeping and Reporting Requirements [326 IAC 2-8-4(3)]

D.7.6 Record Keeping Requirement

(a) To document the compliance status with Conditions D.7.1, the Permittee shall maintain records in accordance with (1) through (3) below.

(1) Calendar dates covered in the compliance determination period;

(2) Actual fuel usage of each fuel used since last compliance determination period;

(3) If the fuel supplier certification is used to demonstrate compliance the following, as a minimum, shall be maintained:

(i) Fuel supplier certifications.

(ii) The name of the fuel supplier; and

(iii) A statement from the fuel supplier that certifies the sulfur content of the fuel oil.

(b) To document the compliance status with Condition D.7.5, the Permittee shall maintain records of visible emission notations of the boiler stack (Aux-1) exhaust. The Permittee shall include in its records when a visible emission notation is not taken and the reason for the lack of visible emission notation, (e.g. the process did not operate that day).

(c) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.8 **EMISSIONS UNIT OPERATION CONDITIONS**

Emissions Unit Description: [326 IAC 2-7-5(15)]

(k) One (1) Arsenic Mitigation System consisting of (1) 700 ton Limestone Storage Silo and (1) 300 ton Limestone Surge Bin, scheduled to be installed by 2015. Limestone is pneumatically conveyed from delivery trucks to the Limestone Storage Silo and from the Limestone Storage Silo to the Limestone Surge Bin. Limestone in the Surge Bin is dropped on to the C-1 and C-2 coal conveyors. PM emissions generated during pneumatic conveying and transfer points to the C-1 and C-2 conveyor will be controlled by the bin vent filters. The Limestone Storage Silo and Limestone Surge Bin are identified as emissions points EP-01(LS) and EP-02(LS).

(l) Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of (2) two Sorbent Storage Silos with a storage capacity of 120 tons and system to inject the sorbent material into the flue gas, scheduled to be installed by 2015. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo. The four (4) Sorbent Silos are identified as emission points EP-01(DSI), EP-02(DSI, EP-03(DSI), and EP-04(DSI).

(m) Two (2) Activated Carbon Injection (ACI) Systems, one for each Unit. Each ACI system consists of one (1) storage silo with a 80 ton storage capacity and system for injecting the Activated Carbon into the flue gas, scheduled to be installed by 2015. PM emissions during the silo loading operation are controlled by the bin vent filters located on top of the silos. The two (2) Activated Carbon Storage Silos are identified as emission points EP-01(ACI) and EP-02(ACI).

(n) Two (2) Dry Ash Handling Systems, one for each Unit. The dry ash handling system consists of a pneumatic conveying system, four (4) baghouse separators, two (2) ash silos with a storage capacity of 3,500 each and an ash unloading system, scheduled to be installed by 2015.

(i) Baghouse Separators - Fly ash from the ESP Ash Hoppers, Air Heater Ash Hoppers, Economizer Ash Hoppers and SCR Large Particle Screen Ash Hopper will be pneumatically conveyed to one of four (4) baghouse separators. There will be two (2) baghouse separators for each unit. The dry fly ash is separated from the air stream in a baghouse separator. Each baghouse separator are identified as emissions points EP-01(DFA), EP--02(DFA), EP-03(DFA), and EP-04(DFA). The system is equipped with a spare exhauster identified as emissions point EP-05(DFA).

(ii) Ash Silos - Fly ash collected in the baghouse separators is dropped into a feeder and pneumatically conveyed to one of two (2) ash silos. Each ash silo is equipped with a bin vent filter to control particulate matter emissions from pneumatic conveying. The Ash Silos are identified as emission point EP-06(DFA) and EP-07(DFA).

(iii) Ash Unloading Operation - Fly ash collected in the silos can be unloaded into trucks or pneumatically conveyed to the ash fixation process. Fly ash unloaded into trucks can be unloaded dry or wet. Fly ash unloaded dry is gravity feed to a chute and unloaded into enclosed trucks. The emissions generated from unloading the ash dry are vented back to the silo and controlled by the silo bin vent filter. Ash unloaded wet is feed into a pin mixer where the ash is mixed with water and unloaded into open trucks

(o) One (1) Ash Fixation Process consisting of a pneumatic conveying system, one (1) ash day bin, one (1) lime silo, conveyors, and two (2) pin mixers, scheduled to be installed by 2015.

(i) Fly Ash Day Bin - Fly ash from the ash silos can be pneumatically conveyed to the day bin. The storage capacity of the day bin is 500 tons. The emissions generated from pneumatic conveyance will be controlled by a bin vent filter located on top of the fly ash day bin. The Fly Ash Day Bin is identified as emissions point EP-01(FIX).

(ii) Lime Silo – Lime will be delivered by truck and will pneumatically loaded into the silo. The storage capacity of the silo is 300 tons. The emissions generated by the pneumatic conveying will be controlled by a bin vent filter located on top of the lime silo. The Lime Silo is identified as emissions point EP-02(FIX).

(iii) Conveyor and Transfer Points – Fly ash, Lime and Gypsum will be conveyed to one of two (2) pin mixers where this material will be mixed with water to make the fixated ash. The fixated ash will be unloaded to a storage pile, and then loaded into trucks using front end loaders.

(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 2-7-5(1)]

D.8.1 Prevention of Significant Deterioaration (PSD) Minor Limits [326 IAC 2-2]

Pursuant to Significant Source Modification No. 165-32045-00001, the Permittee shall comply with the following:

(a) Fly ash unloaded from fly ash silo #1 or #2 shall either be unloaded wet into open trucks with the esh having a moisture content of not less than 15% or unloaded dry into enclosed trucks using the telescoping chute to vent emissions back to the fly ash silo bin vent filter.

(b) The PM, PM_{10} and $PM_{2.5}$ emissions from the Activity on Storage Pile shall be controlled by maintaining the average moisture content of the fixated ash not less than 15% moisture content and applying water to the pile as need to prevent dusting.

(c) The PM, PM_{10} and $PM_{2.5}$ emissions from the limestone, dry sorbent, activated carbon, dry ash and ash fixation systems shall not exceed the emission limits listed in the table below:

Emission Point	Unit Description	PM Emission Limit (lbs/hr)	PM10 Emission Limit (lbs/hr)	PM2.5 Emission Limit (lbs/hr)
EP-01(LS)	Limestone Silo	0.55	0.33	0.27
EP-02(LS)	Limestone Surge Bin	0.27	0.16	0.14
EP-01(DSI)	Unit 1DSI Silo #1	0.14	0.08	0.07
EP-02(DSI)	Unit 1 DSI Silo #2	0.14	0.08	0.07
EP-03(DSI)	Unit 2 DSI Silo #1	0.14	0.08	0.07
EP-04(DSI)	Unit 2 DSI Silo #2	0.14	0.08	0.07

Emission Point	Unit Description	PM Emission Limit (lbs/hr)	PM10 Emission Limit (lbs/hr)	PM2.5 Emission Limit (lbs/hr)
EP-01(ACI)	Unit 1 ACI Silo	0.14	0.08	0 07
EP-02(ACI)	Unit 2 ACI Silo	0.14	0.08	0.07
EP-01(DFA)	Baghouse Separator 1A Exhauster	0.26	0.18	0.13
EP-02(DFA)	Baghouse Separator 1B Exhauster	0.26	0.18	0.13
EP-03(DFA)	Baghouse Separator 2A Exhauster	0.26	0.18	0.13
EP-04(DFA)	Baghouse Separator 2B Exhauster	0.26	0.18	0.13
EP-05(DFA)	Spare Baghouse Separator Exhauster	0.26	0.18	0.13
EP-06(DFA)	Ash Silo #1	0.60	0.42	0.30
EP-07(DFA)	Ash Silo #2	0.60	0.42	0.30
EP-01(FIX)	Ash Day Bin	0.38	0.23	0.19
EP-02(FIX)	Lime Silo	0.14	0.08	0.07

Compliance with these limits in conjunction with the potential fugitive emissions from vehicular traffic, will ensure that the PM emissions are less than 25 tons per year, PM_{10} emissions are less than 15 tons per year and $PM_{2.5}$ emissions are less than 10 tons per year, and render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2012 modification.

D.8.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the (4) Sorbent Silos, (1) Lime Silo (1) Limestone Silo and (2) Activated Carbon Silos shall not exceed 30.5 pounds per hour each when operating at a process weight rate of 20 tons per hour. The pound per hour limitation was calculated with the following equation:

$E = 4.1 P^{0.67}$
Where:
E = rate of emission in pounds per hour and
P = process weight rate in tons per hour

(b) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the (1) Limestone Surge Bin shall not exceed 40.0 pounds per hour when operating at a process weight rate of 30 tons per hour each. The pound per hour limitation was calculated with the following equation:

$E = 4.1 P^{0.67}$
Where:
E = rate of emission in pounds per hour and
P = process weight rate in tons per hour

(c) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from (5) exhausters shall not exceed 45.4 pounds per hour each when operating at a process weight rate of 54.4 tons per hour. The pound per hour limitation was calculated with the following 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

(d) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from (2) ash silos and fly ash day bin shall not exceed 47.8 pounds per hour each when operating at a process weight rate of 70 tons per hour. The pound per hour limitation was calculated with the following 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

D.8.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.8.4 Particulate Control [326 IAC 2-7-6(6)]

(a) In order to ensure compliance with the particulate matter emissions limits specified in conditions D.8.1(c) and D.8.2 the filter separators, and silo bin vent filters shall in operation and controlling emissions whenever the equipment is in operation and venting to the control device.

(b) In order to ensure compliance with Condition D.8.1(a), the Permittee shall wet the ash when unloading into open trucks. If the weather conditions preclude the use of water, the Permittee shall use additional wet suppression. The Permittee shall perform moisture content analysis, weekly on the ash to ensure it has a moisture content of not less than 15%. Additional wetting of the ash should be applied if visible emissions are observed during the loading process.

D.8.5 Testing Requirements [326 IAC 2-7-6(1),(6)][326 IAC 2-1.1-11]

(a) Within 180 days after the initial startup of the pneumatic fly ash transfer system, in order to determine compliance with Condition D.8.1(c), the Permittee shall perform PM, PM_{10} and $PM_{2.5}$ testing two (2) of the five (5) separator/exhausters, identified as emissions point EP-01 (DFA), EP-02 (DFA), EP-03 (DFA), EP-04 (DFA) and EP-05 (DFA), using methods as approved by the Commissioner. This testing shall be at least once every 5 years from the date of the last valid compliance demonstration. The separator/exhauster tested shall be the unit in which the longest amount of time has elapsed since its previous test. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

(b) Within 180 days after the initial startup of the pneumatic fly ash transfer system, in order to determine compliance with Condition D.8.1(c), the Permittee shall perform PM, PM_{10} and $PM_{2.5}$ testing on one (1) of the three (3) Fly Ash Silos/Day Bin, identified as emission point EP-06 (DFA), EP-07 (DFA) and EP-01 (FIX) using methods as approved by the Commissioner. This testing shall be at least once every 5 years from the date of the last valid compliance demonstration. The Ash Silo/Day Bin tested shall be the unit in which the longest amount of time has elapsed since its previous test. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.8.6 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

(a) Visible emission notations of the stack exhausts for the (1) Limestone Silo (1) Limestone Surge Bin, (2) ACI Silos, (4) DSI Silos, and (1) Lime Silo shall be performed once per week during normal daylight operations when the equipment is in operation. A trained employee shall record whether emissions are normal or abnormal.

(b) Visible emission notations of the stack for the (4) baghouse separator exhausters, (2) ash silo and (1) ash day bin shall be performed once per day during normal daylight operations when the equipment is in operation. A trained employee shall record whether emissions are normal or abnormal.

(c) Visible emission notations of the fixated material storage pile shall be performed once per week during normal daylight operations when the equipment is in operation. A trained employee shall record whether emissions are normal or abnormal.

(d) For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.

(f) In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.

(g) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

(h) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

D.8.7 Parametric Monitoring [40 CFR 64]

The Permittee shall record the pressure drop across each baghouse filter separator used in conjunction with the dry ash handling system, at least once per day when the dry ash handling system is exhausting to the atmosphere. When, for any one reading, the pressure drop across the baghouse is outside of the normal range, the Permittee shall take a reasonable response. The normal range for this unit is a pressure drop between 1.0 and 6.0 inches of water unless a different upper-bound or lower-bound value for this range is determined during the latest stack test. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered deviation from the permit.

The instrument used for determining the pressure shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated as specified by the manufacturer.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.8.8 Record Keeping Requirements

(a) To document the compliance status with Condition D.8.6(a) - Visible Emission Notation, the Permittee shall maintain weekly records of the visible emission notations of the stack exhausts for the (1) Limestone Silo, (1) Limestone Surge Bin, (2) ACI Silos, (4) DSI Silos and (1) Lime Silo. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that week).

(b) To document the compliance status with Condition D.8.6(b)- Visible Emission Notation, the Permittee shall maintain daily records of the visible emission notations of the stack exhaust for (5) Baghouse Filter Separators Exhausters, (2) Ash Silos and (1) Ash Day Bin when in operation. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that day)

(c) To document the compliance status with Condition D.8.6(c)- Visible Emission Notation, the Permittee shall maintain weekly records of the visible emission notations of the fixated material storage pile when in operation. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that week).

(d) To document the compliance status with Condition D.8.7 - Parametric Monitoring, the Permittee shall maintain the daily records of the pressure drop across the baghouse filter separator. The Permittee shall include in its daily record when a pressure drop reading is not taken and the reason for the lack of a pressure drop reading, (e.g. the process did not operate that day).

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

SECTION E.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(b) One 156.9 HP (100 kW), CI ICE with a displacement 4.4 liters, Diesel Fired Emergency Generator, Manufactured by Caterpillar Model Year 2007, Model D100-6, constructed in 2007, identified as ENG-1. This generator is located in the switch yard and is operated as backup for the black start diesel aux feed.

(c) One 713 Hp (450 kW), CI ICE with a displacement 15.2 liters, Diesel Fired Emergency Engine, Manufactured by Caterpillar, Model Year 2007, Model C15DITA, constructed in 2007, identified as ENG-2. This engine is use to quench the flue gas if the scrubber should fail.

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

New Source Performance Standards (NSPS) Requirements [40 CFR 60] and National Emission Standards for Hazardous Air Pollutants [40 CFR 63]

E.1.1 General Provisions Relating to New Source Performance Standards (NSPS) [326 IAC 12-1] [40 CFR 60, Subpart A] [326 IAC 12]

The provisions of 40 CFR 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to ENG-1 and ENG-2 except when otherwise specified in 40 CFR 60, Subpart IIII.

E.1.2 Standard of Performance for Stationary Compression Ignition Internal Combustion Engines [326 IAC 12] [40 CFR 60, Subpart IIII]

Pursuant to 40 CFR 60 Subpart IIII, the Permittee shall comply with the provisions of 40 CFR 60 Subpart IIII, which are incorporated as 326 IAC 12-1 for ENG-1 and ENG-2, as specified as follows:

(1) 40 CFR 60.4202
(2) 40 CFR 60.4205(b)
(3) 40 CFR 60.4207(a) & (b)
(4) 40 CFR 60.4209(a)
(5) 40 CFR 60.4211(a),(c) & (e)
(6) 40 CFR 60.4214(b)

E.1.3 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) [326 IAC 20-82] [40 CFR 63, Subpart A]

The provisions of 40 CFR 63, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 20-82, apply to ENG-2 except when otherwise specified in 40 CFR 63, Subpart ZZZZ.

E.1.4 Stationary Reciprocating Internal Combustion Engines NESHAP [326 IAC 20-82] [40 CFR 63, Subpart ZZZZ]

Pursuant to 40 CFR 63 Subpart ZZZZ, the Permittee shall comply with the provisions of 40 CFR 63 Subpart ZZZZ, which are incorporated as 326 IAC 20-82 for ENG-2, as specified as follows:

(1) 40 CFR 63.6590(b) & (c)
(2) 40 CFR 63.6645(f)

SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(i) One (1) limestone handling and storage system for the flue gas desulfurization system, constructed in 2006, with a maximum throughput rate of 1,000 tons per hour, consisting of the following:

(1) One (1) conveyor, identified as LH-1, controlled by a telescopic chute, and exhausting to emission point EP-L3. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(2) One (1) active limestone stockout pile, with a maximum capacity of 7,700 tons.

(3) One (1) conveyor, identified as LH-2, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(4) One (1) reversible conveyor, identified as LH-3, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression, and exhausting to emission points EP-L18a and EP-L18c. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(5) Two (2) day bins, each with a maximum throughput rate of 400 tons per hour, and exhausting to EP-L16 and EP-L17, respectively. Under NSPS, Subpart OOO, these units considered storage bins.

(6) Two (2) wet ball mills, each with a maximum capacity of 51 tons of limestone slurry per hour. Under NSPS, Subpart OOO, these units are considered grinding mills.

(7) Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of (2) two Sorbent Storage Silos with a storage capacity of 120 tons and system to inject the sorbent material into the flue gas, scheduled to be installed by 2015. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo. The four (4) Sorbent Silos are identified as emission points EP-01(DSI), EP-02(DSI, EP-03(DSI), and EP-04(DSI).

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

New Source Performance Standards (NSPS) Requirements [40 CFR 60]

E2.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(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 for the ball mills, conveyors, and storage bins of the limestone handling and storage system, except as otherwise specified in 40 CFR Part 60, Subpart OOO.

(b) Pursuant to 40 CFR 60.19, the Permittee shall submit all required notifications and reports to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality

100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

E.2.2 Standard of Performance for Nonmetallic Mineral Processing Plants Requirements [40 CFR Part 60, Subpart OOO] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart OOO, the Permittee shall comply with the provisions of Standard of Performance for Nonmetallic Mineral Processing Plants, which ere incorporated by reference as 326 IAC 12, for the ball mills, conveyors, and storage bins of the limestone handling end storage system as specified as follows:

(1) 40 CFR 60.670
(2) 40 CFR 60.671
(3) 40 CFR 60.672
(4) 40 CFR 60.673
(5) 40 CFR 60.674
(6) 40 CFR 60.675
(7) 40 CFR 60.676
(8) Table 1 to Subpart OOO
(9) Table 2 to Subpart OOO
(10) Table 3 to Subpart OOO

SECTION E.3 ACID RAIN PROGRAM CONDITIONS

ORIS Code: 1001

Title IV Source Description:

(a) One (1) dry bottom, tangentially-fired, pulverized coal boiler, identified as Unit 1(Boiler No. 1 in the Title V permit), installed in 1967, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter (PM), with a low-nitrogen oxides (NOx) burner for control of NOx, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for NOx and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Unit 1 was configured with the low NOx bumer in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

(b) One (1) dry bottom, tangentially-fired, pulverized coal boiler, identified as Unit 2 (Boiler No. 2 in the Title V permit), installed in 1968, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter (PM), with a low-nitrogen oxides (NOx) burner for control of NOx, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for NOx and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Unit 2 was configured with the low NOx burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015

(The information contained in this box is descriptive information and does not constitute enforceable conditions.)

E.3.1. Statutory and Regulatory Authorities

In accordance with IC 13-17-3-4 and IC 13-17-3-11 as well as Titles IV and V of the Clean Air Act, the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ) issues this permit pursuant to 326 IAC 2 and 326 IAC 21 (incorporates by reference 40 Code of Federal Regulations (CFR) 72 through 78).

E.3.2. Standard Permit Requirements [326 IAC 21]

(a) The designated representative has submitted a complete acid rain permit application in accordance with 40 CFR 72.30.

(b) The Permittee shall operate Units 1 and 2 in compliance with this permit.

E.3.3. Monitoring Requirements [326 IAC 21]

(a) The Permittee and, to the extent applicable, the designated representative of Units 1 and 2 shall comply with the monitoring requirements as provided in 40 CFR 75 and 76.

(b) The emissions measurements recorded and reported in accordance with 40 CFR 75 and 76 shall be used to determine compliance by Units 1 and 2 with the acid rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program.

(c) The requirements of 40 CFR 75 and 76 shall not affect the responsibility of the Permittee to monitor emissions of other pollutants or other emissions characteristics at Units 1 and 2 under other applicable requirements of the Clean Air Act and other provisions of the operating permit for the source.

E.3.4. Sulfur Dioxide Requirements [326 IAC 21]

(a) The Permittee shall:

(1) Hold allowances, as of the allowance transfer deadline (as defined in 40 CFR 72.2), in the compliance subaccount of Units 1 and 2, after deductions under 40 CFR 73.34(c), not less than the total annual emissions of sulfur dioxide for the previous calendar year from Units 1 and 2; and,

(2) Comply with the applicable acid rain emissions limitations for sulfur dioxide.

(b) Each ton of sulfur dioxide emitted in excess of the acid rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Clean Air Act.

(c) Units 1 and 2 shall be subject to the requirements under paragraph 4(a) of the sulfur dioxide requirements as follows:

(1) Starting January 1, 2000, an affected unit under 40 CFR 72.6(a)(2); or,

(2) Starting on the latter of January 1, 2000, or the deadline for monitor certification under 40 CFR 75, an affected unit under 40 CFR 72.6(a)(3).

(d) Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program.

(e) An allowance shall not be deducted in order to comply with the requirements under paragraph 4(a) of the sulfur dioxide requirements prior to the calendar year for which the allowance was allocated.

(f) An allowance allocated by the U.S. EPA under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the acid rain permit application, the acid rain permit, the acid rain portion of an operating permit, or the written exemption under 40 CFR 72.7 and 72.8 and 326 IAC 21, and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(g) An allowance allocated by U.S. EPA under the Acid Rain Program does not constitute a property right.

(h) No permit revision may be required for increases in emissions that are authorized by allowances acquired pursuant to tha Acid Rain Program, provided that the increases do not require a permit revision under any other applicable requirement. [326 IAC 2-7-5(4)(A)]

(i) No limit shall be placed on the number of allowances held by the Permittee. The Permittee may not, however, use allowances as a defense to noncompliance with any applicable requirement other than the requirements of the Acid Rain Program. [326 IAC 2-7-5(4)(B)]

E.3.5. Nitrogen Oxides Requirements [326 IAC 21]

The Permittee shall comply with the applicable acid rain emissions limitation of nitrogen oxides (NOx) for Units 1 and 2.

NOx Emission Averaging Plan for Unit 1:

(1) Pursuant to 40 CFR 76.11, the Indiana Department of Environmental Management, Office of Air Quality approves a NOx emission averaging plan for Unit 1, effective from calendar year 2005 through 2007. Under the plan the NOx emissions from Unit 1 shall not exceed the annual average alternative contemporaneous emission limitation (ACEL) of 0.34 lb/MMBtu. In addition, Unit 1 shall not have an annual heat input less than 36,100,000 MMBtu. Unit 1 shall revert to the NO_x Btu-weighted annual average emission rate in compliance with 40 CFR 76.5, 76.6 or 76.7 on January 1, 2008. If Unit 1 is in compliance with its applicable emission limitation for each year of the plan, then Unit 1 shall not be subject to the applicable emission limitation, under 40 CFR 76.5(a)(1), of 0.45 lb/MMBtu until January 1, 2008.

(2) Under the plan, the actual Btu-weighted annual average NOx emission rate for all the units in the plan shall be less than or equal to the Btu-weighted annual average NOx emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then Unit 1 shall be deemed to be in compliance for that year with its annual ACEL and annual heat input limit.

NOx Emission Averaging Plan for Unit 2:

(1) Pursuant to 40 CFR 76.11, the Indiana Department of Environmental Management, Office of Air Quality approves a NOx emission averaging plan for Unit 2, effective from calendar year 2005 through 2007. Under the plan the NOx emissions from Unit 2 shall not exceed the annual average alternative contemporaneous emission limitation (ACEL) of 0.35 lb/MMBtu. In addition, Unit 2 shall not have an annual heat input less than 34,600,000 MMBtu. Unit 2 shall revert to the NO_x Btu-weighted annual average emission rate in compliance with 40 CFR 76.5, 76.6 or 76.7 on January 1, 2008. If Unit 2 is in compliance with its applicable emission limitation for each year of the plan, then Unit 2 shall not be subject to the applicable emission limitation, under 40 CFR 76.5(a)(1), of 0.45 lb/MMBtu until January 1, 2008.

(2) Under the plan, the actual Btu-weighted annual average NOx emission rate for all the units in the plan shall be less than or equal to the Btu-weighted annual average NOx emission rate for the same units had they each been operated, during the same period of time, in compliance with the applicable emission limitations under 40 CFR 76.5, 76.6, or 76.7, except that for any early election units, the applicable emission limitations shall be under 40 CFR 76.7. If the designated representative demonstrates that the requirement of the prior sentence (as set forth in 40 CFR 76.11(d)(1)(ii)(A)) is met for a year under the plan, then Unit 2 shall be deemed to be in compliance for that year with its annual ACEL and annual heat input limit.

In accordance with 40 CFR 72.40(b)(2), approval of the averaging plan shall be final only when the Ohio Environmental Protection Agency, Division of Air Pollution Control; and the Kentucky Department of Environmental Protection, Division of Air Quality have also approved this averaging plan.

In addition to the described NOx compliance plan, Units 1 and 2 shall comply with all other applicable requirements of 40 CFR 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.

Pursuant to 40 CFR 76, Acid Rain Nitrogen Oxides Emission Reduction Program, the natural gas fired turbine, Unit 4 is not subject to the nitrogen oxide limitations set out in 40 CFR 76.

E.3.6 Excess Emissions Requirements [40 CFR 77] [326 IAC 21]

(a) If Unit 1 or 2 has excess emissions of sulfur dioxide in any calendar year, the designated representative shall submit a proposed offset plan to U.S. EPA and IDEM, OAQ as required under 40 CFR 77 and 326 IAC 21.

(b) The designated representative shall submit required information 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

and

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code (6204N)
Washington, DC 20460

(c) If Unit 1 or 2 has excess emissions, as defined in 40 CFR 72.2, in any calendar year the Permittee shall:

(1) Pay to U.S. EPA without demand the penalty required, and pay to U.S. EPA upon demand the interest on that penalty, as required by 40 CFR 77 and 326 IAC 21; and,

(2) Comply with the terms of an approved sulfur dioxide offset plan, as required by 40 CFR 77 and 326 IAC 21.

E.3.7. Record Keeping and Reporting Requirements [326 IAC 21]

(a) Unless otherwise provided, the Permittee shall keep on site each of the following documents for a period of 5 years, as required by 40 CFR 72.9(f), from the date the document is created. This period may be extended for cause, at any time prior to the end of the 5 years, in writing by U.S. EPA or IDEM, OAQ:

(1) The certificate of representation for the designated representative of Units 1 and 2 and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5 year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative;

(2) All emissions monitoring information collected in accordance with 40 CFR 75 shall be retained on site for 3 years;

(3) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and,

(4) Copies of all documents used to complete an acid rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program.

(b) The designated representative of Units 1 and 2 shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 72.90, Subpart I, 40 CFR 75, and 326 IAC 21. The required information is to be submitted to the appropriate authority(ies) as specified in 40 CFR 72.90, Subpart I, and 40 CFR 75.

E.3.8. Submissions [326 IAC 21]

(a) The designated representative of Units 1 and 2 shall submit a certificate of representation, and any superseding certificate of representation, to U.S. EPA and IDEM, OAQ in accordance with 40 CFR 72 and 326 IAC 21.

(b) The designated representative shall submit required information to:

Indiana Department of Environmental Management
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251

and

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code (6204N)
Washington, DC 20460

(c) Each such submission under the Acid Rain Program shall be submitted, signed and certified by the designated representative for all sources on behalf of which the submission is made.

(d) In each submission under the Acid Rain Program, the designated representative shall certify, by his or her signature, the following statements which shall be included verbatim in the submission:

(1) "I am authorized to make this submission on behalf of the owners and operators of the affected source or affected units for which the submission is made."; and,

(2) "I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(e) The designated representative of Units 1 and 2 shall notify the Permittee:

(1) By the date of submission, of any Acid Rain Program submissions by the designated representative;

(2) Within 10 business days of receipt of any written determination by U.S. EPA or IDEM, OAQ; and,

(3) Provided that the submission or determination covers Unit 1 and 2.

(f) The designated representative of Units 1 and 2 shall provide the Permittee a copy of any submission or determination under paragraph 8(e), unless the Permittee expressly waives the right to receive a copy.

E.3.9. Severability [326 IAC 21]

Invalidation of the acid rain portion of an operating permit does not affect the continuing validity of the rest of the operating permit, nor shall invalidation of any other portion of the operating permit affect the continuing validity of the acid rain portion of the permit. [40 CFR 72.72(b), 326 IAC 21, and 326 IAC 2-7-5(5)]

E.3.10. Liability [326 IAC 21]

(a) Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, an acid rain permit, an acid rain portion of an operation permit, or a written exemption under 40 CFR 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement by U.S. EPA pursuant to Section 113(c) of the Clean Air Act and shall be subject to enforcement by IDEM pursuant to 326 IAC 21 and IC 13-30-3.

(b) Any person who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to Section 113(c) of the Clean Air Act, 18 U.S.C. 1001 and IDEM pursuant to 326 IAC 21 and IC 13-30-6-2.

(c) No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect.

(d) Units 1 and 2 shall meet the requirements of the Acid Rain Program.

(e) Any provision of the Acid Rain Program that applies to Unit 1 or 2, including a provision applicable to the designated representative of Unit 1 or 2 shall also apply to the Permittee.

(f) Any provision of the Acid Rain Program that applies to Unit 1 or 2 4, including a provision applicable to the designated representative, shall also apply to the Permittee. Except as provided under 40 CFR 72.44 (Phase II repowering extension plans) and 40 CFR 76.11 (NOx averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR 75, including 40 CFR 75.16, 75.17, and 75.18, the Permittee and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative.

(g) Each violation of a provision of 40 CFR 72, 73, 75, 76, 77, and 78 by Unit 1 or 2, or by the Permittee or designated representative shall be a separate violation of the Clean Air Act.

E.3.11. Effect on Other Authorities [326 IAC 21]

No provision of the Acid Rain Program, an acid rain permit application, an acid rain permit, an acid rain portion of an operation permit, or a written exemption under 40 CFR 72.7 or 72.8 shall be construed as:

(a) Except as expressly provided in Title IV of the Clean Air Act (42 USC 7651 to 7651(o)), exempting or excluding the Permittee and, to the extent applicable, the designated representative of Unit 1 or 2 from compliance with any other provision of the Clean Air

Act, including the provisions of Title I of the Clean Air Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(b) Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Clean Air Act;

(c) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law;

(d) Modifying the Federal Power Act (16 USC 791(a) et seq.) or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(e) Interfering with or impairing any program for competitive bidding for power supply in a state in which such a program is established.

SECTION F Clean Air Interstate (CAIR) Nitrogen Oxides Annual, Sulfur Dioxide, and Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)

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CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Boiler No. 1 was configured with a low NO_X burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Boiler No. 2 was configured with a low NO_X burner in 1993. Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015

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

F.1 Automatic Incorporation of Definitions [326 IAC 24-1-7(e)] [326 IAC 24-2-7(e)] [326 IAC 24-3-7(e)] [40 CFR 97.123(b)] [40 CFR 97.223(b)] [40 CFR 97.323(b)]

This CAIR permit is deemed to incorporate automatically the definitions of terms under 326 IAC 24-1-2, 326 IAC 24-2-2, and 326 IAC 24-3-2.

F.2 Standard Permit Requirements [326 IAC 24-1-4(a)] [326 IAC 24-2-4(a)] [326 IAC 24-3-4(a)] [40 CFR 97.106(a)] [40 CFR 97.206(a)] [40 CFR 97.306(a)]

(a) The owners and operators of the CAIR NOx source, CAIR SO_2 source, and CAIR NOx ozone season source and CAIR NOx units, CAIR SO_2 units, and CAIR NOx ozone season units shall operate each unit in compliance with this CAIR permit.

(b) The CAIR NOx units, CAIR SO_2 units, and CAIR NOx ozone season units subject to this CAIR permit are Boiler No. 1 and Boiler No. 2.

F.3 Monitoring, Reporting, and Record Keeping Requirements [326 IAC 24-1-4(b)] [326 IAC 24-2-4(b)] [326 IAC 24-3-4(b)] [40 CFR 97.106(b)] [40 CFR 97.206(b)] [40 CFR 97.306(b)]

(a) The owners and operators, and the CAIR designated representative, of each CAIR NOx source, CAIR SO_2 source, and CAIR NOx ozone season source and CAIR NOx unit, CAIR SO_2 unit, and CAIR NOx ozone season unit at the source shall comply with the monitoring, reporting, and record keeping requirements of 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) The emissions measurements recorded and reported in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 shall be used to determine compliance by each CAIR NOx source, CAIR SO_2 source, and CAIR NOx ozone season source with the CAIR NOx emissions limitation under 326 IAC 24-1-4(c), CAIR SO_2 emissions limitation under 326 IAC 24-2-4(c), and CAIR NOx ozone season emissions limitation under 326 IAC 24-3-4(c) and Condition G.4.1, Nitrogen Oxides Emission Requirements, Condition G.4.2, Sulfur Dioxide Emission Requirements, and Condition G.4.3, Nitrogen Oxides Ozone Season Emission Requirements.

F.4.1 Nitrogen Oxides Emission Requirements [326 IAC 24-1-4(c)] [40 CFR 97.106(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NO_X allowances available for compliance deductions for the control period under 326 IAC 24-1-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with 326 IAC 24-1-11.

(b) A CAIR NO_X unit shall be subject to the requirements under 326 IAC 24-1-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-1-4(c)(2), and for each control period thereafter.

(c) A CAIR NO_X allowance shall not be deducted for compliance with the requirements under 326 IAC 24-1-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_X allowance was allocated.

(d) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X allowance tracking system accounts in accordance with 326 IAC 24-1-9, 326 IAC 24-1-10, and 326 IAC 24-1-12.

(e) A CAIR NO_X allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_X annual trading program. No provision of the CAIR NO_X annual trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-1-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR NO_X allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-1-8, 326 IAC 24-1-9, 326 IAC 24-1-10, or 326 IAC 24-1-12, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NO_X source's compliance account is incorporated automatically in this CAIR permit.

F.4.2 Sulfur Dioxide Emission Requirements [326 IAC 24-2-4(c)] [40 CFR 97.206(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR SO_2 allowances available for compliance deductions for the control period under 326 IAC 24-2-8(j) and 326 IAC 24-2-8(k) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with 326 IAC 24-2-10.

(b) A CAIR SO_2 unit shall be subject to the requirements under 326 IAC 24-2-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-2-4(c)(2), and for each control period thereafter.

(c) A CAIR SO_2 allowance shall not be deducted for compliance with the requirements under 326 IAC 24-2-4(c)(1), for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.

(d) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 allowance tracking system accounts in accordance with 326 IAC 24-2-8, 326 IAC 24-2-9, and 326 IAC 24-2-11.

(e) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 trading program. No provision of the CAIR SO_2 trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-2-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR SO_2 allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-2-8, 326 IAC 24-2-9, or 326 IAC 24-2-11, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 source's compliance account is incorporated automatically in this CAIR permit.

F.4.3 Nitrogen Oxides Ozone Season Emission Requirements [326 IAC 24-3-4(c)] [40 CFR 97.306(c)]

(a) As of the allowance transfer deadline for a control period, the owners and operators of each CAIR NO_X ozone season source and each CAIR NO_X ozone season unit at the source shall hold, in the source's compliance account, CAIR NO_X ozone season allowances available for compliance deductions for the control period under 326 IAC 24-3-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X ozone season units at the source, as determined in accordance with 326 IAC 24-3-11.

(b) A CAIR NO_X ozone season unit shall be subject to the requirements under 326 IAC 24-3-4(c)(1) for the control period starting on the applicable date, as determined under 326 IAC 24-3-4(c)(2), and for each control period thereafter.

(c) A CAIR NO_X ozone season allowance shall not be deducted for compliance with the requirements under 326 IAC 24-3-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_X ozone season allowance was allocated.

(d) CAIR NO_X ozone season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X ozone season allowance tracking system accounts in accordance with 326 IAC 24-3-9, 326 IAC 24-3-10, and 326 IAC 24-3-12.

(e) A CAIR NO_X ozone season allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_X ozone season trading program. No provision of the CAIR NO_X ozone season trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-3-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR NO_X ozone season allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-3-8, 326 IAC 24-3-9, 326 IAC 24-3-10, or 326 IAC 24-3-12, every allocation, transfer, or deduction of a CAIR NO_x ozone season allowance to or from a CAIR NO_x ozone season source's compliance account is incorporated automatically in this CAIR permit.

F.5 Excess Emissions Requirements [326 IAC 24-1-4(d)] [326 IAC 24-2-4(d)] [326 IAC 24-3-4(d)] [40 CFR 97.106(d)] [40 CFR 97.206(d)] [40 CFR 97.306(d)]

(a) The owners and operators of a CAIR NO_x source and each CAIR NO_x unit that emits nitrogen oxides during any control period in excess of the CAIR NO_x emissions limitation shall do the following:

(1) Surrender the CAIR NO_x allowances required for deduction under 326 IAC 24-1-9(j)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-1-4, the Clean Air Act (CAA), and applicable state law.

(b) The owners and operators of a CAIR SO_2 source and each CAIR SO_2 unit that emits sulfur dioxide during any control period in excess of the CAIR SO_2 emissions limitation shall do the following:

(1) Surrender the CAIR SO_2 allowances required for deduction under 326 IAC 24-2-8(k)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-2-4, the Clean Air Act (CAA), and applicable state law.

(c) The owners and operators of a CAIR NO_x ozone season source and each CAIR NO_x ozone season unit that emits nitrogen oxides during any control period in excess of the CAIR NO_x ozone season emissions limitation shall do the following:

(1) Surrender the CAIR NO_x ozone season allowances required for deduction under 326 IAC 24-3-9(j)(4).

(2) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-3-4, the Clean Air Act (CAA), and applicable state law.

F.6 Record Keeping Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [326 IAC 2-7-5(3)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

Unless otherwise provided, the owners end operators of the CAIR NOx source, CAIR SO_2 source, and CAIR NOx ozone season source end each CAIR NOx unit, CAIR SO_2 unit, end CAIR NOx ozone season unit at the source shall keep on site at the source or at a central location within Indiana for those owners or operators with unattended sources, each of the following documents for a period of five (5) years from the date the document was created:

(a) The certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), 326 IAC 24-3-6(h) for the CAIR designated representative for the source and each CAIR NOx unit, CAIR SO_2 unit, and CAIR NOx ozone season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation. The certificate and documents shall be retained on site at the source or at a central location within Indiana for those owners or operators with unattended sources beyond such five (5) year period until such documents are superseded because of the submission of a new account certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), 326 IAC 24-3-6(h) changing the CAIR designated representative.

(b) All emissions monitoring information, in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11, provided that to the extent that 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 provides for a three (3) year period for record keeping, the three (3) year period shall apply.

(c) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NOx annual trading program, CAIR SO_2 trading program, and CAIR NOx ozone season trading program.

(d) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NOx annual trading program, CAIR SO_2 trading program, and CAIR NOx ozone season trading program or to demonstrate compliance with the requirements of the CAIR NOx annual trading program, CAIR SO_2 trading program, and CAIR NOx ozone season trading program.

This period may be extended for cause, at any time before the end of five (5) years, in writing by IDEM, OAQ or the U.S. EPA. Unless otherwise provided, all records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

F.7 Reporting Requirements [326 IAC 24-1-4(e)] [326 IAC 24-2-4(e)] [326 IAC 24-3-4(e)] [40 CFR 97.106(e)] [40 CFR 97.206(e)] [40 CFR 97.306(e)]

(a) The CAIR designated representative of the CAIR NOx source, CAIR SO_2 source, and CAIR NOx ozone season source and each CAIR NOx unit, CAIR SO_2 unit, and CAIR NOx ozone season unit at the source shall submit the reports required under the CAIR NOx annual trading program, CAIR SO_2 trading program, and CAIR NOx ozone season trading program, including those under 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) Pursuant to 326 IAC 24-1-4(e), 326 IAC 24-2-4(e), and 326 IAC 24-3-4(e) and 326 IAC 24-1-6(e)(1), 326 IAC 24-2-6(e)(1), and 326 IAC 24-3-6(e)(1), each submission under the CAIR NOx annual trading program, CAIR SO_2 trading program, and CAIR NOx ozone season trading program shall include the following certification statement by the CAIR designated representative: "I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

(c) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to IDEM, OAQ, the CAIR designated representative shall submit required information to:

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

(d) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to U.S. EPA, the CAIR designated representative shall submit required information to:

U.S. Environmental Protection Agency
Clean Air Markets Division
1200 Pennsylvania Avenue, NW
Mail Code 6204N
Washington, DC 20460

F.8 Liability [326 IAC 24-1-4(f)] [326 IAC 24-2-4(f)] [326 IAC 24-3-4(f)] [40 CFR 97.106(f)] [40 CFR 97.206(f)] [40 CFR 97.306(f)]

The owners and operators of each CAIR NOx source, CAIR SO_2 source, and CAIR NOx ozone season source and each CAIR NOx unit, CAIR SO_2 unit, and CAIR NOx ozone season unit shall be liable as follows:

(a) Each CAIR NOx source, CAIR SO_2 source, and CAIR NOx ozone season source and each CAIR NOx unit, CAIR SO_2 unit, and CAIR NOx ozone season unit shall meet the requirements of the CAIR NOx annual trading program, CAIR SO_2 trading program, and CAIR NOx ozone season trading program.

(b) Any provision of the CAIR NOx annual trading program, CAIR SO_2 trading program, and CAIR NOa ozone season trading program that applies to a CAIR NOx source, CAIR SO_2 source, and CAIR NOx ozone season source or the CAIR designated representative of a CAIR NOx source, CAIR SO_2 source, and CAIR NOx ozone season source shall also apply to the owners and operators of such source and of the CAIR NOx units, CAIR SO_2 units, and CAIR NOx ozone season units at the source

(c) Any provision of the CAIR NOx annual trading program, CAIR SO_2 trading program, and CAIR NOx ozone season trading program that applies to a CAIR NOx unit, CAIR SO_2 unit, and CAIR NOx ozone season unit or the CAIR designated representative of a CAIR NOx unit, CAIR SO_2 unit, and CAIR NOx ozone season unit shall also apply to the owners and operators of such unit.

F.9 Effect on Other Authorities [326 IAC 24-1-4(g)] [326 IAC 24-2-4(g)] [326 IAC 24-3-4(g)] [40 CFR 97.106(g)] [40 CFR 97.206(g)] [40 CFR 97.306(g)]

No provision of the CAIR NOx annual trading program, CAIR SO_2 trading program, and CAIR NOx ozone season trading program, a CAIR permit application, a CAIR permit, or an exemption under 326 IAC 24-1-3, 326 IAC 24-2-3, and 326 IAC 24-3-3 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NOx source, CAIR SO_2 source, and CAIR NOx ozone season source or a CAIR NOx unit, CAIR SO_2 unit, and CAIR NOx ozone season unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act (CAA).

F.10 CAIR Designated Representative and Alternate CAIR Designated Representative [326 IAC 24-1-6] [326 IAC 24-2-6] [326 IAC 24-3-6] [40 CFR 97, Subpart BB] [40 CFR 97, Subpart BBB] [40 CFR 97, Subpart BBBB]

Pursuant to 326 IAC 24-1-6, 326 IAC 24-2-6, and 326 IAC 24-3-6:

(a) Except as specified in 326 IAC 24-1-6(f)(3), 326 IAC 24-2-6(f)(3), and 326 IAC 24-3-6(f)(3), each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source, including all CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units at the source, shall have one (1) and only one (1) CAIR designated representative, with regard to all matters under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program concerning the source or any CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source.

(b) The provisions of 326 IAC 24-1-6(f), 326 IAC 24-2-6(f), and 326 IAC 24-3-6(f) shall apply where the owners or operators of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source choose to designate an alternate CAIR designated representative.

Except as specified in 326 IAC 24-1-6(f)(3), 326 IAC 24-2-6(f)(3), and 326 IAC 24-3-6(f)(3), whenever the term "CAIR designated representative" is used, the term shall be construed to include the CAIR designated representative or any alternate CAIR designated representative.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
PART 70 OPERATING PERMIT
CERTIFICATION

Source Name:	Duke Energy, Inc. - Cayuga Generating Station
Source Address:	State Road 63, Cayuga, Indiana 47928
Part 70 Permit No.:	T 165-27260-00001

This certification shall be included when submitting monitoring, testing reports/results or other documents as required by this permit.

Please check what document is being certified:

- ☐ Annual Compliance Certification Letter
- ☐ Test Result (specify)
- ☐ Report (specify)
- ☐ Notification (specify)
- ☐ Affidavit (specify)
- ☐ Other (specify)

I certify that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.
Signature:
Printed Name:
Title/Position:
Phone:
Date:

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

100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
Phone: (317) 233-0178
Fax: (317) 233-6865

PART 70 OPERATING PERMIT
EMERGENCY OCCURRENCE REPORT

Source Name: Duke Energy, Inc. - Cayuga Generating Station
Source Address: State Road 63, Cayuga, Indiana 47928
Part 70 Permit No.: T 165-27260-00001

This form consists of 2 pages **Page 1 of 2**

☐ This is an emergency as defined in 326 IAC 2-7-1(12)

- The Permittee must notify the Office of Air Quality (OAQ), no later than four (4) daytime business hours (1-800-451-6027 or 317-233-0178, ask for Compliance Section); and
- The Permittee must submit notice in writing or by facsimile no later than two (2) working days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.

If any of the following are not applicable, mark N/A

Facility/Equipment/Operation:
Control Equipment:
Permit Condition or Operation Limitation in Permit:
Description of the Emergency:
Describe the cause of the Emergency:

If any of the following are not applicable, mark N/A

Date/Time Emergency started:
Date/Time Emergency was corrected:
Was the facility being properly operated at the time of the emergency? Y N
Type of Pollutants Emitted: TSP, PM-10, SO_2, VOC, NO_X, CO, Pb, other:
Estimated amount of pollutant(s) emitted during emergency:
Describe the steps taken to mitigate the problem:
Describe the corrective actions/response steps taken:
Describe the measures taken to minimize emissions:
If applicable, describe the reasons why continued operation of the facilities are necessary to prevent imminent injury to persons, severe damage to equipment, substantial loss of capital investment, or loss of product or raw materials of substantial economic value:

Form Completed by:__________________________

Title / Position: __________________________

Date:__________________________

Phone: __________________________

A certification is not required for this report.

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

Part 70 Quarterly Report

Source Name: Duke Energy, Inc. - Cayuga Generating Station
Source Address: State Road 63, Cayuga, Indiana 47928
Part 70 Permit No.: T 165-27260-00001
Facility: Limestone Handling System
Parameter: Amount of limestone received
Limit: Less than 509,000 tons per twelve (12) consecutive month period with compliance determined at the end of each month. (Condition D.6.1(a))

QUARTER : YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________
Title / Position: ______________________
Signature: ______________________
Date: ______________________
Phone: ______________________

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

Part 70 Quarterly Report

Source Name:	Duke Energy Indiana, Inc. - Cayuga Generating Station
Source Address:	State Road 63, Cayuga, Indiana 47928
Part 70 Permit No.:	T 165-27260-00001
Facility:	Gypsum Handling System
Parameter:	The amount of gypsum received
Limit:	Less than 900,528 tons per twelve (12) consecutive month period with compliance determined at the end of each month. (Condition D.6.1(d))

QUARTER :   YEAR:

Month	Column 1	Column 2	Column 1 + Column 2
	This Month	Previous 11 Months	12 Month Total
Month 1			
Month 2			
Month 3			

☐ No deviation occurred in this quarter.

☐ Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ____________________
Title / Position: ____________________
Signature: ____________________
Date: ____________________
Phone: ____________________

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
COMPLIANCE AND ENFORCEMENT BRANCH
PART 70 OPERATING PERMIT
QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

Source Name: Duke Energy, Inc. - Cayuga Generating Station
Source Address: State Road 63, Cayuga, Indiana 47928
Part 70 Permit No.: T 165-27260-00001

Months: ______ to ________ Year: ________

Page 1 of 2

This report shall be submitted quarterly based on a calendar year. Any deviation from the requirements of this permit, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".	
☐ NO DEVIATIONS OCCURRED THIS REPORTING PERIOD.	
☐ THE FOLLOWING DEVIATIONS OCCURRED THIS REPORTING PERIOD	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	
Permit Requirement (specify permit condition #)	
Date of Deviation:	**Duration of Deviation:**
Number of Deviations:	
Probable Cause of Deviation:	
Response Steps Taken:	

Form Completed by: ______________________

Title / Position: ______________________

Date: ______________________

Phone: ______________________

Attach a signed certification that meets the requirements of 326 IAC 2-7-6(1) to complete this report.

Attachment A
Fugitive Dust Control Plan

Source Name: Duke Energy Indiana Inc., Cayuga Generating Station
Source Location: State Road 63, Cayuga, IN 46168
County: Vermillion
SIC Code: 4911
Permit Renewal No.: T 165-27260-00001

This fugitive dust plan is required under 326 IAC 6-1-5. This plan covers only those fugitive dust emitting processes/areas which are covered under the Significant Permit Modification #165-23011-00001 for the installation of a flue gas desulfurization (FGD) system. This plan includes the information required under 3267 IAC 6-5-5. The control measures identified in this plan are consistent with the requirements under 326 IAC 6-5-4.

Tables 1, 2 and 3 below identify each fugitive emissions area/process, the type of material handled, throughput, and control measures.

Table 1 - Limestone handling operations

Unit ID and Description	Maximum Throughput (units/hr)	Measures used to control fugitive emissions
TP-L1, transfer into hopper from railcar or truck	1000 tons/hr limestone	Fogging dust suppression
TP-L2 to L4, Truck and railcar unloading transfer points	1000 tons/hr limestone	Enclosure, Fogging dust suppression
TP-L5, transfer from conveyor LH-1 to active limestone pile	1000 tons/hr limestone	Telescoping chute
TP-L10 to L12, transfer points in the limestone reclaim hopper	400 tons/hr limestone	Enclosure, Fogging dust suppression
TP-L13, transfer from conveyor LH-2 to LH-3 within limestone prep. Building	400 tons/hr limestone	Enclosure, Fogging dust suppression
TP-L14, transfer point from conveyor LH-3 to day bin #1	400 tons/hr limestone	Enclosure
TP-L15, transfer point from conveyor LH-3 to day bin #2	400 tons/hr limestone	Enclosure
F-L6 & F-L7, Active limestone pile , dozer operations	NA	Clean around perimeter of the storage pile, watering as needed
F-L8 & F-L9, Inactive limestone pile , dozer operations	NA	Clean around perimeter of the storage pile, watering as needed

Table 2 - Gypsum dewatering process fugitive emissions points

Unit ID and Description	Maximum Throughput (units/hr)	Measures used to control fugitive emissions
TP-G1 to TP-G6, Gypsum Dewatering Building	150	Enclosed Transfer Point
TP-G7, Transfer Tower B-1	150	Enclosed Transfer Point
TP-G8, Transfer Tower A-1	150	Enclosed Transfer Point
TP-G9, Transferring gypsum from radial stacker conveyor GH-A1 to gypsum stock out pile	150	Readjust drop point to minimize fugitive PM emissions
TP-G10 , Transferring gypsum from conveyor GH-2B to emergency gypsum stock out pile (TP-G10)	150	Telescoping chute
F-G1 & F-G3, Gypsum Stock out pile and dozer operation	NA	Clean around the perimeter of pile, watering as needed
F-G2 & F-G3, Emergency Gypsum Stock out pile and dozer operation	NA	Clean around the perimeter of pile, watering as needed

Table 3 - Transport Gypsum Using Road Legal Trucks

Unit ID and Description	Maximum rate (units/hr)	Measures used to control fugitive emissions
F-4A & F-4B, Front end loader vehicle traffic and loading Gypsum into Road Legal Trucks at the gypsum pile.	891,770 tons/yr Gypsum	Minimize transport distance, wet suppression as needed
F-4C. Paved Road, Road Legal Truck Traffic to and from Landfill [1]	NA	Wet suppression as needed
F-4A & F-4F & F-4E, Landfill, Dozer and Compactor Traffic on the Landfill, Unloading Trucks At Landfill	NA	Wet suppression as needed

[1] Haul road to landfill shall be paved prior to hauling of Gypsum to the Landfill.

The station will keep records to document control measures and activities implemented to control fugitive dust emissions.

Attachment B
to a Part 70 Operating Permit

New Source Performance Standards (NSPS)

40 CFR 60, Subpart OOO— Standards of Performance for Nonmetallic Mineral Processing Plants

Source Name:	**Duke Energy Indiana Inc., Cayuga Generating Station**
Source Location:	**State Road 63, Cayuga, IN 46168**
County:	**Vermillion**
SIC Code:	**4911**
Operation Permit No.:	**T 165-27260-00001**
Operation Permit Issuance Date:	**August 20, 2009**
Significant Source Modification No.:	**165-32045-00001**
Significant Permit Modification No.:	**165-32048-00001**
Permit Reviewer:	**Josiah Balogun**

Subpart OOO—Standards of Performance for Nonmetallic Mineral Processing Plants

Source: 74 FR 19309, Apr. 28, 2009, unless otherwise noted.

§ 60.670 Applicability and designation of affected facility.

(a)(1) Except as provided in paragraphs (a)(2), (b), (c), and (d) of this section, the provisions of this subpart are applicable to the following affected facilities in fixed or portable nonmetallic mineral processing plants: each crusher, grinding mill, screening operation, bucket elevator, belt conveyor, bagging operation, storage bin, enclosed truck or railcar loading station. Also, crushers and grinding mills at hot mix asphalt facilities that reduce the size of nonmetallic minerals embedded in recycled asphalt pavement and subsequent affected facilities up to, but not including, the first storage silo or bin are subject to the provisions of this subpart.

(2) The provisions of this subpart do not apply to the following operations: All facilities located in underground mines; plants without crushers or grinding mills above ground; and wet material processing operations (as defined in §60.671).

(b) An affected facility that is subject to the provisions of subparts F or I of this part or that follows in the plant process any facility subject to the provisions of subparts F or I of this part is not subject to the provisions of this subpart.

(c) Facilities at the following plants are not subject to the provisions of this subpart:

(1) Fixed sand and gravel plants and crushed stone plants with capacities, as defined in §60.671, of 23 megagrams per hour (25 tons per hour) or less;

(2) Portable sand and gravel plants and crushed stone plants with capacities, as defined in §60 671, of 136 megagrams per hour (150 tons per hour) or less; and

(3) Common clay plants and pumice plants with capacities, as defined in §60.671, of 9 magagrams per hour (10 tons per hour) or less.

(d)(1) When an existing facility is replaced by a piece of equipment of equal or smaller size, as defined in §60.671, having the same function as the existing facility, and there is no increase in the amount of emissions, the new facility is exempt from the provisions of §§60.672, 60.674, and 60.675 except as provided for in paragraph (d)(3) of this section.

(2) An owner or operator complying with paragraph (d)(1) of this section shall submit the information required in §60.676(a).

(3) An owner or operator replacing all existing facilities in a production line with new facilities does not qualify for the exemption described in paragraph (d)(1) of this section and must comply with the provisions of §§60.672, 60.674 and 60 675.

(e) An affected facility under paragraph (a) of this section that commences construction, modification, or reconstruction after August 31, 1983, is subject to the requirements of this part.

(f) Table 1 of this subpart specifies the provisions of subpart A of this part 60 that do not apply to owners and operators of affected facilities subject to this subpart or that apply with certain exceptions.

§ 60.671 Definitions.

All terms used in this subpart, but not specifically defined in this section, shall have the meaning given them in the Act and in subpart A of this part.

Bagging operation means the mechanical process by which bags are filled with nonmetallic minerals.

Belt conveyor means a conveying device that transports material from one location to another by means of an endless belt that is carried on a series of idlers and routed around a pulley at each end.

Bucket elevator means a conveying device of nonmetallic minerals consisting of a head and foot assembly which supports and drives an endless single or double strand chain or belt to which buckets are attached.

Building means any frame structure with a roof.

Capacity means the cumulative rated capacity of all initial crushers that are part of the plant.

Capture system means the equipment (including enclosures, hoods, ducts, fans, dampers, etc.) used to capture and transport particulate matter generated by one or more affected facilities to a control device.

Control device means the air pollution control equipment used to reduce particulate matter emissions released to the atmosphere from one or more affected facilities at a nonmetallic mineral processing plant.

Conveying system means a device for transporting materials from one piece of equipment or location to another location within a plant. Conveying systems include but are not limited to the following: Feeders, belt conveyors, bucket elevators and pneumatic systems.

Crush or *Crushing* means to reduce the size of nonmetallic mineral material by means of physical impaction of the crusher or grinding mill upon the material.

Crusher means a machine used to crush any nonmetallic minerals, and includes, but is not limited to, the following types: Jaw, gyratory, cone, roll, rod mill, hammermill, and impactor.

Enclosed truck or railcar loading station means that portion of a nonmetallic mineral processing plant where nonmetallic minerals are loaded by an enclosed conveying system into enclosed trucks or railcars.

Fixed plant means any nonmetallic mineral processing plant at which the processing equipment specified in §60.670(a) is attached by a cable, chain, turnbuckle, bolt or other means (except electrical connections) to any anchor, slab, or structure including bedrock.

Fugitive emission means particulate matter that is not collected by a capture system and is released to the atmosphere at the point of generation.

Grinding mill means a machine used for the wet or dry fine crushing of any nonmetallic mineral. Grinding mills include, but are not limited to, the following types: Hammer, roller, rod, pebble and ball, and fluid energy. The grinding mill includes the air conveying system, air separator, or air classifier, where such systems are used.

Initial crusher means any crusher into which nonmetallic minerals can be fed without prior crushing in the plant.

Nonmetallic mineral means any of the following minerals or any mixture of which the majority is any of the following minerals:

(1) Crushed and Broken Stone, including Limestone, Dolomite, Granite, Traprock, Sandstone, Quartz, Quartzite, Marl, Marble, Slate, Shale, Oil Shale, and Shell.

(2) Sand and Gravel.

(3) Clay including Kaolin, Fireclay, Bentonite, Fuller's Earth, Ball Clay, and Common Clay.

(4) Rock Salt.

(5) Gypsum (natural or synthetic).

(6) Sodium Compounds, including Sodium Carbonate, Sodium Chloride, and Sodium Sulfate.

(7) Pumice.

(8) Gilsonite.

(9) Talc and Pyrophyllite

(10) Boron, including Borax, Kernite, and Colemanite.

(11) Barite.

(12) Fluorospar.

(13) Feldspar.

(14) Diatomite.

(15) Perlite.

(16) Vermiculite.

(17) Mica.

(18) Kyanite, including Andalusite, Sillimanite, Topaz, and Dumortierite.

Nonmetallic mineral processing plant means any combination of equipment that is used to crush or grind any nonmetallic mineral wherever located, including lime plants, power plants, steel mills, asphalt concrete plants, portland cement plants, or any other facility processing nonmetallic minerals except as providad in §60.670 (b) and (c).

Portable plant means any nonmetallic mineral processing plant that is mounted on any chassis or skids and may be moved by the application of a lifting or pulling force. In addition, there shall be no cable, chain, turnbuckle, bolt or other means (except electrical connections) by which any piece of equipment is attached or clamped to any anchor, slab, or structure, including bedrock that must be removed prior to the application of a lifting or pulling force for the purpose of transporting the unit.

Production line means all affected facilities (crushers, grinding mills, screening operations, bucket elevators, belt conveyors, bagging operations, storage bins, and enclosed truck and railcar loading stations) which are directly connected or are connected together by a conveying system.

Saturated material means, for purposes of this subpart, mineral material with sufficient surface moisture such that particulate matter emissions are not generated from processing of the material through screening operations, bucket elevators and belt conveyors. Material that is wetted solely by wet suppression systems is not considered to be "saturated" for purposes of this definition.

Screening operation means a device for separating material according to size by passing undersize material through one or more mesh surfaces (screens) in series, and retaining oversize material on the mesh surfaces (screens). Grizzly feeders associated with truck dumping and static (non-moving) grizzlies used anywhere in the nonmetallic mineral processing plant are not considered to be screening operations.

Seasonal shut down means shut down of an affected facility for a period of at least 45 consecutive days due to weather or seasonal market conditions.

Size means the rated capacity in tons per hour of a crusher, grinding mill, bucket elevator, bagging operation, or enclosed truck or railcar loading station; the total surface area of the top screen of a screening operation; the width of a conveyor belt; and the rated capacity in tons of a storage bin.

Stack emission means the particulate matter that is released to the atmosphere from a capture system.

Storage bin means a facility for storage (including surge bins) of nonmetallic minerals prior to further processing or loading.

Transfer point means a point in a conveying operation where the nonmetallic mineral is transferred to or from a belt conveyor except where the nonmetallic mineral is being transferred to a stockpile.

Truck dumping means the unloading of nonmetallic minerals from movable vehicles designed to transport nonmetallic minerals from one location to another. Movable vehicles includa but are not limited to: Trucks, front end loaders, skip hoists, and railcars.

Vent means an opening through which there is mechanically induced air flow for the purpose of exhausting from a building air carrying particulate matter emissions from one or more affected facilities.

Wet material processing oparation(s) means any of the following:

(1) Wet screening operations (as defined in this section) and subsequent screening operations, bucket elevators and belt conveyors in the production line that process saturated materials (as defined in this section) up to the first crusher, grinding mill or storage bin in the production line; or

(2) Screening operations, bucket elevators and belt conveyors in the production line downstream of wet mining operations (as defined in this section) that process saturated materials (as defined in this section) up to the first crusher, grinding mill or storage bin in the production line.

Wet mining operation means a mining or dredging operation designed and operated to extract any nonmetallic mineral regulated under this subpart from deposits existing at or below the water table, where the nonmetallic mineral is saturated with water.

Wet screening operation means a screening operation at a nonmetallic mineral processing plant which removes unwanted material or which separates marketable fines from the product by a washing process which is designed and operated at all times such that the product is saturated with water.

§ 60.672 Standard for particulate matter (PM).

(a) Affected facilities must meet the stack emission limits and compliance requirements in Table 2 of this subpart within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under §60 8. The requirements in Table 2 of this subpart apply for affected facilities with capture systems used to capture and transport particulate matter to a control device.

(b) Affected facilities must meet the fugitive emission limits and compliance requirements in Table 3 of this subpart within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup as required under §60.11. The requirements in Table 3 of this subpart apply for fugitive emissions from affected facilities without capture systems and for fugitive emissions escaping capture systems.

(c) [Reserved]

(d) Truck dumping of nonmetallic minerals into any screening operation, feed hopper, or crusher is exempt from the requirements of this section.

(e) If any transfer point on a conveyor belt or any other affected facility is enclosed in a building, then each enclosed affected facility must comply with the emission limits in paragraphs (a) and (b) of this section, or the building enclosing the affected facility or facilities must comply with the following emission limits:

(1) Fugitive emissions from the building openings (except for vents as defined in §60.671) must not exceed 7 percent opacity; and

(2) Vents (as defined in §60.671) in the building must meet the applicable stack emission limits and compliance requirements in Table 2 of this subpart.

(f) Any baghouse that controls emissions from only an individual, enclosed storage bin is exempt from the applicable stack PM concentration limit (and associated performance testing) in Table 2 of this subpart but must meet the applicable stack opacity limit and compliance requirements in Table 2 of this subpart. This exemption from the stack PM concentration limit does not apply for multiple storage bins with combined stack emissions.

§ 60.673 Reconstruction.

(a) The cost of replacement of ore-contact surfaces on processing equipment shall not be considered in calculating either the "fixed capital cost of the new components" or the "fixed capital cost that would be required to construct a comparable new facility" under §60.15. Ore-contact surfaces are crushing surfaces; screen meshes, bars, and plates; conveyor belts; and elevator buckets.

(b) Under §60.15, the "fixed capital cost of the new components" includes the fixed capital cost of all depreciable components (except components specified in paragraph (a) of this section) which are or will be replaced pursuant to all continuous programs of component replacement commenced within any 2-year period following August 31, 1983.

§ 60.674 Monitoring of operations.

(a) The owner or operator of any affected facility subject to the provisions of this subpart which uses a wet scrubber to control emissions shall install, calibrate, maintain and operate the following monitoring devices:

(1) A device for the continuous measurement of the pressure loss of the gas stream through the scrubber. The monitoring device must be certified by the manufacturer to be accurate within ±250 pascals ±1 inch water gauge pressure and must be calibrated on an annual basis in accordance with manufacturer's instructions.

(2) A device for the continuous measurement of the scrubbing liquid flow rate to the wet scrubber. The monitoring device must be certified by the manufacturer to be accurate within ±5 percent of design scrubbing liquid flow rate and must be calibrated on an annual basis in accordance with manufacturer's instructions.

(b) The owner or operator of any affected facility for which construction, modification, or reconstruction commenced on or after April 22, 2008, that uses wet suppression to control emissions from the affected facility must perform monthly periodic inspections to check that water is flowing to discharge spray nozzles in the wet suppression system. The owner or operator must initiate corrective action within 24 hours and complete corrective action as expediently as practical if the owner or operator finds that water is not flowing properly during an inspection of the water spray nozzles. The owner or operator must record each inspection of the water spray nozzles, including the date of each inspection end eny corrective actions taken, in the logbook required under §60.676(b).

(1) If an affected facility relies on water carryover from upstream water sprays to control fugitive emissions, then that effected facility is exempt from the 5-year repeat testing requirement specified in Table 3 of this subpart provided that the affected facility meets the criteria in paragraphs (b)(1)(i) and (ii) of this section:

(i) The owner or operator of the affected facility conducts periodic inspections of the upstream water spray(s) that are responsible for controlling fugitive emissions from the affected facility. These inspections are conducted according to paragraph (b) of this section and §60 676(b), and

(ii) The owner or operator of the affected facility designates which upstream water spray(s) will be periodically inspected at the time of tha initial performance test required under §60.11 of this part and §60.675 of this subpart.

(2) If an affected facility that routinely uses wet suppression water sprays ceases operation of the water sprays or is using a control mechanism to reduce fugitive emissions other than water sprays during the monthly inspection (for example, water from recent rainfall), the logbook entry required under §60.676(b) must specify the control mechanism being used instead of the water sprays.

(c) Except es specified in paragraph (d) or (e) of this section, the owner or operator of any affected facility for which construction, modification, or reconstruction commenced on or after April 22, 2008, that uses a baghouse to control emissions must conduct quarterly 30-minute visible emissions inspections using EPA Method 22 (40 CFR part 60, Appendix A–7). The Method 22 (40 CFR part 60, Appendix A–7) test shall be conducted while the baghouse is operating. The test is successful if no visible emissions are observed. If any visible emissions ere observed, the owner or operator of the affected facility must initiate corrective action within 24 hours to return the baghouse to normal operation. The owner or operator must record each Method 22 (40 CFR part 60, Appendix A–7) test, including the date and any corrective actions taken, in the logbook required under §60.676(b). The owner or operator of the affected facility may establish a different baghouse-specific success level for the visible emissions test (other than no visible emissions) by conducting a PM performance test according to §60.675(b) simultaneously with a Method 22 (40 CFR part 60, Appendix A–7) to determine what constitutes normal visible emissions from that affected facility's baghouse when it is in compliance with the applicable PM concentration limit in Table 2 of this subpart. The revised visible emissions success level must be incorporated into the permit for the affected facility.

(d) As en alternative to the periodic Method 22 (40 CFR part 60, Appendix A–7) visible emissions inspections specified in paragraph (c) of this section, the owner or operator of any affected facility for which construction, modification, or reconstruction commenced on or after April 22, 2008, that uses a baghouse to control emissions may use a bag leak detection system. The owner or operator must install, operate, and maintain the bag leak detection system according to peragraphs (d)(1) through (3) of this section.

(1) Each bag leak detection system must meet the specifications end requirements in paragraphs (d)(1)(i) through (viii) of this section.

(i) The bag leak detection system must be certified by the manufacturer to be capable of detecting PM emissions at concentrations of 1 milligram per dry standard cubic meter (0.00044 grains per actual cubic foot) or less.

(ii) The bag leak detection system sensor must provide output of relative PM loadings. The owner or operator shall continuously record the output from the bag leak detection system using electronic or other means (*e g* , using a strip chart recorder or a data logger).

(iii) The bag leak detection system must be equipped with an alarm system that will sound when the system detects an increase in relative particulate loading over the alarm set point established according to paragraph (d)(1)(iv) of this section, and the alarm must be located such that it can be heard by the appropriate plant personnel.

(iv) In the initial adjustment of the bag leak detection system, the owner or operator must establish, at a minimum, the baseline output by adjusting the sensitivity (range) and the averaging period of the device, the alarm set points, and the alarm delay time.

(v) Following initial adjustment, the owner or operator shall not adjust the averaging period, alarm set point, or alarm delay time without approval from the Administrator or delegated authority except as provided in paragraph (d)(1)(vi) of this section.

(vi) Once per quarter, the owner or operator may adjust the sensitivity of the bag leak detection system to account for seasonal effects, including temperature end humidity, according to the procedures identified in the site-specific monitoring plan required by paragraph (d)(2) of this section.

(vii) The owner or operator must install the bag leak detection sensor downstream of the fabric filter.

(viii) Where multiple detectors are required, the system's instrumentation and alarm may be shared among detectors.

(2) The owner or operator of the affected facility must develop and submit to the Administrator or delegated authority for approval of a site-specific monitoring plan for each bag leak detection system. The owner or operator must operate and maintain the bag leak detection system according to the site-specific monitoring plan at all times. Each monitoring plan must describe the items in paragraphs (d)(2)(i) through (vi) of this section.

(i) Installation of the bag leak detection system;

(ii) Initial and periodic adjustment of the bag leak detection system, including how the alarm set-point will be established;

(iii) Operation of the bag leak detection system, including quality assurance procedures;

(iv) How the bag leak detection system will be maintained, including e routine maintenance schedule and spare parts inventory list;

(v) How the bag leak detection system output will be recorded and stored; and

(vi) Corrective action procedures es specified in paragraph (d)(3) of this section. In approving the site-specific monitoring plan, the Administrator or delegated authority may allow owners and operators more than 3 hours to alleviate a specific condition that causes an alarm if the owner or operator identifies in the monitoring plan this specific condition as one that could lead to an alarm, edequately explains why it is not feasible to alleviate this condition within 3 hours of the time the alarm occurs, and demonstrates that the requested time will ensure alleviation of this condition as expeditiously as practicable.

(3) For each bag leak detection system, the owner or operator must initiate procedures to determine the cause of every alarm within 1 hour of the alarm. Except as provided in paragraph (d)(2)(vi) of this section, the owner or operator must alleviate the cause of the alarm within 3 hours of the alarm by taking whatever corrective action(s) are necessary. Corrective ections may include, but ere not limited to the following:

(i) Inspecting the fabric filter for air leaks, torn or broken bags or filter media, or any other condition that may cause an increase in PM emissions;

(ii) Sealing off defective bags or filter media;

(iii) Replacing defective bags or filter media or otherwise repairing the control device;

(iv) Sealing off a defective fabric filter compartment;

(v) Cleaning the bag leak detection system probe or otherwise repairing the bag leak detection system; or

(vi) Shutting down the process producing the PM emissions.

(e) As an alternative to the periodic Method 22 (40 CFR part 60, Appendix A–7) visible emissions inspections specified in paragraph (c) of this section, the owner or operator of any affected facility that is subject to the requirements for processed stone handling operations in the Lime Manufacturing NESHAP (40 CFR part 63, subpart AAAAA) may follow the continuous compliance requirements in row 1 items (i) through (iii) of Table 6 to Subpart AAAAA of 40 CFR part 63.

§ 60.675 Test methods and procedures.

(a) In conducting the performance tests required in §60.8, the owner or operator shall use as reference methods and procedures the test methods in appendices A–1 through A–7 of this part or other methods and procedures as specified in this section, except as provided in §60.8(b). Acceptable alternative methods and procedures are given in paragraph (e) of this section.

(b) The owner or operator shall determine compliance with the PM standards in §60.672(a) as follows:

(1) Except as specified in paragraphs (e)(3) and (4) of this section, Method 5 of Appendix A–3 of this part or Method 17 of Appendix A–6 of this part shall be used to determine the particulate matter concentration. The sample volume shall be at least 1.70 dscm (60 dscf). For Method 5 (40 CFR part 60, Appendix A–3), if the gas stream being sampled is at ambient temperature, the sampling probe and filter may be operated without heaters. If the gas stream is above ambient temperature, the sampling probe and filter may be operated at a temperature high enough, but no higher than 121 °C (250 °F), to prevent water condensation on the filter.

(2) Method 9 of Appendix A–4 of this part and the procedures in §60.11 shall be used to determine opacity.

(c)(1) In determining compliance with the particulate matter standards in §60.672(b) or §60.672(e)(1), the owner or operator shall use Method 9 of Appendix A–4 of this part and the procedures in §60.11, with the following additions:

(i) The minimum distance between the observer and the emission source shall be 4.57 meters (15 feet).

(ii) The observer shall, when possible, select a position that minimizes interference from other fugitive emission sources (*e.g* , road dust). The required observer position relative to the sun (Method 9 of Appendix A–4 of this part, Section 2.1) must be followed.

(iii) For affected facilities using wet dust suppression for particulate matter control, a visible mist is sometimes generated by the spray. The water mist must not be confused with particulate matter emissions and is not to be considered a visible emission. When a water mist of this nature is present, the observation of emissions is to be made at a point in the plume where the mist is no longer visible.

(2)(i) In determining compliance with the opacity of stack emissions from any baghouse that controls emissions only from an individual enclosed storage bin under §60.672(f) of this subpart, using Method 9 (40 CFR part 60, Appendix A–4), the duration of the Method 9 (40 CFR part 60, Appendix A–4) observations shall be 1 hour (ten 6-minute averages).

(ii) The duration of the Method 9 (40 CFR part 60, Appendix A–4) observations may be reduced to the duration the affected facility operates (but not less than 30 minutes) for baghouses that control storage bins or enclosed truck or railcar loading stations that operate for less than 1 hour at a time.

(3) When determining compliance with the fugitive emissions standard for any affected facility described under §60.672(b) or §60.672(e)(1) of this subpart, the duration of the Method 9 (40 CFR part 60, Appendix A–4) observations must be 30 minutes (five 6-minute averages). Compliance with the applicable fugitive emission limits in Table 3 of this subpart must be based on the average of the five 6-minute averages.

(d) To demonstrate compliance with the fugitive emission limits for buildings specified in §60.672(e)(1), the owner or operator must complete the testing specified in paragraph (d)(1) and (2) of this section. Performance tests must be conducted while all affected facilities inside the building are operating.

(1) If the building encloses any affected facility that commences construction, modification, or reconstruction on or after April 22, 2008, the owner or operator of the affected facility must conduct an initial Method 9 (40 CFR part 60, Appendix A–4) performance test according to this section and §60.11.

(2) If the building encloses only affected facilities that commenced construction, modification, or reconstruction before April 22, 2008, and the owner or operator has previously conducted an initial Method 22 (40 CFR part 60, Appendix A–7) performance test showing zero visible emissions, then the owner or operator has demonstrated compliance with the opacity limit in §60 672(e)(1). If the owner or operator has not conducted an initial performance test for the building before April 22, 2008, then the owner or operator must conduct an initial Method 9 (40 CFR part 60, Appendix A–4) performance test according to this section and §60.11 to show compliance with the opacity limit in §60.672(e)(1).

(e) The owner or operator may use the following as alternatives to the reference methods and procedures specified in this section:

(1) For the method and procedure of paragraph (c) of this section, if emissions from two or more facilities continuously interfere so that the opacity of fugitive emissions from an individual affected facility cannot be read, either of the following procedures may be used:

(i) Use for the combined emission stream the highest fugitive opacity standard applicable to any of the individual affected facilities contributing to the emissions stream.

(ii) Separate the emissions so that the opacity of emissions from each affected facility can be read.

(2) A single visible emission observer may conduct visible emission observations for up to three fugitive, stack, or vent emission points within a 15-second interval if the following conditions are met:

(i) No more than three emission points may be read concurrently.

(ii) All three emission points must be within a 70 degree viewing sector or angle in front of the observer such that the proper sun position can be maintained for all three points.

(iii) If an opacity reading for any one of the three emission points equals or exceeds the applicable standard, then the observer must stop taking readings for the other two points and continue reading just that single point.

(3) Method 5I of Appendix A–3 of this part may be used to determine the PM concentration as an alternative to the methods specified in paragraph (b)(1) of this section. Method 5I (40 CFR part 60, Appendix A–3) may be useful for affected facilities that operate for less than 1 hour at a time such as (but not limited to) storage bins or enclosed truck or railcar loading stations.

(4) In some cases, velocities of exhaust gases from building vents may be too low to measure accurately with the type S pitot tube specified in EPA Method 2 of Appendix A–1 of this part [*i e.*, velocity head <1.3 mm H_2O (0.05 in. H_2O)] and referred to in EPA Method 5 of Appendix A–3 of this part. For these conditions, the owner or operator may determine the average gas flow rate produced by the power fans (*e g.*, from vendor-supplied fan curves) to the

building vent. The owner or operator may calculate the average gas velocity at the building vent measurement site using Equation 1 of this section and use this average velocity in determining and maintaining isokinetic sampling rates.

$$v_e = \frac{Q_f}{A_e} \quad \text{(Eq 1)}$$

Where:

V_e= average building vent velocity (feet per minute);

Q_f= average fan flow rate (cubic feet per minute); and

A_e= area of building vent and measurement location (square feet).

(f) To comply with §60.676(d), the owner or operator shall record the measurements as required in §60 676(c) using the monitoring devices in §60.674 (a)(1) and (2) during each particulate matter run and shall determine the averages

(g) For performance tests involving only Method 9 (40 CFR part 60 Appendix A–4) testing, the owner or operator may reduce the 30-day advance notification of performance test in §60.7(a)(6) and 60.8(d) to a 7-day advance notification.

(h) [Reserved]

(i) If the initial performance test date for an affected facility falls during a seasonal shut down (as defined in §60 671 of this subpart) of the affected facility, then with approval from the permitting authority, the owner or operator may postpone the initial performance test until no later than 60 calendar days after resuming operation of the affected facility.

§ 60.676 Reporting and recordkeeping.

(a) Each owner or operator seeking to comply with §60.670(d) shall submit to the Administrator the following information about the existing facility being replaced and the replacement piece of equipment.

(1) For a crusher, grinding mill, bucket elevator, bagging operation, or enclosed truck or railcar loading station:

(i) The rated capacity in megagrams or tons per hour of the existing facility being replaced and

(ii) The rated capacity in tons per hour of the replacement equipment.

(2) For a screening operation:

(i) The total surface area of the top screen of the existing screening operation being replaced and

(ii) The total surface area of the top screen of the replacement screening operation.

(3) For a conveyor belt:

(i) The width of the existing belt being replaced and

(ii) The width of the replacement conveyor belt.

(4) For a storage bin:

(i) The rated capacity in megagrams or tons of the existing storage bin being replaced and

(ii) The rated capacity in megagrams or tons of replacement storage bins.

(b)(1) Owners or operators of affected facilities (as defined in §§60 670 and 60 671) for which construction, modification, or reconstruction commenced on or after April 22, 2008, must record each periodic inspection required under §60.674(b) or (c), including dates and any corrective actions taken, in a logbook (in written or electronic format). The owner or operator must keep the logbook onsite and make hard or electronic copies (whichever is requested) of the logbook available to the Administrator upon request.

(2) For each bag leak detection system installed and operated according to §60.674(d), the owner or operator must keep the records specified in paragraphs (b)(2)(i) through (iii) of this section.

(i) Records of the bag leak detection system output;

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings; and

(iii) The date end time of all bag leak detection system alarms, the time that procedures to determine the cause of the alarm were initiated, the cause of the alarm, an explanation of the actions taken, the date and time the cause of the alarm was alleviated, and whether the cause of the alarm was alleviated within 3 hours of the alarm.

(3) The owner or operator of each affected facility demonstrating compliance according to §60.674(e) by following the requirements for processed stone handling operations in the Lime Manufacturing NESHAP (40 CFR part 63, subpart AAAAA) must maintain records of visible emissions observations required by §63.7132(a)(3) and (b) of 40 CFR part 63, subpart AAAAA.

(c) During the initial performance test of a wet scrubber, and daily thereafter, the owner or operator shall record the measurements of both the change in pressure of the gas stream across the scrubber and the scrubbing liquid flow rate.

(d) After the initial performance test of a wet scrubber, the owner or operator shall submit semiannual reports to the Administrator of occurrences when the measurements of the scrubber pressure loss and liquid flow rate decrease by more than 30 percent from the average determined during the most recent performance test.

(e) The reports required under paragraph (d) of this section shall be postmarked within 30 days following end of the second and fourth calendar quarters.

(f) The owner or operator of any affected facility shall submit written reports of the results of all performance tests conducted to demonstrate compliance with the standards set forth in §60.672 of this subpart, including reports of opacity observations made using Method 9 (40 CFR part 60, Appendix A–4) to demonstrate compliance with §60.672(b), (e) and (f).

(g) The owner or operator of any wet material processing operation that processes saturated and subsequently processes unsaturated materials, shall submit a report of this change within 30 days following such change. At the time of such change, this screening operation, bucket elevator, or belt conveyor becomes subject to the applicable opacity limit in §60.672(b) and the emission test requirements of §60.11.

(h) The subpart A requirement under §60.7(a)(1) for notification of the date construction or reconstruction commenced is waived for affected facilities under this subpart.

(i) A notification of the actual date of initial startup of each affected facility shall be submitted to the Administrator.

(1) For a combination of affected facilities in a production line that begin actual initial startup on the same day, a single notification of startup may be submitted by the owner or operator to the Administrator. The notification shall be

postmarked within 15 days after such date and shall include a description of each affected facility, equipment manufacturer, and serial number of the equipment, if available.

(2) For portable aggregate processing plants, the notification of the actual date of initial startup shall include both the home office and the current address or location of the portable plant.

(j) The requirements of this section remain in force until and unless the Agency, in delegating enforcement authority to a State under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such States. In that event, affected facilities within the State will be relieved of the obligation to comply with the reporting requirements of this section, provided that they comply with requirements established by the State.

(k) Notifications and reports required under this subpart and under subpart A of this part to demonstrate compliance with this subpart need only to be sent to the EPA Region or the State which has been delegated authority according to §60.4(b).

Table 1 to Subpart OOO—Exceptions to Applicability of Subpart A to Subpart OOO

Table 1 to Subpart OOO—Exceptions to Applicability of Subpart A to Subpart OOO

Subpart A reference	Applies to subpart OOO	Explanation
60.4, Address	Yes	Except in §60.4(a) and (b) submittals need not be submitted to both the EPA Region and delegated State authority (§60.676(k)).
60.7, Notification and recordkeeping	Yes	Except in (a)(1) notification of the date construction or reconstruction commenced (§60.676(h)).
		Also, except in (a)(6) performance tests involving only Method 9 (40 CFR part 60, Appendix A–4) require a 7-day advance notification instead of 30 days (§60.675(g)).
60.8, Performance tests	Yes	Except in (d) performance tests involving only Method 9 (40 CFR part 60, Appendix A–4) require a 7-day advance notification instead of 30 days (§60.675(g)).
60.11, Compliance with standards and maintenance requirements	Yes	Except in (b) under certain conditions (§§60.675(c)), Method 9 (40 CFR part 60, Appendix A–4) observation is reduced from 3 hours to 30 minutes for fugitive emissions.
60.18, General control device	No	Flares will not be used to comply with the emission limits.

Table 2 to Subpart OOO—Stack Emission Limits for Affected Facilities With Capture Systems

Table 2 to Subpart OOO—Stack Emission Limits for Affected Facilities With Capture Systems

For * * *	The owner or operator must meet a PM limit of * * *	And the owner or operator must meet an opacity limit of * * *	The owner or operator must demonstrate compliance with these limits by conducting * * *
Affected facilities (as defined in §§60.670 and 60.671) that commenced construction, modification, or reconstruction after August 31, 1983 but before April 22, 2008	0.05 g/dscm (0.022 gr/dscf)[a]	7 percent for dry control devices[b]	An initial performance test according to §60.8 of this part and §60.675 of this subpart; and Monitoring of wet scrubber parameters according to §60.674(a) and §60.676(c), (d), and (e).
Affected facilities (as defined in §§60.670 and 60.671) that commence construction, modification, or reconstruction on or after April 22, 2008	0.032 g/dscm (0.014 gr/dscf)[a]	Not applicable (except for individual enclosed storage bins) 7 percent for dry control devices on individual enclosed storage bins	An initial performance test according to §60.8 of this part and §60.675 of this subpart; and Monitoring of wet scrubber parameters according to §60.674(a) and §60.676(c), (d), and (e); and
			Monitoring of baghouses according to §60.674(c), (d), or (e) and §60.676(b).

[a]Exceptions to the PM limit apply for individual enclosed storage bins and other equipment. See §60.672(d) through (f).

[b]The stack opacity limit and associated opacity testing requirements do not apply for affected facilities using wet scrubbers.

Table 3 to Subpart OOO—Fugitive Emission Limits

Table 3 to Subpart OOO—Fugitive Emission Limits

For * * *	The owner or operator must meet the following fugitive emissions limit	The owner or operator must meet the	The owner or operator must demonstrate compliance with these limits by

	for grinding mills, screening operations, bucket elevators, transfer points on belt conveyors, bagging operations, storage bins, enclosed truck or railcar loading stations or from any other affected facility (as defined in §§60.670 and 60.671) * * *	following fugitive emissions limit for crushers at which a capture system is not used * * *	conducting * * *
Affected facilities (as defined in §§60.670 and 60.671) that commenced construction, modification, or reconstruction after August 31, 1983 but before April 22, 2008	10 percent opacity	15 percent opacity	An initial performance test according to §60.11 of this part and §60.675 of this subpart.
Affected facilities (as defined in §§60.670 and 60.671) that commence construction, modification, or reconstruction on or after April 22, 2008	7 percent opacity	12 percent opacity	An initial performance test according to §60.11 of this part and §60.675 of this subpart; and Periodic inspections of water sprays according to §60.674(b) and §60.676(b); and
			A repeat performance test according to §60.11 of this part and §60.675 of this subpart within 5 years from the previous performance test for fugitive emissions from affected facilities without water sprays. Affected facilities controlled by water carryover from upstream water sprays that are inspected according to the requirements in §60.674(b) and §60.676(b)

			are exempt from this 5-year repeat testing requirement.

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Attachment C: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines [40 CFR 60, Subpart IIII]

Source Description and Location	
Source Name:	Duke Energy Indiana Inc., Cayuga Generating Station
Source Location:	State Road 63, Cayuga, IN 46168
County:	Vermillion
SIC Code:	4911
Operation Permit No.:	T 165-27260-00001
Operation Permit Issuance Date:	August 20, 2009
Significant Source Modification No.:	165-32045-00001
Significant Permit Modification No.:	165-32048-00001
Permit Reviewer:	Josiah Balogun

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

Source: 71 FR 39172, July 11, 2006, unless otherwise noted.

What This Subpart Covers

§ 60.4200 Am I subject to this subpart?

(a) The provisions of this subpart are applicable to manufacturers, owners, and operators of stationary compression ignition (CI) internal combustion engines (ICE) as specified in paragraphs (a)(1) through (3) of this section. For the purposes of this subpart, the date that construction commences is the date the engine is ordered by the owner or operator.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines,

(ii) The model year listed in table 3 to this subpart or later model year, for fire pump engines.

(2) Owners and operators of stationary CI ICE that commence construction after July 11, 2005 where the stationary CI ICE are:

(i) Manufactured after April 1, 2006 and are not fire pump engines, or

(ii) Manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

(3) Owners and operators of stationary CI ICE that modify or reconstruct their stationary CI ICE after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

Emission Standards for Manufacturers

§ 60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

§ 60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power.

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

§ 60.4203 How long must my engines meet the emission standards if I am a stationary CI internal combustion engine manufacturer?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the useful life of the engines.

Emission Standards for Owners and Operators

§ 60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (c)(1) and (2) of this section.

(1) Reduce nitrogen oxides (NO_X) emissions by 90 percent or more, or limit the emissions of NO_xin the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (g/KW-hr) (1.2 grams per HP-hour (g/HP-hr)).

(2) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4205 What emission standards must I meet for emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(c) Owners and operators of fire pump engines with a displacement of less than 30 liters per cylinder must comply with the emission standards in table 4 to this subpart, for all pollutants.

(d) Owners and operators of emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in paragraphs (d)(1) and (2) of this section.

(1) Reduce NO_xemissions by 90 percent or more, or limit the emissions of NO_xin the stationary CI internal combustion engine exhaust to 1.6 grams per KW-hour (1.2 grams per HP-hour).

(2) Reduce PM emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

§ 60.4206 How long must I meet the emission standards if I am an owner or operator of a stationary CI internal combustion engine?

Owners and operators of stationary CI ICE must operate and maintain stationary CI ICE that achieve the emission standards as required in §§60.4204 and 60.4205 according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer, over the entire life of the engine.

Fuel Requirements for Owners and Operators

§ 60.4207 What fuel requirements must I meet if I am an owner or operator of a stationary CI internal combustion engine subject to this subpart?

(a) Beginning October 1, 2007, owners and operators of stationary CI ICE subject to this subpart that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(a).

(b) Beginning October 1, 2010, owners and operators of stationary CI ICE subject to this subpart with a displacement of less than 30 liters per cylinder that use diesel fuel must use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel.

(c) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart may petition the Administrator for approval to use remaining non-compliant fuel that does not meet the fuel requirements of paragraphs (a) and (b) of this section beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(d) Owners and operators of pre-2011 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the Federal Aid Highway System may petition the Administrator for approval to use any fuels mixed with used lubricating oil that do not meet the fuel requirements of paragraphs (a) and (b) of this section. Owners and operators must demonstrate in their petition to the Administrator that there is no other place to use the lubricating oil. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the owner or operator is required to submit a new petition to the Administrator.

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

Other Requirements for Owners and Operators

§ 60.4208 What is the deadline for importing or installing stationary CI ICE produced in the previous model year?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (f) of this section after the dates specified in paragraphs (a) through (f) of this section.

(h) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

§ 60.4209 What are the monitoring requirements if I am an owner or operator of a stationary CI internal combustion engine?

If you are an owner or operator, you must meet the monitoring requirements of this section. In addition, you must also meet the monitoring requirements specified in §60.4211.

(a) If you are an owner or operator of an emergency stationary CI internal combustion engine, you must install a non-resettable hour meter prior to startup of the engine.

(b) If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in §60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.

Compliance Requirements

§ 60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and §60.4202(c) using the certification procedures required in 40 CFR part 94 subpart C, and must test their engines as specified in 40 CFR part 94.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 40 CFR 1039.125, 40 CFR 1039.130, 40 CFR 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89 or 40 CFR part 94 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in part 89, 94 or 1039, as appropriate, but the words "stationary" must be included instead of "nonroad" or "marine" on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under parts 89, 94, or 1039 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words "and stationary" after the word "nonroad" or "marine," as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as "Fire Pump Applications Only".

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

§ 60.4211 What are my compliance requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) If you are an owner or operator and must comply with the emission standards specified in this subpart, you must operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's written instructions or procedures developed by the owner or operator that are approved by the engine manufacturer. In addition, owners and operators may only change those settings that are permitted by the manufacturer. You must also meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply to you.

(b) If you are an owner or operator of a pre-2007 model year stationary CI internal combustion engine and must comply with the emission standards specified in §§60.4204(a) or 60.4205(a), or if you are an owner or operator of a CI fire pump engine that is manufactured prior to the model years in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must demonstrate compliance according to one of the methods specified in paragraphs (b)(1) through (5) of this section.

(1) Purchasing an engine certified according to 40 CFR part 89 or 40 CFR part 94, as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications.

(2) Keeping records of performance test results for each pollutant for a test conducted on a similar engine. The test must have been conducted using the same methods specified in this subpart and these methods must have been followed correctly.

(3) Keeping records of engine manufacturer data indicating compliance with the standards.

(4) Keeping records of control device vendor data indicating compliance with the standards.

(5) Conducting an initial performance test to demonstrate compliance with the emission standards according to the requirements specified in §60.4212, as applicable.

(c) If you are an owner or operator of a 2007 model year and later stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(b) or §60.4205(b), or if you are an owner or operator of a CI fire pump engine that is manufactured during or after the model year that applies to your fire pump engine power rating in table 3 to this subpart and must comply with the emission standards specified in §60.4205(c), you must comply by purchasing an engine certified to the emission standards in §60.4204(b), or §60.4205(b) or (c), as applicable, for the same model year and maximum (or in the case of fire pumps, NFPA nameplate) engine power. The engine must be installed and configured according to the manufacturer's specifications.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and $NO_x$and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit $NO_x$and PM emissions;

(iii) A discussion of how you wiii establish the upper and/or lower values for these parameters which wiii establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you wiil use to monitor these parameters, as weii as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local govemment, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. Anyone may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. For owners and operators of emergency engines meeting standards under §60.4205 but not §60.4204, any operation other than emergency operation, and maintenance and testing as permitted in this section, is prohibited.

Testing Requirements for Owners and Operators

§ 60.4212 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of less than 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests pursuant to this subpart must do so according to paragraphs (a) through (d) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F.

(b) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1039 must not exceed the not-to-exceed (NTE) standards for the same model year and maximum engine power as required in 40 CFR 1039.101(e) and 40 CFR 1039.102(g)(1), except as specified in 40 CFR 1039.104(d). This requirement starts when NTE requirements take effect for nonroad diesel engines under 40 CFR part 1039.

(c) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8, as applicable, must not exceed the NTE numerical requirements, rounded to the same number of decimai places as the applicable standard in 40 CFR 89.112 or 40 CFR 94.8, as applicable, determined from the following equation:

$$\text{NTE requirement for each pollutant} = (1.25) \times (STD) \qquad \text{(Eq 1)}$$

Where:

STD = The standard specified for that pollutant in 40 CFR 89.112 or 40 CFR 94.8, as applicable.

Alternatively, stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR 89.112 or 40 CFR 94.8 may follow the testing procedures specified in §60.4213 of this subpart, as appropriate.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

§ 60.4213 What test methods and other procedures must I use if I am an owner or operator of a stationary CI internal combustion engine with a displacement of greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (d) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq 2)}$$

Where:

C_i= concentration of NO_Xor PM at the control device inlet,

C_o= concentration of NO_Xor PM at the control device outlet, and

R = percent reduction of NO_Xor PM emissions.

(2) You must normalize the NO_xor PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \% O_2} \qquad \text{(Eq 3)}$$

Where:

C_{adj}= Calculated NO_Xor PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$= Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209_{F_d}}{F_c} \quad \text{(Eq 4)}$$

Where:

F_o= Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

F_c= Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm^3 /J (dscf/10^6 Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \quad \text{(Eq 5)}$$

Where:

X_{CO2}= CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_x and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \quad \text{(Eq 6)}$$

Where:

C_{adj}= Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d= Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$= Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_x mass per unit output emission limitation, convert the concentration of NO_x in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \quad \text{(Eq 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d= Measured NO_X concentration in ppm.

1.912×10^{-3} = Conversion constant for ppm NO_x to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj}= Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

Notification, Reports, and Records for Owners and Operators

§ 60.4214 What are my notification, reporting, and recordkeeping requirements if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI Internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(b) If the stationary CI internal combustion engine is an emergency stationary internal combustion engine, the owner or operator is not required to submit an initial notification. Starting with the model years in table 5 to this subpart, if the emergency engine does not meet the standards applicable to non-emergency engines in the applicable model year, the owner or operator must keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. The owner must record the time of operation of the engine and the reason the engine was in operation during that time.

(c) If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.

Special Requirements

§ 60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §60.4205. Non-emergency stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder, must meet the applicable emission standards in §60.4204(c).

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northem Mariana Islands are not required to meet the fuel requirements in §60.4207.

§ 60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI engines located in areas of Alaska not accessible by the Federal Aid Highway System should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) The Governor of Alaska may submit for EPA approval, by no later than January 11, 2008, an alternative plan for implementing the requirements of 40 CFR part 60, subpart IIII, for public-sector electrical utilities located in rural areas of Alaska not accessible by the Federal Aid Highway System. This alternative plan must be based on the requirements of section 111 of the Clean Air Act including any increased risks to human health and the environment and must also be based on the unique circumstances related to remote power generation, climatic conditions, and serious economic impacts resulting from implementation of 40 CFR part 60, subpart IIII. If EPA approves by rulemaking process an alternative plan, the provisions as approved by EPA under that plan shall apply to the diesel engines used in new stationary internal combustion engines subject to this paragraph.

§ 60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

(a) Owners and operators of stationary CI ICE that do not use diesel fuel, or who have been given authority by the Administrator under §60.4207(d) of this subpart to use fuels that do not meet the fuel requirements of paragraphs (a) and (b) of §60.4207, may petition the Administrator for approval of alternative emission standards, if they can demonstrate that they use a fuel that is not the fuel on which the manufacturer of the engine certified the engine and that the engine cannot meet the applicable standards required in §60.4202 or §60.4203 using such fuels.

(b) [Reserved]

General Provisions

§ 60.4218 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

Definitions

§ 60.4219 What definitions apply to this subpart?

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

Combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle combustion turbine, any regenerative/recuperative cycle combustion turbine, the combustion turbine portion of any cogeneration cycle combustion system, or the combustion turbine portion of any combined cycle steam/electric generating system.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is number 2 distillate oil.

Diesel particulate filter means an emission control technology that reduces PM emissions by trapping the particles in a flow filter substrate and periodically removes the collected particles by either physical action or by oxidizing (burning off) the particles in a process called regeneration.

Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary CI ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Engine manufacturer means the manufacturer of the engine. See the definition of "manufacturer" in this section.

Fire pump engine means an emergency stationary internal combustion engine certified to NFPA requirements that is used to provide power to pump water for fire suppression or protection.

Manufacturer has the meaning given in section 216(1) of the Act. In general, this term includes any person who manufactures a stationary engine for sale in the United States or otherwise introduces a new stationary engine into commerce in the United States. This includes importers who import stationary engines for sale or resale.

Maximum engine power means maximum engine power as defined in 40 CFR 1039.801.

Model year means either:

(1) The calendar year in which the engine was originally produced, or

(2) The annual new model production period of the engine manufacturer if it is different than the calendar year. This must include January 1 of the calendar year for which the model year is named. It may not begin before January 2 of the previous calendar year and it must end by December 31 of the named calendar year. For an engine that is converted to a stationary engine after being placed into service as a nonroad or other non-stationary engine, model year means the calendar year or new model production period in which the engine was originally produced.

Other internal combustion engine means any internal combustion engine, except combustion turbines, which is not a reciprocating internal combustion engine or rotary internal combustion engine.

Reciprocating internal combustion engine means any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work.

Rotary internal combustion engine means any internal combustion engine which uses rotary motion to convert heat energy into mechanical work.

Spark ignition means relating to a gasoline, natural gas, or liquefied petroleum gas fueled engine or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary internal combustion engine means any internal combustion engine, except combustion turbines, that converts heat energy into mechanical work and is not mobile. Stationary ICE differ from mobile ICE in that a stationary internal combustion engine is not a nonroad engine as defined at 40 CFR 1068.30 (excluding paragraph (2)(ii) of that definition), and is not used to propel a motor vehicle or a vehicle used solely for competition. Stationary ICE include reciprocating ICE, rotary ICE, and other ICE, except combustion turbines.

Subpart means 40 CFR part 60, subpart IIII.

Useful life means the period during which the engine is designed to properly function in terms of reliability and fuel consumption, without being remanufactured, specified as a number of hours of operation or calendar years, whichever comes first. The values for useful life for stationary CI ICE with a displacement of less than 10 liters per cylinder are given in 40 CFR 1039.101(g). The values for useful life for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder are given in 40 CFR 94.9(a).

Table 1 to Subpart IIII of Part 60—Emission Standards for Stationary Pre-2007 Model Year Engines With a Displacement of <10 Liters per Cylinder and 2007–2010 Model Year Engines >2,237 KW (3,000 HP) and With a Displacement of <10 Liters per Cylinder

[As stated in §§60.4201(b), 60.4202(b), 60.4204(a), and 60.4205(a), you must comply with the following emission standards]

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Maximum engine power	Emission standards for stationary pre-2007 model year engines with a displacement of <10 liters per cylinder and 2007–2010 model year engines >2,237 KW (3,000 HP) and with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)				
	NMHC + NO_X	HC	NO_X	CO	PM
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
KW>560 (HP>750)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)

Table 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X+ NMHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8 0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

Table 3 to Subpart IIII of Part 60—Certification Requirements for Stationary Fire Pump Engines

[As stated in §60.4202(d), you must certify new stationary fire pump engines beginning with the following model years:]

Engine power	Starting model year engine manufacturers must certify new stationary fire pump engines according to §60.4202(d)
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

Table 4 to Subpart IIII of Part 60—Emission Standards for Stationary Fire Pump Engines

[As stated in §§60.4202(d) and 60.4205(c), you must comply with the following emission standards for stationary fire pump engines]

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
225≤KW<450 (300≤HP<600)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+[3]	4.0 (3.0)		0.20 (0.15)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		0.20 (0.15)

[1]For model years 2011–2013, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 revolutions per minute (rpm) may comply with the emission limitations for 2010 model year engines.
[2]For model years 2010–2012, manufacturers, owners and operators of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2009 model year engines.
[3]In model years 2009–2011, manufacturers of fire pump stationary CI ICE in this engine power category with a rated speed of greater than 2,650 rpm may comply with the emission limitations for 2008 model year engines.

Table 5 to Subpart IIII of Part 60—Labeling and Recordkeeping Requirements for New Stationary Emergency Engines

[You must comply with the labeling requirements in §60.4210(f) and the recordkeeping requirements in §60.4214(b) for new emergency stationary CI ICE beginning in the following model years:]

Engine power	Starting model year
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
KW≥130 (HP≥175)	2011

Table 6 to Subpart IIII of Part 60—Optional 3-Mode Test Cycle for Stationary Fire Pump Engines

[As stated in §60.4210(g), manufacturers of fire pump engines may use the following test cycle for testing fire pump engines:]

Mode No.	Engine speed[1]	Torque (percent)[2]	Weighting factors
1	Rated	100	0.30
2	Rated	75	0.50
3	Rated	50	0.20

[1]Engine speed: ±2 percent of point.
[2]Torque: NFPA certified nameplate HP for 100 percent point. All points should be ±2 percent of engine percent load value.

Table 7 to Subpart IIII of Part 60—Requirements for Performance Tests for Stationary CI ICE With a Displacement of ≥30 Liters per Cylinder

[As stated in §60.4213, you must comply with the following requirements for performance tests for stationary CI ICE with a displacement of ≥30 liters per cylinder:]

For each	Complying with the requirement to	You must	Using	According to the following requirements
1. Stationary CI internal combustion engine with a displacement of ≥30 liters per cylinder	a. Reduce NO_x emissions by 90 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for NO_x concentration.

For each	Complying with the requirement to	You must	Using	According to the following requirements
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurements for NO_xconcentration.
		iv. Measure NO_xat the inlet and outlet of the control device	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(d) NO_xconcentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	b. Limit the concentration of NO_xin the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2concentration of the stationary internal combustion engine exhaust at the sampling port location; and,	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2concentration must be made at the same time as the measurement for NO_xconcentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and,	(3) Method 4 of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by reference, see §60.17)	(c) Measurements to determine moisture content must be made at the same time as the measurement for NO_xconcentration.
		iv. Measure NO_xat the exhaust of the stationary internal combustion engine	(4) Method 7E of 40 CFR part 60, appendix A, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03 (incorporated by	(d) NO_xconcentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

For each	Complying with the requirement to	You must	Using	According to the following requirements
			reference, see §60.17)	
	c. Reduce PM emissions by 60 percent or more	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) Sampling sites must be located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content at the inlet and outlet of the control device; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine and moisture content must be made at the same time as the measurements for PM concentration.
		iv. Measure PM at the inlet and outlet of the control device	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
	d. Limit the concentration of PM in the stationary CI internal combustion engine exhaust	i. Select the sampling port location and the number of traverse points;	(1) Method 1 or 1A of 40 CFR part 60, appendix A	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A	(b) Measurements to determine O_2 concentration must be made at the same time as the measurements for PM concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(3) Method 4 of 40 CFR part 60, appendix A	(c) Measurements to determine moisture content must be made at the same time as the measurements for PM concentration.

For each	Complying with the requirement to	You must	Using	According to the following requirements
		iv. Measure PM at the exhaust of the stationary internal combustion engine	(4) Method 5 of 40 CFR part 60, appendix A	(d) PM concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.

Table 8 to Subpart IIII of Part 60—Applicability of General Provisions to Subpart IIII

[As stated in §60.4218, you must comply with the following applicable General Provisions:]

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.4219.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and Recordkeeping	Yes	Except that §60.7 only applies as specified in §60.4214(a).
§60.8	Performance tests	Yes	Except that §60.8 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder end engines that are not certified.
§60.9	Availability of information	Yes	
§60.10	State Authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart IIII.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Except that §60.13 only applies to stationary CI ICE with a displacement of (≥30 liters per cylinder.
§60.14	Modification	Yes	

General Provisions citation	Subject of citation	Applies to subpart	Explanation
§60.15	Reconstruction	Yes	
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Attachment D to a Part 70 Operating Permit

40 CFR 63, Subpart ZZZZ—National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines:

Source Name:	**Duke Energy Indiana Inc., Cayuga Generating Station**
Source Location:	**State Road 63, Cayuga, IN 46168**
County:	**Vermillion**
SIC Code:	**4911**
Operation Permit No.:	**T 165-27260-00001**
Operation Permit Issuance Date:	**August 20, 2009**
Significant Source Modification No.:	**165-32045-00001**
Significant Permit Modification No.:	**165-32048-00001**
Permit Reviewer:	**Josiah Balogun**

Subpart ZZZZ—National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

Source: 69 FR 33506, June 15, 2004, unless otherwise noted.

What This Subpart Covers

§ 63.6580 What is the purpose of subpart ZZZZ?

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

[73 FR 3603, Jan. 18, 2008]

§ 63.6585 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary RICE at a major or area source of HAP emissions, except if the stationary RICE is being tested at a stationary RICE test cell/stand.

(a) A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

(b) A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

(c) An area source of HAP emissions is a source that is not a major source.

(d) If you are an owner or operator of an area source subject to this subpart, your status as an entity subject to a standard or other requirements under this subpart does not subject you to the obligation to obtain a permit under 40

CFR part 70 or 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart as applicable.

(e) If you are an owner or operator of a stationary RICE used for national security purposes, you may be eligible to request an exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3603, Jan. 18, 2008]

§ 63.6590 What parts of my plant does this subpart cover?

This subpart applies to each affected source.

(a) *Affected source.* An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand.

(1) *Existing stationary RICE.*

(i) For stationary RICE with a site rating of more than 500 brake horsepower (HP) located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before December 19, 2002.

(ii) For stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iii) For stationary RICE located at an area source of HAP emissions, a stationary RICE is existing if you commenced construction or reconstruction of the stationary RICE before June 12, 2006.

(iv) A change in ownership of an existing stationary RICE does not make that stationary RICE a new or reconstructed stationary RICE.

(2) *New stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or efter June 12, 2006.

(3) *Reconstructed stationary RICE.* (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major sourca of HAP emissions is reconstructed if you maet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is reconstructed if you meet the definition of reconstruction in §63.2 and reconstruction is commenced on or after June 12, 2006.

(b) *Stationary RICE subject to limited requirements.* (1) An affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(2) A new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis must meet the initial notification requirements of §63.6645(f) and the requirements of §§63.6625(c), 63.6650(g), and 63.6655(c). These stationary RICE do not have to meet the emission limitations and operating limitations of this subpart.

(3) The following stationary RICE do not have to meet the requirements of this subpart and of subpart A of this part, including initial notification requirements:

(i) Existing spark ignition 2 stroke lean bum (2SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(ii) Existing spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iii) Existing emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(iv) Existing limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions;

(v) Existing stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(vi) Existing residential emergency stationary RICE located et an area source of HAP emissions;

(vii) Existing commercial emergency stationary RICE located at en area source of HAP emissions; or

(viii) Existing institutional emergency stationary RICE located at an area source of HAP emissions.

(c) *Stationary RICE subject to Regulations under 40 CFR Part 60.* An affected source that meets any of the criteria in paragraphs (c)(1) through (7) of this section must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

(1) A new or reconstructed stationary RICE located at an area source;

(2) A new or reconstructed 2SLB stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(3) A new or reconstructed 4SLB stationary RICE with a site rating of less than 250 brake HP located at a major source of HAP emissions;

(4) A new or reconstructed spark ignition 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(5) A new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis;

(6) A new or reconstructed emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions;

(7) A new or reconstructed compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9674, Mar. 3, 2010; 75 FR 37733, June 30, 2010; 75 FR 51588, Aug. 20, 2010]

§ 63.6595 When do I have to comply with this subpart?

(a) *Affected sources.* (1) If you have an existing stationary RICE, excluding existing non-emergency CI stationary RICE, with e site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than June 15, 2007. If you have an existing non-emergency CI stationary RICE with a site rating of more than 500 brake HP located et a major source of HAP emissions, an existing stationary CI RICE with e site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary CI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than May 3, 2013. If you have an existing stationary SI RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, or an existing stationary SI RICE located at an area source of HAP emissions, you must comply with the applicable emission limitations and operating limitations no later than October 19, 2013.

(2) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart no later than August 16, 2004.

(3) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions after August 16, 2004, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(4) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(5) If you start up your new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(6) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions before January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart no later than January 18, 2008.

(7) If you start up your new or reconstructed stationary RICE located at an area source of HAP emissions after January 18, 2008, you must comply with the applicable emission limitations and operating limitations in this subpart upon startup of your affected source.

(b) *Area sources that become major sources.* If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, the compliance dates in paragraphs (b)(1) and (2) of this section apply to you.

(1) Any stationary RICE for which construction or reconstruction is commenced after the date when your area source becomes a major source of HAP must be in compliance with this subpart upon startup of your affected source.

(2) Any stationary RICE for which construction or reconstruction is commenced before your area source becomes a major source of HAP must be in compliance with the provisions of this subpart that are applicable to RICE located at major sources within 3 years after your area source becomes a major source of HAP.

(c) If you own or operate an affected source, you must meet the applicable notification requirements in §63 6645 and in 40 CFR part 63, subpart A.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3604, Jan. 18, 2008; 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

Emission and Operating Limitations

§ 63.6600 What emission limitations and operating limitations must I meet if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63 6620 and Table 4 to this subpart.

(a) If you own or operate an existing, new, or reconstructed spark ignition 4SRB stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 1a to this subpart and the operating limitations in Table 1b to this subpart which apply to you.

(b) If you own or operate a new or reconstructed 2SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, a new or reconstructed 4SLB stationary RICE with a site rating of more than 500 brake HP located at major source of HAP emissions, or a new or reconstructed CI stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

(c) If you own or operate any of the following stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the emission limitations in Tables 1a, 2a, 2c, and 2d to this subpart or operating limitations in Tables 1b and 2b to this subpart: an existing 2SLB stationary RICE; an existing 4SLB stationary RICE; a stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis; an emergency stationary RICE; or a limited use stationary RICE.

(d) If you own or operate an existing non-emergency stationary CI RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you must comply with the emission limitations in Table 2c to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010]

§ 63.6601 What emission limitations must I meet if I own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 brake HP and less than or equal to 500 brake HP located at a major source of HAP emissions?

Compliance with the numerical emission limitations established in this subpart is based on the results of testing the average of three 1-hour runs using the testing requirements and procedures in §63.6620 and Table 4 to this subpart. If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at major source of HAP emissions manufactured on or after January 1, 2008, you must comply with the emission limitations in Table 2a to this subpart and the operating limitations in Table 2b to this subpart which apply to you.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 9675, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010]

§ 63.6602 What emission limitations must I meet if I own or operate an

existing stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions?

If you own or operate an axisting stationary RICE with a site rating of aqual to or less than 500 braka HP located at a major source of HAP emissions, you must comply with the amission limitations in Table 2c to this subpart which apply to you. Compliance with the numerical emission limitations established in this subpart is based on the results of testing tha averaga of three 1-hour runs using tha testing raquirements and procedures in §63.6620 and Table 4 to this subpart.

[75 FR 51589, Aug. 20, 2010]

§ 63.6603 What emission limitations and operating limitations must I meet if I own or operate an existing stationary RICE located at an area source of HAP emissions?

Complianca with tha numerical emission limitations established in this subpart is based on tha results of testing tha avaraga of three 1-hour runs using the testing requirements and procedures in §63.6620 and Tabla 4 to this subpart.

(a) If you own or oparata an axisting stationary RICE located at an area sourca of HAP emissions, you must comply with tha requiremants in Table 2d to this subpart and tha operating limitations in Tabla 1b and Tabla 2b to this subpart that apply to you.

(b) If you own or operata an axisting stationary non-emergency CI RICE greater than 300 HP located at area sourcas in areas of Alaska not accessibla by tha Federal Aid Highway System (FAHS) you do not hava to meet tha numerical CO emission limitations specifiad in Tabla 2d to this subpart. Existing stationary non-emergency CI RICE greater than 300 HP located at area sources in areas of Alaska not accessible by tha FAHS must meet the management practices that ara shown for stationary non-emergency CI RICE less than or aqual to 300 HP in Tabla 2d to this subpart.

[75 FR 9675, Mar. 3, 2010, as amendad at 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6604 What fuel requirements must I meet if I own or operate an existing stationary CI RICE?

If you own or operate an axisting non-emergency, non-black start CI stationary RICE with a site rating of mora than 300 brake HP with a displacement of less than 30 liters per cylinder that uses diesel fuel, you must use diesel fuei that meets tha requirements in 40 CFR 80.510(b) for nonroad diesel fuel. Existing non-emergency CI stationary RICE located in Guam, American Samoa, tha Commonwealth of tha Northem Mariana Islands, or at area sources in areas of Alaska not accessibie by tha FAHS ara axempt from the requirements of this section.

[75 FR 51589, Aug. 20, 2010]

General Compliance Requirements

§ 63.6605 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limitations and operating limitations in this subpart that apply to you at all times.

(b) At all times you must operate and maintain any affected sourca, including associated air pollution control equipment and monitoring aquipment, in a manner consistent with safaty and good air pollution control practices for minimizing amissions. Tha general duty to minimize emissions does not requira you to make any further efforts to reduca emissions if levels required by this standard hava been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation end maintenance procedures, review of operation and maintenance records, and inspection of the source.

[75 FR 9675, Mar. 3, 2010]

Testing and Initial Compliance Requirements

§ 63.6610 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions?

If you own or operate a stationary RICE with a site rating of more than 500 brake HP located et a major source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct the initial performance test or other initial compliance demonstrations in Table 4 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a sita rating of more than 500 brake HP located at a major source of HAP emissions, you must demonstrate initial compliance with either the proposed emission limitations or the promulgated emission limitations no later than February 10, 2005 or no later than 180 days after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(c) If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004 and own or operate stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, and you chose to comply with the proposed emission limitations when demonstrating initial compliance, you must conduct a second performance tast to demonstrata compliance with the promulgated emission limitations by December 13, 2007 or after startup of the source, whichever is later, according to §63.7(a)(2)(ix).

(d) An owner or operator is not required to conduct an initial parformance test on units for which a performance test has been previously conducted, but the test must meet all of tha conditions described in paragraphs (d)(1) through (5) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Eithar no process or aquipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

(5) The test must be conducted at any load condition within plus or minus 10 percent of 100 percent load.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3605, Jan. 18, 2008]

§ 63.6611 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate a new or

reconstructed 4SLB SI stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions?

If you own or operate a new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must conduct an initial performance test within 240 days after the compliance date that is specified for your stationary RICE in §63 6595 and according to the provisions specified in Table 4 to this subpart, as appropriate.

[73 FR 3605, Jan. 18, 2008, as amended at 75 FR 51589, Aug 20, 2010]

§ 63.6612 By what date must I conduct the initial performance tests or other initial compliance demonstrations if I own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions?

If you own or operate an existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing stationary RICE located at an area source of HAP emissions you are subject to the requirements of this section.

(a) You must conduct any initial performance test or other initial compliance demonstration according to Tables 4 and 5 to this subpart that apply to you within 180 days after the compliance date that is specified for your stationary RICE in §63.6595 and according to the provisions in §63.7(a)(2).

(b) An owner or operator is not required to conduct an initial performance test on a unit for which a performance test has been previously conducted, but the test must meet all of the conditions described in paragraphs (b)(1) through (4) of this section.

(1) The test must have been conducted using the same methods specified in this subpart, and these methods must have been followed correctly.

(2) The test must not be older than 2 years.

(3) The test must be reviewed and accepted by the Administrator.

(4) Either no process or equipment changes must have been made since the test was performed, or the owner or operator must be able to demonstrate that the results of the performance test, with or without adjustments, reliably demonstrate compliance despite process or equipment changes.

[75 FR 9676, Mar. 3, 2010, as amended at 75 FR 51589, Aug. 20, 2010]

§ 63.6615 When must I conduct subsequent performance tests?

If you must comply with the emission limitations and operating limitations, you must conduct subsequent performance tests as specified in Table 3 of this subpart.

§ 63.6620 What performance tests and other procedures must I use?

(a) You must conduct each performance test in Tables 3 and 4 of this subpart that applies to you.

(b) Each performance test must be conducted according to the requirements that this subpart specifies in Table 4 to this subpart. If you own or operate a non-operational stationary RICE that is subject to performance testing, you do not need to start up the engine solely to conduct the performance test. Owners and operators of a non-operational engine can conduct the performance test when the engine is started up again.

(c) [Reserved]

(d) You must conduct three separate test runs for each performance test required in this section, as specified in §63.7(e)(3). Each test run must last at least 1 hour.

(e)(1) You must use Equation 1 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq 1)}$$

Where:

C_i= concentration of CO or formaldehyde at the control device inlet,

C_o= concentration of CO or formaldehyde at the control device outlet, and

R = percent reduction of CO or formaldehyde emissions.

(2) You must normalize the carbon monoxide (CO) or formaldehyde concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen, or an equivalent percent carbon dioxide (CO_2). If pollutant concentrations are to be corrected to 15 percent oxygen and CO_2concentration is measured in lieu of oxygen concentration measurement, a CO_2correction factor is needed. Calculate the CO_2correction factor as described in paragraphs (e)(2)(i) through (iii) of this section.

(i) Calculate the fuel-specific $F_o$value for the fuel burned during the test using values obtained from Method 19, section 5.2, and the following equation:

$$F_o = \frac{0.209\, F_d}{F_c} \qquad \text{(Eq 2)}$$

Where:

F_o= Fuel factor based on the ratio of oxygen volume to the ultimate CO_2volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is oxygen, percent/100.

F_d= Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm^3/J (dscf/10^6 Btu).

F_c= Ratio of the volume of CO_2produced to the gross calorific value of the fuel from Method 19, dsm^3/J (dscf/10^6 Btu).

(ii) Calculate the CO_2correction factor for correcting measurement data to 15 percent oxygen, as follows:

$$X_{co_2} = \frac{5.9}{F_o} \qquad \text{(Eq 3)}$$

Where:

X_{co2}= CO_2correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2correction value, percent.

(iii) Calculate the $NO_X$and SO_2gas concentrations adjusted to 15 percent O_2using CO_2as follows:

$$C_{adj} = C_d \frac{X_{co_2}}{\%CO_2} \qquad \text{(Eq 4)}$$

Where:

$\%CO_2$= Measured CO_2concentration measured, dry basis, percent.

(f) If you comply with the emission limitation to reduce CO and you are not using an oxidation catalyst, if you comply with the emission limitation to reduce formaldehyde end you are not using NSCR, or if you comply with the emission limitation to limit the concentration of formaldehyde in the stationary RICE exhaust and you are not using an oxidation catalyst or NSCR, you must petition the Administrator for operating limitations to be established during the initial performance test and continuously monitored thereafter; or for approval of no operating limitations. You must not conduct the initial performance test until after the petition has been approved by the Administrator.

(g) If you petition the Administrator for approval of operating limitations, your petition must include the information described in paragraphs (g)(1) through (5) of this section.

(1) Identification of the specific parameters you propose to use as operating limitations;

(2) A discussion of the relationship between these parameters and HAP emissions, identifying how HAP emissions change with changes in these parameters, and how limitations on these parameters will serve to limit HAP emissions;

(3) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(4) A discussion identifying the methods you will use to measure and the instruments you will use to monitor these parameters, es well as the relative accuracy and precision of these methods end instruments; and

(5) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(h) If you petition the Administrator for approval of no operating limitations, your petition must include the information described in paragraphs (h)(1) through (7) of this section.

(1) Identification of the parameters associated with operation of the stationary RICE and any emission control device which could change intentionally (*e.g.*, operator adjustment, automatic controller adjustment, etc.) or unintentionally (*e g.*, wear and tear, error, etc.) on a routine basis or over time;

(2) A discussion of the relationship, if any, between changes in the parameters and changes in HAP emissions;

(3) For the parameters which could change in such a way as to increase HAP emissions, a discussion of whether establishing limitations on the paramaters would serve to limit HAP emissions;

(4) For the parameters which could change in such a way as to increase HAP emissions, a discussion of how you could establish upper and/or lower values for the parameters which would establish limits on the parameters in operating limitations;

(5) For the parameters, a discussion identifying the methods you could use to measure them and the instruments you could use to monitor them, as well as the relative accuracy and precision of the methods and instruments;

(6) For the parameters, a discussion identifying the frequency and methods for recalibrating the instruments you could use to monitor them; and

(7) A discussion of why, from your point of view, it is infeasible or unreasonable to adopt the parameters as operating limitations.

(i) The engine percent load during a performance test must be determined by documenting the calculations, assumptions, and measurement devices used to measure or estimate the percent load in a specific application. A written report of the average percent load determination must be included in the notification of compliance status. The following information must be included in the written report: the engine model number, tha engine manufacturer, the year of purchase, the manufacturer's site-rated brake horsepower, the ambient temperature, prassure, and humidity during the performance test, and all assumptions that were made to estimate or calculata percent load during the performance test must be clearly explained. If measurement devices such as flow meters, kilowatt meters, beta analyzers, stain gauges, etc. are used, the model number of the measurement device, and an estimate of its accurate in percentage of true value must be provided.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9676, Mar. 3, 2010]

§ 63.6625 What are my monitoring, installation, collection, operation, and maintenance requirements?

(a) If you elect to install a CEMS as specified in Table 5 of this subpart, you must install, operate, and maintain a CEMS to monitor CO and either oxygen or CO_2at both the inlet and the outlet of the control device according to the requirements in paragraphs (a)(1) through (4) of this section.

(1) Each CEMS must be installed, operated, and maintained according to the applicable performance specifications of 40 CFR part 60, appendix B.

(2) You must conduct an initial performance evaluation and an annual relative accuracy test audit (RATA) of each CEMS according to the requirements in §63.8 and according to the applicable performance specifications of 40 CFR part 60, appendix B as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.

(3) As specified in §63.8(c)(4)(ii), each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. You must have at least two data points, with each representing a different 15-minute period, to have a valid hour of data.

(4) The CEMS data must be reduced as specified in §63.8(g)(2) and recorded in parts per million or parts per billion (as appropriate for the applicable limitation) at 15 percent oxygen or the equivalent CO_2concentration.

(b) If you are required to install a continuous parameter monitoring system (CPMS) as specified in Table 5 of this subpart, you must install, operate, and maintain each CPMS according to the requirements in paragraphs (b)(1) through (5) of this section. For an affected source that is complying with the emission limitations and operating limitations on March 9, 2011, the requirements in paragraph (b) of this section are applicable September 6, 2011.

(1) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (b)(1)(i) through (v) of this section and in §63.8(d). As specified in §63 8(f)(4), you may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in paragraphs (b)(1) through (5) of this section in your site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations;

(ii) Sampling interface (*e g* , thermocouple) location such that the monitoring system will provide representative measurements;

(iii) Equipment performance evaluations, system accuracy audits, or other eudit procedures;

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §63.8(c)(1) and (c)(3); and

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §63.10(c), (e)(1), and (e)(2)(i).

(2) You must install, operate, end maintain each CPMS in continuous operation according to the procedures in your site-specific monitoring plan.

(3) The CPMS must collect data at least once every 15 minutes (see also §63.6635).

(4) For a CPMS for measuring temperature range, the temperature sensor must have a minimum tolerance of 2.8 degrees Celsius (5 degrees Fahrenheit) or 1 percent of the measurement range, whichever is larger.

(5) You must conduct the CPMS equipment performance evaluation, system accuracy audits, or other audit procedures specified in your site-specific monitoring plan at least annually.

(6) You must conduct a performance evaluation of each CPMS in accordance with your site-specific monitoring plan.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must monitor and record your fuel usage daily with separate fuel meters to measure the volumetric flow rate of each fuel. In addition, you must operate your stationary RICE in a manner which reasonably minimizes HAP emissions.

(d) If you are operating a new or reconstructed emergency 4SLB stationary RICE with a site rating of greater than or equal to 250 and less than or equal to 500 brake HP located at a major source of HAP emissions, you must install a non-resettable hour meter prior to the startup of the engine.

(e) If you own or operate any of the following stationary RICE, you must operate and maintain the stationary RICE and after-treatmant control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions:

(1) An existing stationary RICE with a site rating of less than 100 HP located at a major source of HAP emissions;

(2) An existing emergency or black start stationary RICE with a site rating of less than or equal to 500 HP located at a major source of HAP emissions;

(3) An existing emergency or black start stationary RICE located at an area source of HAP emissions;

(4) An existing non-emergency, non-black start stationary CI RICE with a site rating less than or equal to 300 HP located at an area source of HAP emissions;

(5) An existing non-emergency, non-black start 2SLB stationary RICE located at an area source of HAP amissions;

(6) An existing non-emergency, non-black start landfill or digester gas stationary RICE located at an area source of HAP emissions;

(7) An existing non-emergency, non-black start 4SLB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(8) An existing non-emergency, non-black start 4SRB stationary RICE with a site rating less than or equal to 500 HP located at an area source of HAP emissions;

(9) An existing, non-emergency, non-black start 4SLB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year; and

(10) An existing, non-emergency, non-black start 4SRB stationary RICE with a site rating greater than 500 HP located at an area source of HAP emissions that is operated 24 hours or less per calendar year.

(f) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions or an existing emergency stationary RICE located at an area source of HAP emissions, you must install a non-resettable hour meter if one is not already installed.

(g) If you own or operate an existing non-emergency, non-black start CI engine greater than or equal to 300 HP that is not equipped with a closed crankcase ventilation system, you must comply with either paragraph (g)(1) or paragraph (g)(2) of this section. Owners and operators must follow the manufacturer's specified maintenance requirements for operating and maintaining the open or closed crankcase ventilation systems and replacing the crankcase filters, or can request the Administrator to approve different maintenance requirements that are as protective as manufacturer requirements. Existing CI engines located at area sources in areas of Alaska not accessible by the FAHS do not have to meet the requirements of paragraph (g) of this section.

(1) Install a closed crankcase ventilation system that prevents crankcase emissions from being emitted to the atmosphere, or

(2) Install an open crankcase filtration emission control system that reduces emissions from the crankcase by filtering the exhaust stream to remove oil mist, particulates, and metals.

(h) If you operate a new, reconstructed, or existing stationary engine, you must minimize the engine's time spent at idle during startup and minimize the engine's startup time to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup in Tables 1a, 2a, 2c, and 2d to this subpart apply.

(i) If you own or operate a stationary CI engine that is subject to the work, operation or management practices in items 1 or 2 of Table 2c to this subpart or in items 1 or 4 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Base Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Base Number is less than 30 percent of the Total Base Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

(j) If you own or operate a stationary SI engine that is subject to the work, operation or management practices in items 6, 7, or 8 of Table 2c to this subpart or in items 5, 6, 7, 9, or 11 of Table 2d to this subpart, you have the option of utilizing an oil analysis program in order to extend the specified oil change requirement in Tables 2c and 2d to this subpart. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c or 2d to this subpart. The analysis program must at a minimum analyze the following three parameters: Total Acid Number, viscosity, and percent water content. The condemning limits for these parameters are as follows: Total Acid Number increases by more than 3.0 milligrams of potassium hydroxide (KOH) per gram from Total Acid Number of the oil when new; viscosity of the oil has changed by more than 20 percent from the viscosity of the oil when new; or percent water content (by volume) is greater than 0.5. If all of these condemning limits are not exceeded, the engine owner or operator is not required to change the oil. If any of the limits are exceeded, the engine owner or operator must change the oil within 2 days of receiving the results of the analysis; if the engine is not in operation when the results of the analysis are received, the engine owner or operator must change the oil within 2 days or before commencing operation, whichever is later. The owner or operator must keep records of the parameters that are analyzed as part of the program, the results of the analysis, and the oil changes for the engine. The analysis program must be part of the maintenance plan for the engine.

[69 FR 33506, June 15, 2004, as amended at 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51589, Aug. 20, 2010; 76 FR 12866, Mar. 9, 2011]

§ 63.6630 How do I demonstrate initial compliance with the emission limitations and operating limitations?

(a) You must demonstrate initial compliance with each emission and operating limitation that applies to you according to Table 5 of this subpart.

(b) During the initial performance test, you must establish each operating limitation in Tables 1b and 2b of this subpart that applies to you.

(c) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in §63.6645.

Continuous Compliance Requirements

§ 63.6635 How do I monitor and collect data to demonstrate continuous compliance?

(a) If you must comply with emission and operating limitations, you must monitor and collect data according to this section.

(b) Except for monitor malfunctions, associated repairs, required performance evaluations, and required quality assurance or control activities, you must monitor continuously at all times that the stationary RICE is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(c) You may not use data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities in data averages and calculations used to report emission or operating levels. You must, however, use all the valid data collected during all other periods.

[69 FR 33506, June 15, 2004, as amended at 76 FR 12867, Mar. 9, 2011]

§ 63.6640 How do I demonstrate continuous compliance with the emission limitations and operating limitations?

(a) You must demonstrate continuous compliance with each emission limitation and operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you according to methods specified in Table 6 to this subpart.

(b) You must report each instance in which you did not meet each emission limitation or operating limitation in Tables 1a and 1b, Tables 2a and 2b, Table 2c, and Table 2d to this subpart that apply to you. These instances are deviations from the emission and operating limitations in this subpart. These deviations must be reported according to the requirements in §63 6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE.

(c) [Reserved]

(d) For new, reconstructed, and rebuilt stationary RICE, deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. Rebuilt stationary RICE means a stationary RICE that has been rebuilt as that term is defined in 40 CFR 94.11(a).

(e) You must also report each instance in which you did not meet the requirements in Table 8 to this subpart that apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart· An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing emergency stationary RICE, an existing limited use stationary RICE, or an existing stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in Table 8 to this subpart, except for the initial notification requirements: a new or reconstructed stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new or reconstructed emergency stationary RICE, or a new or reconstructed limited use stationary RICE.

(f) *Requirements for emergency stationary RICE.* (1) If you own or operate an existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions, a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed on or after June 12, 2006, or en existing emergency stationary RICE located at an area source of HAP emissions, you must operate the emergency stationary RICE according to the requirements in paragraphs (f)(1)(i) through (iii) of this section. Any operation other than emergency operation, maintenance and testing, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1)(i) through (iii) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State or local government, the manufacturer, the vendor, or the insurance company associated with the engina. Maintenance checks and readiness testing of such units is limited to 100 hours per year. The owner or operator may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency RICE beyond 100 hours per year.

(iii) You may operate your emergency stationary RICE up to 50 hours per year in non-emergency situations, but those 50 hours are counted towards the 100 hours per year provided for maintenance and testing. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity; except that owners and operators may operate the emergency engine for a maximum of 15 hours per year as part of a demand response program if the regional transmission organization or equivalent balancing authority and transmission operator has determined there are emergency conditions that could lead to a potential electrical blackout, such as unusually low frequency, equipment overload, capacity or energy deficiency, or unacceptable voltage level. The engine may not be operated for more than 30 minutes prior to the time when the emergency condition is expected to occur, end the engine operation must be terminated immediately after the facility is notified that the emergency condition is no longer imminent. The 15 hours per year of demand response operation are counted as part of the 50 hours of operation per year provided for non-emergency situations. The supply of emergency power to another entity or entities pursuant to financial arrangement is not limited by this paragraph (f)(1)(iii), as long as the power provided by the financial arrangement is limited to emergency power.

(2) If you own or operate an emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions that was installed prior to June 12, 2006, you must operate the engine according to the conditions described in paragraphs (f)(2)(i) through (iii) of this section. If you do not operate the engine according to the requirements in paragraphs (f)(2)(i) through (iii) of this section, the engine will not be considered an emergency engine under this subpart and will need to meet all requirements for non-emergency engines.

(i) There is no time limit on the use of emergency stationary RICE in emergency situations.

(ii) You may operate your emergency stationary RICE for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by the manufacturer, the vendor, or the insurance company associated with the engine. Required testing of such units should be minimized, but there is no time limit on the use of emergency stationary RICE in emergency situations and for routine testing and maintenance.

(iii) You may operate your emergency stationary RICE for an additional 50 hours per year in non-emergency situations. The 50 hours per year for non-emergency situations cannot be used for peak shaving or to generate income for a facility to supply power to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3606, Jan. 18, 2008; 75 FR 9676, Mar. 3, 2010; 75 FR 51591, Aug. 20, 2010]

Notifications, Reports, and Records

§ 63.6645 What notifications must I submit and when?

(a) You must submit all of the notifications in §§63.7(b) and (c), 63.8(e), (f)(4) and (f)(6), 63.9(b) through (e), and (g) and (h) that apply to you by the dates specified if you own or operate any of the following;

(1) An existing stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions.

(2) An existing stationary RICE located at an area source of HAP emissions.

(3) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(4) A new or reconstructed 4SLB stationary RICE with a site rating of greater than or equal to 250 HP located at a major source of HAP emissions.

(5) This requirement does not apply if you own or operate an existing stationary RICE less than 100 HP, an existing stationary emergency RICE, or an existing stationary RICE that is not subject to any numerical emission standards.

(b) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart, you must submit an Initial Notification not later than December 13, 2004.

(c) If you start up your new or reconstructed stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions on or after August 16, 2004, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(d) As specified in §63.9(b)(2), if you start up your stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions before the effective date of this subpart and you are required to submit an initial notification, you must submit an Initial Notification not later than July 16, 2008.

(e) If you start up your new or reconstructed stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions on or after March 18, 2008 and you are required to submit an initial notification, you must submit an Initial Notification not later than 120 days after you become subject to this subpart.

(f) If you are required to submit an Initial Notification but are otherwise not affected by the requirements of this subpart, in accordance with §63.6590(b), your notification should include the information in §63 9(b)(2)(i) through (v), and a statement that your stationary RICE has no additional requirements and explain the basis of the exclusion (for example, that it operates exclusively as an emergency stationary RICE if it has a site rating of more than 500 brake HP located at a major source of HAP emissions).

(g) If you are required to conduct a performance test, you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin as required in §63.7(b)(1)

(h) If you are required to conduct a performance test or other initial compliance demonstration as specified in Tables 4 and 5 to this subpart, you must submit a Notification of Compliance Status according to §63.9(h)(2)(ii).

(1) For each initial compliance demonstration required in Table 5 to this subpart that does not include a performance test, you must submit the Notification of Compliance Status before the close of business on the 30th day following the completion of the initial compliance demonstration.

(2) For each initial compliance demonstration required in Table 5 to this subpart that includes a performance test conducted according to the requirements in Table 3 to this subpart, you must submit the Notification of Compliance Status, including the performance test results, before the close of business on the 60th day following the completion of the performance test according to §63.10(d)(2).

[73 FR 3606, Jan. 18, 2008, as amended at 75 FR 9677, Mar. 3, 2010, 75 FR 51591, Aug 20, 2010]

§ 63.6650 What reports must I submit and when?

(a) You must submit each report in Table 7 of this subpart that applies to you.

(b) Unless the Administrator has approved a different schedule for submission of reports under §63.10(a), you must submit each report by the date in Table 7 of this subpart and according to the requirements in paragraphs (b)(1) through (b)(9) of this section.

(1) For semiannual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on June 30 or December 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in §63.6595.

(2) For semiannual Compliance reports, the first Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date follows the end of the first calendar half after the compliance date that is specified for your affected source in §63.6595.

(3) For semiannual Compliance reports, each subsequent Compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31.

(4) For semiannual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period.

(5) For each stationary RICE that is subject to permitting regulations pursuant to 40 CFR part 70 or 71, and if the permitting authority has established dates for submitting semiannual reports pursuant to 40 CFR 70 6(a)(3)(iii)(A) or 40 CFR 71.6 (a)(3)(iii)(A), you may submit the first and subsequent Compliance reports according to the dates the permitting authority has established instead of according to the dates in paragraphs (b)(1) through (b)(4) of this section.

(6) For annual Compliance reports, the first Compliance report must cover the period beginning on the compliance date that is specified for your affected source in §63.6595 and ending on December 31.

(7) For annual Compliance reports, the first Compliance report must be postmarked or delivered no later than January 31 following the end of the first calendar year after the compliance date that is specified for your affected source in §63.6595.

(8) For annual Compliance reports, each subsequent Compliance report must cover the annual reporting period from January 1 through December 31.

(9) For annual Compliance reports, each subsequent Compliance report must be postmarked or delivered no later than January 31.

(c) The Compliance report must contain the information in paragraphs (c)(1) through (6) of this section.

(1) Company name and address.

(2) Statement by a responsible official, with that official's name, title, and signature, certifying the accuracy of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) If you had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.6605(b), including actions taken to correct a malfunction.

(5) If there are no deviations from any emission or operating limitations that apply to you, a statement that there were no deviations from the emission or operating limitations during the reporting period.

(6) If there were no periods during which the continuous monitoring system (CMS), including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were no periods during which the CMS was out-of-control during the reporting period.

(d) For each deviation from an emission or operating limitation that occurs for a stationary RICE where you are not using a CMS to comply with the emission or operating limitations in this subpart, the Compliance report must contain the information in paragraphs (c)(1) through (4) of this section and the information in paragraphs (d)(1) and (2) of this section.

(1) The total operating time of the stationary RICE at which the deviation occurred during the reporting period.

(2) Information on the number, duration, and cause of deviations (including unknown cause, if applicable), as applicable, and the corrective action taken.

(e) For each deviation from an emission or operating limitation occurring for a stationary RICE where you are using a CMS to comply with the emission and operating limitations in this subpart, you must include information in paragraphs (c)(1) through (4) and (e)(1) through (12) of this section.

(1) The date and time that each malfunction started and stopped.

(2) The date, time, and duration that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out-of-control, including the information in §63.8(c)(8).

(4) The date and time that each deviation started and stopped, and whether each deviation occurred during a period of malfunction or during another period.

(5) A summary of the total duration of the deviation during the reporting period, and the total duration as a percent of the total source operating time during that reporting period.

(6) A breakdown of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS downtime during the reporting period, and the total duration of CMS downtime as a percent of the total operating time of the stationary RICE at which the CMS downtime occurred during that reporting period.

(8) An identification of each parameter and pollutant (CO or formaldehyde) that was monitored at the stationary RICE.

(9) A brief description of the stationary RICE.

(10) A brief description of the CMS.

(11) The date of the latest CMS certification or audit.

(12) A description of any changes in CMS, processes, or controls since the last reporting period.

(f) Each affected source that has obtained a title V operating permit pursuant to 40 CFR part 70 or 71 must report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70 6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of this subpart along with, or as part of, the semiannual monitoring report required by 40 CFR 70 6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in this subpart, submission of the Complianca report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to tha permit authority.

(g) If you are operating as a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must submit an annual report according to Table 7 of this subpart by the date specified unless the Administrator has approved a different schedule, according to the information described in paragraphs (b)(1) through (b)(5) of this section. You must report the data specified in (g)(1) through (g)(3) of this section.

(1) Fuel flow rate of each fuel and the heating values that were used in your calculations. You must also demonstrate that the percentage of heat input provided by landfill gas or digester gas is equivalent to 10 percent or more of the total fuel consumption on an annual basis.

(2) The operating limits provided in your federally enforceable permit, and any deviations from these limits.

(3) Any problems or errors suspected with the meters.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9877, Mar. 3, 2010]

§ 63.6655 What records must I keep?

(a) If you must comply with the emission and operating limitations, you must keep the records described in paragraphs (a)(1) through (a)(5), (b)(1) through (b)(3) and (c) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted, according to the requirement in §63.10(b)(2)(xiv).

(2) Records of the occurrence and duration of each malfunction of operation (*i e* , process equipment) or the air pollution control and monitoring equipment.

(3) Records of performance tests and performance evaluations as required in §63.10(b)(2)(viii).

(4) Records of all required maintenance performed on the air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with §63.6605(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(b) For each CEMS or CPMS, you must keep tha records listed in paragraphs (b)(1) through (3) of this section

(1) Records described in §63.10(b)(2)(vi) through (xi).

(2) Previous (*i.e.,* superseded) versions of the performance evaluation plan as required in §63 8(d)(3).

(3) Requests for alternatives to the relative accuracy test for CEMS or CPMS as required in §63.8(f)(6)(i), if applicable.

(c) If you are operating a new or reconstructed stationary RICE which fires landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, you must keep the records of your daily fuel usage monitors.

(d) You must keep the records required in Table 6 of this subpart to show continuous compliance with each emission or operating limitation that applies to you.

(e) You must keep records of the maintenance conducted on the stationary RICE in order to demonstrate that you operated and maintained the stationary RICE and after-treatment control device (if any) according to your own maintenance plan if you own or operate any of the following stationary RICE;

(1) An existing stationary RICE with a site rating of less than 100 brake HP located at a major source of HAP emissions.

(2) An existing stationary emergency RICE.

(3) An existing stationary RICE located at an area source of HAP emissions subject to management practices as shown in Table 2d to this subpart.

(f) If you own or operate any of the stationary RICE in paragraphs (f)(1) or (2) of this section, you must keep records of the hours of operation of the engine that is recorded through the non-resettable hour meter. The owner or operator must document how many hours are spent for emergency operation, including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engines are used for demand response operation, the owner or operator must keep records of the notification of the emergency situation, and the time the engine was operated as part of demand response.

(1) An existing emergency stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions that does not meet the standards applicable to non-emergency engines.

(2) An existing emergency stationary RICE located at an area source of HAP emissions that does not meet the standards applicable to non-emergency engines.

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010]

§ 63.6660 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review according to §63.10(b)(1).

(b) As specified in §63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record readily accessible in hard copy or electronic form for at least 5 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to §63.10(b)(1).

[69 FR 33506, June 15, 2004, as amended at 75 FR 9678, Mar. 3, 2010]

Other Requirements and Information

§ 63.6665 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§63.1 through 63.15 apply to you. If you own or operate a new or reconstructed stationary RICE with a site rating of less than or equal to 500 brake HP located at a major source of HAP emissions (except new or reconstructed 4SLB engines greater than or equal to 250 and less than or equal to 500 brake HP), a new or reconstructed stationary RICE located at an area source of HAP emissions, or any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with any of the requirements of the General Provisions specified in Table 8: An existing 2SLB stationary RICE, an existing 4SLB stationary RICE, an existing stationary RICE that combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an existing emergency stationary RICE, or an existing limited use stationary RICE. If you own or operate any of the following RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, you do not need to comply with the requirements in the General Provisions specified in Table 8 except for the initial notification requirements: A new stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, a new emergency stationary RICE, or a new limited use stationary RICE.

[75 FR 9678, Mar. 3, 2010]

§ 63.6670 Who implements and enforces this subpart?

(a) This subpart is implemented and enforced by the U.S. EPA, or a delegated authority such as your State, local, or tribal agency. If the U.S. EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as the U.S. EPA) has the authority to implement and enforce this subpart. You should contact your U.S. EPA Regional Office to find out whether this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraph (c) of this section are retained by the Administrator of the U.S. EPA and are not transferred to the State, local, or tribal agency.

(c) The authorities that will not be delegated to State, local, or tribal agencies are:

(1) Approval of alternatives to the non-opacity emission limitations and operating limitations in §63.6600 under §63.6(g).

(2) Approval of major alternatives to test methods under §63.7(e)(2)(ii) and (f) and as defined in §63.90.

(3) Approval of major alternatives to monitoring under §63.8(f) and as defined in §63.90.

(4) Approval of major alternatives to recordkeeping and reporting under §63.10(f) and as defined in §63.90.

(5) Approval of a performance test which was conducted prior to the effective date of the rule, as specified in §63.6610(b).

§ 63.6675 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act (CAA); in 40 CFR 63.2, the General Provisions of this part; and in this section as follows:

Area source means any stationary source of HAP that is not a major source as defined in part 63.

Associated equipment as used in this subpart and as referred to in section 112(n)(4) of the CAA, means equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the well bore to the point of custody transfer, except glycol dehydration units, storage vessels with potential for flash emissions, combustion turbines, and stationary RICE.

Black start engine means an engine whose only purpose is to start up a combustion turbine.

CAA means the Clean Air Act (42 U.S.C. 7401 *et seq* , as amended by Public Law 101–549, 104 Stat. 2399)

Commercial emergency stationary RICE means an emergency stationary RICE used in commercial establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Compression ignition means relating to a type of stationary internal combustion engine that is not a spark ignition engine.

Custody transfer means the transfer of hydrocarbon liquids or natural gas· After processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation. For the purposes of this subpart, the point at which such liquids or natural gas enters a natural gas processing plant is a point of custody transfer.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart, including but not limited to any emission limitation or operating limitation;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limitation or operating limitation in this subpart during malfunction, regardless or whether or not such failure is permitted by this subpart.

(4) Fails to satisfy the general duty to minimize emissions established by §63 6(e)(1)(i).

Diesel engine means eny stationary RICE in which a high boiling point liquid fuel injected into the combustion chamber ignites when the air charge has been compressed to a temperature sufficiently high for auto-ignition. This process is also known as compression ignition.

Diesel fuel means any liquid obtained from the distillation of petroleum with a boiling point of approximately 150 to 360 degrees Celsius. One commonly used form is fuel oil number 2. Diesel fuel also includes any non-distillate fuel with comparable physical and chemical properties (*e.g.* biodiesel) that is suitable for use in compression ignition engines.

Digester gas means any gaseous by-product of wastewater treatment typically formed through the anaerobic decomposition of organic waste materials and composed principally of methane and CO_2.

Dual-fuel engine means any stationary RICE in which a liquid fuel (typically diesel fuel) is used for compression ignition and gaseous fuel (typically natural gas) is used as the primary fuel.

Emergency stationary RICE means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary RICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary RICE used to pump water in the case of fire or flood, *etc.* Stationary RICE used for peak shaving are not considered emergency stationary RICE. Stationary RICE used to supply power to an electric grid or that supply non-emergency power as part of a financial arrangement with another entity are not considered to be emergency engines, except as permitted under §63 6640(f). All emergency stationary RICE must comply with the requirements specified in §63 6640(f) in order to be considered emergency stationary RICE. If the engine does not comply with the requirements specified in §63.6640(f), then it is not considered to be an emergency stationary RICE under this subpart.

Engine startup means the time from initial start until applied load and engine and associated equipment reaches steady state or normal operation. For stationary engine with catalytic controls, engine startup means the time from initial start until applied load and engine and associated equipment, including the catalyst, reaches steady state or normal operation.

Four-stroke engine means any type of engine which completes the power cycle in two crankshaft revolutions, with intake and compression strokes in the first revolution and power and exhaust strokes in the second revolution.

Gaseous fuel means a material used for combustion which is in the gaseous state at standard atmospheric temperature and pressure conditions.

Gasoline means any fuel sold in any State for use in motor vehicles and motor vehicle engines, or nonroad or stationary engines, and commonly or commercially known or sold as gasoline.

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

Hazardous air pollutants (HAP) means any air pollutants listed in or pursuant to section 112(b) of the CAA.

Institutional emergency stationary RICE means an emergency stationary RICE used in institutional establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, end fire stations.

ISO standard day conditions means 288 degrees Kelvin (15 degrees Celsius), 60 percent relative humidity and 101.3 kilopascals pressure.

Landfill gas means a gaseous by-product of the land application of municipal refuse typically formed through the anaerobic decomposition of waste materials and composed principally of methane and CO_2.

Lean burn engine means any two-stroke or four-stroke spark ignited engine that does not meet the definition of a rich burn engine.

Limited use stationary RICE means any stationary RICE that operates less than 100 hours per year.

Liquefied petroleum gas means any liquefied hydrocarbon gas obtained as a by-product in petroleum refining of natural gas production.

Liquid fuel means any fuel in liquid form at standard temperature and pressure, including but not limited to diesel, residual/crude oil, kerosene/naphtha (jet fuel), and gasoline.

Major Source, as used in this subpart, shall have the same meaning as in §63.2, except that:

(1) Emissions from any oil or gas exploration or production well (with its associated equipment (as defined in this section)) and emissions from any pipeline compressor station or pump station shall not be aggregated with emissions from other similar units, to determine whether such emission points or stations are major sources, even when emission points are in a contiguous area or under common control,

(2) For oil and gas production facilities, emissions from processes, operations, or equipment that are not part of the same oil and gas production facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated;

(3) For production field facilities, only HAP emissions from glycol dehydration units, storage vessel with the potential for flash emissions, combustion turbines and reciprocating internal combustion engines shall be aggregated for a major source determination; and

(4) Emissions from processes, operations, and equipment that are not part of the same natural gas transmission and storage facility, as defined in §63.1271 of subpart HHH of this part, shall not be aggregated

Malfunction means any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner which causes, or has the potential to cause, the emission limitations in an applicable standard to be exceeded. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Natural gas means a naturally occurring mixture of hydrocarbon and non-hydrocarbon gases found in geologic formations beneath the Earth's surface, of which the principal constituent is methane. Natural gas may be field or pipeline quality.

Non-selective catalytic reduction (NSCR) means an add-on catalytic nitrogen oxides (NO_X) control device for rich burn engines that, in a two-step reaction, promotes the conversion of excess oxygen, NO_X, CO, end volatile organic compounds (VOC) into CO_2, nitrogen, end water.

Oil and gas production facility as used in this subpart means any grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.*, remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer; or where natural gas is processed, upgraded, or stored prior to entering the natural gas transmission and storaga source category. For purposes of a major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in this section. Equipment that is part of a facility will typically be located within close proximity to other equipment locatad at the same facility. Pieces of production equipment or groupings of equipment located on different oil and gas leases, mineral fee tracts, lease tracts, subsurface or surface unit areas, surface fee tracts, surface lease tracts, or separate surface sites, whether or not connected by a road, waterway, power line or pipeline, shall not be considered part of the same facility. Examples of facilities in the oil and natural gas production source category include, but are not limited to, well sites, satellite tank batteries, central tank batteries, a compressor station that transports natural gas to a natural gas processing plant, and natural gas processing plants.

Oxidation catalyst means an add-on catalytic control device that controls CO and VOC by oxidation.

Peaking unit or engine means any standby engine intended for use during periods of high demand that are not emergencies.

Percent load means the fractional power of an engine compared to its maximum manufacturer's design capacity at engine site conditions. Percent load may range between 0 percent to above 100 percant.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the stationary source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of matarial combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. For oil and natural gas production facilities subject to subpart HH of this part, the potential to emit provisions in §63.760(a) may be used. For natural gas transmission and storage facilities subject to subpart HHH of this part, the maximum annual facility gas throughput for storage facilities may be determined according to §63.1270(a)(1) and the maximum annual throughput for transmission facilities may be determined according to §63.1270(a)(2).

Production field facility means those oil and gas production facilities located prior to the point of custody transfer.

Production well means any hole drilled in the earth from which crude oil, condensate, or field natural gas is extracted.

Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Residential emergency stationary RICE means an emergency stationary RICE used in residential establishments such as homes or apartment buildings.

Responsible official means responsible official as defined in 40 CFR 70.2.

Rich burn engine means any four-stroke spark ignited engine where the manufacturer's recommended operating air/fuel ratio divided by the stoichiometric air/fuel ratio at full load conditions is less than or equal to 1.1. Engines originally manufactured as rich burn engines, but modified prior to December 19, 2002 with passive emission control technology for NO_X(such as pre-combustion chambers) will be considered lean burn engines. Also, existing engines where there are no manufacturer's recommendations regarding air/fuel ratio will be considered a rich burn engine if the excess oxygen content of the exhaust at full load conditions is less than or equal to 2 percent.

Site-rated HP means the maximum manufacturer's design capacity at engine site conditions.

Spark ignition means relating to either: A gasoline-fueled engine; or any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle. Spark ignition engines usually use a throttle to regulate intake air flow to control power during normal operation. Dual-fuel engines in which a liquid fuel (typically diesel fuel) is used for CI and gaseous fuel (typically natural gas) is used as the primary fuel at an annual average ratio of less than 2 parts diesel fuel to 100 parts total fuel on an energy equivalent basis are spark ignition engines.

Stationary reciprocating internal combustion engine (RICE) means any reciprocating internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. Stationary RICE differ from mobile RICE in that a stationary RICE is not a non-road engine as defined at 40 CFR 1068.30, and is not used to propel a motor vehicle or a vehicle used solely for competition.

Stationary RICE test cell/stand means an engine test cell/stand, as defined in subpart PPPPP of this part, that tests stationary RICE.

Stoichiometric means the theoretical air-to-fuel ratio required for complete combustion.

Storage vessel with the potential for flash emissions means any storage vessel that contains a hydrocarbon liquid with a stock tank gas-to-oil ratio equal to or greater than 0.31 cubic meters per liter and an American Petroleum Institute gravity equal to or greater than 40 degrees and an actual annual average hydrocarbon liquid throughput equal to or greater than 79,500 liters per day. Flash emissions occur when dissolved hydrocarbons in the fluid evolve from solution when the fluid pressure is reduced.

Subpart means 40 CFR part 63, subpart ZZZZ.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Two-stroke engine means a type of engine which completes the power cycle in single crankshaft revolution by combining the intake end compression operations into one stroke and the power and exhaust operations into a second stroke. This system requires auxiliary scavenging and inherently runs lean of stoichiometric.

[69 FR 33506, June 15, 2004, as amended at 71 FR 20467, Apr. 20, 2006; 73 FR 3607, Jan. 18, 2008; 75 FR 9679, Mar. 3, 2010; 75 FR 51592, Aug. 20, 2010; 76 FR 12867, Mar. 9, 2011]

Table 1ato Subpart ZZZZ of Part 63—Emission Limitations for Existing, New, and Reconstructed Spark Ignition, 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63 6640, you must comply with the following emission limitations at 100 percent load plus or minus 10 percent for existing, new and reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 4SRB stationary RICE	a. Reduce formaldehyde emissions by 76 percent or more. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may reduce formaldehyde emissions by 75 percent or more until June 15, 2007 or	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
	b. Limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63 6(g) for alternative work practices.

[75 FR 9679, Mar. 3, 2010, as amended et 75 FR 51592, Aug 20, 2010]

Table 1bto Subpart ZZZZ of Part 63—Operating Limitations for Existing, New, and Reconstructed Spark Ignition 4SRB Stationary RICE >500 HP Located at a Major Source of HAP Emissions and Existing Spark Ignition 4SRB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6603, 63.6630 and 63.6640, you must comply with the following operating limitations for existing, new end reconstructed 4SRB stationary RICE >500 HP located at a major source of HAP emissions and existing 4SRB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .
1. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and using	a. Maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst

NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and using NSCR.	measured during the initial performance test; and b. Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 750 °F and less than or equal to 1250 °F.
2. 4SRB stationary RICE complying with the requirement to reduce formaldehyde emissions by 76 percent or more (or by 75 percent or more, if applicable) and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 350 ppbvd or less at 15 percent O2 and not using NSCR; or 4SRB stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd or less at 15 percent O2 and not using NSCR.	Comply with any operating limitations approved by the Administrator.

[76 FR 12867, Mar. 9, 2011]

Table 2ato Subpart ZZZZ of Part 63—Emission Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP and New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600 and 63.6640, you must comply with the following emission limitations for new and reconstructed lean burn and new and reconstructed compression ignition stationary RICE at 100 percent load plus or minus 10 percent:

For each . . .	You must meet the following emission limitation, except during periods of startup . . .	During periods of startup you must . . .
1. 2SLB stationary RICE	a. Reduce CO emissions by 58 percent or more; or b. Limit concentration of formaldehyde in the stationary RICE exhaust to 12 ppmvd or less at	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe

	15 percent O_2. If you commenced construction or reconstruction between December 19, 2002 and June 15, 2004, you may limit concentration of formaldehyde to 17 ppmvd or less at 15 percent O_2until June 15, 2007	loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[1]
2. 4SLB stationary RICE	a. Reduce CO emissions by 93 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15 percent O_2	
3. CI stationary RICE	a. Reduce CO emissions by 70 percent or more; or	
	b. Limit concentration of formaldehyde in the stationary RICE exhaust to 580 ppbvd or less at 15 percent O_2	

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices.

[75 FR 9680, Mar. 3, 2010]

Table 2bto Subpart ZZZZ of Part 63— Operating Limitations for New and Reconstructed 2SLB and Compression Ignition Stationary RICE >500 HP Located at a Major Source of HAP Emissions, New and Reconstructed 4SLB Stationary RICE ≥250 HP Located at a Major Source of HAP Emissions, Existing Compression Ignition Stationary RICE >500 HP, and Existing 4SLB Stationary RICE >500 HP Located at an Area Source of HAP Emissions

As stated in §§63.6600, 63.6601, 63 6603, 63 6630, and 63.6640, you must comply with the following operating limitations for new and reconstructed 2SLB and compression ignition stationary RICE located at a major source of HAP emissions; new and reconstructed 4SLB stationary RICE ≥250 HP located at a major source of HAP emissions; existing compression ignition stationary RICE >500 HP; and existing 4SLB stationary RICE >500 HP located at an area source of HAP emissions that operate more than 24 hours per calendar year:

For each . . .	You must meet the following operating limitation . . .
I. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the	a. maintain your catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance

stationary RICE exhaust and using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and using an oxidation catalyst	test; and b. maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450 °F and less than or equal to 1350 °F.[1]
2. 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to reduce CO emissions and not using an oxidation catalyst; or 2SLB and 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of formaldehyde in the stationary RICE exhaust and not using an oxidation catalyst; or 4SLB stationary RICE and CI stationary RICE complying with the requirement to limit the concentration of CO in the stationary RICE exhaust and not using an oxidation catalyst	Comply with any operating limitations approved by the Administrator.

[1]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63.8(g) for e different temperature range.

[75 FR 51593, Aug. 20, 2010, as amended at 76 FR 12867, Mar. 9, 2011]

Table 2cto Subpart ZZZZ of Part 63—Requirements for Existing Compression Ignition Stationary RICE Located at a Major Source of HAP Emissions and Existing Spark Ignition Stationary RICE ≤500 HP Located at a Major Source of HAP Emissions

As stated in §§63.6600, 63.6602, and 63 6640, you must comply with the following requirements for existing compression ignition stationary RICE located at a major source of HAP emissions and existing spark ignition stationary RICE ≤500 HP located at a major source of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Emergency stationary CI RICE and black start stationary CI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2] b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; c. Inspect all hoses and belts every 500 hours of	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.[3]

	operation or annually, whichever comes first, and replace as necessary.[3]	
2. Non-Emergency, non-black start stationary CI RICE <100 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[2]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
3. Non-Emergency, non-black start CI stationary RICE 100≤HP≤300 HP	Limit concentration of CO in the stationary RICE exhaust to 230 ppmvd or less at 15 percent O_2	
4. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
5. Non-Emergency, non-black start stationary CI RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd or less at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
6. Emergency stationary SI RICE and black start stationary SI RICE.[1]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first;	

	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
7. Non-Emergency, non-black start stationary SI RICE <100 HP that are not 2SLB stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
8. Non-Emergency, non-black start 2SLB stationary SI RICE <100 HP	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[2]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first;	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.[3]	
9. Non-emergency, non-black start 2SLB stationary RICE $100 \leq HP \leq 500$	Limit concentration of CO in the stationary RICE exhaust to 225 ppmvd or less at 15 percent O_2	
10. Non-emergency, non-black start 4SLB stationary RICE $100 \leq HP \leq 500$	Limit concentration of CO in the stationary RICE exhaust to 47 ppmvd or less at 15 percent O_2	
11. Non-emergency,	Limit concentration of	

non-black start 4SRB stationary RICE 100≤HP≤500	formaldehyde in the stationary RICE exhaust to 10.3 ppmvd or less at 15 percent O_2	
12. Non-emergency, non-black start landfill or digester gas-fired stationary RICE 100≤HP≤500	Limit concentration of CO in the stationary RICE exhaust to 177 ppmvd or less at 15 percent O_2	

[1]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable.

[2]Sources have the option to utilize an oil analysis program as described in §63.6625(i) in order to extend the specified oil change requirement in Table 2c of this subpart.

[3]Sources can petition the Administrator pursuant to the requirements of 40 CFR 63 6(g) for alternative work practices.

[75 FR 51593, Aug. 20, 2010]

Table 2dto Subpart ZZZZ of Part 63—Requirements for Existing Stationary RICE Located at Area Sources of HAP Emissions

As stated in §§63.6603 and 63.6640, you must comply with the following requirements for existing stationary RICE located at area sources of HAP emissions:

For each . . .	You must meet the following requirement, except during periods of startup . . .	During periods of startup you must . . .
1. Non-Emergency, non-black start CI stationary RICE ≤300 HP	a. Change oil and filter every 1,000 hours of operation or annually, whichever comes first;[1]	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.
	b. Inspect air cleaner every 1,000 hours of operation or annually,	

	whichever comes first; c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
2. Non-Emergency, non-black start CI stationary RICE 300<HP≤500	a. Limit concentration of CO in the stationary RICE exhaust to 49 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
3. Non-Emergency, non-black start CI stationary RICE >500 HP	a. Limit concentration of CO in the stationary RICE exhaust to 23 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 70 percent or more.	
4. Emergency stationary CI RICE and black start stationary CI RICE.[2]	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	
	b. Inspect air cleaner every 1,000 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
5. Emergency stationary SI RICE; black start stationary SI RICE; non-emergency, non-black start 4SLB stationary RICE >500 HP that operate	a. Change oil and filter every 500 hours of operation or annually, whichever comes first;[1]	

24 hours or less per calendar year; non-emergency, non-black start 4SRB stationary RICE >500 HP that operate 24 hours or less per calendar year.[2]	b. Inspect spark plugs every 1,000 hours of operation or annually, whichever comes first; and c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.	
6. Non-emergency, non-black start 2SLB stationary RICE	a. Change oil and filter every 4,320 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 4,320 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first, and replace as necessary.	
7. Non-emergency, non-black start 4SLB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
8. Non-emergency, non-black start	a. Limit concentration	

4SLB stationary RICE >500 HP	of CO in the stationary RICE exhaust to 47 ppmvd at 15 percent O_2; or	
	b. Reduce CO emissions by 93 percent or more.	
9. Non-emergency, non-black start 4SRB stationary RICE ≤500 HP	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	
10. Non-emergency, non-black start 4SRB stationary RICE >500 HP	a. Limit concentration of formaldehyde in the stationary RICE exhaust to 2.7 ppmvd at 15 percent O_2; or	
	b. Reduce formaldehyde emissions by 76 percent or more.	
11. Non-emergency, non-black start landfill or digester gas-fired stationary RICE	a. Change oil and filter every 1,440 hours of operation or annually, whichever comes first;[1]	
	b. Inspect spark plugs every 1,440 hours of operation or annually, whichever comes first; and	
	c. Inspect all hoses and	

	belts every 1,440 hours of operation or annually, whichever comes first, and replace as necessary.	

[1]Sources have the option to utilize an oil analysis program as described in §63 6625(i) in order to extend the specified oil change requirement in Table 2d of this subpart.

[2]If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the management practice requirements on the schedule required in Table 2d of this subpart, or if performing the management practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the management practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The management practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has ebated. Sources must report any failure to perform the management practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable

[75 FR 51595, Aug 20, 2010]

Table 3 to Subpart ZZZZ of Part 63—Subsequent Performance Tests

As stated in §§63.6615 and 63.6620, you must comply with the following subsequent performance test requirements:

For each . . .	Complying with the requirement to . . .	You must . . .
1. New or reconstructed 2SLB stationary RICE with a brake horsepower >500 located at major sources; new or reconstructed 4SLB stationary RICE with a brake horsepower ≥250 located at major sources; and new or reconstructed CI stationary RICE with a brake horsepower >500 located at major sources	Reduce CO emissions and not using a CEMS	Conduct subsequent performance tests semiannually.[1]
2. 4SRB stationary RICE with a brake horsepower ≥5,000 located at major sources	Reduce formaldehyde emissions	Conduct subsequent performance tests semiannually.[1]
3. Stationary RICE with a brake horsepower >500 located at major sources and new or reconstructed 4SLB stationary RICE with a brake horsepower 250≤HP≤500 located at major sources	Limit the concentration of formaldehyde in the stationary RICE exhaust	Conduct subsequent performance tests semiannually.[1]
4. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are not limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 3 years, whichever comes first.

stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year that are not limited use stationary RICE		
5. Existing non-emergency, non-black start CI stationary RICE with a brake horsepower >500 that are limited use stationary RICE; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE located at an area source of HAP emissions with a brake horsepower >500 that are operated more than 24 hours per calendar year and are limited use stationary RICE	Limit or reduce CO or formaldehyde emissions	Conduct subsequent performance tests every 8,760 hrs. or 5 years, whichever comes first.

[1]After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[75 FR 51596, Aug 20, 2010]

Table 4 to Subpart ZZZZ of Part 63—Requirements for Performance Tests

As stated in §§63.6610, 63.6611, 63.6612, 63.6620, and 63 6640, you must comply with the following requirements for performance tests for stationary RICE:

For each . . .	Complying with the requirement to . . .	You must . . .	Using . . .	According to the following requirements . . .
1. 2SLB, 4SLB, and CI stationary RICE	a. Reduce CO emissions	i. Measure the O_2at the inlet and outlet of the control device; and	(1) Portable CO and O_2analyzer	(a) Using ASTM D6522–00 (2005)[a](incorporated by reference, see §63.14). Measurements to determine O_2must be made at the same time as the measurements for CO concentration.
		ii. Measure the CO at the inlet and the outlet of the control device	(1) Portable CO and O_2analyzer	(a) Using ASTM D6522–00 (2005)[ab](incorporated by reference, see §63.14) or Method 10 of 40 CFR appendix A. The CO concentration must be at 15 percent O_2, dry basis.
2. 4SRB	a. Reduce	i. Select the	(1) Method 1 or 1A of	(a) Sampling sites must be

stationary RICE	formaldehyde emissions	sampling port location and the number of traverse points; and	40 CFR part 60, appendix A §63.7(d)(1)(i)	located at the inlet and outlet of the control device.
		ii. Measure O_2 at the inlet and outlet of the control device; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00m (2005)	(a) Measurements to determine O_2 concentration must be made at the same time as the measurements for formaldehyde concentration.
		iii. Measure moisture content at the inlet and outlet of the control device; and	(1) Method 4 of 40 CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	(a) Measurements to determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the inlet and the outlet of the control device	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c] provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
3. Stationary RICE	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. Select the sampling port location and the number of traverse points; and	(1) Method 1 or 1A of 40 CFR part 60, appendix A §63.7(d)(1)(i)	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary RICE exhaust at the sampling port location; and	(1) Method 3 or 3A or 3B of 40 CFR part 60, appendix A, or ASTM Method D6522–00 (2005)	(a) Measurements to determine O_2 concentration must be made at the same time and location as the measurements for formaldehyde concentration.
		iii. Measure	(1) Method 4 of 40	(a) Measurements to

		moisture content of the stationary RICE exhaust at the sampling port location; and	CFR part 60, appendix A, or Test Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348–03	determine moisture content must be made at the same time and location as the measurements for formaldehyde concentration.
		iv. Measure formaldehyde at the exhaust of the stationary RICE; or	(1) Method 320 or 323 of 40 CFR part 63, appendix A; or ASTM D6348–03,[c] provided in ASTM D6348–03 Annex A5 (Analyte Spiking Technique), the percent R must be greater than or equal to 70 and less than or equal to 130	(a) Formaldehyde concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour or longer runs.
		v. Measure CO at the exhaust of the stationary RICE	(1) Method 10 of 40 CFR part 60, appendix A, ASTM Method D6522–00 (2005),[a] Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03	(a) CO Concentration must be at 15 percent O_2, dry basis. Results of this test consist of the average of the three 1-hour longer runs.

[a]You may also use Methods 3A and 10 as options to ASTM–D6522–00 (2005). You may obtain a copy of ASTM–D6522–00 (2005) from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48108. ASTM–D6522–00 (2005) may be used to test both CI and SI stationary RICE.

[b]You may also use Method 320 of 40 CFR part 63, appendix A, or ASTM D6348–03.

[c]You may obtain a copy of ASTM–D6348–03 from at least one of the following addresses: American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959, or University Microfilms International, 300 North Zeeb Road, Ann Arbor, MI 48106.

[75 FR 51597, Aug. 20, 2010]

Table 5 to Subpart ZZZZ of Part 63—Initial Compliance With Emission Limitations and Operating Limitations

As stated in §§63.6612, 63.6625 and 63.6630, you must initially comply with the emission and operating limitations as required by the following:

For each . . .	Complying with the requirement to . . .	You have demonstrated initial compliance if. . .

1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions and using oxidation catalyst, and using a CPMS	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
2. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, using oxidation catalyst, and using a CPMS	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions and not using oxidation catalyst	i. The average reduction of emissions of CO determined from the initial performance test achieves the required CO percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.

4. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, and not using oxidation catalyst	i. The average CO concentration determined from the initial performance test is less than or equal to the CO emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and iii. You have recorded the approved operating parameters (if any) during the initial performance test.
5. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at both the inlet and outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and iii. The average reduction of CO calculated using §63.6620 equals or exceeds the required percent reduction. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average percent reduction achieved during the 4-hour period.
6. Non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP located at an area source of HAP, and existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Limit the concentration of CO, and using a CEMS	i. You have installed a CEMS to continuously monitor CO and either O_2 or CO_2 at the outlet of the oxidation catalyst according to the requirements in §63.6625(a); and ii. You have conducted a performance evaluation of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B; and
		iii. The average concentration of

		CO calculated using §63.6620 is less than or equal to the CO emission limitation. The initial test comprises the first 4-hour period after successful validation of the CEMS. Compliance is based on the average concentration measured during the 4-hour period.
7. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
8. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce formaldehyde emissions and not using NSCR	i. The average reduction of emissions of formaldehyde determined from the initial performance test is equal to or greater than the required formaldehyde percent reduction; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
9. Existing non-emergency 4SRB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per	a. Limit the concentration of formaldehyde and not using NSCR	i. The average formaldehyde concentration determined from the initial performance test is less than or equal to the formaldehyde

calendar year		emission limitation; and
		ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
10. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor catalyst inlet temperature according to the requirements in §63.6625(b); and
		iii. You have recorded the catalyst pressure drop and catalyst inlet temperature during the initial performance test.
11. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP, and existing non-emergency 4SRB stationary RICE >500 HP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	i. The average formaldehyde concentration, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde emission limitation; and ii. You have installed a CPMS to continuously monitor operating parameters approved by the Administrator (if any) according to the requirements in §63.6625(b); and
		iii. You have recorded the approved operating parameters (if any) during the initial performance test.
12. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and	a. Reduce CO or formaldehyde emissions	i. The average reduction of emissions of CO or formaldehyde, as applicable determined from the

existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP		initial performance test is equal to or greater than the required CO or formaldehyde, as applicable, percent reduction.
13. Existing non-emergency stationary RICE 100≤HP≤500 located at a major source of HAP, and existing non-emergency stationary CI RICE 300<HP≤500 located at an area source of HAP	a. Limit the concentration of formaldehyde or CO in the stationary RICE exhaust	i. The average formaldehyde or CO concentration, as applicable, corrected to 15 percent O_2, dry basis, from the three test runs is less than or equal to the formaldehyde or CO emission limitation, as applicable.

[76 FR 12867, Mar. 9, 2011]

Table 6 to Subpart ZZZZ of Part 63—Continuous Compliance With Emission Limitations, Operating Limitations, Work Practices, and Management Practices

As stated in §63.6640, you must continuously comply with the emissions and operating limitations and work or management practices as required by the following:

For each . . .	Complying with the requirement to . . .	You must demonstrate continuous compliance by . . .
1. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	a. Reduce CO emissions and using an oxidation catalyst, and using a CPMS	i. Conducting semiannual performance tests for CO to demonstrate that the required CO percent reduction is achieved;[a] and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
2. New or reconstructed non-emergency 2SLB stationary RICE	a. Reduce CO emissions and not using an	i. Conducting semiannual performance tests for CO to

>500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, and new or reconstructed non-emergency CI stationary RICE >500 HP located at a major source of HAP	oxidation catalyst, and using a CPMS	demonstrate that the required CO percent reduction is achieved;[a]and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
3. New or reconstructed non-emergency 2SLB stationary RICE >500 HP located at a major source of HAP, new or reconstructed non-emergency 4SLB stationary RICE ≥250 HP located at a major source of HAP, new or reconstructed non-emergency stationary CI RICE >500 HP located at a major source of HAP, existing non-emergency stationary CI RICE >500 HP, existing non-emergency 4SLB stationary RICE >500 HP located at an area source of HAP that are operated more than 24 hours per calendar year	a. Reduce CO emissions or limit the concentration of CO in the stationary RICE exhaust, and using a CEMS	i. Collecting the monitoring data according to §63.6625(a), reducing the measurements to 1-hour averages, calculating the percent reduction or concentration of CO emissions according to §63.6620; and ii. Demonstrating that the catalyst achieves the required percent reduction of CO emissions over the 4-hour averaging period, or that the emission remain at or below the CO concentration limit; and iii. Conducting an annual RATA of your CEMS using PS 3 and 4A of 40 CFR part 60, appendix B, as well as daily and periodic data quality checks in accordance with 40 CFR part 60, appendix F, procedure 1.
4. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and using NSCR	i. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		iv. Measuring the pressure drop

		across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
5. Non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP	a. Reduce formaldehyde emissions and not using NSCR	i. Collecting the approved operating parameter (if any) data according to §63.6625(b); and ii. Reducing these data to 4-hour rolling averages; and
		iii. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
6. Non-emergency 4SRB stationary RICE with a brake HP ≥5,000 located at a major source of HAP	a. Reduce formaldehyde emissions	Conducting semiannual performance tests for formaldehyde to demonstrate that the required formaldehyde percent reduction is achieved.[a]
7. New or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	a. Limit the concentration of formaldehyde in the stationary RICE exhaust and using oxidation catalyst or NSCR	i. Conducting semiannual performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a] and ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
8. New or reconstructed non-	a. Limit the	i. Conducting semiannual

emergency stationary RICE >500 HP located at a major source of HAP and new or reconstructed non-emergency 4SLB stationary RICE 250 ≤HP≤500 located at a major source of HAP	concentration of formaldehyde in the stationary RICE exhaust and not using oxidation catalyst or NSCR	performance tests for formaldehyde to demonstrate that your emissions remain at or below the formaldehyde concentration limit;[a]and ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
9. Existing emergency and black start stationary RICE ≤500 HP located at a major source of HAP, existing non-emergency stationary RICE <100 HP located at a major source of HAP, existing emergency and black start stationary RICE located at an area source of HAP, existing non-emergency stationary CI RICE ≤300 HP located at an area source of HAP, existing non-emergency 2SLB stationary RICE located at an area source of HAP, existing non-emergency landfill or digester gas stationary SI RICE located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE ≤500 HP located at an area source of HAP, existing non-emergency 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate 24 hours or less per calendar year	a. Work or Management practices	i. Operating and maintaining the stationary RICE according to the manufacturer's emission-related operation and maintenance instructions; or ii. Develop and follow your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions.
10. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or

of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	the stationary RICE exhaust, and using oxidation catalyst or NSCR	formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
11. Existing stationary CI RICE >500 HP that are not limited use stationary RICE, and existing 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year and are not limited use stationary RICE	a. Reduce CO or formaldehyde emissions, or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 3 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating parameters established during the performance test.
12. Existing limited use CI	a. Reduce CO or	i. Conducting performance tests

stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year	formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and using an oxidation catalyst or NSCR	every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the catalyst inlet temperature data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the catalyst inlet temperature; and
		v. Measuring the pressure drop across the catalyst once per month and demonstrating that the pressure drop across the catalyst is within the operating limitation established during the performance test.
13. Existing limited use CI stationary RICE >500 HP and existing limited use 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP that operate more than 24 hours per calendar year	a. Reduce CO or formaldehyde emissions or limit the concentration of formaldehyde or CO in the stationary RICE exhaust, and not using an oxidation catalyst or NSCR	i. Conducting performance tests every 8,760 hours or 5 years, whichever comes first, for CO or formaldehyde, as appropriate, to demonstrate that the required CO or formaldehyde, as appropriate, percent reduction is achieved or that your emissions remain at or below the CO or formaldehyde concentration limit; and
		ii. Collecting the approved operating parameter (if any) data according to §63.6625(b); and
		iii. Reducing these data to 4-hour rolling averages; and
		iv. Maintaining the 4-hour rolling averages within the operating limitations for the operating

		parameters established during the performance test.

*After you have demonstrated compliance for two consecutive tests, you may reduce the frequency of subsequent performance tests to annually. If the results of any subsequent annual performance test indicate the stationary RICE is not in compliance with the CO or formaldehyde emission limitation, or you deviate from any of your operating limitations, you must resume semiannual performance tests.

[76 FR 12870, Mar. 9, 2011]

Table 7 to Subpart ZZZZ of Part 63—Requirements for Reports

As stated in §63.6650, you must comply with the following requirements for reports:

For each ...	You must submit a ...	The report must contain ...	You must submit the report ...
1. Existing non-emergency, non-black start stationary RICE 100≤HP≤500 located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >500 HP located at a major source of HAP; existing non-emergency 4SRB stationary RICE >500 HP located at a major source of HAP; existing non-emergency, non-black start stationary CI RICE >300 HP located at an area source of HAP; existing non-emergency, non-black start 4SLB and 4SRB stationary RICE >500 HP located at an area source of HAP and operated more than 24 hours per calendar year; new or reconstructed non-emergency stationary RICE >500 HP located at a major source of HAP; and new or reconstructed non-emergency 4SLB stationary RICE 250≤HP≤500 located at a major source of HAP	Compliance report	a. If there are no deviations from any emission limitations or operating limitations that apply to you, a statement that there were no deviations from the emission limitations or operating limitations during the reporting period. If there were no periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), a statement that there were not periods during which the CMS was out-of-control during the reporting period; or b. If you had a deviation from any emission limitation or operating limitation during the reporting period, the information in §63.6650(d). If there were periods during which the CMS, including CEMS and CPMS, was out-of-control, as specified in §63.8(c)(7), the information in §63.6650(e); or c. If you had a malfunction during the reporting period, the information in §63.6650(c)(4)	

		i. Semiannually according to the requirements in §63.6650(b)(1)–(5) for engines that are not limited use stationary RICE subject to numerical emission limitations; and ii. Annually according to the requirements in §63.6650(b)(6)–(9) for engines that are limited use stationary RICE subject to numerical emission limitations. i. Semiannually according to the requirements in §63.6650(b). i. Semiannually according to the requirements in §63.6650(b).	
2. New or reconstructed non-emergency stationary RICE that combusts landfill gas or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis	Report	a. The fuel flow rate of each fuel and the heating values that were used in your calculations, and you must demonstrate that the percentage of heat input provided by landfill gas or digester gas, is equivalent to 10 percent or more of the gross heat input on an annual basis; and i. Annually, according to the requirements in §63.6650.	
		b. The operating limits provided in your federally enforceable permit, and any deviations from these limits; and i. See item 2.a.i.	
		c. Any problems or errors suspected with the meters. i. See item 2.a.i.	

[75 FR 51603, Aug. 20, 2010]

Table 8 to Subpart ZZZZ of Part 63—Applicability of General Provisions to Subpart ZZZZ.

As stated in §63.6665, you must comply with the following applicable general provisions.

General provisions citation	Subject of citation	Applies to subpart	Explanation
§63.1	General applicability of the	Yes.	

	General Provisions		
§63.2	Definitions	Yes	Additional terms defined in §63.6675.
§63.3	Units and abbreviations	Yes.	
§63.4	Prohibited activities and circumvention	Yes.	
§63.5	Construction and reconstruction	Yes.	
§63.6(a)	Applicability	Yes.	
§63.6(b)(1)–(4)	Compliance dates for new and reconstructed sources	Yes.	
§63.6(b)(5)	Notification	Yes.	
§63.6(b)(6)	[Reserved]		
§63.6(b)(7)	Compliance dates for new and reconstructed area sources that become major sources	Yes.	
§63.6(c)(1)–(2)	Compliance dates for existing sources	Yes.	
§63.6(c)(3)–(4)	[Reserved]		
§63.6(c)(5)	Compliance dates for existing area sources that become major sources	Yes.	
§63.6(d)	[Reserved]		
§63.6(e)	Operation and maintenance	No.	
§63.6(f)(1)	Applicability of standards	No.	
§63.6(f)(2)	Methods for determining compliance	Yes.	
§63.6(f)(3)	Finding of compliance	Yes.	
§63.6(g)(1)–(3)	Use of alternate standard	Yes.	
§63.6(h)	Opacity and visible emission standards	No	Subpart ZZZZ does not contain opacity or visible emission standards.
§63.6(i)	Compliance extension procedures and criteria	Yes.	

§63.6(j)	Presidential compliance exemption	Yes.	
§63.7(a)(1)-(2)	Performance test dates	Yes	Subpart ZZZZ contains performance test dates at §§63.6610, 63.6611, and 63.6612.
§63.7(a)(3)	CAA section 114 authority	Yes.	
§63.7(b)(1)	Notification of performance test	Yes	Except that §63.7(b)(1) only applies as specified in §63.6645.
§63.7(b)(2)	Notification of rescheduling	Yes	Except that §63.7(b)(2) only applies as specified in §63.6645.
§63.7(c)	Quality assurance/test plan	Yes	Except that §63.7(c) only applies as specified in §63.6645.
§63.7(d)	Testing facilities	Yes.	
§63.7(e)(1)	Conditions for conducting performance tests	No.	Subpart ZZZZ specifies conditions for conducting performance tests at §63.6620.
§63.7(e)(2)	Conduct of performance tests and reduction of data	Yes	Subpart ZZZZ specifies test methods at §63.6620.
§63.7(e)(3)	Test run duration	Yes.	
§63.7(e)(4)	Administrator may require other testing under section 114 of the CAA	Yes.	
§63.7(f)	Alternative test method provisions	Yes.	
§63.7(g)	Performance test data analysis, recordkeeping, and reporting	Yes.	
§63.7(h)	Waiver of tests	Yes.	
§63.8(a)(1)	Applicability of monitoring requirements	Yes	Subpart ZZZZ contains specific requirements for monitoring at §63.6625.
§63.8(a)(2)	Performance specifications	Yes.	
§63.8(a)(3)	[Reserved]		

§63.8(a)(4)	Monitoring for control devices	No.	
§63.8(b)(1)	Monitoring	Yes.	
§63.8(b)(2)–(3)	Multiple effluents and multiple monitoring systems	Yes.	
§63.8(c)(1)	Monitoring system operation and maintenance	Yes.	
§63.8(c)(1)(i)	Routine and predictable SSM	Yes.	
§63.8(c)(1)(ii)	SSM not in Startup Shutdown Malfunction Plan	Yes.	
§63.8(c)(1)(iii)	Compliance with operation and maintenance requirements	Yes.	
§63.8(c)(2)–(3)	Monitoring system installation	Yes.	
§63.8(c)(4)	Continuous monitoring system (CMS) requirements	Yes	Except that subpart ZZZZ does not require Continuous Opacity Monitoring System (COMS).
§63.8(c)(5)	COMS minimum procedures	No	Subpart ZZZZ does not require COMS.
§63.8(c)(6)–(8)	CMS requirements	Yes	Except that subpart ZZZZ does not require COMS.
§63.8(d)	CMS quality control	Yes.	
§63.8(e)	CMS performance evaluation	Yes	Except for §63.8(e)(5)(ii), which applies to COMS.
		Except that §63.8(e) only applies as specified in §63.6645.	
§63.8(f)(1)–(5)	Alternative monitoring method	Yes	Except that §63.8(f)(4) only applies as specified in §63.6645.
§63.8(f)(6)	Alternative to relative accuracy test	Yes	Except that §63.8(f)(6) only applies as specified in §63.6645.
§63.8(g)	Data reduction	Yes	Except that provisions for COMS are not applicable. Averaging periods for

			demonstrating compliance are specified at §§63.6635 and 63.6640.
§63.9(a)	Applicability and State delegation of notification requirements	Yes.	
§63.9(b)(1)–(5)	Initial notifications	Yes	Except that §63.9(b)(3) is reserved.
		Except that §63.9(b) only applies as specified in §63.6645.	
§63.9(c)	Request for compliance extension	Yes	Except that §63.9(c) only applies as specified in §63.6645.
§63.9(d)	Notification of special compliance requirements for new sources	Yes	Except that §63.9(d) only applies as specified in §63.6645.
§63.9(e)	Notification of performance test	Yes	Except that §63.9(e) only applies as specified in §63.6645.
§63.9(f)	Notification of visible emission (VE)/opacity test	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(1)	Notification of performance evaluation	Yes	Except that §63.9(g) only applies as specified in §63.6645.
§63.9(g)(2)	Notification of use of COMS data	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.9(g)(3)	Notification that criterion for alternative to RATA is exceeded	Yes	If alternative is in use.
		Except that §63.9(g) only applies as specified in §63.6645.	

§63.9(h)(1)-(6)	Notification of compliance status	Yes	Except that notifications for sources using a CEMS are due 30 days after completion of performance evaluations. §63.9(h)(4) is reserved.
			Except that §63.9(h) only applies as specified in §63.6645.
§63.9(i)	Adjustment of submittal deadlines	Yes.	
§63.9(j)	Change in previous information	Yes.	
§63.10(a)	Administrative provisions for recordkeeping/reporting	Yes.	
§63.10(b)(1)	Record retention	Yes.	
§63.10(b)(2)(i)-(v)	Records related to SSM	No.	
§63.10(b)(2)(vi)-(xi)	Records	Yes.	
§63.10(b)(2)(xii)	Record when under waiver	Yes.	
§63.10(b)(2)(xiii)	Records when using alternative to RATA	Yes	For CO standard if using RATA alternative.
§63.10(b)(2)(xiv)	Records of supporting documentation	Yes.	
§63.10(b)(3)	Records of applicability determination	Yes.	
§63.10(c)	Additional records for sources using CEMS	Yes	Except that §63.10(c)(2)-(4) and (9) are reserved.
§63.10(d)(1)	General reporting requirements	Yes.	
§63.10(d)(2)	Report of performance test results	Yes.	
§63.10(d)(3)	Reporting opacity or VE observations	No	Subpart ZZZZ does not contain opacity or VE standards.
§63.10(d)(4)	Progress reports	Yes.	
§63.10(d)(5)	Startup, shutdown, and	No.	

	malfunction reports		
§63.10(e)(1) and (2)(i)	Additional CMS Reports	Yes.	
§63.10(e)(2)(ii)	COMS-related report	No	Subpart ZZZZ does not require COMS.
§63.10(e)(3)	Excess emission and parameter exceedances reports	Yes.	Except that §63.10(e)(3)(i)(C) is reserved.
§63.10(e)(4)	Reporting COMS data	No	Subpart ZZZZ does not require COMS.
§63.10(f)	Waiver for recordkeeping/reporting	Yes.	
§63.11	Flares	No.	
§63.12	State authority and delegations	Yes.	
§63.13	Addresses	Yes.	
§63.14	Incorporation by reference	Yes.	
§63.15	Availability of information	Yes.	

[75 FR 9688, Mar. 3, 2010]

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (ATSD) for a Part 70 Significant Source and Permit Modification

Source Description and Location

Source Name:	**Duke Energy Indiana Inc., Cayuga Generating Station**
Source Location:	**State Road 63, Cayuga, IN 46168**
County:	**Vermillion**
SIC Code:	**4911**
Operation Permit No.:	**T 165-27260-00001**
Operation Permit Issuance Date:	**August 20, 2009**
Significant Source Modification No.:	**165-32045-00001**
Significant Permit Modification No.:	**165-32048-00001**
Permit Reviewer:	**Josiah Balogun**

Public Notice Information

On July 30, 2012, the Office of Air Quality (OAQ) had a notice published in the Daily Clintonian in Clinton, Indiana, stating that Duke Energy Indiana Inc., Cayuga Generating Station had applied for a Significant Modification to their Part 70 Operating Title V Permit issued on August 20, 2009 relating to the installation of Selective Catalytic Reduction (SCR) on each unit to control emissions of NOx and to convert Hg into a form which can be more easily captured with the existing controls. The notice also stated that OAQ proposed to issue a permit for this operation and provided information on how the public could review the proposed permit and other documentation. Finally, the notice informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

Comments Received

On August 29, 2012, IDEM, OAQ received comments from Patrick Coughlin of Duke Energy Indiana. The comments are summarized in the subsequent pages, with IDEM's corresponding responses.

No changes have been made to the TSD because the OAQ prefers that the Technical Support Document reflects the permit that was on public notice. Changes that occur after the public notice are documented in this Addendum to the Technical Support Document. This accomplishes the desired result, ensuring that these types of concerns are documented and part of the record regarding this permit decision.

The summary of the comments and IDEM, OAQ responses, including changes to the permit T165-27260-00001 (language deleted is shown in ~~strikeout~~ and language added is shown in **bold**) are as follows:

Comment 1: The first sentence in condition D.8.4(a) contains a typo. The first sentence should be revised to cite condition D.8.1(c) and not D.8.1(b).

Response 1: The typo in Condition D.8.4(a) has been corrected in the permit accordingly.

D.8.4 Particulate Control [326 IAC 2-7-6(6)]

(a) In order to ensure compliance with the particulate matter emissions limits specified in conditions D.8.1(cb) and D.8.2 the filter separators, and silo bin vent filters shall in operation and controlling emissions whenever the equipment is in operation and venting to the control device.

....

Comment 2: The first sentence in conditions D.8.5(a) and (b) contains a typo. The first sentence in these conditions should be revised to cite condition D.8.1(c) and not D.8.1(b).

Response 2: The typo in Condition D.8.5(a) and (b) have been corrected in the permit accordingly.

D.8.5 Testing Requirements [326 IAC 2-7-6(1),(6)][326 IAC 2-1.1-11]

(a) Within 180 days after the initial startup of the pneumatic fly ash transfer system, in order to determine compliance with Condition D.8.1(cb), the Permittee shall perform PM, PM_{10} and $PM_{2.5}$ testing two (2) of the five (5) separator/exhausters, identified as emissions point EP-01 (DFA), EP-02 (DFA), EP-03 (DFA), EP-04 (DFA) and EP-05 (DFA), using methods as approved by the Commissioner. This testing shall be at least once every 5 years from the date of the last valid compliance demonstration. The separator/exhauster tested shall be the unit in which the longest amount of time has elapsed since its previous test. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

(b) Within 180 days after the initial startup of the pneumatic fly ash transfer system, in order to determine compliance with Condition D.8.1(cb), the Permittee shall perform PM, PM_{10} and $PM_{2.5}$ testing on one (1) of the three (3) Fly Ash Silos/Day Bin, identified as emission point EP-06 (DFA), EP-07 (DFA) and EP-01 (FIX) using methods as approved by the Commissioner. This testing shall be at least once every 5 years from the date of the last valid compliance demonstration. The Ash Silo/Day Bin tested shall be the unit in which the longest amount of time has elapsed since its previous test. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Significant Source and Permit Modification

Source Description and Location	
Source Name:	**Duke Energy Indiana Inc., Cayuga Generating Station**
Source Location:	**State Road 63, Cayuga, IN 46168**
County:	**Vermillion**
SIC Code:	**4911**
Operation Permit No.:	**T 165-27260-00001**
Operation Permit Issuance Date:	**August 20, 2009**
Significant Source Modification No.:	**165-32045-00001**
Significant Permit Modification No.:	**165-32048-00001**
Permit Reviewer:	**Josiah Balogun**

Source Definition

Duke Energy Indiana, Inc.'s Cayuga Generating Station, identified as 165-00001, is located on the same property as Duke Energy Indiana, Inc.'s Unit 4 combustion turbine plant identified as 165-00086. IDEM, OAQ has examined whether the Cayuga Generating Station plant and the combustion turbine plant are part of the same major source. The term "major source" is defined at 326 IAC 2-7-1(22). In order for these two plants to be considered one major source, they must meet all three of the following criteria:

(1) the plants must be under common ownership or common control;

(2) the plants must belong to a single major industrial grouping or one must serve as a support facility for the other; and,

(3) the plants must be located on contiguous or adjacent properties.

The two plants are owned by Duke Energy Indiana, Inc. Since there is a common owner, the first element of the definition of major source is met.

The SIC Code Manual of 1987 sets out how to determine the proper SIC Code for each type of business, called establishments. The SIC Codes are divided up into eleven divisions, lettered A through K. Each division is broken down into separate major groups. Each major group has a distinct two-digit SIC Code. The two plants have the same two-digit SIC Code, 49, for Electric, Gas and Sanitary Services. Therefore the second element of the definition is met.

The two plants are located on the same piece of property in separate buildings. Since the plants are located on the same piece of property, they the third element of the definition. IDEM, OAQ finds that the two plants are part of the same major source. IDEM, OAQ will issue separate Part 70 permits to each plant solely for administrative purposes.

Existing Approvals

The source was issued Part 70 Operating Permit No. 165-27260-00001 on August 20, 2009. The source has since received the following approvals:

(a) Administrative Amendment No. 165-28471-00001, issued on October 20, 2009;

(b) Acid Rain Permit No. 165-29750-00001, issued on January 4, 2011;

(c) Temporary Operation No. 165-31135-00001, issued on November 28, 2011;

(d) Temporary Operation No. 165-31235-00001, issued on December 19, 2011; and

(e) Temporary Operation No. 165-31882-00001, issued on June 14, 2012.

County Attainment Status

The source is located in Vermillion County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Unclassifiable or attainment effective November 15, 1990.
O_3	Unclassifiable or attainment effective June 15, 2004, for the 8-hour ozone standard.[1]
PM_{10}	Attainment effective October 27, 1997, for the part of Clinton Township that includes sections 15, 16, 21, 22, 27, 28, 33, and 34. Unclassifiable effective November 15, 1990, for the remainder of Vermillion County.
NO_2	Cannot be classified or better than national standards.
Pb	Not designated.
[1]Unclassifiable or attainment effective October 18, 2000, for the 1-hour ozone standard which was revoked effective June 15, 2005. Unclassifiable or attainment effective April 5, 2005, for PM2.5.	

(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. Therefore, VOC and NOx emissions are considered when evaluating the rule applicability relating to ozone. Vermillion County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(b) $PM_{2.5}$
Vermillion County has been classified as attainment for $PM_{2.5}$. On May 8, 2008 U.S. EPA promulgated the requirements for Prevention of Significant Deterioration (PSD) for $PM_{2.5}$ emissions. These rules became effective on July 15, 2008. On May 4, 2011 the air pollution control board issued an emergency rule establishing the direct $PM_{2.5}$ significant level at ten (10) tons per year. This rule became effective, June 28, 2011. Therefore, direct $PM_{2.5}$ and SO_2 emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2. See the State Rule Applicability – Entire Source section.

(c) Other Criteria Pollutants
Vermillion County has been classified as attainment or unclassifiable in Indiana for all criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

Since this source is classified as a Fossil fuel fired stem electric plant of more than (250 MMBtu per hour), it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Source Status

The table below summarizes the potential to emit of the entire source, prior to the proposed modification, after consideration of all enforceable limits established in the effective permits:

Pollutant	Emissions (ton/yr)
PM	>100
PM_{10}	>100
$PM_{2.5}$	>100
SO_2	>100
VOC	>100
CO	>100
NO_X	> 100
GHGs as CO_2e	---
HAPs	
Single HAP	> 10
Total HAPs	> 25

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a regulated pollutant is emitted at a rate of 100 tons per year or more, and it is one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1).

(b) These emissions are based upon Part 70 Operating permit No T165-27260-00001, issued on August 20, 2009.

(c) This existing source is a major source of HAPs, as defined in 40 CFR 63.2, because HAP emissions are greater than ten (10) tons per year for a single HAP and greater than twenty-five (25) tons per year for a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed a modification application, submitted by Duke Energy Indiana Inc., Cayuga Generating Station on June 26, 2012, relating to the installation of Selective Catalytic Reduction (SCR) on each unit to control emissions of NOx and to convert Hg into a form which can be more easily captured with the existing controls. The proposed SCR system will include an Arsenic mitigation system, SO_3 mitigation system, and Ammonia storage facility. The Arsenic mitigation system is needed to reduce degradation of the catalyst material from trace quantities of Arsenic in the coal. Duke Energy is proposing to install an activated carbon injection system on each Unit to achieve additional Hg control. In addition, Duke Energy is proposing to install a dry fly ash handling and ash fixation system. Currently the fly ash collected in the ESP is sluiced to ash ponds. The following are the list of the modified and new emission unit(s) and pollution control device(s):

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Boiler No. 1 was configured with a low NO_X burner in 1993. **Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.**

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Boiler No. 2 was configured with a low NO_X burner in 1993.**Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015**

(c) **One (1) Arsenic Mitigation System consisting of (1) 700 ton Limestone Storage Silo and (1) 300 ton Limestone Surge Bin, scheduled to be installed by 2015. Limestone is pneumatically conveyed from delivery trucks to the Limestone Storage Silo and from the Limestone Storage Silo to the Limestone Surge Bin. Limestone in the Surge Bin is dropped on to the C-1 and C-2 coal conveyors. PM emissions generated during pneumatic conveying and transfer points to the C-1 and C-2 conveyor will be controlled by the bin vent filters. The Limestone Storage Silo and Limestone Surge Bin are identified as emissions points EP-01(LS) and EP-02(LS).**

(d) **Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of (2) two Sorbent Storage Silos with a storage capacity of 120 tons and system to inject the sorbent material into the flue gas, scheduled to be installed by 2015. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo. The four (4) Sorbent Silos are identified as emission points EP-01(DSI), EP-02(DSI, EP-03(DSI), and EP-04(DSI).**

(e) **Two (2) Activated Carbon Injection (ACI) Systems, one for each Unit. Each ACI system consists of one (1) storage silo with a 80 ton storage capacity and system for injecting the Activated Carbon into the flue gas, scheduled to be installed by 2015. PM emissions during the silo loading operation are controlled by the bin vent filters located on top of the silos. The two (2) Activated Carbon Storage Silos are identified as emission points EP-01(ACI) and EP-02(ACI).**

(f) **Two (2) Dry Ash Handling Systems, one for each Unit. The dry ash handling system consists of a pneumatic conveying system, four (4) baghouse separators, two (2) ash silos with a storage capacity of 3,500 each and an ash unloading system, scheduled to be installed by 2015.**

(i) **Baghouse Separators - Fly ash from the ESP Ash Hoppers, Air Heater Ash Hoppers, Economizer Ash Hoppers and SCR Large Particle Screen Ash Hopper will be pneumatically conveyed to one of four (4) baghouse separators. There will be two (2) baghouse separators for each unit. The dry fly ash is separated from the air stream in a baghouse separator. Each baghouse separator are identified as emissions points EP-01(DFA), EP--02(DFA), EP-03(DFA), and EP-04(DFA). The system is equipped with a spare exhauster identified as emissions point EP-05(DFA).**

(ii) **Ash Silos - Fly ash collected in the baghouse separators is dropped into a feeder and pneumatically conveyed to one of two (2) ash silos. Each ash silo is equipped with a bin vent filter to control particulate matter emissions from pneumatic conveying. The Ash Silos are identified as emission point**

EP-06(DFA) and EP-07(DFA).

(iii) Ash Unloading Operation - Fly ash collected in the silos can be unloaded into trucks or pneumatically conveyed to the ash fixation process. Fly ash unloaded into trucks can be unloaded dry or wet. Fly ash unloaded dry is gravity feed to a chute and unloaded into enclosed trucks. The emissions generated from unloading the ash dry are vented back to the silo and controlled by the silo bin vent filter. Ash unloaded wet is feed into a pin mixer where the ash is mixed with water and unloaded into open trucks

(g) One (1) Ash Fixation Process consisting of a pneumatic conveying system, one (1) ash day bin, one (1) lime silo, conveyors, and two (2) pin mixers, scheduled to be installed by 2015.

(i) Fly Ash Day Bin - Fly ash from the ash silos can be pneumatically conveyed to the day bin. The storage capacity of the day bin is 500 tons. The emissions generated from pneumatic conveyance will be controlled by a bin vent filter located on top of the fly ash day bin. The Fly Ash Day Bin is identified as emissions point EP-01(FIX).

(ii) Lime Silo – Lime will be delivered by truck and will pneumatically loaded into the silo. The storage capacity of the silo is 300 tons. The emissions generated by the pneumatic conveying will be controlled by a bin vent filter located on top of the lime silo. The Lime Silo is identified as emissions point EP-02(FIX).

(iii) Conveyor and Transfer Points – Fly ash, Lime and Gypsum will be conveyed to one of two (2) pin mixers where this material will be mixed with water to make the fixated ash. The fixated ash will be unloaded to a storage pile, and then loaded into trucks using front end loaders.

Enforcement Issues

There are no pending enforcement actions.

Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

Permit Level Determination – Part 70

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as "the maximum capacity of a stationary source or emission unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, IDEM, or the appropriate local air pollution control agency."

The following table is used to determine the appropriate permit level under 326 IAC 2-7-10.5. This table reflects the PTE before controls. Control equipment is not considered federally enforceable until it has been required in a federally enforceable permit.

Increase In PTE Before Controls of the Modification	
Pollutant	**Potential To Emit (ton/yr)**
PM	1355.8
PM_{10}	1331.2
$PM_{2.5}$	1322.8
SO_2	0.00
VOC	0.00
CO	0.00
NO_X	0.00

This source modification is subject to 326 IAC 2-7-10.5(f)(4) because the emission unit has potential to emit greater than 25 tons per year of PM, PM10 and PM 2.5 emissions. Additionally, the modification will be incorporated into the Part 70 Operation Permit through a significant permit modification issued pursuant to 326 IAC 2-7-12(d) because this permit modification requires a case-by-case determination of emission limits.

Permit Level Determination – PSD

The table below summarizes the potential to emit, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of this Part 70 permit modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit. Past Actual to Future Projected Analysis

	Past Actual to Future Projected Actual Analysis for Boilers 1 and Unit 2 (Tons/year)											
	PM	PM_{10}	$PM_{2.5}$	SO_2	NOx	CO	VOC	Hg	Pb	H_2SO_4	HF	CO2e
Past Act. emissions	382	2,468	2,468	34,172	8,349	676	81	0.061	0.283	592	83	6,280,278
Projected Act. Boilers 1 & 2	138	1,001	1,001	6,746	1,874	792	95	0.035	0.013	745	6	7,662,250
Net Emission for ATPA	0	0	0	0	0	137	16	0	0	157	0	1,582,414
Demand Growth	0	0	0	0	0	137	16	0	0.00	157	0.00	1,582,414
Attributed to Project	0	0	0	0	0	0	0	0	0	0	0	0

The Permittee completed an Actual to Projected test (pursuant to 326 IAC 2-2-2, and 326 IAC 2-1.1-5) for this modification at a major stationary source that indicates that the modification will not be major for Prevention of Significant Deterioration (PSD) (326 IAC 2-2). IDEM, OAQ has not reviewed this information and will not be making any determination in this regard as part of this approval. The applicant will be required to keep records and report in accordance with 326 IAC 2-2-8 (Source Obligation) for Boilers 1 and 2 emissions and will report the emissions annually to IDEM for a period of 5 years.

	Potential to Emit (ton/yr)								
Process / Emission Unit	PM	PM_{10}	$PM_{2.5}$*	SO_2	VOC	CO	NO_X	GHGs	Pb
Total increase from ATPA	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
SCR System (Ammonia)									
Roadway Emissions - NH3 delivery F- 01	0.010	0.020	0.005	0	0	0	0	0	0
SCR System (Includes DSI Lime Silos)									
Sorbent Silo #1 for Unit #1 EP01	0.61	0.35	0.31	0	0	0	0	0	0
Sorbent Silo #2 for Unit #1 EP02	0.61	0.35	0.31	0	0	0	0	0	0
Sorbent Silo #1 for Unit #2 EP03	0.61	0.35	0.31	0	0	0	0	0	0
Sorbent Silo #1 for Unit # 2 EP04	0.61	0.35	0.31	0	0	0	0	0	0
Roadway Emissions - sorbent delivery F- 01	0.37	0.007	0.018	0	0	0	0	0	0
SCR System (Limestone)									
Limestone Silo EP01	2.41	1.45	1.18	0	0	0	0	0	0
Limestone Surge Bin EP02	1.18	0.70	0.61	0	0	0	0	0	0
Transfer Point to C1 Conveyor F01	0.004	0.001	0.001	0	0	0	0	0	0
Transfer Point to C1 Conveyor F02	0.004	0.001	0.001	0	0	0	0	0	0
Roadway Emissions - limestone delivery F03	0.42	0.08	0.021	0	0	0	0	0	0
ACI System									
Activated Carbon Silo #1 EP01	0.61	0.35	0.31	0	0	0	0	0	0
Activated Carbon Silo #2 EP02	0.61	0.35	0.31	0	0	0	0	0	0
Roadway Emissions - Carbon delivery F01	0.06	0.012	0.003	0	0	0	0	0	0
Dry Fly Ash System									
Exhauster for 1A Baghouse Seprator EP01	1.14	0.79	0.57	0	0	0	0	0	0

	Potential to Emit (ton/yr)								
Process / Emission Unit	PM	PM_{10}	$PM_{2.5}$*	SO_2	VOC	CO	NO_x	GHGs	Pb
Exhauster for 1B Baghouse Seprator EP02	1.14	0.79	0.57	0	0	0	0	0	0
Exhauster for 2A Baghouse Seprator EP03	1.14	0.79	0.57	0	0	0	0	0	0
Exhauster for 2B Baghouse Seprator EP04	1.14	0.79	0.57	0	0	0	0	0	0
Spare Exhauster	--	--	--	0	0	0	0	0	0
Fly Ash Silo #1	2.63	1.84	1.31	0	0	0	0	0	0
Fly Ash Silo #2	2.63	1.84	1.31	0	0	0	0	0	0
Flyash Silo #1 Truck Loadout	0.037	0.017	0.003	0	0	0	0	0	0
Flyash Silo #2 Truck Loadout	0.037	0.017	0.003	0	0	0	0	0	0
Fixation System									
Fly Ash Day Bin	1.66	1.01	0.83	0	0	0	0	0	0
Roadway Emissions - Lime delivery	0.2	0.04	0.01	0	0	0	0	0	0
Lime Silo	0.61	0.35	0.31	0	0	0	0	0	0
Gypsum Transfer Point	0.079	0.037	0.006	0	0	0	0	0	0
Fixation Building Transfer Point	0.125	0.059	0.009	0	0	0	0	0	0
Radial Stacker Conveyor Transfer Point	0.125	0.059	0.009	0	0	0	0	0	0
Storage Pile Transfer Point	0.125	0.059	0.009	0	0	0	0	0	0
Activity on Storage Pile	3.22	0.87	0.087	0	0	0	0	0	0
Fixation Material loaded into trucks	0.125	0.059	0.009	0	0	0	0	0	0
Waste pile wind erosion	0.354	0.18	0.03	0	0	0	0	0	0
Total for Modification	24.57	14.03	9.91	0	0	0	0	0	0
Significant Level	25	15	10	40	40	100	40	75,000 CO_2e	0.6

This modification to an existing major stationary source is not major because the emissions increases are less than the PSD significant levels. Therefore, pursuant to 326 IAC 2-2, the PSD requirements do not apply.

Federal Rule Applicability Determination

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to new or modified emission units that involve a pollutant-specific emission unit and meet the following criteria:

(1) has a potential to emit before controls equal to or greater than the Part 70 major source threshold for the pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant; and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

The following table is used to identify the applicability of each of the criteria, under 40 CFR 64.1, to each new or modified emission unit involved:

CAM Applicability Analysis							
Emission Unit	**Control Device Used**	**Emission Limitation (Y/N)**	**Uncontrolled PTE** (ton/yr)	**Controlled PTE** (ton/yr)	**Part 70 Major Source Threshold** (ton/yr)	**CAM Applicable (Y/N)**	**Large Unit (Y/N)**
Baghouse Separator EP-01 PM	Y	Y	112.6	1.14	100	Y	N
Baghouse Separator EP-01 PM10	Y	Y	112.6	0.79	100	Y	N
Baghouse Separator EP-01 PM2.5	Y	Y	112.6	0.57	100	Y	N
Baghouse Separator EP-02 PM	Y	Y	112.6	1.14	100	Y	N
Baghouse Separator EP-02 PM10	Y	Y	112.6	0.79	100	Y	N
Baghouse Separator EP-02 PM2.5	Y	Y	112.6	0.57	100	Y	N
Baghouse Separator EP-03 PM	Y	Y	112.6	1.14	100	Y	N
Baghouse Separator EP-03 PM10	Y	Y	112.6	0.79	100	Y	N
Baghouse Separator EP-03 PM2.5	Y	Y	112.6	0.57	100	Y	N
Baghouse Separator EP-04 PM	Y	Y	112.6	1.14	100	Y	N
Baghouse Separator EP-04 PM10	Y	Y	112.6	0.79	100	Y	N
Baghouse Separator EP-04 PM2.5	Y	Y	112.6	0.57	100	Y	N
Spare Exhauster EP-05 PM	Y	Y	112.6	1.14	100	Y	N
Spare			112.6	0.79	100	Y	N

CAM Applicability Analysis							
Emission Unit	**Control Device Used**	**Emission Limitation** (Y/N)	**Uncontrolled PTE** (ton/yr)	**Controlled PTE** (ton/yr)	**Part 70 Major Source Threshold** (ton/yr)	**CAM Applicable** (Y/N)	**Large Unit** (Y/N)
Exhauster EP-05 PM10	Y	Y					
Spare Exhauster EP-05 PM2.5	Y	Y	112.6	0.57	100	Y	N
Fly Ash Silo#1 EP-06 PM	Y	Y	262.8	2.63	100	Y	N
Fly Ash Silo#1 EP-06 PM10	Y	Y	262.8	1.84	100	Y	N
Fly Ash Silo#1 EP-06 PM2.5	Y	Y	262.8	1.31	100	Y	N
Fly Ash Silo#2 EP-07 PM	Y	Y	262.8	2.63	100	Y	N
Fly Ash Silo#2 EP-07 PM10	Y	Y	262.8	1.84	100	Y	N
Fly Ash Silo#2 EP-07 PM2.5	Y	Y	262.8	1.31	100	Y	N

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are applicable to Baghouse Separator EP-01, EP-02, EP-03, EP-04, EP-05 Fly Ash Silo#1 EP-06 and Fly Ash Silo#2 EP-07 for PM, PM_{10}, and $PM_{2.5}$ upon issuance of this permit modification. A CAM plan has been incorporated into this Part 70 operating permit.

The other emission units have the potential to emit regulated pollutants (uncontrolled) less than the major source thresholds, therefore are not subject to the requirements of CAM.

The two (2) dry sorbent injection system are subject to the requirements of the New Source Performance Standard, 40 CFR 60, Subpart OOO, Standards of Performance for Nonmetallic Mineral Processing Plants, because the proposed project may involve milling of trona which is considered as a nonmetallic mineral as defined in 40 CFR 60.671. The specific facility subject to this rule includes the following.

(a) Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of (2) two Sorbent Storage Silos with a storage capacity of 120 tons and system to inject the sorbent material into the flue gas to be constructed in 2012. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo. The four (4) Sorbent Silos are identified as emission points EP-01(DSI), EP-02(DSI, EP-03(DSI), and EP-04(DSI).

The two (2) Dry Sorbent Injection (DSI) Systems are subject to the following sections of 40 CFR Part 60, Subpart OOO.

(1) 40 CFR 60.670
(2) 40 CFR 60.671
(3) 40 CFR 60.672
(4) 40 CFR 60.673
(5) 40 CFR 60.674
(6) 40 CFR 60.675
(7) 40 CFR 60.676
(8) Table 1 to Subpart OOO

(9) Table 2 to Subpart OOO
(10) Table 3 to Subpart OOO

(b) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) applicable to this proposed modification.

State Rule Applicability Determination

326 IAC 2-2 (Prevention of Significant Deterioration (PSD))
This source is a major source for PSD because the potential to emit of one of the regulated pollutants are emitted at a rate greater than 100 tons per year and is in 1 of 28 source categories. The uncontrolled potential to emit of this modification is greater than 25 tons per year for PM, 15 ton per year for PM_{10} and greater than 10 tons per year for $PM_{2.5}$. In order to make the requirements of 326 IAC 2-2 (PSD) not applicable to the 2012 modification, the Permittee has taken the following limits:

(a) Fly ash unloaded from fly ash silo #1 or #2 shall either be unloaded wet into open trucks with the ash having a moisture content of not less than 15% or unloaded dry into enclosed trucks using the telescoping chute to vent emissions back to the fly ash silo bin vent filter.

(b) The PM, PM_{10} and $PM_{2.5}$ emissions from the Activity on Storage Pile shall be controlled by maintaining the average moisture content of the fixated ash not less than 15% moisture content and applying water to the pile as need to prevent dusting.

(c) The PM, PM10 and $PM_{2.5}$ emissions from the limestone, dry sorbent, activated carbon, dry ash and ash fixation systems shall not exceed the emission limits listed in the table below:

Emission Point	Unit Description	PM Emission Limit (lbs/hr)	PM10 Emission Limit (lbs/hr)	PM2.5 Emission Limit (lbs/hr)
EP-01(LS)	Limestone Silo	0.55	0.33	0.27
EP-02(LS)	Limestone Surge Bin	0.27	0.16	0.14
EP-01(DSI)	Unit 1DSI Silo #1	0.14	0.08	0.07
EP-02(DSI)	Unit 1 DSI Silo #2	0.14	0.08	0.07
EP-03(DSI)	Unit 2 DSI Silo #1	0.14	0.08	0.07
EP-04(DSI)	Unit 2 DSI Silo #2	0.14	0.08	0.07
EP-01(ACI)	Unit 1 ACI Silo	0.14	0.08	0.07
EP-02(ACI)	Unit 2 ACI Silo	0.14	0.08	0.07
EP-01(DFA)	Baghouse Separator 1A Exhauster	0.26	0.18	0.13
EP-02(DFA)	Baghouse Separator 1B Exhauster	0.26	0.18	0.13
EP-03(DFA)	Baghouse Separator 2A Exhauster	0.26	0.18	0.13
EP-04(DFA)	Baghouse Separator 2B Exhauster	0.26	0.18	0.13
EP-05(DFA)	Spare Baghouse Separator Exhauster	0.26	0.18	0.13
EP-06(DFA)	Ash Silo #1	0.60	0.42	0.30
EP-07(DFA)	Ash Silo #2	0.60	0.42	0.30
EP-01(FIX)	Ash Day Bin	0.38	0.23	0.19
EP-02(FIX)	Lime Silo	0.14	0.08	0.07

Compliance with these limits in conjunction with the potential fugitive emissions from vehicular traffic, will ensure that the PM emissions are less than 25 tons per year, PM_{10} emissions are less than 15 tons per year and $PM_{2.5}$ emissions are less than 10 tons per year, and render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2012 modification.

326 IAC 2-4.1 (Major Sources of Hazardous Air Pollutants (HAP))
The operation of these emission units will each, emit less than ten (10) tons per year for a single HAP and less than twenty-five (25) tons per year for a combination of HAPs. Therefore, 326 IAC 2-4.1 does not apply.

326 IAC 6-3-2 (Particulate Emission Limitations for Manufacturing Processes)

(a) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the (4) Sorbent Silos, (1) Lime Silo (1) Limestone Silo and (2) Activated Carbon Silos shall not exceed 30.5 pounds per hour each when operating at a process weight rate of 20 tons per hour. The pound per hour limitation was calculated with the following equation:

$E = 4.1\ P^{0.67}$
Where:
E = rate of emission in pounds per hour and
P = process weight rate in tons per hour

(b) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the (1) Limestone Surge Bin shall not exceed 40.0 pounds per hour when operating at a process weight rate of 30 tons per hour each. The pound per hour limitation was calculated with the following equation:

$E = 4.1\ P^{0.67}$
Where:
E = rate of emission in pounds per hour and
P = process weight rate in tons per hour

(c) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from (5) exhausters shall not exceed 45.4 pounds per hour each when operating at a process weight rate of 54.4 tons per hour. The pound per hour limitation was calculated with the following 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

(d) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from (2) ash silos and fly ash day bin shall not exceed 47.8 pounds per hour each when operating at a process weight rate of 70 tons per hour. The pound per hour limitation was calculated with the following 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

The baghouse and the bin vent filter shall be in operation at all times the emission units are in operation, in order to comply with these limits.

326 IAC 6-4 (Fugitive Dust Emissions)
The Permittee 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).

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to ensure that sources can demonstrate compliance with all applicable state and federal rules on a continuous basis. All state and federal rules contain compliance provisions; however, these provisions do not always fulfill the requirement for a continuous demonstration. When this occurs, IDEM, OAQ, in conjunction with the source, must develop specific conditions to satisfy 326 IAC 2-7-5. As a result, Compliance Determination Requirements are included in the permit. The Compliance Determination Requirements in Section D of the permit are those conditions that are found directly within state and federal rules and the violation of which serves as grounds for enforcement action.

If the Compliance Determination Requirements are not sufficient to demonstrate continuous compliance, they will be supplemented with Compliance Monitoring Requirements, also in Section D of the permit. Unlike Compliance Determination Requirements, failure to meet Compliance Monitoring conditions would serve as a trigger for corrective actions and not grounds for enforcement action. However, a violation in relation to a compliance monitoring condition will arise through a source's failure to take the appropriate corrective actions within a specific time period.

The Compliance Determination Requirements applicable to this modification ere as follows:

Testing Requirements

(a) PM, PM_{10} and $PM_{2.5}$ Testing

Emission Units	Control Device	Next Test date	Pollutants	Frequency of testing	Limits or requirements
Five (5) separator/exhausters, identified as emissions point EP-01(DFA), EP-02(DFA), EP-03(DFA), EP-04(DFA) and EP-05 (DFA),	Baghouse	Within 60 days of reaching maximum capacity but not later than 180 days after the startup	PM, PM_{10} and $PM_{2.5}$	Every five years	326 IAC 2-2
Three (3) Fly Ash Silos/Day Bin, identified as emission point EP-06(DFA), EP-07(DFA) and EP-01 (FIX)	Bin Vent Filter	Within 60 days of reaching maximum capacity but not later than 180 days after the startup	PM, PM_{10} and $PM_{2.5}$	Every five years	326 IAC 2-2

(b) The compliance monitoring requirements applicable to this source are as follows

Facilities	Control	Parameter	Frequency	Range	Excursions and Exceedances	Limits or requirements
One (1) Limestone Silo, One (1) Limestone Surge Bin, Two (2) ACI Silos, Four (4) DSI Silos, and One (1) Lime Silo	Bin Vent Filter	Visible Emissions	Weekly	Normal-Abnormal	Response Steps	326 IAC 2-2 and 40 CFR 64
Four (4) baghouse separator exhausters	Baghouse	Water Pressure Drop	Daily	1.0 to 6.0 inches		
		Visible Emissions		Normal-Abnormal		
Two (2) ash silo	Bin Vent Filter	Visible Emissions	Daily	Normal-Abnormal		
Fixated Material Storage Pile	Wetting	Visible Emissions	weekly	Normal-Abnormal		

Proposed Changes

The changes listed below have been made to Part 70 Operating Permit No. 165-27260-00001. Deleted language appears as ~~strikethroughs~~ and new language appears in **bold**:

Change 1: The new and modified emission units have been added to Section A.1, D.1 and D.2 of the permit accordingly. On October 27, 2010, the Indiana Air Pollution Control Board issued revisions to 326 IAC 2. These revisions resulted in changes to the rule sites listed in the permit.

A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)] [326 IAC 2-7-5(**14**~~5~~)]

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

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Boiler No. 1 was configured with a low NO_X burner in 1993. **Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.**

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Boiler No. 2 was configured with a low NO_X burner in 1993.**Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.**

....

(k) **One (1) Arsenic Mitigation System consisting of (1) 700 ton Limestone Storage Silo and (1) 300 ton Limestone Surge Bin, scheduled to be installed by 2015. Limestone is pneumatically conveyed from delivery trucks to the Limestone Storage Silo and from the Limestone Storage Silo to the Limestone Surge Bin. Limestone in the Surge Bin is dropped on to the C-1 and C-2 coal conveyors. PM emissions generated during pneumatic conveying and transfer points to the C-1 and C-2 conveyor will be controlled by the bin vent filters. The Limestone Storage Silo and Limestone Surge Bin are identified as emissions points EP-01(LS) and EP-02(LS).**

(l) **Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of (2) two Sorbent Storage Silos with a storage capacity of 120 tons and system to inject the sorbent material into the flue gas, scheduled to be installed by 2015. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo. The four (4) Sorbent Silos are identified as emission points EP-01(DSI), EP-02(DSI, EP-03(DSI), and EP-04(DSI).**

(m) **Two (2) Activated Carbon Injection (ACI) Systems, one for each Unit. Each ACI system consists of one (1) storage silo with a 80 ton storage capacity and system for injecting the Activated Carbon into the flue gas, scheduled to be installed by 2015. PM emissions during the silo loading operation are controlled by the bin vent**

filters located on top of the silos. The two (2) Activated Carbon Storage Silos are identified as emission points EP-01(ACI) and EP-02(ACI).

(n) Two (2) Dry Ash Handling Systems, one for each Unit. The dry ash handling system consists of a pneumatic conveying system, four (4) baghouse separators, two (2) ash silos with a storage capacity of 3,500 each and an ash unloading system, scheduled to be installed by 2015.

(i) Baghouse Separators - Fly ash from the ESP Ash Hoppers, Air Heater Ash Hoppers, Economizer Ash Hoppers and SCR Large Particle Screen Ash Hopper will be pneumatically conveyed to one of four (4) baghouse separators. There will be two (2) baghouse separators for each unit. The dry fly ash is separated from the air stream in a baghouse separator. Each baghouse separator are identified as emissions points EP-01(DFA), EP-02(DFA), EP-03(DFA), and EP-04(DFA). The system is equipped with a spare exhauster identified as emissions point EP-05(DFA).

(ii) Ash Silos - Fly ash collected in the baghouse separators is dropped into a feeder and pneumatically conveyed to one of two (2) ash silos. Each ash silo is equipped with a bin vent filter to control particulate matter emissions from pneumatic conveying. The Ash Silos are identified as emission point EP-06(DFA) and EP-07(DFA).

(iii) Ash Unloading Operation - Fly ash collected in the silos can be unloaded into trucks or pneumatically conveyed to the ash fixation process. Fly ash unloaded into trucks can be unloaded dry or wet. Fly ash unloaded dry is gravity feed to a chute and unloaded into enclosed trucks. The emissions generated from unloading the ash dry are vented back to the silo and controlled by the silo bin vent filter. Ash unloaded wet is feed into a pin mixer where the ash is mixed with water and unloaded into open trucks

(o) One (1) Ash Fixation Process consisting of a pneumatic conveying system, one (1) ash day bin, one (1) lime silo, conveyors, and two (2) pin mixers, scheduled to be installed by 2015.

(i) Fly Ash Day Bin - Fly ash from the ash silos can be pneumatically conveyed to the day bin. The storage capacity of the day bin is 500 tons. The emissions generated from pneumatic conveyance will be controlled by a bin vent filter located on top of the fly ash day bin. The Fly Ash Day Bin is identified as emissions point EP-01(FIX).

(ii) Lime Silo – Lime will be delivered by truck and will pneumatically loaded into the silo. The storage capacity of the silo is 300 tons. The emissions generated by the pneumatic conveying will be controlled by a bin vent filter located on top of the lime silo. The Lime Silo is identified as emissions point EP-02(FIX).

(iii) Conveyor and Transfer Points – Fly ash, Lime and Gypsum will be conveyed to one of two (2) pin mixers where this material will be mixed with water to make the fixated ash. The fixated ash will be unloaded to a storage pile, and then loaded into trucks using front end loaders.

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(a) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 1, installed in 1967, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 1. Stack 1 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) and sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Boiler No. 1 was configured with a low NO_X burner in 1993. **Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.**

(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 2-7-5(1)]

....

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description [326 IAC 2-7-5(15)]

(b) One (1) dry bottom, pulverized coal-fired boiler, identified as Boiler No. 2, installed in 1968, with a nominal heat input capacity of 4,802 million Btu per hour (MMBtu/hr), with an electrostatic precipitator (ESP) for control of particulate matter, a flue gas desulfurization (FGD) system for control of SO_2, and exhausting to stack 2. Stack 2 has continuous emissions monitors (CEMs) for nitrogen oxides (NO_X) end sulfur dioxide (SO_2) and a continuous opacity monitor (COM). Boiler No. 2 was configured with a low NO_X burner in 1993. **Selective Catalytic Oxidation (SCR) to control NOx, Dry Sorbent Injection System to Control SO_3, Activated Carbon Injection System to assist in Control of Hg emissions scheduled to be installed by 2015.**

(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 2-7-5(1)]

....

Change 3: The new emission units have been added to the new Section D.8 of the permit. All the permit conditions have been added to the Section.

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: [326 IAC 2-7-5(15)]

(k) One (1) Arsenic Mitigation System consisting of (1) 700 ton Limestone Storage Silo and (1) 300 ton Limestone Surge Bin, scheduled to be installed by 2015. Limestone is pneumatically conveyed from delivery trucks to the Limestone Storage Silo and from the Limestone Storage Silo to the Limestone Surge Bin. Limestone in the Surge Bin is dropped on to the C-1 and C-2 coal conveyors. PM emissions generated during pneumatic conveying and transfer points to the C-1 and C-2 conveyor will be controlled by the bin vent filters. The Limestone Storage Silo and Limestone Surge Bin are identified as emissions points EP-01(LS) and EP-02(LS).

(l) Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of (2) two Sorbent Storage Silos with a storage capacity of 120 tons and system to inject the sorbent material into the flue gas, scheduled to be installed by 2015. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo. The four (4) Sorbent Silos are identified as emission points EP-01(DSI), EP-02(DSI, EP-03(DSI), and EP-04(DSI).

(m) Two (2) Activated Carbon Injection (ACI) Systems, one for each Unit. Each ACI system consists of one (1) storage silo with a 80 ton storage capacity and system for injecting the Activated Carbon into the flue gas, scheduled to be installed by 2015. PM emissions during the silo loading operation are controlled by the bin vent filters located on top of the silos. The two (2) Activated Carbon Storage Silos are identified as emission points EP-01(ACI) and EP-02(ACI).

(n) Two (2) Dry Ash Handling Systems, one for each Unit. The dry ash handling system consists of a pneumatic conveying system, four (4) baghouse separators, two (2) ash silos with a storage capacity of 3,500 each and an ash unloading system, scheduled to be installed by 2015.

(i) Baghouse Separators - Fly ash from the ESP Ash Hoppers, Air Heater Ash Hoppers, Economizer Ash Hoppers and SCR Large Particle Screen Ash Hopper will be pneumatically conveyed to one of four (4) baghouse separators. There will be two (2) baghouse separators for each unit. The dry fly ash is separated from the air stream in a baghouse separator. Each baghouse separator are identified as emissions points EP-01(DFA), EP--02(DFA), EP-03(DFA), and EP-04(DFA). The system is equipped with a spare exhauster identified as emissions point EP-05(DFA).

(ii) Ash Silos - Fly ash collected in the baghouse separators is dropped into a feeder and pneumatically conveyed to one of two (2) ash silos. Each ash silo is equipped with a bin vent filter to control particulate matter emissions from pneumatic conveying. The Ash Silos are identified as emission point EP-06(DFA) and EP-07(DFA).

(iii) Ash Unloading Operation - Fly ash collected in the silos can be unloaded into trucks or pneumatically conveyed to the ash fixation process. Fly ash unloaded into trucks can be unloaded dry or wet. Fly ash unloaded dry is gravity feed to a chute and unloaded into enclosed trucks. The emissions generated from unloading the ash dry are vented back to the silo and controlled by the silo bin vent filter. Ash unloaded wet is feed into a pin mixer where the ash is mixed with water and unloaded into open trucks

(o) One (1) Ash Fixation Process consisting of a pneumatic conveying system, one (1) ash day bin, one (1) lime silo, conveyors, and two (2) pin mixers, scheduled to be installed by 2015.

(i) Fly Ash Day Bin - Fly ash from the ash silos can be pneumatically conveyed to the day bin. The storage capacity of the day bin is 500 tons. The emissions generated from pneumatic conveyance will be controlled by a bin vent filter located on top of the fly ash day bin. The Fly Ash Day Bin is identified as emissions point EP-01(FIX).

(ii) Lime Silo – Lime will be delivered by truck and will pneumatically loaded into the silo. The storage capacity of the silo is 300 tons. The emissions generated by the pneumatic conveying will be controlled by a bin vent filter located on top of the lime silo. The Lime Silo is identified as emissions point EP-02(FIX).

(iii) Conveyor and Transfer Points – Fly ash, Lime and Gypsum will be conveyed to one of two (2) pin mixers where this material will be mixed with water to make the fixated ash. The fixated ash will be unloaded to a

storage pile, and then loaded into trucks using front end loaders.

(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 2-7-5(1)]

D.8.1 Prevention of Significant Deterioaration (PSD) Minor Limits [326 IAC 2-2]

Pursuant to Significant Source Modification No. 165-32045-00001, the Permittee shall comply with the following:

(a) Fly ash unloaded from fly ash silo #1 or #2 shall either be unloaded wet into open trucks with the ash having a moisture content of not less than 15% or unloaded dry into enclosed trucks using the telescoping chute to vent emissions back to the fly ash silo bin vent filter.

(b) The PM, PM_{10} and $PM_{2.5}$ emissions from the Activity on Storage Pile shall be controlled by maintaining the average moisture content of the fixated ash not less than 15% moisture content and applying water to the pile as need to prevent dusting.

(c) The PM, PM_{10} and $PM_{2.5}$ emissions from the limestone, dry sorbent, activated carbon, dry ash and ash fixation systems shall not exceed the emission limits listed in the table below:

Emission Point	Unit Description	PM Emission Limit (lbs/hr)	PM10 Emission Limit (lbs/hr)	PM2.5 Emission Limit (lbs/hr)
EP-01(LS)	Limestone Silo	0.55	0.33	0.27
EP-02(LS)	Limestone Surge Bin	0.27	0.16	0.14
EP-01(DSI)	Unit 1DSI Silo #1	0.14	0.08	0.07
EP-02(DSI)	Unit 1 DSI Silo #2	0.14	0.08	0.07
EP-03(DSI)	Unit 2 DSI Silo #1	0.14	0.08	0.07
EP-04(DSI)	Unit 2 DSI Silo #2	0.14	0.08	0.07
EP-01(ACI)	Unit 1 ACI Silo	0.14	0.08	0.07
EP-02(ACI)	Unit 2 ACI Silo	0.14	0.08	0.07
EP-01(DFA)	Baghouse Separator 1A Exhauster	0.26	0.18	0.13
EP-02(DFA)	Baghouse Separator 1B Exhauster	0.26	0.18	0.13
EP-03(DFA)	Baghouse Separator 2A Exhauster	0.26	0.18	0.13
EP-04(DFA)	Baghouse Separator 2B Exhauster	0.26	0.18	0.13
EP-05(DFA)	Spare Baghouse Separator Exhauster	0.28	0.18	0.13
EP-06(DFA)	Ash Silo #1	0.60	0.42	0.30
EP-07(DFA)	Ash Silo #2	0.60	0.42	0.30
EP-01(FIX)	Ash Day Bin	0.38	0.23	0.19
EP-02(FIX)	Lime Silo	0.14	0.08	0.07

Compliance with these limits in conjunction with the potential fugitive emissions from vehicular traffic, will ensure that the PM emissions are less than 25 tons per year, PM_{10} emissions are less than 15 tons per year and $PM_{2.5}$ emissions are less than 10 tons per year, and render the requirements of 326 IAC 2-2 (PSD) not applicable to the 2012 modification.

D.8.2 Particulate Emission Limitations for Manufacturing Processes [326 IAC 6-3-2]

(a) Pursuant to 326 IAC 6-3-2, the allowable particulate matter (PM) from the (4) Sorbent Silos, (1) Lime Silo (1) Limestone Silo and (2) Activated Carbon Silos shall not exceed 30.5 pounds per hour each when operating at a process weight rate of 20 tons per hour. The pound per hour limitation was calculated with the following equation:

$E = 4.1\ P^{0.67}$
Where:
E = rate of emission in pounds per hour and
P = process weight rate in tons per hour

(b) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from the (1) Limestone Surge Bin shall not exceed 40.0 pounds per hour when operating at a process weight rate of 30 tons per hour each. The pound per hour limitation was calculated with the following equation:

$E = 4.1\ P^{0.67}$
Where:
E = rate of emission in pounds per hour and
P = process weight rate in tons per hour

(c) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from (5) exhausters shall not exceed 45.4 pounds per hour each when operating at a process weight rate of 54.4 tons per hour. The pound per hour limitation was calculated with the following 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

(d) Pursuant to 326 IAC 6-3-2, the particulate matter (PM) from (2) ash silos and fly ash day bin shall not exceed 47.8 pounds per hour each when operating at a process weight rate of 70 tons per hour. The pound per hour limitation was calculated with the following 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

D.8.3 Preventive Maintenance Plan [326 IAC 2-7-5(13)]

A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.8.4 Particulate Control [326 IAC 2-7-6(6)]

(a) In order to ensure compliance with the particulate matter emissions limits specified in conditions D.8.1(b) and D.8.2 the filter separators, and silo bin vent filters shall in operation and controlling emissions whenever the equipment is in operation and venting to the control device.

(b) In order to ensure compliance with Condition D.8.1(a), the Permittee shall wet the ash when unloading into open trucks. If the weather conditions preclude the use of water, the Permittee shall use additional wet suppression. The Permittee shall

perform moisture content analysis, weekly on the ash to ensure it has a moisture content of not less than 15%. Additional wetting of the ash should be applied if visible emissions are observed during the loading process.

D.8.5 Testing Requirements [326 IAC 2-7-6(1),(6)][326 IAC 2-1.1-11]

(a) **Within 180 days after the initial startup of the pneumatic fly ash transfer system, in order to determine compliance with Condition D.8.1(b), the Permittee shall perform PM, PM_{10} and $PM_{2.5}$ testing two (2) of the five (5) separator/exhausters, identified as emissions point EP-01 (DFA), EP-02 (DFA), EP-03 (DFA), EP-04 (DFA) and EP-05 (DFA), using methods as approved by the Commissioner. This testing shall be at least once every 5 years from the date of the last valid compliance demonstration. The separator/exhauster tested shall be the unit in which the longest amount of time has elapsed since its previous test. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.**

(b) **Within 180 days after the initial startup of the pneumatic fly ash transfer system, in order to determine compliance with Condition D.8.1(b), the Permittee shall perform PM, PM_{10} and $PM_{2.5}$ testing on one (1) of the three (3) Fly Ash Silos/Day Bin, identified as emission point EP-06 (DFA), EP-07 (DFA) and EP-01 (FIX) using methods as approved by the Commissioner. This testing shall be at least once every 5 years from the date of the last valid compliance demonstration. The Ash Silo/Day Bin tested shall be the unit in which the longest amount of time has elapsed since its previous test. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C - Performance Testing contains the Permittee's obligations with regard to the performance testing required by this condition.**

Compliance Monitoring Requirements [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)]

D.8.6 Visible Emissions Notations [326 IAC 2-7-6(1)] [326 IAC 2-7-5(1)] [40 CFR 64]

(a) **Visible emission notations of the stack exhausts for the (1) Limestone Silo (1) Limestone Surge Bin, (2) ACI Silos, (4) DSI Silos, and (1) Lime Silo shall be performed once per week during normal daylight operations when the equipment is in operation. A trained employee shall record whether emissions are normal or abnormal.**

(b) **Visible emission notations of the stack for the (4) baghouse separator exhausters, (2) ash silo and (1) ash day bin shall be performed once per day during normal daylight operations when the equipment is in operation. A trained employee shall record whether emissions are normal or abnormal.**

(c) **Visible emission notations of the fixated material storage pile shall be performed once per week during normal daylight operations when the equipment is in operation. A trained employee shall record whether emissions are normal or abnormal.**

(d) **For processes operated continuously, "normal" means those conditions prevailing, or expected to prevail, eighty percent (80%) of the time the process is in operation, not counting startup or shut down time.**

(f) **In the case of batch or discontinuous operations, readings shall be taken during that part of the operation that would normally be expected to cause the greatest emissions.**

(g) A trained employee is an employee who has worked at the plant at least one (1) month and has been trained in the appearance and characteristics of normal visible emissions for that specific process.

(h) If abnormal emissions are observed, the Permittee shall take reasonable response steps. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps shall be considered a deviation from this permit. Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.

D.8.7 Parametric Monitoring [40 CFR 64]

The Permittee shall record the pressure drop across each baghouse filter separator used in conjunction with the dry ash handling system, at least once per day when the dry ash handling system is exhausting to the atmosphere. When, for any one reading, the pressure drop across the baghouse is outside of the normal range, the Permittee shall take a reasonable response. The normal range for this unit is a pressure drop between 1.0 and 6.0 inches of water unless a different upper-bound or lower-bound value for this range is determined during the latest stack test. Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition. A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps shall be considered deviation from the permit.

The instrument used for determining the pressure shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated as specified by the manufacturer.

Record Keeping and Reporting Requirements [326 IAC 2-7-5(3)] [326 IAC 2-7-19]

D.8.8 Record Keeping Requirements

(a) To document the compliance status with Condition D.8.6(a) - Visible Emission Notation, the Permittee shall maintain weekly records of the visible emission notations of the stack exhausts for the (1) Limestone Silo, (1) Limestone Surge Bin, (2) ACI Silos, (4) DSI Silos and (1) Lime Silo. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that week).

(b) To document the compliance status with Condition D.8.6(b)- Visible Emission Notation, the Permittee shall maintain daily records of the visible emission notations of the stack exhaust for (5) Baghouse Filter Separators Exhausters, (2) Ash Silos and (1) Ash Day Bin when in operation. The Permittee shall include in its daily record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that day).

(c) To document the compliance status with Condition D.8.6(c)- Visible Emission Notation, the Permittee shall maintain weekly records of the visible emission notations of the fixated material storage pile when in operation. The Permittee shall include in its weekly record when a visible emission notation is not taken and the reason for the lack of a visible emission notation, (e.g. the process did not operate that week).

(d) To document the compliance status with Condition D.8.7 - Parametric Monitoring, the Permittee shall maintain the daily records of the pressure drop across the baghouse filter separator. The Permittee shall include in its daily record when a

pressure drop reading is not taken and the reason for the lack of a pressure drop reading, (e.g. the process did not operate that day).

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

Other Changes

Upon further review IDEM, OAQ has made the following changes to the Title V permit T165-27260-00001. (deleted language appears as ~~strikout~~ and the new language **bolded**):

Change 1: IDEM has determined that it is not necessary to include the mailing address in Section A.1 of the permit. The mailing address has been deleted throughout the permit. IDEM will continue to maintain records of the mailing address.

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(15)][326 IAC 2-7-1(22)]

The Permittee owns and operates a stationary electric utility generating station.

Source Address:	State Road 63, Cayuga, Indiana 47928
~~Mailing Address:~~	~~1000 East Main St., Plainfield, IN 46168~~
General Source Phone Number:	(317) 838-2108
SIC Code:	4911
County Location:	Vermillion
Source Location Status:	Attainment for all criteria pollutants
Source Status:	Part 70 Operating Permit Program Major Source, under PSD Rules Major Source, Section 112 of the Clean Air Act 1 of 28 Source Categories

Change 2: IDEM has added clarification to Condition B.2, Permit Term, as follows:

B.2 Permit Term [326 IAC 2-7-5(2)][326 IAC 2-1.1-9.5][326 IAC 2-7-4(a)(1)(D)][IC 13-15-3-6(a)]

(a) ~~This permit~~ **The Part 70 Operating Permit, T 165-27260-00001,** is issued for a fixed term of five (5) years ~~from the issuance date of this permit~~, as determined in accordance with IC 4-21.5-3-5(f) and IC 13-15-5-3. Subsequent revisions, modifications, or amendments of this permit do not affect the expiration date of this permit or of permits issued pursuant to Title IV of the Clean Air Act and 326 IAC 21 (Acid Deposition Control).

....

Change 3: There may be times when it is unnecessary for a responsible official to "certify" additional information requested by IDEM; therefore, paragraph (a) of Condition B.7, Duty to Provide Information, is revised as follows:

B.7 Duty to Provide Information [326 IAC 2-7-5(6)(E)]

(a) The Permittee shall furnish to IDEM, OAQ, within a reasonable time, any information that IDEM, OAQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit, or to determine compliance with this permit. ~~The submittal by the Permittee does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~ Upon request, the Permittee shall also furnish to IDEM, OAQ copies of records required to ba kept by this permit.

(b) ....

B.8 Certification [326 IAC 2-7-4(f)][326 IAC 2-7-6(1)][326 IAC 2-7-5(3)(C)]

(a) ~~Where specifically designated by this permit or required by an applicable requirement, any application form, report, or compliance certification submitted shall contain certification by the "responsible official" of truth, accuracy, and completeness. This certification shall state that~~ **A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:**

(i) **it contains a certification by a "responsible official", as defined by 326 IAC 2-7-1 (34), and**

(ii) **the certification is** based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) ~~One (1) certification shall be included, using~~ **The Permittee may use** the attached Certification Form, **or its equivalent** with each submittal requiring certification. One (1) certification may cover multiple forms in one (1) submittal.

(c) ....

Change 4: The Preventive Maintenance Plan requirements have been clarified as follows:

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(1),(3) and (13)][326 IAC 2-7-6(1) and (6)][326 IAC 1-6-3]

~~(a) If required by specific condition(s) in Section D of this permit, the Permittee shall maintain and implement Preventive Maintenance Plans (PMPs) including the following information on each facility:~~

(a) **A Preventive Maintenance Plan meets the requirements of 326 IAC 1-6-3 if it includes, at a minimum:**

(1) **Identification of the individual(s), by title or classification, responsible for inspecting, maintaining, and repairing emission control devices;**

(2) **A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and**

(3) **Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.**

The Permittee shall implement the PMPs.

(b) **If required by specific condition(s) in Section D of this permit where no PMP was previously required, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this permit or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:**

(1) Identification of the individual(s) ~~by job title or classification~~ responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions; and

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

If, due to circumstances beyond the Permittee's control, the PMPs cannot be prepared and maintained within the time frame specified in Section D, the Permittee may extend the date an additional ninety (90) days provided the Permittee notifies:

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

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).

(~~b~~c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions ~~or potential to emit~~. The PMPs do not require ~~the~~ a certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ a "responsible official" as defined by 326 IAC 2-7-1(34).

(~~c~~d) To the extent the Permittee is required by 40 CFR Part 60/63 to have an Operation Maintenance, and Monitoring (OMM) Plan for a unit, such Plan is deemed to satisfy the PMP requirements of 326 IAC 1-6-3 for that unit.

Change 5: The emergency provisions requirements have been clarified as follows:

B.11 Emergency Provisions [326 IAC 2-7-16]

(a) (b) ...

(1) - (3) ...

(4) For each emergency lasting one (1) hour or more, the Permittee notified IDEM, OAQ, ~~within~~ **no later than** four (4) daytime business hours after the beginning of the emergency, or after the emergency was discovered or reasonably should have been discovered;

.....

(5) .....

~~within~~ **no later than** two (2) working days of the time when emission limitations were exceeded due to the emergency.

The notice fulfills the requirement of 326 IAC 2-7-5(3)(C)(ii) and must contain the following:

(A) - (C)...

The notification which shall be submitted by the Permittee does not require ~~the~~ a certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ a "responsible official" as defined by 326 IAC 2-7-1(34).

(6) ....

(c) - (g) ...

~~(h) The Permittee shall include all emergencies in the Quarterly Deviation and Compliance Monitoring Report. Any emergencies that have been previously reported pursuant to paragraph (b)(5) of this condition and certified by the "responsible official" need only reference the date of the original report.~~

Change 6: IDEM has removed the Condition B.15, Deviations from Permit Requirements and Conditions, and moved the requirements to Condition C.21, General Reporting Requirements, as follows:

~~B.15 Deviations from Permit Requirements and Conditions [326 IAC 2-7-5(3)(C)(ii)]~~

~~(a) Deviations from any permit requirements (for emergencies see Section B - Emergency Provisions), the probable cause of such deviations, and any response steps or preventive measures taken shall be reported 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~~

~~using the attached Quarterly Deviation and Compliance Monitoring Report, or its equivalent. A deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report.~~

~~The Quarterly Deviation and Compliance Monitoring Report does require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(b) A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.~~

Change 7: The Permit Modification, Reopening, Revocation and Reissuance, or Termination provisions have been clarified as follows:

B.15 6 Permit Modification, Reopening, Revocation and Reissuance, or Termination [326 IAC 2-7-5(6)(C)][326 IAC 2-7-8(a)][326 IAC 2-7-9]

(a) This permit may be modified, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a Part 70 Operating Permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any condition of this permit.
[326 IAC 2-7-5(6)(C)] The notification by the Permittee does require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

....

Change 8: The Permit Renewal requirements have been clarified as follows:

B.16 ~~7~~ Permit Renewal [326 IAC 2-7-3][326 IAC 2-7-4][326 IAC 2-7-8(e)]

(a) The application for renewal shall be submitted using the application form or forms prescribed by IDEM, OAQ and shall include the information specified in 326 IAC 2-7-4. Such information shall be included in the application for each emission unit at this source, except those emission units included on the trivial or insignificant activities list contained in 326 IAC 2-7-1(21) and 326 IAC 2-7-1(40). The renewal application does require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

....

(c) If the Permittee submits a timely and complete application for renewal of this permit, the source's failure to have a permit is not a violation of 326 IAC 2-7 until IDEM, OAQ takes final action on the renewal application, except that this protection shall cease to apply if, subsequent to the completeness determination, the Permittee fails to submit by the deadline specified, **pursuant to 326 IAC 2-7-4(a)(2)(D),** in writing by IDEM, OAQ any additional information identified as being needed to process the application.

Change 9: The words "or notice" have been added to Condition B.19(a) as follows:

B.18 9 Permit Revision Under Economic Incentives and Other Programs
[326 IAC 2-7-5(8)][326 IAC 2-7-12(b)(2)]

(a) No Part 70 permit revision **or notice** shall be required under any approved economic incentives, marketable Part 70 permits, emissions trading, and other similar programs or processes for changes that are provided for in a Part 70 permit.

....

Change 10: The Operational Flexibility provisions have been clarified as follows:

B.~~20~~19 Operational Flexibility [326 IAC 2-7-20][326 IAC 2-7-10.5]

(a) The Permittee may make any change or changes at the source that are described in 326 IAC 2-7-20(b)~~,~~ **or** (c)~~, or (e)~~ without a prior permit revision, if each of the following conditions is met:
******

(5) The Permittee maintains records on-site, on a rolling five (5) year basis, which document all such changes and emission trades that are subject to 326 IAC 2-7-20(b)~~,~~ **or** (c)~~, or (e)~~. The Permittee shall make such records available, upon reasonable request, for public review.

Such records shall consist of all information required to be submitted to IDEM, OAQ in the notices specified in 326 IAC 2-7-20(b)(1)~~,~~ **and** (c)(1)~~, and (e)(2)~~.

(b) The Permittee may make Section 502(b)(10) of the Clean Air Act changes (this term is defined at 326 IAC 2-7-1(36)) without a permit revision, subject to the constraint of 326 IAC 2-7-20(a). For each such Section 502(b)(10) of the Clean Air Act change, the required written notification shall include the following:

....

The notification which shall be submitted is not considered an application form, report or compliance certification. Therefore, the notification by the Permittee does not require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

Change 11: The Transfer of Ownership or Operational Control provisions have been clarified as follows:

B.22 3 Transfer of Ownership or Operational Control [326 IAC 2-7-11]

****

(b) ***********

The application which shall be submitted by the Permittee does require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

....

Change 12: The Opacity requirements have been clarified as follows:

C.2 Opacity [326 IAC 5-1]

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

(a) - (b) ...

Change 13: The Incineration requirements have been clarified as follows:

C.4 Incineration [326 IAC 4-2] [326 IAC 9-1-2]

The Permittee shall not operate an incinerator ~~or incinerate any waste or refuse~~ except as provided in 326 IAC 4-2 ~~and 326 IAC 9-1-2~~ **or in this permit. The Permittee shall not operate a refuse incinerator or refuse burning equipment except as provided in 326 IAC 9-1-2 or in this permit.**

Change 14: The Performance Testing requirements have been clarified as follows:

C.9 Performance Testing [326 IAC 3-6]

(a) ~~All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this permit, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.~~

A **For performance testing required by this permit, a** test protocol, except as provided elsewhere in this permit, shall be submitted 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

no later than thirty-five (35) days prior to the intended test date. The protocol submitted by the Permittee does not require a certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

(b) The Permittee shall notify IDEM, OAQ of the actual test date at least fourteen (14) days prior to the actual test date. The notification submitted by the Permittee does not require a certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

(c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ not later than forty-five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ if the Permittee submits to IDEM, OAQ a reasonable written explanation not later than five (5) days prior to the end of the initial forty-five (45) day period. **The extension request submitted by the Permittee does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34).**

Change 15: The Compliance Monitoring requirements have been clarified as follows: IDEM, OAQ has decided to clarify the Permittee's responsibility under CAM.

C.11 Compliance Monitoring [326 IAC 2-7-5(3)][326 IAC 2-7-6(1)] **[40 CFR 64][326 IAC 3-8]**

~~Unless otherwise specified in this permit, all monitoring and record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance or ninety (90) days of initial start-up, whichever is later. If required by Section D, the Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. If due to circumstances beyond its control, that equipment cannot be installed and operated within ninety (90) days, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:~~

(a) **Unless otherwise specified in this permit, for all monitoring requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or of initial start-up, whichever is later, to begin such monitoring. If due to circumstances beyond the Permittee's control, any monitoring equipment required by this permit cannot be installed and operated no later than ninety (90) days after permit issuance or the date of initial startup, whichever is later, the Permittee may extend the compliance schedule related to the equipment for an additional ninety (90) days provided the Permittee notifies:**

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

In writing, prior to the end of the initial ninety (90) day compliance schedule, with full justification of the reasons for the inability to meet this date.

The notification which shall be submitted by the Permittee does require ~~the~~ a certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ a "responsible official" as defined by 326 IAC 2-7-1(34).

Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units or emission units added through a source modification shall be implemented when operation begins.

(b) **For monitoring required by CAM, at all times, the Permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.**

(c) **For monitoring required by CAM, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.**

Change 16: The general requirements for Monitoring Methods were removed from Section C as follows (This provision will be included as needed in Section D of the permit.):

~~C.12 Monitoring Methods [326 IAC 3] [40 CFR 60] [40 CFR 63]~~

~~Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, 40 CFR 60, Appendix B, 40 CFR 63, or other approved methods as specified in this permit.~~

Change 17: IDEM is revising Condition C.16 (now C.15) as follows: IDEM, OAQ has decided to clarify the Permittee's responsibility under CAM.

C.156 Response to Excursions or Exceedances **[40 CFR 64][326 IAC 3-8]** [326 IAC 2-7-5] [326 IAC 2-7-6]

Upon detecting an excursion where a response step is required by the D Section or an exceedance of a limitation in this permit:

(a) ~~Upon detecting an excursion or exceedance, the~~ The Permittee shall **take reasonable response steps to** restore operation of the emissions unit (including any control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing **excess** emissions.

(b) The response shall include minimizing the period of any startup, shutdown or malfunction ~~and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions)~~. ~~Corrective actions~~ **The response** may include, but ~~are~~ **is** not limited to, the following:

(1) initial inspection and evaluation;

(2) recording that operations returned to normal without operator action (such as through response by a computerized distribution control system); or

(3) any necessary follow-up actions to return operation ~~to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable~~ **normal or usual manner of operation.**

(c) A determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include, but is not **necessarily** limited to, the following:

(1) - (3) ...

(d) ....

(e) The Permittee shall ~~maintain the following records:~~ **record the reasonable response steps taken.**

~~(1) monitoring data;~~

~~(2) monitor performance data, if applicable; and~~

~~(3) corrective actions taken.~~

(II)

(a) CAM *Response to excursions or exceedances.*

(1) Upon detecting an excursion or exceedance, subject to CAM, the Permittee shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to

its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable.

(2) Determination of whether the Permittee has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process.

(b) If the Permittee identifies a failure to achieve compliance with an emission limitation, subject to CAM, or standard, subject to CAM, for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the IDEM, OAQ and, if necessary, submit a proposed significant permit modification to this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

(c) Based on the results of a determination made under paragraph (II)(a)(2) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a QIP. The Permittee shall develop and implement a QIP if notified to in writing by the EPA or IDEM, OAQ.

(d) Elements of a QIP:
The Permittee shall maintain a written QIP, if required, and have it available for inspection. The plan shall conform to 40 CFR 64.8 b (2).

(e) If a QIP is required, the Permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the IDEM, OAQ if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(f) Following implementation of a QIP, upon any subsequent determination pursuant to paragraph (II)(a)(2) of this condition the EPA or the IDEM, OAQ may require that the Permittee make reasonable changes to the QIP if the QIP is found to have:
(1) Failed to address the cause of the control device performance problems; or
(2) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(g) Implementation of a QIP shall not excuse the Permittee from compliance

with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(h) *CAM recordkeeping requirements.*

(1) The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to paragraph (II)(a)(2) of this condition and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this condition (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions). Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

(2) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements

Change 18: IDEM is revising paragraph (b) of Condition C.17 (now C.16) as follows:

C.16 ~~7~~ Actions Related to Noncompliance Demonstrated by a Stack Test [326 IAC 2-7-5][326 IAC 2-7-6]

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the ~~Permittee shall take appropriate response actions. The~~ Permittee shall submit a description of ~~these~~ **its** response actions to IDEM, OAQ, no later than ~~thirty (30)~~ **seventy-five (75)** days after ~~receipt~~ **the date of** the test~~-results. The Permittee shall take appropriate action to minimize excess emissions from the affected facility while the response actions are being implemented.~~

(b) A retest to demonstrate compliance shall be performed ~~within~~ **no later than** one hundred ~~twenty (120)~~ **eighty (180)** days ~~of receipt~~ **after the date of** the ~~original~~ test~~-results~~. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred ~~twenty (120)~~ **eighty (180)** days is not practicable, IDEM, OAQ may extend the retesting deadline.

(c) ...

The response action documents submitted pursuant to this condition do require ~~the~~ **a** certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ **a** "responsible official" as defined by 326 IAC 2-7-1(34).

Change 19: IDEM is revising paragraph (a) of Condition C.17 as follows:

C.17 ~~8~~ Emission Statement [326 IAC 2-7-5(3)(C)(iii)][326 IAC 2-7-5(7)][326 IAC 2-7-19(c)][326 IAC 2-6]

~~(a)~~ Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit ~~by~~ **no later than** July 1 of each year an emission statement covering the previous calendar year. The emission statement shall contain, at a minimum, the information specified in 326 IAC 2-6-4(c) and shall meet the following requirements:

(~~1~~**a**) Indicate estimated actual emissions of all pollutants listed in 326 IAC 2-6-4(a);

(~~2~~**b**) Indicate estimated actual emissions of regulated pollutants as defined by 326 IAC 2-7-1(32) ("Regulated pollutant, which is used only for purposes of Section 19 of this rule") from the source, for purpose of fee assessment.

The statement must be submitted to:

Indiana Department of Environmental Management
Technical Support and Modeling Section, Office of Air Quality
100 North Senate Avenue
MC 61-50 IGCN 1003
Indianapolis, Indiana 46204-2251

The emission statement does require ~~the~~ a certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ a "responsible official" as defined by 326 IAC 2-7-1(34).

~~(b) The emission statement required by this permit 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.~~

Change 20: On October 27, 2010, the Indiana Air Pollution Control Board issued revisions to 326 IAC 2. These revisions included the incorporation of the U.S. EPA's definition of reasonable possibility. The permit previously sited to the EPA definition. Also, the revisions resulted in changes to other rule sites listed in the permit. Neither of these changes are changes to the underlining provisions. The change is only to site of these rules in Section C - General Reporting and Section C - General Recordkeeping. IDEM, OAQ has clarified the Permittee's responsibility with regards to record keeping.

C.18 9 General Record Keeping Requirements [326 IAC 2-7-5(3)][326 IAC 2-7-6]
[326 IAC 2-2][326 IAC 2-3]

(a) **Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. Support information includes the following:**

(AA) All calibration and maintenance records.

(BB) All original strip chart recordings for continuous monitoring instrumentation.

(CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following:

(AA) The date, place, as defined in this permit, and time of sampling or measurements.

(BB) The dates analyses were performed.

(CC) The company or entity that performed the analyses.

(DD) The analytical techniques or methods used.

(EE) The results of such analyses.

(FF) The operating conditions as existing at the time of sampling or measurement.

These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the

Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Unless otherwise specified in this permit, for all record keeping requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or the date of initial start-up, whichever is later, to begin such record keeping.

(c) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A), 326 IAC 2-2-8 (b)(6)(B), 326 IAC 2-3-2 (l)(6)(A), and/or 326 IAC 2-3-2 (l)(6)(B)) that a "project" (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Before beginning actual construction of the "project" (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, document and maintain the following records:

(A) A description of the project.

(B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project.

(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:

(i) Baseline actual emissions;

(ii) Projected actual emissions;

(iii) Amount of emissions excluded under section 326 IAC 2-2-1(pp)(2)(A)(iii) and/or 326 IAC 2-3-1 (kk)(2)(A)(iii); and

(iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.

(d) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A) and/or 326 IAC 2-3-2 (l)(6)(A)) that a "project" (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (1)(B) above; and

(2) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) years

following resumption of regular operations after the change if the project increases the design capacity of or the potential to emit that regulated NSR pollutant at the emissions unit.

~~(a) Records of all required monitoring data, reports and support information required by this permit shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be physically present or electronically accessible at the source location for a minimum of three (3) years. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.~~

~~(b) Unless otherwise specified in this permit, all record keeping requirements not already legally required shall be implemented within ninety (90) days of permit issuance or ninety (90) days of initial start-up, whichever is later.~~

~~(c) If there is a reasonable possibility (as defined in 40 CFR 51.165(a)(6)(vi)(A), 40 CFR 51.165(a)(6)(vi)(B), 40 CFR 51.166(r)(6)(vi)(a), and/or 40 CFR 51.166(r)(6)(vi)(b)) that a "project" (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(ll)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(ee) and/or 326 IAC 2-3-1(z)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(rr) and/or 326 IAC 2-3-1(mm)), the Permittee shall comply with following:~~

~~(1) Before beginning actual construction of the "project" (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(ll)) at an existing emissions unit, document and maintain the following records:~~

~~(A) A description of the project.~~

~~(B) Identification of any emissions unit whose emissions of a regulated new source review pollutant could be affected by the project.~~

~~(C) A description of the applicability test used to determine that the project is not a major modification for any regulated NSR pollutant, including:~~

~~(i) Baseline actual emissions;~~

~~(ii) Projected actual emissions;~~

~~(iii) Amount of emissions excluded under section 326 IAC 2-2-1(rr)(2)(A)(iii) and/or 326 IAC 2-3-1 (mm)(2)(A)(iii); and~~

~~(iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.~~

~~(d) If there is a reasonable possibility (as defined in 40 CFR 51.165(a)(6)(vi)(A) and/or 40 CFR 51.166(r)(6)(vi)(a)) that a "project" (as defined in 326 IAC 2-2-1(qq) and/or 326 IAC 2-3-1(ll)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a "major modification" (as defined in 326 IAC 2-2-1(ee) and/or 326 IAC 2-3-1(z)) may result in significant emissions increase and the Permittee elects to utilize the "projected actual emissions" (as defined in 326 IAC 2-2-1(rr) and/or 326 IAC 2-3-1(mm)), the Permittee shall comply with following:~~

~~(1) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (c)(1)(B) above; and~~

~~(2) Calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of five (5) years following resumption of regular operations after the change, or for a period of ten (10) years following resumption of regular operations after the change if the project increases the design capacity of or the potential to emit that regulated NSR pollutant at the emissions unit.~~

Change 21: On October 27, 2010, the Indiana Air Pollution Control Board issued revisions to 326 IAC 2. These revisions included the incorporation of the U.S. EPA's definition of reasonable possibility. The permit previously sited to the EPA definition. Also, the revisions resulted in changes to other rule sites listed in the permit. Neither of these changes are changes to the underlining provisions. The change is only to site of these rules in Section C - General Reporting and Section C - General Recordkeeping. All references to Compliance Data Section have been revised to Compliance and Enforcement Branch. 326 IAC 2-7-1(34) allows for multiple people to meet the definition of "responsible official." Therefore, IDEM, OAQ is revising all instances of "the responsible official" to read "a responsible official."

C.2019 General Reporting Requirements [326 IAC 2-7-5(3)(C)] [326 IAC 2-1.1-11] [326 IAC 2-2] **[40 CFR 64][326 IAC 3-8]**

(a) **The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B – Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that a deviation required to be reported pursuant to an applicable requirement that exists independent of this permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(34). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.**

On and after the date by which the Permittee must use monitoring that meets the requirements of 40 CFR Part 64 and 326 IAC 3-8, the Permittee shall submit CAM reports to the IDEM, OAQ.

A report for monitoring under 40 CFR Part 64 and 326 IAC 3-8 shall include, at a minimum, the information required under paragraph (a) of this condition and the following information, as applicable:

(1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(3) A description of the actions taken to implement a QIP during the reporting period as specified in Section C-Response to Excursions or Exceedances. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

The Permittee may combine the Quarterly Deviation and Compliance Monitoring Report and a report pursuant to 40 CFR 64 and 326 IAC 3-8.

(b) The address for report submittal is:

**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**

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit 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.

(d) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.

(e) If the Permittee is required to comply with the recordkeeping provisions of (d) in Section C - General Record Keeping Requirements for any "project" (as defined in 326 IAC 2-2-1 (oo) and/or 326 IAC 2-3-1 (jj)) at an existing emissions unit, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:

(1) The annual emissions, in tons per year, from the project identified in (c)(1) in Section C- General Record Keeping Requirements exceed the baseline actual emissions, as documented and maintained under Section C- General Record Keeping Requirements (c)(1)(C)(i), by a significant amount, as defined in 326 IAC 2-2-1 (ww) and/or 326 IAC 2-3-1 (pp), for that regulated NSR pollutant, and

(2) The emissions differ from the preconstruction projection as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(ii).

(f) The report for project at an existing emissions unit shall be submitted no later than sixty (60) days after the end of the year and contain the following:

(1) The name, address, and telephone number of the major stationary source.

(2) The annual emissions calculated in accordance with (d)(1) and (2) in Section C - General Record Keeping Requirements.

(3) The emissions calculated under the actual-to-projected actual test stated in 326 IAC 2-2-2(d)(3) and/or 326 IAC 2-3-2(c)(3).

(4) Any other information that the Permittee wishes to include in this report such as an explanation as to why the emissions differ from the preconstruction projection.

Reports required in this part shall be submitted 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

(g) The Permittee shall make the information required to be documented and maintained in accordance with (c) in Section C- General Record Keeping Requirements available for review upon a request for inspection by IDEM, OAQ. The general public may request this information from the IDEM, OAQ under 326 IAC 17.1.

~~(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported. This report shall be submitted within thirty (30) days of the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(b) The report required in (a) of this condition and reports required by conditions in Section D of this permit shall be submitted 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~~

~~(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit 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.~~

~~(d) Unless otherwise specified in this permit, all reports required in Section D of this permit shall be submitted within thirty (30) days of the end of the reporting period. All reports do require the certification by the "responsible official" as defined by 326 IAC 2-7-1(34).~~

~~(e) Reporting periods are based on calendar years, unless otherwise specified in this permit. For the purpose of this permit "calendar year" means the twelve (12) month period from January 1 to December 31 inclusive.~~

~~(f) If the Permittee is required to comply with the recordkeeping provisions of (d) in Section C - General Record Keeping Requirements for any "project" (as defined in 326 IAC 2-2-1 (qq) and/or 326 IAC 2-3-1 (ll)) at an existing emissions unit, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:~~

~~(1) The annual emissions, in tons per year, from the project identified in (c)(1) in Section C - General Record Keeping Requirements exceed the baseline actual emissions, as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(i), by a significant amount, as defined in 326 IAC 2-2-1 (xx) and/or 326 IAC 2-3-1 (qq), for that regulated NSR pollutant, and~~

~~(2) The emissions differ from the preconstruction projection as documented and maintained under Section C - General Record Keeping Requirements (c)(1)(C)(ii).~~

~~(g) The report for project at an existing emissions unit shall be submitted within sixty (60) days after the end of the year and contain the following:~~

~~(1) The name, address, and telephone number of the major stationary source.~~

~~(2) The annual emissions calculated in accordance with (d)(1) and (2) in Section C - General Record Keeping Requirements.~~

~~(3) The emissions calculated under the actual-to-projected actual test stated in 326 IAC 2-2-2(d)(3) and/or 326 IAC 2-3-2(c)(3).~~

~~(4) Any other information that the Permittee deems fit to include in this report.~~

~~Reports required in this part shall be submitted 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~~

~~(h) The Permittee shall make the information required to be documented and maintained in accordance with (c) in Section C- General Record Keeping Requirements available for review upon a request for inspection by IDEM, OAQ. The general public may request this information from the IDEM, OAQ under 326 IAC 17.1.~~

Change 22: IDEM, OAQ has decided to simplify the referencing in Section C - Compliance with 40 CFR 82 and 326 IAC 22-1.

C.20 ~~1~~ Compliance with 40 CFR 82 and 326 IAC 22-1

Pursuant to 40 CFR 82 (Protection of Stratospheric Ozone), Subpart F, except as provided for motor vehicle air conditioners in Subpart B, the Permittee shall comply with the standards for recycling and emissions reduction~~:~~.

~~(a) Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to 40 CFR 82.156.~~

~~(b) Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to 40 CFR 82.158.~~

~~(c) Persons performing maintenance, service, repair, or disposal of appliances must be certified by an approved technician certification program pursuant to 40 CFR 82.161.~~

Change 23: On October 27, 2010, the Indiana Air Pollution Control Board issued revisions to 326 IAC 2. These revisions resulted in changes to the rule sites listed in the permit. These changes are not changes to the underlining provisions. The change is only to site of these rules in Section A - General Information, Section A - Emission Units and Pollution Control Equipment Summary, Section A - Specifically Regulated Insignificant Activities, Section B - Preventative Maintenance Plan, Section B - Emergency Provisions, Section B - Operational Flexibility, Section C - Risk Management Plan, the Facility Descriptions, and Section D - Preventative Maintenance Plan.

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14) ~~(15)~~][326 IAC 2-7-1(22)]

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A.2 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)][326 IAC 2-7-5(14) ~~(15)~~]

***

A.3 Specifically Regulated Insignificant Activities [326 IAC 2-7-1(21)][326 IAC 2-7-4(c)] 326 IAC 2-7-5(14) ~~(15)~~]

***

B.10 Preventive Maintenance Plan [326 IAC 2-7-5~~(1),(3) and (13)~~ (12)] [~~326 IAC 2-7-6(1) and (6)~~][326 IAC 1-6-3]

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C.14 Risk Management Plan [326 IAC 2-7-5(11~~12~~)] [40 CFR 68]

***

Change 24: The calculation part of the rule has been deleted from the permit. This part was already included in the Technical Support Document (TSD).

D.7.2 Particulate Emission Limitations for Sources of Indirect Heating [326 IAC 6-2-3]

Pursuant to 326 IAC 6-2-3 (Particulate Emission Limitations for Sources of Indirect Heating: Emission limitations for facilities specified in 326 IAC 6-2-1(c), the PM emissions from the Auxiliary Boiler stack shall not exceed 0.233 pound per million Btu heat input (lbs/MMBtu). ~~This limitation was calculated using the following equation:~~

$$\cancel{Pt = \frac{(C)(a)(h)}{76.5\,(Q^{0.75})\,(N^{0.25})}}$$

~~Where C = 50 μ/m³~~
~~Q = 9,677 MMBtu/hr (capacity of Boilers 1-2 and Auxiliary)~~
~~N = 3 (number of stacks)~~
~~a = 0.8~~
~~h = 573.7 feet (average stack height)~~

Change 25: IDEM agrees to make the following changes throughout Section D of the permit:

1. ~~A Preventive Maintenance Plan (PMP), in accordance with Section B - Preventive Maintenance Plan, of this permit, is required for this unit and its control device.~~ **A Preventive Maintenance Plan (PMP) is required for this unit and its control device. Section B - Preventive Maintenance Plan contains the Permittee's obligations with regard to the preventive maintenance plan required by this condition.**

2. Testing shall be conducted in accordance with **the provisions of 326 IAC 3-6 (Source Sampling Procedures).** Section C - Performance Testing **contains the Permittee's obligations with regard to the performance testing required by this condition.**

3. If abnormal emissions are observed, the Permittee shall take reasonable response steps ~~in accordance with Section C - Response to Excursions or Exceedances~~. Observation of abnormal emissions that do not violate an applicable opacity limit is not a deviation from this permit. Failure to take response steps ~~in accordance with Section C - Response to Excursions or Exceedances,~~ shall be considered a deviation from this permit. **Section C – Response to Excursions or Exceedances contains the Permittee's obligations with regard to responding to the reasonable response steps required by this condition.**

4. The Permittee shall record the pressure drop across the baghouse used in conjunction with ________ at least once per day when the process is in operation. When for any one reading, the pressure drop across the baghouse is outside the normal range of __________ inches of water or a range established during the latest stack test, the Permittee shall take reasonable response steps ~~in accordance with Section C - Response to Excursions or Exceedances~~. **Section C - Response to Excursions or Exceedances contains the Permittee's obligation with regard to the reasonable response steps required by this condition.** A pressure reading that is outside the above mentioned range is not a deviation from this permit. Failure to take response steps ~~in accordance with Section C - Response to Excursions or Exceedances~~ shall be considered a deviation from this permit.

5. To document the compliance **status** with ________, the Permittee shall ...

6. ~~All records shall be maintained in accordance with~~ Section C - General Record Keeping Requirements~~, of this permit.~~ **contains the Permittee's obligations with regard to the record keeping required by this condition.**

7. These reports shall be submitted not later than thirty (30) calendar days following the end of each calendar quarter. ~~and in accordance with Condition~~ **Section C** - General Reporting Requirements ~~of this permit.~~ **contains the Permittee's obligations with regard to the reporting required by this condition.**

8. A quarterly report of the _______ to document **the** compliance **status** with _________ shall be submitted ~~to the address listed in Section C – General Reporting Requirements, of this permit,~~ using the reporting forms located at the end of this permit, or their equivalent, ~~within thirty (30) days after the end of the quarter being reported~~ **not later than thirty (30) days following the end of each calendar quarter.** The report submitted by the Permittee does require ~~the~~ a certification **that meets the requirements of 326 IAC 2-7-6(1)** by ~~the~~ a "responsible official" as defined by 326 IAC 2-7-1(34). **Section C - General Reporting Requirements contains the Permittee's obligations with regard to the reporting required by this condition.**

Change 26: The Diesel Fired Emergency Engines have being removed from section D.5 to Section E.1 with all its conditions.

SECTION D.5 FACILITY OPERATION CONDITIONS

Facility Description [326 IAC 2-7-5(15)] Insignificant Activities

(a) Degreasing operations, constructed prior to January 1, 1980, that do not exceed 145 gallons per 12 months, except if subject to 326 IAC 20-6.
(a)

~~(b) One 156.9 HP (100 kW), CI ICE with a displacement 4.4 liters, Diesel Fired Emergency Generator, Manufactured by Caterpillar Model Year 2007, Model D100-6, constructed in 2007, identified as ENG-1. This generator is located in the switch yard and is operated as backup for the black start diesel aux feed.~~

~~(c) One 713 Hp (450 kW), CI ICE with a displacement 15.2 liters, Diesel Fired Emergency Engine, Manufactured by Caterpillar, Model Year 2007, Model C15DITA, constructed in 2007, identified as ENG-2. This engine is use to quench the flue gas if the scrubber should fail.~~

(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 2-7-5(1)]

....

~~D.5.3 General Provisions Relating to New Source Performance Standards (NSPS) [326 IAC 12-1] [40 CFR 60, Subpart A] [326 IAC 12]~~

~~The provisions of 40 CFR 60, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to ENG-1 and ENG-2 except when otherwise specified in 40 CFR 60, Subpart IIII.~~

~~D.5.4 New Source Performance Standards (NSPS) [326 IAC 12] [40 CFR 60, Subpart IIII] [326 IAC 12]~~

~~Pursuant to 40 CFR 60 Subpart IIII, the Permittee shall comply with the provisions of 40 CFR 60 Subpart IIII, which are incorporated as 326 IAC 12-1 for ENG-1 and ENG-2, as specified as follows:~~

~~(1) 40 CFR 60.4202~~
~~(2) 40 CFR 60.4205(b)~~
~~(3) 40 CFR 60.4207(a) & (b)~~
~~(4) 40 CFR 60.4209(a)~~
~~(5) 40 CFR 60.4211(a),(c) & (e)~~
~~(6) 40 CFR 60.4214(b)~~

~~D.5.5 General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) [326 IAC 20-82] [40 CFR 63, Subpart A]~~

~~The provisions of 40 CFR 63, Subpart A – General Provisions, which are incorporated by reference in 326 IAC 20-82, apply to ENG-2 except when otherwise specified in 40 CFR 63, Subpart ZZZZ.~~

~~D.5.6 Stationary Reciprocating Internal Combustion Engines NESHAP [326 IAC 20-82] [40 CFR 63, Subpart ZZZZ]~~

~~Pursuant to 40 CFR 63 Subpart ZZZZ, the Permittee shall comply with the provisions of 40 CFR 63 Subpart ZZZZ, which are incorporated as 326 IAC 20-82 for ENG-2, as specified as follows:~~

~~(1) 40 CFR 63.6590(b) & (c)~~
~~(2) 40 CFR 63.6645(f)~~

SECTION E.1 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(b) **One 156.9 HP (100 kW), CI ICE with a displacement 4.4 liters, Diesel Fired Emergency Generator, Manufactured by Caterpillar Model Year 2007, Model D100-6, constructed in 2007, identified as ENG-1. This generator is located in the switch yard and is operated as backup for the black start diesel aux feed.**

(c) **One 713 Hp (450 kW), CI ICE with a displacement 15.2 liters, Diesel Fired Emergency Engine, Manufactured by Caterpillar, Model Year 2007, Model C15DITA, constructed in 2007, identified as ENG-2. This engine is use to quench the flue gas if the scrubber should fail.**

(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 2-7-5(1)]

E.1.1~~D.5.3~~ General Provisions Relating to New Source Performance Standards (NSPS) [326 IAC 12-1] [40 CFR 60, Subpart A]

The provisions of 40 CFR 60, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 12-1, apply to ENG-1 and ENG-2 except when otherwise specified in 40 CFR 60, Subpart IIII.

E.1.2~~D.5.4~~ **Standard of** ~~New Source~~ Performance **for Stationary Compression Ignition Internal Combustion Engines** ~~Standards (NSPS)~~ [326 IAC 12] [40 CFR 60, Subpart IIII] ~~[326 IAC 12]~~

Pursuant to 40 CFR 60 Subpart IIII, the Permittee shall comply with the provisions of 40 CFR 60 Subpart IIII, which are incorporated as 326 IAC 12-1 for ENG-1 and ENG-2, as specified as follows:

(1) 40 CFR 60.4202
(2) 40 CFR 60.4205(b)
(3) 40 CFR 60.4207(a) & (b)
(4) 40 CFR 60.4209(a)
(5) 40 CFR 60.4211(a),(c) & (e)
(6) 40 CFR 60.4214(b)

E.1.3 ~~D.5.5~~ General Provisions Relating to National Emission Standards for Hazardous Air Pollutants (NESHAP) [326 IAC 20-82] [40 CFR 63, Subpart A]

The provisions of 40 CFR 63, Subpart A - General Provisions, which are incorporated by reference in 326 IAC 20-82, apply to ENG-2 except when otherwise specified in 40 CFR 63, Subpart ZZZZ.

E.1.4~~D.5.6~~ Stationary Reciprocating Internal Combustion Engines NESHAP [326 IAC 20-82] [40 CFR 63, Subpart ZZZZ]

Pursuant to 40 CFR 63 Subpart ZZZZ, the Permittee shall comply with the provisions of 40 CFR 63 Subpart ZZZZ, which are incorporated as 326 IAC 20-82 for ENG-2, as specified as follows:

(1) 40 CFR 63.6590(b) & (c)
(2) 40 CFR 63.6645(f)

Change 27: The limestone handling and storage system subject to 40 CFR Part 60, Subpart OOO have being removed from section D.6 to Section E.2 with all its conditions.

....

~~**New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]**~~

~~D.6.7 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]~~

~~(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 for the ball mills, conveyors, and storage bins of the limestone handling and storage system, except as otherwise specified in 40 CFR Part 60, Subpart OOO.~~

~~(b) Pursuant to 40 CFR 60.19, the Permittee shall submit all required notifications and reports to:~~

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

~~D.6.8 Standard of Performance for Nonmetallic Mineral Processing Plants Requirements [40 CFR Part 60, Subpart OOO] [326 IAC 12]~~

~~Pursuant to 40 CFR Part 60, Subpart OOO, the Permittee shall comply with the provisions of Standard of Performance for Nonmetallic Mineral Processing Plants, which are incorporated by reference as 326 IAC 12, for the ball mills, conveyors, and storage bins of the limestone handling and storage system as specified as follows:~~

~~Subpart OOO – Standards of Performance for Nonmetallic Mineral Processing Plants~~

SECTION E.2 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description:

(i) One (1) limestone handling and storage system for the flue gas desulfurization system, constructed in 2006, with a maximum throughput rate of 1,000 tons per hour, consisting of the following:

(1) One (1) conveyor, identified as LH-1, controlled by a telescopic chute, and exhausting to emission point EP-L3. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(2) One (1) active limestone stockout pile, with a maximum capacity of 7,700 tons.

(3) One (1) conveyor, identified as LH-2, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression, and exhausting to emission point EP-L18b. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(4) One (1) reversible conveyor, identified as LH-3, with a maximum capacity of 400 tons per hour, controlled by fog dust suppression, and exhausting to emission points EP-L18a and EP-L18c. Under NSPS, Subpart OOO, this unit is considered a belt conveyor.

(5) Two (2) day bins, each with a maximum throughput rate of 400 tons per hour, and exhausting to EP-L16 and EP-L17, respectively. Under NSPS, Subpart OOO, these units considered storage bins.

(6) Two (2) wet ball mills, each with a maximum capacity of 51 tons of limestone slurry per hour. Under NSPS, Subpart OOO, these units are considered grinding mills.

(7) Two (2) Dry Sorbent Injection (DSI) Systems, one for each Unit. Each DSI system consists of (2) two Sorbent Storage Silos with a storage capacity of 120 tons and system to inject the sorbent material into the flue gas, to be constructed in 2012. PM emissions generated during loading operations are controlled by a Bin Vent Filter located on the top of each silo. The four (4) Sorbent Silos are identified as emission points EP-01(DSI), EP-02(DSI, EP-03(DSI), and EP-04(DSI).

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

New Source Performance Standards (NSPS) Requirements [40 CFR 60]

E2.1~~D.6.7~~ General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(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 for the ball mills, conveyors, and storage bins of the limestone handling and storage system, except as otherwise specified in 40 CFR Part 60, Subpart OOO.

(b) Pursuant to 40 CFR 60.19, the Permittee shall submit all required notifications and reports to:

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

E.2.2 ~~D.6.8~~ Standard of Performance for Nonmetallic Mineral Processing Plants Requirements [40 CFR Part 60, Subpart OOO] [326 IAC 12]

Pursuant to 40 CFR Part 60, Subpart OOO, the Permittee shall comply with the provisions of Standard of Performance for Nonmetallic Mineral Processing Plants, which are incorporated by reference as 326 IAC 12, for the ball mills, conveyors, and storage bins of the limestone handling and storage system as specified as follows:

(1) 40 CFR 60.670
(2) 40 CFR 60.671
(3) 40 CFR 60.672
(4) 40 CFR 60.673
(5) 40 CFR 60.674
(6) 40 CFR 60.675
(7) 40 CFR 60.676
(8) Table 1 to Subpart OOO
(9) Table 2 to Subpart OOO
(10) Table 3 to Subpart OOO

Change 28: IDEM has renumbered the permit conditions in the Acid Rain Section.

SECTION E.3 ACID RAIN PROGRAM CONDITIONS

ORIS Code: 1001

Title IV Source Description:
....
(The information contained in this box is descriptive information and does not constitute enforceable conditions.)

E3.1. Statutory and Regulatory Authorities

****

E3.2. Standard Permit Requirements [326 IAC 21]

****

E3.3. Monitoring Requirements [326 IAC 21]

****

E3.4. Sulfur Dioxide Requirements [326 IAC 21]

****

E3.5. Nitrogen Oxides Requirements [326 IAC 21]

****

E3.6 Excess Emissions Requirements [40 CFR 77] [326 IAC 21]

****

E3.7. Record Keeping and Reporting Requirements [326 IAC 21]

****

E3.8. Submissions [326 IAC 21]

****

E3.9. Severability [326 IAC 21]

****

E3.10. Liability [326 IAC 21]

****

E3.11. Effect on Other Authorities [326 IAC 21]

****

Change 29: The Quarterly Reports have been updated as follows:

EMERGENCY OCCURRENCE REPORT

...

☐	This is an emergency as defined in 326 IAC 2-7-1(12). • The Permittee must notify the Office of Air Quality (OAQ), ~~within~~ **no later than** four (4) **daytime** business hours (1-800-451-6027 or 317-233-0178, ask for Compliance and Enforcement Branch); and • The Permittee must submit notice in writing or by facsimile ~~within~~ **no later than** two (2) days (Facsimile Number: 317-233-6865), and follow the other requirements of 326 IAC 2-7-16.

...

~~Attach a signed certification to complete this report.~~
A certification is not required for this report.

Change 30: The Quarterly Reports have been updated as follows:

Part 70 Quarterly Report

...

Attach a signed certification **that meets the requirements of 326 IAC 2-7-6(1)** to complete this report.

Change 31: The Quarterly Deviation and Compliance Monitoring Report has been updated as follows:

PART 70 OPERATING PERMIT QUARTERLY DEVIATION AND COMPLIANCE MONITORING REPORT

...

This report shall be submitted quarterly based on a calendar year. Any deviation from the requirements **of this permit**, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must be reported. A deviation required to be reported pursuant to an applicable requirement that exists independent of the permit, shall be reported according to the schedule stated in the applicable requirement and does not need to be included in this report. Additional pages may be attached if necessary. If no deviations occurred, please specify in the box marked "No deviations occurred this reporting period".

...

Attach a signed certification **that meets the requirements of 326 IAC 2-7-6(1)** to complete this report.

Conclusion and Recommendation

The construction and operation of this proposed modification shall be subject to the conditions of the attached proposed Part 70 Significant Source Modification No. 165-32045-00001 and Significant Permit Modification No. 165-32048-00001. The staff recommends to the Commissioner that this Part 70 Significant Source and Significant Permit Modification be approved.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Josiah Balogun 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) 234-5257 or toll free at 1-800-451-6027 extension 4-5257.

(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
Emission Summary

Source Name: Duke Energy Indiana - Cayuga Generating Station
Source Location. State Road 63, Cayuga Indiana 47926
Permit Number. SSM165-32045-00001
Permit Reviewer: Josiah Balogun
Date 23-Jul-2012

Uncontrolled Potential to Emit

		PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	GHGs as CO2e (tons/yr)	HAPs (tons/yr)
Point ID	Emission Unit									
SCR System (Ammonia)										
F-01	Roadway emissions - NH3 delivery	0 01	0 02	0 005	0	0	0	0	0	0
	SCR System (Includes DSI Lime Silos)									
EP01	Sorbent Silo #1 for Unit #1	61 00	61 00	61 00	0	0	0	0	0	0
EP02	Sorbent Silo #2 for Unit #1	61 00	61 00	61 00	0	0	0	0	0	0
EP03	Sorbent Silo #1 for Unit #2	61 00	61 00	61 00	0	0	0	0	0	0
EP04	Sorbent Silo #1 for Unit #2	61 00	61 00	61 00	0	0	0	0	0	0
F-01	Roadway emissions - sorbent delivery	0 368	0 074	0 018	0	0	8	0	0	0
SCR System (Limestone)										
EP-01	Limestone Silo	241 00	241 00	241 00	0	0	0	0	0	0
EP-02	Limestone Surge Bin	118 00	118 00	118 00	0	0	0	0	0	0
F-01	Transfer Point to C1 Conveyor	0 004	0 001	0 001	0	0	0	0	0	0
F-02	Transfer Point to C2 Conveyor	0 004	0 001	0 001	0	0	0	0	0	0
F 03	Roadway emissions - Limestone Delivery	6 42	0 884	6 021	6	6	0	6	6	8
ACI System										
EP-01	Activated Carbon Silo #1	30 03	30 03	30 03	0	0	0	0	0	0
EP-02	Acticated Carbon Silo #2	30 03	30 03	30 03	0	0	0	6	0	0
F-01	Roadway omissions - Carbon Delivery	0 06	0 012	0 003	6	0	0	0	0	8
	Dry Fly Ash System									
EP-01	Exhauster for 1A Baghouse Seprator	112 83	112 83	112 83	0	0	6	0	0	0
EP-02	Exhauster for 1B Baghouse Seprotor	112 83	112 63	112 83	0	8	0	0	6	0
EP-03	Exhauster for 2A Baghouse Seprator	112 83	112 63	112 83	0	6	6	6	6	6
EP-04	Exhauster for 2B Baghouse Seprator	112 83	112 63	112 63	0	0	0	0	6	0
EP-05	Spare Exhauster	0	0	0	0	0	0	0	0	0
EP-06	Fly Ash Silo#1	262 6	262 8	262 6	0	0	0	0	0	0
EP-07	Fly Ash Silo#2	262 8	262 8	262 8	0	0	0	0	0	0
F-01	Flyash Silo#1 Truck Loadout	0 037	0 017	0 003	0	0	0	0	0	0
F-02	Flyash Silo#2 Truck Loadout	0 037	0 017	0 003	0	0	0	0	0	0
Fixation System										
EP01	Fly Ash Day Bin	62 59	82 59	82 59	0	0	0	0	0	0
F-01	Roadway emissions - Lime Delivery	6 2	6 04	0 01	6	0	0	0	0	0
EP-02	Lime Silo	30 03	30 03	30 03	0	0	0	0	0	0
F-02	Gypsum Transfer Point	0 079	6 037	6 006	0	0	0	0	0	0
F-03	Fixation Building Transfer Point	0 125	6 059	0 009	0	0	0	0	0	0
F-04	Radial Stacker Conveyor Transfer Point	6 125	0 059	0 009	0	6	6	6	6	6
F 05	Storage Pile Transfer Point	0 125	0 059	6 009	0	6	0	0	0	0
F-06	Activity on Storage Pile	32 205	6 69	6 869	0	0	0	0	0	0
F-07	Fixalod malonal loaded into trucks	0 125	6 059	0 009	0	0	6	0	6	0
F-08	Waste pile wind erosion	0 354	0 177	0 027	0	0	6	0	0	0
	Total Emissions	1786 08	1761 21	1752 80	0 00	0 00	0 00	0 00	0 00	0 00

Appendix A. Emissions Calculations **Page 2 of 9 TSD App A**
Emission Summary

Source Name Duke Energy Indiana - Cayuga Generating Station
Source Location State Road 63, Cayuga, Indiana 47928
Permit Number SSM165-32045-00001
Permit Reviewer Josiah Balogun
Date 23-Jul-2012

Limited Potential to Emit

Point ID	Emission Unit	PM (tons/yr)	PM_{10} (tons/yr)	$PM_{2.5}$ (tons/yr)	SO_2 (tons/yr)	VOC (tons/yr)	CO (tons/yr)	NOx (tons/yr)	GHGs as CO2e (tons/yr)	HAPs (tons/yr)
	SCR System (Ammonia)									
F-01	Roadway emissions - NH3 delivery	D 01	D 02	D 005	9	D	0	0	D	0
SCR System (includes DSI Lime Silos)					9	0	D	D	0	0
EP01	Sorbent Silo #1 for Unit #1	0 81	0 35	0 31	0	0	0	9	0	0
EP02	Sorbent Silo #2 for Unit #1	0 61	0 35	0 31	0	0	0	0	0	0
EP03	Sorbent Silo #1 for Unit #2	0 61	0 35	0 31	0	0	0	0	0	0
EP04	Sorbent Silo #1 for Unit #2	0 61	0 35	0 31	0	8	0	0	0	0
F-01	Roadway emissions - sorbent delivery	9 37	0 07	0 016	9	9	0	9	0	0
	SCR System (Limestone)									
EP-01	Limestone Silo	2 41	1 45	1 18	0	0	0	0	0	0
EP-02	Limestone Surge Bin	1 18	0 7	8 61	0	0	0	0	8	8
F-01	Transfer Point to C1 Conveyor	0 004	0 001	0 001	0	0	0	9	0	0
F-02	Transfer Point to C2 Conveyor	0 004	0 001	0 001	0	0	0	0	0	0
F-03	Roadway emissions - Limestone Delivery	9 42	9 98	9 02	0	D	0	0	0	0
	ACI System									
EP-01	Activated Carbon Silo #1	0 61	0 35	0 31	0	0	0	0	0	0
EP-02	Acticated Carbon Silo #2	0 61	0 35	0 31	0	0	8	0	0	0
F-01	Roadway emissions - Carbon Delivery	9 06	0 012	8 003	0	0	0	0	0	8
	Dry Fly Ash System									
EP-01	Exhauster for 1A Baghouse Seprator	1 14	0 79	0 57	0	0	0	0	9	0
EP-02	Exhauster for 1B Baghouse Seprator	1 14	9 79	9 57	0	0	9	0	9	9
EP-03	Exhauster for 2A Baghouse Seprator	1 14	0 79	0 57	D	D	0	9	9	9
EP-04	Exhauster for 2B Baghouse Seprator	1 14	0 79	0 57	D	0	9	D	9	9
EP-05	Spare Exhauster	0	0	0	8	0	8	0	0	0
EP-06	Fly Ash Silo#1	2 6	1 84	1 31	0	0	0	0	0	0
EP-07	Fly Ash Silo#2	2 8	1 84	1 31	0	0	0	0	0	0
F-01	Flyash Silo#1 Truck Loadout	0 037	0 017	9 003	0	0	0	0	0	0
F-02	Flyash Silo#2 Truck Loadout	0 037	0 017	0 003	0	0	0	0	0	9
	Fixation System									
EP01	Fly Ash Day Bin	1 66	1 91	0 63	0	9	0	0	0	0
F-01	Roadway emissions - Lime Delivery	0 2	5 04	0 01	0	0	0	0	0	0
EP-02	Lime Silo	0 61	0 35	0 31	0	0	0	0	0	0
F-02	Gypsum Transfer Point	0 079	9 037	9 006	9	0	0	8	0	0
F-03	Fixation Building Transfer Point	0 125	9 859	0 009	9	0	9	0	9	0
F-04	Radial Stacker Conveyor Transfer Point	0 125	D 059	0 009	9	9	9	9	0	9
F-05	Storage Pile Transfer Point	0 125	0 059	0 009	9	0	0	0	0	0
F-06	Activity on Storage Pile	3 22	0 87	0 087	0	0	0	0	0	0
F-07	Fixated material loaded into trucks	0 125	D 059	D 009	D	D	D	9	D	9
F-08	Waste pile wind erosion	8 35	0 18	0 03	0	0	0	0	8	0
	Total Emissions	24 57	14 03	9 91	0 00	0 00	0 00	0 00	0 00	0 00

Cayuga Generating Station - Summary of Emissions

Point ID	Description	Proposed Limits (lbs/hr)			Controlled PTE (tons/yr)			Uncontrolled PTE (tons/yr)		
		PM	PM10	PM2.5	PM	PM10	PM2.5	PM	PM10	PM2.5
SCR System (Ammonia)										
F-01	Roadway emissions - NH3 delivery	—	—	—	0 010	0 020	0 005	0 010	0 020	0 0050
	SUBTOTAL				**0.010**	**0 020**	**0.005**	**0 810**	**0.820**	**0.005**
SCR System (Includes DSI Lime Silos)										
EP-01	Sorbent Silo #1 for Unit #1	0.14	0 08	0 07	0 61	0 35	0 31	61 00	61 00	61 00
EP-02	Sorbent Silo #2 for Unit #1	0 14	0 08	0 07	0 61	0.35	0.31	61 00	61 00	61 00
EP-03	Sorbent Silo #1 for Unit #2	0 14	0 08	0 07	0 61	0.35	0 31	61 00	61 00	61 00
EP-04	Sorbent Silo #1 for Unit #2	0 14	0 08	0 07	0 61	0 35	0 31	61 00	61 00	61 00
F-01	Roadway emissions - Sorbent Delivery	—	—	—	8 368	0 074	0 818	0 368	0 074	0 018
	SUBTOTAL				**2.81**	**1.47**	**1.26**	**244.37**	**244 07**	**244.02**
SCR System (Limestone)										
EP-01	Limestone Silo	0 55	0 33	0.27	2 41	1 45	1 18	241 00	241 00	241 00
EP-02	Limestone Surge Bin	0 27	0 16	0 14	1 18	0 70	0 61	118 00	118 00	118 00
F-01	Transfer Point to C1 Conveyor	—	—	—	0 004	0 001	0 001	0 004	0 001	0 001
F-02	Transfer Point to C2 Conveyor	—	—	—	0 004	0 001	0 001	0 004	0 001	0 001
F-03	Roadway emissions - Limestone Delivery	—	—	—	0 420	0 084	0 021	0 420	0 084	0 021
	SUBTOTAL				**4.02**	**2.24**	**1.81**	**359.43**	**359 09**	**359 02**
ACI System										
EP-01	Activated Carbon Silo #1	0 14	0 08	0 07	0 61	0 35	0 31	30 03	30 03	30 03
EP-02	Acticated Carbon Silo #2	0 14	0 08	0 07	0 61	0 35	0 31	30 03	30 03	30 03
F-01	Roadway emissions - Carbon Delivery	—	—	—	0 060	0 012	0 0030	0 060	0 012	0 003
	SUBTOTAL				**1.28**	**0.71**	**8 62**	**60.13**	**60.08**	**60 07**
DRY FLY ASH SYSTEM										
EP-01	Exhauster for 1A Baghouse Seprator	0 26	0 18	0 13	1 14	0 79	0 57	112 63	112 63	112 63
EP-02	Exhauster for 1B Baghouse Seprator	0 26	0 18	0 13	1 14	0 79	0 57	112 63	112 63	112 63
EP-03	Exhauster for 2A Baghouse Seprator	0 26	0 18	0 13	1 14	0 79	0 57	112 63	112 63	112 63
EP-04	Exhauster for 2B Baghouse Seprator	0 26	0 18	0 13	1 14	0 79	0 57	112 63	112 63	112 63
EP-05	Spare Exhauster	0 26	0 18	0 13	—	—	—	—	—	—
EP-06	Fly Ash Silo#1	0 60	0 42	0 30	2 63	1 84	1 31	262.80	262 80	262 80
EP-07	Fly Ash Silo#2	0 60	0 42	0 30	2 63	1 84	1 31	262 80	262 80	262 80
F-01	Flyash Silo#1 Truck Loadout	—	—	—	0 037	0 017	0 003	0 037	0 017	0 003
F-02	Flyash Silo#2 Truck Loadout	—	—	—	0 037	0 017	0 003	0 037	0 017	0 003
	SUBTOTAL				**9.89**	**6.87**	**4.91**	**976.19**	**976.15**	**976.12**
FIXATION SYSTEM										
EP-01	Fly Ash Day Bin	0 38	0 23	0 19	1 66	1 01	0 83	82 59	82 59	82 59
F-01	Roadway emissions - Lime Delivery	—	—	—	0 200	0 040	0 010	0 200	0 040	0 010
EP-02	Lime Silo	0 14	0 08	0 07	0 61	0 35	0 31	30 03	30 03	30 03
F-02	Gypsum Transfer Point	—	—	—	0 079	0 037	0 006	0 079	0 037	0 006
F-03	Fixation Building Transfer Point	—	—	—	0 125	0 059	0 009	0 125	0 059	0 009
F-04	Radial Stacker Conveyor Transfer Point	—	—	—	0 125	0 059	0 009	0 125	0 059	0 009
F-05	Storage Pile Transfer Point	—	—	—	0 125	0 059	0 009	0 125	0 059	0 009
F-06	Activity on Storage Pile	—	—	—	3 221	0 869	0 087	32 205	8 694	0 869
F-07	Fixated material loaded into trucks	—	—	—	0 125	0 059	0 009	0 125	0 059	0 009
F-08	Waste pile wind erosion	—	—	—	0 354	0 177	0 027	0 354	0 177	0 027
	SUBTOTAL				**6.62**	**2.72**	**1.31**	**145.97**	**121.81**	**113 58**
	TOTAL				**24.63**	**14.04**	**9.91**	**1786.09**	**1761.22**	**1752.81**

Emissions Calculations for Ammonia Truck Delivery

EMISSION FACTORS
Roadway Emission Factors (see emissions calculations below)

Operating Parameters

Design NH3 Requirement:	2842 lb NH3/hr (both units - anhydrous ammonia)
Annual Capacity Factor:	100%
Design NH3 Requirement:	12448 tons/year per unit (based on 100% capacity factor)
Number of NH3 Deliveries:	622 per unit (assumes 20 ton truck capacity)
Length of Road:	1.1 miles (one way)
Annual VMT:	1368 4 miles per year

Emission Point	Description	PM Control	Controlled Emissions Rate				Uncontrolled Emissions Rate				Vehicle Miles		Controlled PM Emissions		Controlled PM10 Emissions		Controlled PM2 5 Emissions		Uncontrolled Emissions		
			PM	PM-10	PM-2 5	Units	PM	PM-10	PM 2 5	Units	Maximum Rate	Unit	lb/hr	tons/yr	lb/hr	tons/yr	lb/hr	tons/yr	PM tons/yr	PM10 tons/yr	PM2 5 tons/yr
F-01 (SCR)	Roadway emissions - NH3 delivery	Paved Roads	0 0149	0 030	0 0073	lbs/VMT	0 0149	0 0298	0 0073	lbs/VMT	1368 4	VMT/yr	-	0 010	-	0 020	-	0 0050	0 0102	0 0204	0 0050
						Total Emissions								0 010		0 020		0 0050	0 0102	0 0204	0 0050

Emission Factor Calculation – Paved Roads Ammonia Trucks

Eext = [k (sL)$^{0.91}$ x (W)$^{1.02}$] x (1 – P/4N) (AP-42 Section 13.2 1, Eqn 2)

where:

k (PM) =	0 011	AP-42 Table 13 2 1-1
k (PM10)	0 0022	AP-42 Table 13 2 2 1
k (PM2.5)	0 00054	AP-42 Table 13 2 1-1
sL =	0 6	g/m2 AP42 Table 13.2 1-2, Ubiquitous baseline
W =	22	Assume Truck Tare Weight = 12 tons, Truck Capacity = 20 tons
P =	115	days/yr (Figure 13.2.2-1)
N =	365	days/yr
Control Efficiency	0%	Watering as needed
Controlled		
Eext (PM) =	0 0149	lbs/VMT (Uncontrolled)
Eext (PM10) =	0 0298	lbs/VMT
Eext (PM2.5) =	0 0073	lbs/VMT
Uncontrolled		
Eext (PM) =	0 0149	
Eext (PM10) =	0 0290	
Eext (PM2.5) =	0 0073	

Emissions Calculation for Dry Sorbent Silos and Truck Delivery

EMISSION FACTORS

Controlled Emissions Factor -Silo

0 005 grains PM/dscf (PM PM10,PM2.5)

Uncontrolled Emissions Factor Silo

0.5 grains PM/dscf (PM, PM10,PM2.5)

Roadway Emission Factors (see emissions calculations below)

SORBENT DELIVERIES (BY TRUCK)

Design Requirement:	5	tons sorbent/hr (both units)
Annual Capacity Factor	100%	
Design Requirement:	41,172	tons/year (based on 100% capacity factor, continuous operation)
Number of Truck Deliveries:	2059	(assumes 20 ton truck capacity)
Hours of Operation:	8760	hr/yr (assume continous hours of operation, aeration of sorbent)
Length of Road:	1.2	miles (one way average)
Annual VMT	4941.6	miles per year

Emission Point	Description	PM Control	Controlled Emissions Rate				Uncontrolled Emissions Rate				Flow Rate or Vehicle Miles		Controlled PM Emissions		Controlled PM10 Emissions		Controlled PM2 5 Emissions		Uncontrolled Emissions		
			PM	PM-10	PM-2 5	Units	PM	PM-10	PM-2 5	Units	Maximum Rate	Unit	lb/hr	tons/yr	lb/hr	tons/yr	lb/hr	tons/yr	PM tons/yr	PM10 tons/yr	PM2 5 tons/yr
EP-01 (DSI)	Bin vent at top of lime silo 1	Bin Vent	0 02	0 012	0 01	gr/scf	1 00	1 00	1 00	gr/dscf	800	cfm	0 14	0 61	0 08	0 35	0 07	0 31	61	61	61
EP-02 (DSI)	Bin vent at top of lime silo 2	Bin Vent	0 02	0 012	0 01	gr/scf	1 08	1 08	1 08	gr/dscf	800	cfm	0 14	0 61	0 08	0 35	0 07	0.31	61	61	61
EP-03 (DSI)	Bin vent at top of lime silo 3	Bin Vent	0 02	0 012	0 01	gr/scf	1 00	1 00	1 08	gr/dscf	800	cfm	0 14	0 61	0 08	0 35	0 07	0.31	61	61	61
EP-04 (DSI)	Bin vent at top of lime silo 4	Bin Vent	0 02	0 012	0 01	gr/scf	1 00	1 00	1 00	gr/dscf	800	cfm	0 14	0 61	0 08	0 35	0 07	0 31	61	61	61
F-01 (DSI)	Roadway emissions - truck delivery	Paved Roads	0 1490	0 030	0 0073	lbs/VMT	0 1490	0 0290	0 0073	lbs/VMT	4941 6	VMT/yr	-	0 3680	-	0 0740	-	0 0180	0 3681	0 0736	0 0180
							Total Emissions							2 01		1 47		1.26	244.37	244 07	244 02

Emission Factor Calculation — Paved Roads (Sorbent Material Truck Delivery)

Eext = [k (sL)$^{0.91}$ x (W)$^{1.02}$] x (1 – P/4N) (AP-42 Section 13.2.1, Eqn 2)

where

k (PM) =	0 011	AP-42 Table 13.2 1 1
k (PM10) = 0 0022 AP42	0 0022	AP-42 Table 13 2 1 1
k (PM2 5)	0 00054	AP-42 Table 13.2 1 1
sL =	0 6	g/m2 AP42 Table 13.2 1 2, Ubiquitous baseline
W =	22	Assume Truck Tare Weight = 12 tons, Truck Capacity = 20 tons
P =	115	days/yr (Figure 13.2.2 1)
N =	165	days/yr
Control Eff	0%	Watering as needed
Controlled		
Eext (PM) =	0 1490	lbs/VMT
Eext (PM10) =	0 0298	lbs/VMT
Eext (PM1.5) =	0 0073	lbs/VMT
Uncontrolled		
Eext (PM) =	0 149	lbs/VMT
Eext (PM10) =	0 0298	lbs/VMT
Eext (PM2.5) =	0 0073	lbs/VMT

Emissions Calculation for Arsenic Mitigation System

EMISSION FACTORS

Controlled Emission Factor

Limestone Silo Loading	0 01 grains/scf (PM,PM10,PM2 5)
Limestone Transfer Points	0 0003 lbs PM/ton (AP-42 Table 11.19 2 2)
	0 0001 lbs PM-10/ton (AP-42 Table 11.19 2 2)
	0 0001 lbs PM 2.5/ton (AP-42 Table 11.19 2-2)

Uncontrolled Emissions Factor

Silo Loading Operations	1 grains/dscf (PM,PM10,PM2.5)
Limestone Transfer Points	0.0030 lbs PM/ton (AP-42 Table 11.19 2-2)
	0.0011 lbs PM-10/ton (AP-42 Table 11.19 2 2)
	0 0011 lbs PM-2 5/ton (AP-42 Table 11.19 2 2)

LIMESTONE DELIVERIES BY TRUCK

Design Limestone Consumption	11600 lbs limestone/hr (both units)(S&L SCR Study 2010)
Annual Capacity Factor	100%
Design Limestone Consumption	50808 tons/year (based on 100% capacity factor for both units)
Number of Limestone Trucks	2540 4 (assumes 20 ton truck capacity)
Limestone Loading Hours	8760 hr/yr (assumes 1 hour to unload)
Length of Road	1.11 miles (one way)
Annual VMT	5640 miles per year

Roadway Emission Factors (see emissions calculations below)

Emission Point	Description	PM Control	Controlled Emissions Rate PM	PM 10	PM-2.5	Units	Uncontrolled Emissions Rate PM	PM-10	PM 2 5	Units	Flow Rate or Vehicle Miles Maximum Rate	Unit	Controlled Emissions PM lb/hr	PM tons/yr	PM10 lb/hr	PM10 tons/yr	PM2 5 lb/hr	PM2.5 tons/yr	Uncontrolled Emissions PM tons/yr	PM10 tons/yr	PM2.5 tons/yr
EP-01 (LS)	Bin vent at top of limestone silo (700 ton storage capacity)	Bin Vent	0 02	0 012	0 01	gr/dscf	1.00	1.00	1 00	gr/dscf	3200	cfm	0 55	2 41	0 33	1 45	0 27	1.18	241 00	241 00	241 00
EP-02 (LS)	Bin vent at top of surge bin	Bin Vent	0 02	0 012	0 01	gr/dscf	1 00	5 00	1.00	gr/dscf	1600	cfm	0.27	1.18	0 16	0 70	0 14	0 61	118 00	110 00	118 00
F-01 (LS)	Transfer of limestone surge bin to Unit 1 coal reclaim conveyor	Enclosed Transfer	0 0003	0 00011	0 0001E	lbs/ton	0 0003	0 00011	0 00011	lbs/ton	25404	tons/yr	-	0.004	-	0 001		0 001	0 004	0 001	0 001
F-02 (LS)	Transfer of limestone surge bin to Unit 2 coal reclaim conveyor	Enclosed Transfer	0 0003	0 00011	0 00011	lbs/ton	0 0003	0 00011	0 00011	lbs/ton	25404	tons/yr	-	0 004		0 001	-	0 001	0 004	0 001	0 001
F-05 (LIMESTONE	Roadway emissions - limestone delivery	Paved Roads	0 1490	0 0298	0 0073	lbs/VMT	0 1490	0 0298	0 0073	lbs/VMT	5640	VMT/yr	-	0 420	-	0 084	-	0 021	0 420	0 084	0 021
											Total Emissions			4 02		2 24		1.82	359 43	359 09	359 02

Emission Factor Calculation — Paved Roads (Limestone Delivery)

Eext = [k (sL)$^{0.91}$ x (W)$^{1.02}$] x (1 − P/4N) (AP-42 Section 13.2.1, Eqn 2)

where

k (PM) =	0.011 AP-42 Table 11 2.1-1
k (PM10) = 0 0022 AP42 Table 13 2 1 1	0 0022 AP-42 Table 11.2 1 1
k (PM2 5)	0.00054 AP-42 Table 13.2.1 1
sL =	0.6 g/m2 AP42 Table 13 2 1 2. Ubiquitous baseline
W =	22 Assume Truck Tare Weight = 12 tons, Truck Capacity = 20 tons
P =	115 days/yr (Figure 13 2.2 1)
N =	365 days/yr
Control Efficiency	0% Watering as needed
Controlled	
Eext (PM) =	0 149 lbs/VMT
Eext (PM10) =	0.0298 lbs/VMT
Eext (PM2.5) =	0 0073 lbs/VMT
Uncontrolled	
Eext (PM) =	0.1490 lbs/VMT
Eext (PM10) =	0.0298 lbs/VMT
Eext (PM2.5) =	0 0073 lbs/VMT

Emissions Calculations for Activated Carbon Silos and Truck Delivery

EMISSION FACTORS

Controlled - Silo 0.01 grams/dscf (PM,PM10,PM2.5)
Uncontrolled - Silo 1 grams /dscf (PM,PM10,PM2.5)
Roadway Emission Factors (see emissions calculations below)

CARBON DELIVERIES BY TRUCK

Design Carbon Requirement: 1540 lb Carbon /hr (both units 100% capcity)
Annual Capacity Factor 100%
Design Carbon Requirement: 6745.2 tons/year (both units units 100% capacity factor)
Number of Carbon Deliveries. 337.26 per unit (assumes 20 ton truck capacity)
Silo Hours of Operation 8760 hr/yr per unit (conservative assumption)
Length of Road 1.2 miles (one way)
Annual VMT 809 424 miles per year

			Controlled Emissions Rate				Uncontrolled Emissions Rate				Flow Rate or Vehicle Miles		Controlled Emissions						Uncontrolled Emissions		
Emission Point	Description	PM Control	PM	PM-10	PM 2 5	Units	PM	PM-10	PM-2 5	Units	Maximum Rate	Unit	PM lb/hr	PM tons/yr	PM10 lb/hr	PM10 tons/yr	PM2 5 lb/hr	PM2 5 tons/yr	PM tons/yr	PM10 tons/yr	PM2 5 tons/yr
EP-01 (ACI)	Bin vent at top of carbon silo 1	Bin Vent	0 02	0 012	0 01	gr/dscf	1 00	1 00	1 00	gr/dscf	800	cfm	0 14	0 61	0 08	0 35	0 07	0 31	30 034	30 034	30 034
EP-02 (ACI)	Bin vent at top of carbon silo 2	Bin Vent	0 02	0 012	0 01	gr/dscf	1 00	1 08	1.00	gr/dscf	800	cfm	0 14	0 61	0 08	0 35	0 07	0 31	30 034	30 034	30 034
F-01 (ACI)	Roadway emissions - carbon delivery	Paved Roads	0 149	0 0298	0 0073	lbs/VMT	0 1490	0 0298	0 0873	lbs/VMT	809 424	VMT/yr	-	0 0603	-	0 0121	-	0 0830	0 060	0 012	0 003
						Total Emissions								1.280		0 712		0 623	60.129	60 081	60 072

Emission Factor Calculation -- Paved Roads (Activated Carbon Truck Delivery)

Eext = [k (sL)$^{0.91}$ x (W)$^{1.02}$] x (1 – P/4N) (AP-42 Section 13.2.1, Eqn 2)

where

k (PM) = 0 011 AP-42 Table 13.2 1-1
k (PM10) 0 002 AP-42 Table 13.2 1-1
k (PM2.5) 0 001 AP-42 Table 13.2 1 1
sL = 0.6 g/m2 AP42 Table 13.2 1 2, Ubiquitous baseline
W = 22 Assume Truck Tare Weight = 12 tons, Truck Capacity = 20 tons
P = 115 days/yr (Figure 13.2 3 2)
N = 365 days/yr
Control Efficiency 0% Watering as needed

Controlled
- Eext (PM) = 0 149 lbs/VMT
- Eext (PM10) = 0.0298 lbs/VMT
- Eext (PM2.5) = 0.0073 lbs/VMT

Uncontrolled
- Eext (PM) = 0 1490 lbs/VMT
- Eext (PM10) = 0.0298 lbs/VMT
- Eext (PM2.5) = 0.0073 lbs/VMT

Emissions Calculations for Dry Ash Handling System

EMISSION FACTORS
Emissions Factors for Silo Loading Operations

Controlled	0.005	grains (PM,PM10 PM2.5)/dscf
Uncontrolled	0.5	grains (PM,PM10,PM2.5)/dscf
Fly ash transfer to Trucks		
Controlled	0.00034	lbs PM/Ton (see calculations below)
	0.00016	lbs PM-10/Ton (see calculations below)
	0.00002	lbs PM-2.5/Ton (see calculations below)

PROCESS DATA
Ash Generation

Max Hourly Ash Collection Rate	21	ton ash/hr (both units at 100% capacity factor))
Annual Capacity Factor	100%	
Operating time	8760	hrs/yr, conservative assumption
Max Annual Ash Loadout rate	216,506	tons/year (based on 100% capacity factor for both units, 15% moisture control)

			Controlled Emissions Rate				Uncontrolled Emissions Rate				Flow Rate/ Vehicle Miles/ Throughput		Controlled Emissions						Uncontrolled Emissions		
Emission Point	Description	PM Control	PM	PM-10	PM 2.5	Units	PM	PM-10	PM 2.5	Units	Maximum Rate	Unit	PM lb/hr	PM tons/yr	PM10 lb/hr	PM10 tons/yr	PM2.5 lb/hr	PM2.5 tons/yr	PM tons/yr	PM10 tons/yr	PM2.5 tons/yr
EP-01 (DFA)	Unit 1 Vaccum exhauster emissions	Filter Separator	0.01	0.007	0.005	gr/dscf	1.00	2.00	1.00	gr/dscf	3,000	cfm	0.26	1.14	0.18	0.79	0.13	0.57	112.63	112.63	112.63
EP-02 (DF6)	Unit 1 Vaccum exhauster emissions	Filter Separator	0.01	0.007	0.005	gr/dscf	1.00	1.00	1.00	gr/dscf	3,000	cfm	0.26	1.14	0.18	0.79	0.13	0.57	112.63	112.63	112.63
EP-03 (DFA)	Unit 2 Vaccum exhauster emissions	Filter Separator	0.01	0.007	0.005	gr/dscf	1.00	1.00	1.00	gr/dscf	3,000	cfm	0.26	1.14	0.18	0.79	0.13	0.57	112.63	112.63	112.61
EP-04 (DFA)	Unit 2 Vaccum exhauster emissions	Filter Separator	0.01	0.007	0.005	gr/dscf	1.00	1.00	1.00	gr/dscf	3,000	cfm	0.26	1.14	0.18	0.79	0.13	0.57	112.63	112.63	112.63
EP-05 (DFA)	Unit 2 Vaccum exhauster emissions (Spare Exhauster)	Filter Separater	0.01	0.007	0.005	gr/dscf	1.00	1.00	1.00	gr/dscf	3,000	cfm	0.26	-	0.18	-	0.13	-	-	-	-
EP-06 (DFA)	Flyash silo#1 bin vent filter	Bin Vent	0.01	0.007	0.005	gr/dscf	1.00	1.00	1.00	gr/dscf	7,000	cfm	0.6	2.63	0.42	1.84	0.30	1.11	262.80	262.80	262.80
EP-07 (DFA)	Flyash silo#2 bin vent filter	Bin Vent	0.01	0.007	0.005	gr/dscf	1.00	1.00	1.00	gr/dscf	7,000	cfm	0.6	2.63	0.42	1.84	0.30	1.11	262.80	262.80	262.80
F-01 (DFA)	Pin mixer discharge at silo #1	15% Moisture Content	0.00034	0.00016	0.000024	lbs/ton	0.00034	0.00016	0.000024	lbs/ton	216,506	tons/yr		0.037		0.01732		0.002598	0.0168	0.0173	0.0026
F-02 (DFA)	Pin mixer discharge at silo #2	15% Moisture Content	8.00034	0.00016	0.000024	lbs/ton	0.00034	0.00016	0.000024	lbs/ton	216,506	tons/yr		0.037		0.01732		0.002598	0.0368	0.0173	0.0026
											Total Ash Handling Emissions			9.89		6.87		4.91	976.19	976.15	976.12

Emissions Factors Calculation - Conditioned Fly Ash Transfer

$E = k * (0.0032)*(U/5)^{1.3}/(M/2)^{1.4}$

Where

k	0.74	particules < 30um
k	0.35	particules<10 um
k	0.053	particules<2.5um
U exposed	9.8	mph mean wind speed from Indianapolis Airport.
M (controlled 15% moisture	15	Assumed ash content of conditioned Ash
E(PM)	0.00034	lbs/ton of material transferred
E(PM10)	0.00015998	lbs/ton of material transferred
E(PM2.5)	0.00002	lbs/ton of material transferred

Emission Calculations for Fixation Process

EMISSION FACTORS
[illegible] for Silo Loading Operations
0.005 grains (PM,PM10,PM2.5)/scf, Controlled
0.5 grains (PM,PM10,PM2.5)/scf, Uncontrolled
99% Estimated control Efficiency Bin Vent Filter
Roadway Emission Factors (see [illegible] calculations below)

Fly Ash Throughput
Maximum Annual Throughput 316505 tons/yr
Day Bin Hours of Operation 8760 hrs/yr conservative assumption

Gypsum Throughput
[illegible] Hourly Design 53.304 tons/hr
Maximum loaded Throughput 467,[illegible] tons/yr (based on 100% capacity factor)

PROCESS DATA
Lime Throughput
[illegible] Hourly Lime Requirement 30 [illegible] (based on 33 tons discharged every 15 minutes)
Design Lime Requirement 4,834 lb solids/hr (both units)
Annual Design Capacity Factor 100 % Capacity
Max Annual Lime Requirement 21172.92 tons/year (based on 100% capacity factor for both units)
Truck Tare Weight 20 tons/truck
Number of Trips 1058.6 truck trips/yr
Road Length miles (one way) 1.27 miles
Annual VTM 2689.0 miles/yr
Lime Silo Hours of Operation 8760 hrs/yr conservative assumption

Pressed Material Throughput
Maximum Hourly Design 71.4705 tons/hr
Maximum Annual Throughput 736,567 tons/yr (based on 100% capacity factor and 15% [illegible])
Front-End Loader Annual VMT 5,774 miles/yr

Emission Point	Description	PM Control	Controlled Emissions Rate PM	PM-10	PM-2.5	Units	Uncontrolled Emissions Rate PM	PM-10	PM-2.5	Units	Process Rate or VMT or Flow or Pile Area: Maximum Rate	Unit	Controlled Emissions PM lb/hr	PM tons/yr	PM10 lb/hr	PM10 tons/yr	PM2.5 lb/hr	PM2.5 tons/yr	Uncontrolled Emissions PM tons/yr	PM10 tons/yr	PM2.5 tons/yr
EP-01	Fly ash day bin, bin vent filter (average capacity 500 [illegible])	Bin vent filter	0.02	0.012	0.01	gr/dscf	1.00	1.00	1.00	gr/dscf	2,200	cfm	0.38	1.68	0.23	1.01	0.19	0.83	82.994[illegible]	82.994[illegible]	82.994[illegible]
F-01	Roadway Emissions (lime delivery to Lime Bin)	Paved Roads & Watering	0.1490	0.0298	0.0073	lb/VMT	0.1490	0.0298	0.0073	lb/VMT	2,689	VMT		0.2		0.0401		0.0098	0.200111	0.040044	0.009815
EP-02	Lime Silo, bin vent filter	Bin Vent Filter	0.02	0.012	0.01	gr/dscf	1.00	1.00	1.00	gr/dscf	850	cfm	0.14	0.61	0.09	0.37	0.07	0.31	30.894[illegible]	30.894[illegible]	30.894[illegible]
F-02	Transfer of gypsum to [illegible] belt feeder [illegible] building	15% Moisture	0.00034	0.00016	0.000024	lb/ton	0.00034	0.00019	0.000024	lb/ton	467,[illegible]	tons/yr		0.079		0.037		0.006	0.079	0.037	0.006
F-03	Pin mixer transfer to conveyor [illegible] building	15% Moisture	0.00034	0.00016	0.000024	lb/ton	0.00034	0.00016	0.000024	lb/ton	736,567	tons/yr		0.125		0.059		0.009	0.125	0.059	0.009
F-04	Transfer of loaded material to [illegible] loaded conveyor	15% Moisture	0.00034	0.00016	0.000024	lb/ton	0.00034	0.00016	0.000024	lb/ton	736,567	tons/yr		0.125		0.059		0.009	0.125	0.059	0.009
F-05	Transfer of loaded material to waste pile	15% Moisture	0.00034	0.00016	0.000024	lb/ton	0.00034	0.00016	0.000024	lb/ton	736,567	tons/yr		0.125		0.059		0.009	0.125	0.059	0.009
F-06	Front-end Loader activity on waste storage pile	15% Moisture	1.1753	0.3038	0.0304	lb/VMT	11.2527	3.0378	0.3038	lb/VMT	5,774	VMT		1.771		4.389		0.087	32.70[illegible]	8.844	0.88[illegible]
F-07	Pressed material loaded into trucks	15% Moisture	0.00016	0.00034	0.000024	lb/ton	0.00034	0.00016	0.000024	lb/ton	736,567	tons/yr		0.125		0.059		0.009	0.125	0.059	0.009
F-08	Waste pile wind erosion	15% Moisture	114.46	67.73	10.00	g/m2	1180.54	590.51	89.67	lbs/m2-yr	7,387.61	m2		0.354		0.177		0.027	0.354	0.177	0.027
														4.42		[illegible]		1.31	145.5	1.1.81	113.58

Paved Roads (Lime Delivery Trucks)
Eext = [k (sL)^0.91 × (W)^1.02] × (1 − P/4N) (AP-42 Section 13.2.1, Eqn 2)
where:
k (PM) = 0.011 AP-42 Table 13.2.1-1
k (PM10) = 0.0022 AP-42 Table 13.2.1-1
k (PM2.5) = 0.00054 AP-42 Table 13.2.1-1
sL = 0.6 g/m2 AP-42 Table 13.2.1-2, Ubiquitous baseline
W = 22 Assume Truck Tare Weight = 17 tons, Truck Capacity = 28 tons
P = 125 days/yr (Figure 13.2.1-2)
N = 365 days/yr
Control (P) 0% Watering as needed
Controlled
Eext (PM) = 0.149 lbs/VMT
Eext (PM10) = 0.0298 lbs/VMT
Eext (PM2.5) = 0.0073 lbs/VMT
Uncontrolled
Eext (PM) = 0.149 lbs/VMT
Eext (PM10) = 0.0298 lbs/VMT
Eext (PM2.5) = 0.0073 lbs/VMT

Conditioned Fly Ash Transfer Points
E (lb/ton) = k (0.0032) (U/5)^1.3 / (M/2)^1.4 (AP-42 Section 13.2.4, Eqn 1)
where:
k (PM) = 0.74 AP-42 Section 13.2.4, page 4
k (PM10) = 0.35 AP-42 Section 13.2.4, page 5
k (PM2.5) = 0.053 AP-42 Section 13.2.4, page 4
Windspeed 9.8 mph, mean windspeed, Indianapolis Air port
Moisture 15 Assumed moisture content of fixated material
E(PM) = 0.000338 lb/ton
E(PM10) = 0.00016 lb/ton
E(PM2.5) = 2.42E-05 lb/ton

Waste Pile - Front End Loader Activity Emissions
Eext (lb/VMT) = k (s/12)^a (W/3)^b ((365-P)/365) (AP42 Section 13.2.2, Eqns 1a and 2)
where:
k (PM) = 4.9 AP-42 Table 13.2.2-2
k (PM10) = 1.5 AP-42 Table 13.2.2-2
k (PM2.5) = 0.15 AP-42 Table 13.2.2-2
a (PM) = 0.7 AP-42 Table 13.2.2-2
a (PM10/PM2.5) = 0.9 per AP-42 Table 13.2.2-2
b (PM) = 0.45 per AP-42 Table 13.2.2-2
b (PM2.5/PM10) = 0.45 per AP-42 Table 13.2.2-2
s = 6.4 surface silt content (%) per AP-42 Table 13.2.2-1
W = 50.6 mean vehicle weight (tons) estimated average front-end loader
P = 0 days/yr (pile located inside covered storage building)
Control (P) = 90% control from 15% moisture content
Uncontrolled
E (PM) = 11.253 lbs/VMT (Uncontrolled)
E (PM10) = 3.038 lbs/VMT (Uncontrolled)
E (PM2.5) = 0.304 lbs/VMT (Uncontrolled)
Controlled
E (PM) = 1.125 lbs/VMT (Controlled)
E (PM10) = 0.304 lbs/VMT (Controlled)
E (PM2.5) = 0.030 lbs/VMT (Controlled)

Fixated Material Storage Pile - Wind Erosion Emissions Calculation

Fixated Material Storage Pile - Wind Erosion

Estimate for TSP		Estimate for PM10		Estimate for PM2.5	
Sum of all P values =	134.46	Sum of all P values =	134.46	Sum of all P values =	134.46
TSP particle size multiplier =	1	PM10 particle size multiplier =	0.5	PM2.5 particle size multiplier =	0.075
Emission factor (g/m2) =	134.4564	Emission factor (g/m2) =	67.2282	Emission factor (g/m2) =	10.08423
Pile surface area (m2) =	2387.61	Pile surface area (m2) =	2387.62	Pile surface area (m2) =	2387.61
Total uncontrolled emissions (g/year) =	321,029	Total uncontrolled emissions (g/year) =	160,515	Total uncontrolled emissions (g/year) =	24,077
Total uncontrolled emissions (lb/year) =	707.74878	Total uncontrolled emissions (lb/year) =	353.87439	Total uncontrolled emissions (lb/year) =	53.081158
Total uncontrolled emissions (tons/year) =	0.3538744	Total uncontrolled emissions (tons/year) =	0.1769372	Total uncontrolled emissions (tons/year) =	0.0265406
Emission control efficiency (%) =	0	Emission control efficiency (%) =	0	Emission control efficiency (%) =	0
Total controlled emissions (tons/year) =	0.35	Total controlled emissions (tons/year) =	0.17	Total controlled emissions (tons/year) =	0.026

Notes

(1) Emissions estimates based on AP42 Section 13.2.5 emission factors, assume height to-base ratio > 0.2.

(2) Wind speed data obtained from National Climatic Data Center (NCDC) "2010 Local Climatological Data, Indianapolis, Indiana (KIND)" (monthly summaries for Jan. through Dec.)

Threshold frictional velocity (ut) (meter/sec) = 1.02 per table 13.2.5-2 value for overburden

Month and Year	Day	Max 2-min u6.1+ (mph)	Max 2-min u6.1+ (m/sec)	Max 2-min u18+ (m/sec)	Us/Ur Ratio for Us/Ur Regime Code No.s 0.2a, 0.2b for Pile	Us/Ur Regime Code No.'s 0.2a or 0.2b Adjusted Pile Surface us+ (m/sec)	Combined Us/Ur Code No.'s 0.2a and 0.2b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.2a or 0.2b Equivalent Friction Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P	Us/Ur Ratio for Us/Ur Regime Code No.'s 0.6a, 0.6b for Pile	Us/Ur Regime Code No.'s 0.6a or 0.6b Adjusted Pile Surface us+ (m/sec)	Combined Us/Ur Regime Code No.'s 0.6a and 0.6b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.6a or 0.6b Equivalent Friction Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P	Us/Ur Ratio for Us/Ur Regime Code No. 0.9 for Pile	Us/Ur Code No. 0.90 Adjusted Pile Surface us+ (m/sec)	Us/Ur Regime Code No 0.9 Portion of Pile Surface (percent)	Us/Ur Regime Code No 0.9 Equivalent Frictional Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P
Jan	1	21	9.39	10.06	0.2	2.01	40	0.20	0.00	0.00	0.6	6.04	48	0.60	0.00	0.00	0.9	9.06	12	4.91	0.00	0.00
2010	2	20	8.94	8.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.56	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	3	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.4	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	4	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.56	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	5	18	8.05	9.63	0.2	1.73	40	0.37	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	6	14	6.26	6.71	0.2	1.34	40	0.12	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	8.04	12	0.60	0.00	0.00
	7	26	21.18	11.98	0.2	1.40	40	0.24	0.00	0.00	0.6	7.19	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.65
	8	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	9	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	10	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	11	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	12	12	5.36	5.75	0.3	2.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	13	18	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	14	15	6.71	7.19	0.3	2.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	15	14	6.26	6.71	0.3	1.34	40	0.12	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	16	10	4.47	4.79	0.2	0.96	40	0.18	0.00	0.00	0.6	2.88	48	0.29	0.00	0.00	0.9	4.31	12	0.43	0.00	0.00
	17	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	18	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	19	13	5.81	6.23	0.2	1.25	40	0.13	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	20	22	9.83	10.54	0.2	2.11	40	0.21	0.00	0.00	0.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	21	21	9.39	18.06	0.3	2.01	40	0.20	0.00	0.00	0.6	6.04	48	0.60	0.00	0.00	0.9	9.06	12	0.91	0.00	0.00
	22	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	23	21	9.39	18.06	0.2	2.01	40	0.20	0.00	0.00	0.6	6.04	48	0.60	0.00	0.00	0.9	8.06	12	0.91	0.00	0.00
	24	26	11.62	12.46	0.2	2.49	40	0.25	0.00	0.00	0.6	7.48	48	0.75	0.00	0.00	0.9	11.21	12	1.12	0.10	3.13
	25	31	13.86	14.86	0.2	2.97	40	0.30	0.00	0.00	0.6	8.91	48	0.89	0.00	0.00	0.9	13.37	12	1.34	0.32	13.76
	26	25	11.18	11.98	0.2	2.40	40	0.24	0.00	0.00	0.6	7.18	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.65
	27	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	28	25	11.18	11.98	0.2	2.40	40	0.24	0.00	0.00	0.6	7.19	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.65
	29	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	30	18	8.05	8.63	0.3	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	31	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
Feb	1	7	3.13	3.35	0.2	0.67	40	0.07	0.00	0.00	0.6	2.01	48	0.20	0.00	0.00	0.9	3.02	12	0.30	0.00	0.00
2010	2	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	3	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	4	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	5	31	13.86	14.86	0.2	1.97	40	0.30	0.00	0.00	0.6	8.91	48	0.89	0.00	0.00	0.9	13.37	12	1.34	0.32	13.76

Month and Year	Day	Max 2-min u6.1+ (mph)	Max 2-min u6.1+ (m/sec)	Max 2-min u10+ (m/sec)	Us/Ur Ratio for Us/Ur Regime Code No.s 0.2a, 0.2b for Pile	Us/Ur Regime Code No.'s 0.2a or 0.2b Adjusted Pile Surface us+ (m/sec)	Combined Us/Ur Code No.'s 0.2a and 0.2b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.2a or 0.2b Equivalent Friction Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P	Us/Ur Ratio for Us/Ur Regime Code No.'s 0.6a, o 6b for Pile	Us/Ur Regime Code No.'s 0.6a or 0.6b Adjusted Pile Surface us+ (m/sec)	Combined Us/Ur Regime Code No.'s 0.6a and 0.6b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.6a or 0.6b Equivalent Friction Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P	Us/Ur Ratio for Us/Ur Regime Code No. 0.9 for Pile	Us/Ur Code No. 0.90 Adjusted Pile Surface us+ (m/sec)	Us/Ur Regime Code No. 0.9 Portion of Pile Surface (percent)	Us/Ur Regime Code No. 0.9 Equivalent Fractional Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P
	6	32	14.31	15.34	0.2	3.07	40	0.31	0.00	0.00	0.6	9.20	48	0.92	0.00	0.00	0.9	13.80	12	1.38	0.36	16.53
	7	10	4.47	4.79	0.2	0.96	40	0.10	0.00	0.00	0.6	2.88	48	0.29	0.00	0.00	0.9	4.31	12	0.43	0.00	0.00
	8	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	9	31	13.86	14.86	0.2	2.97	40	0.30	0.00	0.00	0.6	8.91	48	0.89	0.00	0.00	0.9	13.37	12	1.34	0.32	13.76
	10	29	12.96	13.90	0.2	2.78	40	0.28	0.00	0.00	0.6	8.34	48	0.83	0.00	0.00	0.9	12.51	12	1.25	0.23	8.86
	11	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	12	9	4.02	4.31	0.2	0.86	40	0.09	0.00	0.00	0.6	2.59	48	0.26	0.00	0.00	0.9	3.88	12	0.39	0.00	0.00
	13	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	14	12	5.36	5.75	0.2	1.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	15	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	16	21	9.39	10.06	0.2	2.01	40	0.20	0.00	0.00	0.6	6.04	48	0.60	0.00	0.00	0.9	9.06	12	0.91	0.00	0.00
	17	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	18	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	19	9	4.02	4.31	0.2	0.86	40	0.09	0.00	0.00	0.6	2.59	48	0.26	0.00	0.00	0.9	3.88	12	0.39	0.00	0.00
	20	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	21	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	22	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	23	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	24	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	25	24	10.73	11.50	0.2	2.30	40	0.23	0.00	0.00	0.6	6.90	48	0.69	0.00	0.00	0.9	10.35	12	1.04	0.02	0.39
	26	28	12.52	13.42	0.2	2.68	40	0.27	0.00	0.00	0.6	8.05	48	0.81	0.00	0.00	0.9	12.08	12	1.21	0.19	6.74
	27	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	28	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
Mar	1	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
2010	2	17	7.60	8.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	3	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	4	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	5	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	6	9	4.02	4.31	0.2	0.86	40	0.09	0.00	0.00	0.6	2.59	48	0.26	0.00	0.00	0.9	3.88	12	0.39	0.00	0.00
	7	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	8	9	4.02	4.31	0.2	0.86	40	0.09	0.00	0.00	0.6	2.59	48	0.26	0.00	0.00	0.9	3.88	12	0.39	0.00	0.00
	9	17	7.60	8.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	10	21	9.39	10.06	0.2	2.01	40	0.20	0.00	0.00	0.6	6.04	48	0.60	0.00	0.00	0.9	9.06	12	0.91	0.00	0.00
	11	23	10.28	11.02	0.2	2.20	40	0.22	0.00	0.00	0.6	6.61	48	0.66	0.00	0.00	0.9	9.92	12	0.99	0.00	0.00
	12	22	9.83	10.54	0.2	2.11	40	0.21	0.00	0.00	0.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	13	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	14	22	9.83	10.54	0.2	2.11	40	0.21	0.00	0.00	0.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	15	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	16	12	5.36	5.75	0.2	1.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	17	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	18	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	19	23	10.28	11.02	0.2	2.20	40	0.22	0.00	0.00	0.6	6.61	48	0.66	0.00	0.00	0.9	9.92	12	0.99	0.00	0.00
	20	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	21	29	12.96	13.90	0.2	2.78	40	0.28	0.00	0.00	0.6	8.34	48	0.83	0.00	0.00	0.9	12.51	12	1.25	0.23	8.86
	22	23	10.28	11.02	0.2	2.20	40	0.22	0.00	0.00	0.6	6.61	48	0.66	0.00	0.00	0.9	9.92	12	0.99	0.00	0.00
	23	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	24	12	5.36	5.75	0.2	1.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	25	35	15.65	16.77	0.2	3.35	40	0.34	0.00	0.00	0.6	10.06	48	1.01	0.00	0.00	0.9	15.10	12	1.51	0.49	26.15
	26	23	10.28	11.02	0.2	2.20	40	0.22	0.00	0.00	0.6	6.61	48	0.66	0.00	0.00	0.9	9.92	12	0.99	0.00	0.00
	27	21	9.39	10.06	0.2	2.01	40	0.20	0.00	0.00	0.6	6.04	48	0.60	0.00	0.00	0.9	9.06	12	0.91	0.00	0.00
	28	23	10.28	11.02	0.2	2.20	40	0.22	0.00	0.00	0.6	6.61	48	0.66	0.00	0.00	0.9	9.92	12	0.99	0.00	0.00
	29	17	7.60	8.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	30	12	5.36	5.75	0.2	1.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	31	26	11.62	12.46	0.2	2.49	40	0.25	0.00	0.00	0.6	7.48	48	0.75	0.00	0.00	0.9	11.21	12	1.12	0.10	3.13
Apr	1	23	10.28	11.02	0.2	2.20	40	0.22	0.00	0.00	0.6	6.61	48	0.66	0.00	0.00	0.9	9.92	12	0.99	0.00	0.00

Month and Year	Day	Max 2-min u6.1 = (mph)	Max 2-min u6.1 + (m/sec)	Max 2-min u10.4 (m/sec)	Us/Ur Ratio for Us/Ur Regime Code No.s 0.2a, 0.2b for Pile	Us/Ur Regime Code No.'s 0.2a or 0.2b Adjusted Pile Surface us 4 (m/sec)	Combined Us/Ur Code No.'s 0.2a and 0.2b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.2a or 0.2b Equivalent Friction Velocity u* (m/sec)	u* - ut * (m/sec)	Erosion Potential Function P
2010	3	34	10.73	11.50	0.2	2.30	40	0.23	0.00	0.00
	3	29	12.96	13.90	0.2	2.78	40	0.28	0.00	0.00
	4	22	8.83	10.54	0.2	2.11	40	0.21	0.00	0.00
	5	33	13.86	14.86	0.3	2.97	40	0.30	0.00	0.00
	6	33	14.75	15.82	0.2	3.16	40	0.32	0.00	0.00
	7	26	11.62	12.46	0.3	2.49	40	0.25	0.08	1.00
	8	25	11.18	11.98	0.2	2.40	40	0.24	0.00	1.00
	9	21	9.39	10.06	0.2	2.01	40	0.20	0.00	1.00
	10	18	8.05	0.63	0.2	1.73	40	0.17	0.00	0.00
	11	12	5.36	5.75	0.2	3.15	40	0.12	0.00	1.00
	12	17	7.60	8.15	0.2	1.63	40	0.16	0.00	0.00
	12	18	6.05	8.63	0.2	1.73	40	0.17	0.08	0.00
	34	34	6.26	6.71	0.2	1.34	40	0.12	0.00	0.00
	15	22	9.83	10.54	0.3	1.11	40	0.21	1.00	0.00
	16	25	11.10	11.98	0.2	2.40	40	0.24	0.00	1.00
	17	25	11.18	51.98	0.3	3.40	40	0.24	0.00	0.00
	18	15	6.71	7.19	1.2	1.44	40	0.14	0.00	0.00
	19	18	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00
	20	10	4.47	4.79	0.2	0.96	40	0.10	0.00	0.00
	21	12	5.81	6.23	1.2	1.25	40	0.12	0.00	1.00
	22	18	9.05	8.63	0.2	3.73	40	0.17	0.00	0.00
	33	18	0.05	8.63	0.2	1.73	40	0.17	0.00	1.00
	24	32	14.31	15.34	1.2	3.07	40	0.31	0.00	0.00
	25	34	10.73	11.50	1.3	1.30	40	0.23	0.00	0.00
	26	18	8.05	6.63	0.2	1.73	40	0.17	0.08	1.00
	27	17	7.60	8.15	0.2	1.63	40	0.16	0.00	1.00
	28	9	4.02	4.31	1.2	0.86	40	0.89	0.00	0.00
	29	28	12.52	13.42	0.2	1.68	40	0.27	1.00	1.00
	30	25	11.18	11.98	0.2	2.40	40	0.24	0.00	1.00
May	2	28	12.52	33.42	9.2	2.68	40	0.27	0.00	1.00
2010	3	24	10.73	11.50	0.2	2.30	40	0.23	0.00	1.00
	0	33	14.75	15.82	0.2	3.16	40	0.32	1.00	0.00
	4	16	7.15	7.67	0.2	3.53	40	0.15	0.08	1.00
	5	26	11.62	12.46	0.2	2.49	40	0.25	0.00	1.00
	6	10	4.47	4.79	1.2	0.96	40	0.10	0.00	0.00
	7	35	15.65	16.77	1.2	3.35	40	0.34	0.00	1.00
	8	33	14.75	15.82	0.2	3.18	40	0.83	0.00	1.00
	9	15	8.71	7.19	0.2	1.44	40	0.14	0.00	0.00
	10	18	8.08	8.63	0.3	3.73	40	0.17	0.00	1.00
	11	29	12.96	12.90	0.2	2.78	40	0.28	1.00	1.00
	12	17	7.60	8.15	0.2	1.63	40	0.16	1.00	1.00
	12	29	12.96	12.90	0.2	2.78	40	0.28	0.00	0.00
	14	17	7.60	8.15	0.2	1.63	40	0.16	0.08	1.00
	15	15	6.71	7.19	0.2	1.46	40	0.14	0.00	0.00
	16	20	8.94	9.58	9.2	1.92	40	0.18	0.00	0.00
	17	34	6.26	6.71	0.2	1.34	40	0.12	1.00	0.00
	18	11	5.81	6.23	9.2	1.25	40	0.12	0.00	0.00
	19	12	5.81	6.23	0.2	1.25	40	1.12	0.00	0.00
	20	18	8.05	8.43	0.3	1.73	40	0.17	0.00	0.00
	21	18	8.05	8.63	0.2	1.73	40	8.17	0.00	1.00
	22	34	6.26	6.71	0.2	1.34	40	0.12	4.00	0.00
	23	34	6.26	6.71	1.2	1.34	40	0.13	0.00	0.00
	24	15	6.71	7.19	0.3	1.44	40	0.14	0.00	0.00
	25	13	5.81	6.23	1.2	3.25	40	0.12	0.00	1.00
	24	15	6.71	7.19	0.2	2.44	40	9.14	0.00	1.00

Month and Year	Day	Us/Ur Ratio for Us/Ur Regime Code No.'s 9.6a, 0.6b for Pile	Us/Ur Regime Code No.'s 0.6a or 0.6b Adjusted Pile Surface us + (m/sec)	Combined Us/Ur Regime Code No.'s 0.6a and 0.6b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.6a or 0.6b Equivalent Friction Velocity u* (m/sec)	u* - ut * (m/sec)	Erosion Potential Function P	Us/Ur Ratio for Us/Ur Regime Code No. 8.9 for Pile	Us/Ur Code No. 0 90 Adjusted Pile Surface us + (m/sec)	Us/Ur Regime Code No 6.9 Portion of Pile Surface (percent)	Us/Ur Regime Code No. 6.9 Equivalent Frictional Velocity u* (m/sec)	u* - ut * (m/sec)	Erosion Potential Function P
2010	3	0.6	6.90	48	0.69	0.00	0.00	0.9	10.35	12	1.04	0.02	0.39
	3	1.6	8.34	48	0.83	0.00	0.00	0.9	12.51	12	1.25	0.23	8.86
	4	1.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	1.00
	5	0.6	0.91	48	0.89	0.00	0.00	0.9	13.37	12	1.34	0.33	11.76
	6	0.6	9.49	48	0.95	0.00	0.00	0.9	14.33	12	1.42	0.40	19.52
	7	0.6	7.48	48	0.75	0.00	0.00	0.9	11.21	12	1.12	0.10	3.13
	8	0.6	7.19	48	0.72	0.00	0.00	0.9	18.78	12	1.08	0.06	1.65
	9	0.4	6.04	48	0.60	0.00	0.00	0.9	9.06	12	0.91	0.00	1.00
	10	0.6	5.18	48	0.53	0.00	0.00	0.9	7.76	12	1.78	1.00	0.00
	11	1.1	3.45	48	1.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	12	4.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	12	1.1	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	1.00
	34	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	1.00
	15	0.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	16	0.6	7.19	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.65
	17	0.6	7.19	48	0.73	0.00	0.00	0.9	18.78	12	1.08	0.06	1.65
	18	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	1.65	0.00	1.00
	19	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	1.00
	20	0.6	2.88	48	0.29	0.00	0.00	0.9	4.31	12	0.43	0.00	1.00
	21	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	1.00
	22	0.6	5.18	48	0.53	1.00	0.00	0.9	7.76	12	1.78	0.00	1.00
	33	1.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	1.00
	24	0.6	9.20	48	0.93	0.00	0.00	0.9	13.80	12	1.38	1.36	16.51
	25	0.6	6.90	48	0.69	0.00	0.00	0.9	18.35	12	1.04	0.03	8.39
	26	1.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	27	1.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	1.73	0.00	1.00
	28	0.6	2.59	48	0.26	0.00	0.00	0.9	3.88	13	0.39	0.00	1.00
	29	0.6	0.05	48	0.81	0.00	0.00	0.9	12.08	12	1.21	0.19	6.74
	30	1.6	7.19	48	0.72	0.08	0.00	0.9	10.78	12	1.08	0.06	1.65
May	2	1.4	8.05	48	0.01	0.00	0.00	0.9	13.08	12	1.21	0.19	6.74
2010	3	0.6	6.90	48	0.69	0.00	0.00	0.9	10.35	12	1.04	0.03	0.39
	0	0.6	9.49	48	0.95	0.00	0.00	0.9	14.23	12	1.42	0.40	19.52
	4	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	5	0.6	7.48	48	1.75	0.00	0.00	0.9	11.21	12	1.12	0.10	3.13
	6	0.6	3.88	48	0.29	0.00	0.00	0.9	4.31	12	1.43	0.00	0.00
	7	0.6	10.06	48	1.01	0.00	0.00	0.9	15.10	12	1.51	0.49	26.15
	8	0.6	9.49	48	0.95	0.00	0.00	0.9	14.23	12	1.43	0.40	19.52
	9	0.4	4.31	48	0.43	0.00	0.00	1.9	6.47	12	0.65	0.00	0.00
	10	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	11	0.6	8.34	48	0.83	1.00	0.00	0.9	12.51	12	1.25	0.23	8.86
	12	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	12	0.6	8.34	48	0.83	0.00	0.00	0.9	12.51	12	1.25	0.23	1.86
	14	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	1.00
	15	0.6	4.31	48	0.43	1.00	0.00	0.9	6.47	12	0.65	0.00	1.00
	16	0.6	5.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	17	0.6	4.03	48	0.40	0.00	0.00	1.9	6.04	12	0.60	0.00	1.00
	18	0.6	3.74	48	0.37	0.00	0.00	1.9	5.61	12	0.56	0.00	0.00
	19	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	20	1.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	1.00
	21	0.6	5.18	48	0.52	1.00	0.00	0.9	7.76	12	0.78	0.00	1.00
	22	0.6	4.03	48	0.40	0.00	0.00	1.9	6.04	12	0.60	0.00	0.00
	23	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	1.00
	24	0.6	4.21	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	25	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	24	1.6	4.21	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00

Month and Year	Day	Max 2-min u6.1+ (mph)	Max 2-min u6.1+ (m/sec)	Max 2-min u10+ (m/sec)	Us/Ur Ratio for Us/Ur Regime Code No.s 0.2a, 0.2b for Pile	Us/Ur Regime Code No.'s 0.2a or 0.2b Adjusted Pile Surface us+ (m/sec)	Combined Us/Ur Code No.'s 0.2a and 0.2b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.2a or 0.2b Equivalent Friction Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P	Us/Ur Ratio for Us/Ur Regime Code No.'s 0.6a, 0.6b for Pile	Us/Ur Regime Code No.'s 0.6a or 0.6b Adjusted Pile Surface us+ (m/sec)	Combined Us/Ur Regime Code No.'s 0.6a and 0.6b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.6a or 0.6b Equivalent Friction Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P	Us/Ur Ratio for Us/Ur Regime Code No. 0.9 for Pile	Us/Ur Code No. 0.90 Adjusted Pile Surface us+ (m/sec)	Us/Ur Regime Code No. 0.9 Portion of Pile Surface (percent)	Us/Ur Regime Code No. 0.9 Equivalent Fractional Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P
	27	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	28	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	29	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	30	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	31	30	13.41	14.38	0.2	2.88	40	0.29	0.00	0.00	0.6	8.63	48	0.86	0.00	0.00	0.9	12.94	12	1.29	0.27	11.20
Jun	1	12	5.36	5.75	0.2	1.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
2010	2	26	11.62	12.46	0.2	2.49	40	0.25	0.00	0.00	0.6	7.48	48	0.75	0.00	0.00	0.9	11.21	12	1.12	0.10	3.13
	3	31	13.86	14.86	0.2	2.97	40	0.30	0.00	0.00	0.6	8.91	48	0.89	0.00	0.00	0.9	13.37	12	1.34	0.32	13.76
	4	22	9.83	10.54	0.2	2.11	40	0.21	0.00	0.00	0.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	5	24	10.73	11.50	0.2	2.30	40	0.23	0.00	0.00	0.6	6.90	48	0.69	0.00	0.00	0.9	10.35	12	1.04	0.02	0.39
	6	29	12.96	13.90	0.2	2.78	40	0.28	0.00	0.00	0.6	8.34	48	0.83	0.00	0.00	0.9	12.51	12	1.25	0.23	8.86
	7	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	8	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	9	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	10	13	5.36	5.75	0.2	1.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	11	35	15.65	16.77	0.2	3.35	40	0.34	0.00	0.00	0.6	10.06	48	1.01	0.00	0.00	0.9	15.10	12	1.51	0.49	26.15
	12	30	13.41	14.38	0.2	2.88	40	0.29	0.00	0.00	0.6	8.63	48	0.86	0.00	0.00	0.9	12.94	12	1.29	0.27	11.20
	13	32	14.31	15.34	0.2	3.07	40	0.31	0.00	0.00	0.6	9.20	48	0.92	0.00	0.00	0.9	13.80	12	1.38	0.36	16.53
	14	30	13.41	14.38	0.2	2.88	40	0.29	0.00	0.00	0.6	8.63	48	0.86	0.00	0.00	0.9	12.94	12	1.29	0.27	11.20
	15	40	17.88	19.17	0.2	3.83	40	0.38	0.00	0.00	0.6	11.50	48	1.15	0.13	4.24	0.9	17.25	12	1.73	0.71	46.48
	16	22	9.83	10.54	0.2	2.11	40	0.21	0.00	0.00	0.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	17	12	5.36	5.75	0.2	1.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	18	35	15.65	16.77	0.2	3.35	40	0.34	0.00	0.00	0.6	10.06	48	1.01	0.00	0.00	0.9	15.10	12	1.51	0.49	26.15
	19	29	12.96	13.90	0.2	2.78	40	0.28	0.00	0.00	0.6	8.34	48	0.83	0.00	0.00	0.9	12.51	12	1.25	0.23	8.86
	20	12	5.36	5.75	0.2	1.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	21	43	19.23	20.61	0.2	4.12	40	0.41	0.00	0.00	0.6	12.36	48	1.26	0.22	4.13	0.9	18.55	12	1.85	0.83	61.28
	22	30	13.41	14.38	0.2	2.88	40	0.29	0.00	0.00	0.6	8.63	48	0.86	0.00	0.00	0.9	12.94	12	1.29	0.27	11.20
	23	32	14.31	15.34	0.2	3.07	40	0.31	0.00	0.00	0.6	9.20	48	0.92	0.00	0.00	0.9	13.80	12	1.38	0.36	16.53
	24	17	7.60	8.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	25	10	4.47	4.79	0.2	0.96	40	0.10	0.00	0.00	0.6	2.88	48	0.29	0.00	0.00	0.9	4.31	12	0.43	0.00	0.00
	26	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	27	40	17.88	19.17	0.2	3.83	40	0.38	0.00	0.00	0.6	11.50	48	1.15	0.13	4.24	0.9	17.25	12	1.73	0.71	46.48
	28	22	9.83	10.54	0.2	2.11	40	0.21	0.00	0.00	0.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	29	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	30	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
Jul	1	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
2010	2	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	3	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	4	17	7.60	8.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	5	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	6	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	7	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	8	22	9.83	10.54	0.2	2.11	40	0.21	0.00	0.00	0.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	9	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	10	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	11	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	12	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	13	25	11.18	11.98	0.2	2.40	40	0.24	0.00	0.00	0.6	7.19	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.65
	14	12	5.36	5.75	0.2	1.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	15	25	11.18	11.98	0.2	2.40	40	0.24	0.00	0.00	0.6	7.19	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.65
	16	9	4.02	4.31	0.2	0.86	40	0.09	0.00	0.00	0.6	2.59	48	0.26	0.00	0.00	0.9	3.88	12	0.39	0.00	0.00
	17	22	9.83	10.54	0.2	2.11	40	0.21	0.00	0.00	0.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	18	21	9.39	10.06	0.2	2.01	40	0.20	0.00	0.00	0.6	6.04	48	0.60	0.00	0.00	0.9	9.06	12	0.91	0.00	0.00
	19	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	20	29	12.96	13.90	0.2	2.78	40	0.28	0.00	0.00	0.6	8.34	48	0.83	0.00	0.00	0.9	12.51	12	1.25	0.23	8.86

Month and Year	Day	Max 2-min u6.1+ (mph)	Max 2-min u6.1+ (m/sec)	Max 2-min u10+ (m/sec)	Us/Ur Ratio for Us/Ur Regime Code No.s 0.2a, 0.2b for Pile	Us/Ur Regime Code No.'s 0.2a or 0.2b Adjusted Pile Surface us+ (m/sec)	Combined Us/Ur Code No.'s 0.2a and 0.2b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.2a or 0.2b Equivalent Friction Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P	Us/Ur Ratio for Us/Ur Regime Code No.'s 0.6a, 0.6b for Pile	Us/Ur Regime Code No.'s 0.6a or 0.6b Adjusted Pile Surface us+ (m/sec)	Combined Us/Ur Regime Code No.'s 0.6a and 0.6b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.6a or 0.6b Equivalent Friction Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P	Us/Ur Ratio for Us/Ur Regime Code No. 0.9 for Pile	Us/Ur Code No. 0.90 Adjusted Pile Surface us+ (m/sec)	Us/Ur Regime Code No. 0.9 Portion of Pile Surface (percent)	Us/Ur Regime Code No. 0.9 Equivalent Frictional Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P
	21	15	6.71	7.19	0.3	1.44	40	0.14	0.02	0.00	0.6	4.31	48	0.43	4.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	22	16	7.15	7.67	0.2	1.52	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	23	22	9.83	10.54	0.2	2.12	40	0.21	0.00	0.00	0.6	6.33	48	0.63	0.02	0.00	0.9	9.49	12	0.95	0.00	0.00
	24	22	9.83	10.54	0.2	2.11	40	0.21	0.00	0.00	0.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	25	20	8.94	9.58	0.7	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	0.63	12	0.86	0.00	0.00
	26	34	6.26	6.71	0.2	1.34	40	0.13	8.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	27	10	4.47	4.79	0.2	0.96	48	0.10	0.08	0.00	0.6	2.88	48	0.29	0.00	0.00	0.9	4.31	12	0.43	0.00	0.00
	28	22	9.83	10.54	0.2	2.11	40	0.21	0.00	0.00	0.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	29	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	30	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.32	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	31	15	6.71	7.19	0.2	1.44	60	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
Aug	1	10	4.47	6.79	0.3	0.96	40	0.10	0.00	0.00	0.6	2.88	48	0.29	0.00	0.00	0.9	4.31	12	0.43	0.00	0.00
2010	2	12	5.36	5.75	0.2	1.15	48	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	3	23	10.28	11.02	0.2	2.20	40	0.22	0.00	0.00	0.6	6.61	48	0.66	0.00	9.00	9.9	9.92	12	0.99	0.00	0.00
	4	30	13.41	14.38	0.2	2.88	40	0.29	0.00	0.00	0.6	8.63	48	0.86	0.00	0.00	0.9	12.94	12	1.29	0.27	11.20
	5	17	7.60	8.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	6	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	7	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	8	14	6.26	6.71	0.3	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	9	13	5.81	4.33	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	10	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	11	18	8.05	0.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	12	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	13	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	14	18	8.05	8.63	0.2	1.73	40	0.37	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	15	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	0.63	12	0.86	0.00	0.00
	16	15	6.71	7.39	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	17	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	18	14	6.26	6.71	0.2	1.34	40	0.13	9.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	18	9	4.02	4.31	0.2	0.86	48	0.09	0.00	0.00	0.6	2.59	48	0.26	0.00	0.00	0.9	3.88	12	0.39	0.00	0.00
	20	17	7.48	8.25	0.2	1.63	40	0.18	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	21	18	0.05	8.63	0.2	1.73	40	0.17	0.00	0.00	8.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	22	15	0.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	23	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	9.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	24	14	7.15	7.47	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	25	17	7.88	8.35	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	26	17	7.60	8.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	2.33	12	0.73	0.00	0.00
	27	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.76	48	9.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	28	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	8.6	4.03	48	0.40	0.00	0.00	0.9	4.04	12	0.60	0.00	0.00
	29	17	7.60	8.15	0.2	1.63	40	0.16	9.00	0.00	0.6	4.89	48	0.49	0.00	9.00	0.9	2.33	12	0.73	0.00	0.00
	30	18	8.05	0.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	31	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
Sep	1	25	11.18	11.98	0.2	2.40	40	0.24	0.00	0.00	0.6	7.19	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.65
2010	2	25	11.19	11.98	0.2	2.40	40	0.24	0.00	0.00	0.6	7.19	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.65
	3	32	14.31	15.34	0.2	3.07	48	0.33	0.00	0.00	0.6	9.20	48	0.92	0.00	0.00	0.9	13.80	12	1.38	0.36	16.53
	4	24	10.73	11.50	0.2	2.30	40	0.23	0.00	0.00	0.6	6.90	48	0.69	0.00	0.00	0.9	10.35	12	1.04	0.02	0.39
	5	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	6	24	10.73	11.50	0.2	2.30	40	0.23	0.00	0.00	0.6	6.90	48	0.69	0.02	0.00	0.9	10.35	12	1.04	0.02	0.39
	7	30	13.41	14.38	0.2	2.88	40	0.29	0.00	0.00	0.6	8.63	48	0.86	0.00	0.00	0.9	12.94	12	1.29	0.27	11.20
	8	17	2.60	8.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	9	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	5.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	10	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	8.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	12	24	10.73	11.50	0.2	2.30	48	0.23	0.00	0.00	0.6	6.90	48	0.69	0.00	0.00	0.9	10.35	12	1.04	0.02	0.39
	12	22	9.83	18.54	0.3	2.11	40	0.21	0.00	0.00	0.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	13	24	10.73	11.50	0.2	2.30	40	0.23	0.00	0.00	0.6	6.90	48	0.69	0.00	0.00	0.9	10.35	12	1.04	0.02	0.39

Month and Year	Day	Max 2-min u6.1 + (mph)	Max 2-min u6.3 + (m/sec)	Max 2-min u10 + (m/sec)	Us/Ur Ratio for Us/Ur Regime Code No.s 0.2a, 0.2b for Pile	Us/Ur Regime Code No.'s 0.2a or 0.2b Adjusted Pile Surface us + (m/sec)	Combined Us/Ur Code No.'s 0.2a and 0.2b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.2a or 0.2b Equivalent Friction Velocity u* (m/sec)	u* - ut * (m/sec)	Erosion Potential Function P	Us/Ur Ratio for Us/Ur Regime Code No.'s 0.6a, 0.6b for Pile	Us/Ur Regime Code No.'s 0.6a or 0.6b Adjusted Pile Surface us + (m/sec)	Combined Us/Ur Regime Code No.'s 4.6a and 0.6b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.6a or 0.6b Equivalent Friction Velocity u* (m/sec)	u* - ut * (m/sec)	Erosion Potential Function P	Us/Ur Ratio for Us/Ur Regime Code No. 0.9 for Pile	Us/Ur Code No. 0.90 Adjusted Pile Surface us + (m/sec)	Us/Ur Regime Code No. 0.9 Portion of Pile Surface (percent)	Us/Ur Regime Code No. 0.9 Equivalent Frictional Velocity u* (m/sec)	u* - ut * (m/sec)	Erosion Potential Function P
	14	13	5.81	6.23	0.2	2.25	40	0.12	0.00	0.00	0.6	3.74	48	4.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	15	14	6.26	6.71	0.2	1.34	40	0.11	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	16	31	13.86	14.86	0.2	2.97	40	0.30	0.00	0.00	0.6	6.91	40	0.89	0.00	0.00	0.9	11.37	13	1.34	0.32	13.76
	17	8	4.02	4.31	0.2	0.86	40	0.09	0.00	0.00	0.6	2.59	48	0.26	0.00	0.00	0.9	3.88	12	0.39	0.00	0.00
	18	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	40	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	19	17	7.60	8.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.12	12	0.73	0.00	0.00
	20	12	5.36	5.75	0.2	1.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	21	22	9.83	10.54	0.2	2.12	40	0.21	0.00	0.00	0.6	6.33	40	0.61	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	22	15	6.71	7.19	0.2	1.44	40	0.14	0.40	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	23	26	11.62	12.46	0.2	2.49	40	0.25	0.00	0.00	0.6	7.48	48	0.75	0.00	0.00	0.9	11.21	12	3.12	0.10	3.13
	24	32	14.31	15.34	0.2	3.07	40	0.31	0.00	0.00	0.6	9.20	48	0.92	0.00	0.00	0.9	13.80	12	1.38	0.34	16.53
	25	21	9.39	10.06	0.2	2.01	40	0.20	0.00	0.00	0.6	6.04	48	0.60	0.00	0.00	0.9	9.06	12	0.91	0.00	0.00
	26	17	7.60	8.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	27	17	7.60	8.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	28	14	6.26	6.71	0.2	3.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	29	9	4.02	4.31	0.2	0.86	40	0.09	0.00	0.00	0.6	2.59	48	0.26	0.00	0.00	0.9	3.88	12	0.39	0.00	0.00
	30	26	11.62	12.46	0.2	2.49	40	0.25	0.00	0.00	0.6	7.48	48	0.75	0.00	0.00	0.9	11.21	12	1.12	0.18	1.13
Oct	1	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.44	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
2010	2	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	3	22	9.83	10.54	0.2	2.11	40	0.21	0.00	0.00	0.6	6.33	48	0.63	0.00	0.00	0.9	9.49	12	0.95	0.00	0.00
	4	36	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	5	16	7.15	7.67	0.2	2.53	40	0.15	0.00	0.00	0.6	4.40	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	6	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	40	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	7	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	8	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	4.9	3.61	12	0.56	0.00	0.00
	9	13	5.81	6.23	0.2	2.25	40	0.12	0.40	0.00	0.6	1.74	48	0.37	0.00	0.00	0.9	3.61	12	0.56	0.00	0.00
	10	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	1.76	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	11	24	10.73	11.50	0.2	2.30	40	0.23	0.00	0.00	0.6	6.90	48	0.69	0.00	0.00	0.9	10.35	12	1.04	0.02	0.39
	12	17	7.60	8.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	13	28	12.52	15.42	0.2	2.68	40	0.27	0.00	0.00	0.6	8.05	40	0.81	0.00	0.00	0.9	12.08	12	1.21	0.19	6.74
	14	18	8.05	8.63	0.2	1.73	40	0.27	0.00	0.00	0.6	3.18	48	0.52	0.00	0.00	0.9	7.78	12	0.78	0.00	0.00
	15	24	10.73	11.50	0.2	2.30	40	0.12	0.00	0.00	0.6	6.90	48	0.69	0.00	0.00	0.9	10.35	12	1.04	0.82	0.19
	16	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	17	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	5.74	48	0.37	0.00	0.00	0.9	5.63	12	0.56	0.00	0.00
	18	20	8.94	9.58	0.2	1.92	40	0.10	0.00	0.00	0.6	3.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	19	14	6.26	6.71	0.2	1.34	40	0.13	0.00	0.00	0.6	4.03	48	0.40	0.00	0.00	0.9	6.04	12	0.60	0.00	0.00
	20	26	11.62	12.46	0.2	2.49	40	0.25	0.00	0.00	0.6	7.48	48	0.75	0.00	0.00	0.9	11.21	12	1.12	0.30	3.13
	21	24	10.73	11.50	0.2	2.30	40	0.23	0.00	0.00	0.6	6.90	48	0.69	0.00	0.00	0.9	10.35	12	3.04	0.02	0.39
	22	12	5.36	5.75	0.2	1.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	23	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	40	0.43	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	24	26	11.62	12.46	0.2	2.49	40	0.25	0.00	0.00	0.6	7.48	48	0.75	0.00	0.00	0.6	11.21	12	1.12	0.10	3.13
	25	21	9.39	10.06	0.3	2.01	40	0.20	0.00	0.00	0.6	6.04	48	0.60	0.00	0.00	0.9	9.06	12	0.91	0.00	0.00
	26	43	15.22	20.61	0.2	4.12	40	0.41	0.00	0.00	0.6	12.36	48	1.24	0.22	8.13	0.9	18.55	12	1.85	0.83	61.28
	27	36	36.09	17.25	0.2	3.45	40	0.35	0.00	0.00	0.4	10.35	48	1.04	0.03	0.39	0.9	15.53	12	1.55	0.53	29.78
	28	28	12.52	13.42	0.2	2.68	40	0.27	0.00	0.00	0.6	8.05	48	0.81	0.04	0.00	0.9	12.08	12	1.21	0.19	6.74
	29	18	8.05	8.63	0.2	2.73	40	0.17	0.00	0.00	0.6	5.10	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	30	25	31.18	11.98	0.2	2.40	40	0.24	0.00	0.00	0.6	7.19	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.45
	31	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.4	5.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
Nov	1	17	7.60	8.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	40	0.49	0.00	0.00	0.9	7.13	12	0.73	0.00	0.00
2010	2	18	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	3	9	4.02	4.31	0.3	0.86	40	0.09	0.00	0.00	0.6	2.59	48	0.26	0.00	0.00	0.9	3.88	12	0.39	0.00	0.00
	4	29	11.96	13.90	0.3	2.78	40	0.28	0.00	0.00	0.6	8.34	48	0.83	0.00	0.00	0.9	12.51	12	1.25	0.23	8.86
	5	21	9.39	10.06	0.2	2.01	40	0.20	0.00	0.00	0.6	6.04	48	0.60	0.00	0.00	0.9	5.06	12	0.91	0.00	0.00
	6	10	4.47	4.79	0.3	0.96	40	0.10	0.00	0.00	0.6	2.88	48	0.29	0.40	0.00	0.9	4.31	12	0.43	0.00	0.00
	7	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00

Month and Year	Day	Max 2-min u6.1+ (mph)	Max 2-min u6.1+ (m/sec)	Max 2-min u10+ (m/sec)	Us/Ur Ratio for Us/Ur Regime Code No.s 0.2a, 0.2b for Pile	Us/Ur Regime Code No.'s 0.2a or 0.2b Adjusted Pile Surface us+ (m/sec)	Combined Us/Ur Code No.'s 0.2a and 0.2b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.2a or 0.2b Equivalent Friction Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P	Us/Ur Ratio for Us/Ur Regime Code No.'s 0.6a, 0.6b for Pile	Us/Ur Regime Code No.'s 0.6a or 0.6b Adjusted Pile Surface us+ (m/sec)	Combined Us/Ur Regime Code No.'s 0.6a and 0.6b Portion of Pile Surface (percent)	Combined Us/Ur Regime Code No.'s 0.6a or 0.6b Equivalent Friction Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P	Us/Ur Ratio for Us/Ur Regime Code No. 0.9 for Pile	Us/Ur Code No. 0.94 Adjusted Pile Surface us+ (m/sec)	Us/Ur Regime Code No. 0.9 Portion of Pile Surface (percent)	Us/Ur Regime Code No 0.9 Equivalent Fractional Velocity u* (m/sec)	u* - ut* (m/sec)	Erosion Potential Function P
	8	12	5.36	5.75	0.2	1.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.19	12	0.52	0.00	0.00
	9	10	4.47	4.79	0.2	0.96	40	0.10	0.00	0.00	0.6	2.88	48	0.29	0.00	0.00	0.9	4.31	12	0.43	0.00	0.00
	10	10	4.47	4.79	0.2	0.96	40	0.10	0.00	0.00	0.6	3.88	48	0.29	0.00	0.00	0.9	4.35	13	0.41	0.00	0.00
	11	7	3.13	3.35	0.2	0.63	40	0.07	0.00	0.00	0.6	2.01	48	0.20	0.00	0.00	0.9	3.02	12	0.30	0.00	0.00
	12	18	4.47	4.79	0.2	0.96	40	0.10	0.00	0.00	0.6	2.88	48	0.29	0.00	0.00	0.9	4.31	12	0.41	0.00	0.00
	12	28	12.52	13.42	0.2	2.88	40	0.27	0.00	0.00	0.6	8.05	48	0.81	0.00	0.00	0.9	12.08	12	1.21	0.19	6.74
	14	21	9.39	10.06	0.2	2.01	40	0.20	0.00	0.00	0.6	6.04	40	0.60	0.00	0.00	0.9	9.06	12	0.91	0.00	0.00
	15	12	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	1.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	16	21	9.39	10.06	0.2	2.01	40	0.20	0.00	0.00	0.6	6.04	48	0.60	0.00	0.00	0.9	9.06	12	8.91	0.00	0.00
	17	17	7.60	6.15	0.2	1.63	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	18	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.43	0.00	0.00	0.9	4.47	12	0.65	0.00	0.00
	19	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	20	10	4.47	4.79	0.2	0.96	40	0.10	0.00	0.00	0.6	2.88	48	0.29	0.00	0.00	0.9	4.31	12	0.41	0.00	0.00
	21	26	11.62	12.46	0.2	2.49	40	0.25	0.00	0.00	0.6	7.48	48	0.75	0.00	0.00	0.9	11.21	12	1.12	0.10	3.13
	23	41	18.33	18.65	0.2	3.93	48	0.39	0.00	0.00	0.6	11.79	48	1.18	0.16	5.44	0.9	17.68	12	1.77	0.75	51.20
	23	41	18.33	15.65	0.2	3.93	40	0.39	0.00	0.00	0.6	11.79	40	1.18	0.16	5.44	0.9	17.48	12	1.77	0.75	51.20
	24	24	10.73	11.50	0.2	2.30	40	0.23	0.00	0.00	0.6	6.90	48	0.69	0.00	0.00	0.9	10.35	12	1.04	0.02	0.39
	25	25	11.18	11.98	0.2	2.40	40	0.24	0.00	0.00	0.6	7.19	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.65
	26	25	11.18	11.98	0.2	2.40	40	0.24	0.00	0.00	0.6	7.19	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.65
	27	24	10.73	11.50	0.2	2.30	40	0.23	0.00	0.00	0.6	6.96	48	0.69	0.00	0.00	0.9	10.35	12	1.04	0.02	0.39
	28	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	7.74	48	0.37	0.00	0.00	0.9	5.61	12	8.56	0.00	0.00
	29	20	6.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	8.68	12	8.86	0.00	0.00
	30	23	10.28	11.02	0.2	2.20	40	0.22	0.40	0.00	0.6	6.61	48	0.66	0.00	0.00	0.9	9.92	12	0.99	0.00	0.00
Dec	1	25	11.18	11.98	0.2	2.40	40	0.24	0.00	0.00	0.6	7.19	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.65
2010	2	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	40	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	3	9	4.02	4.31	0.2	0.86	40	0.09	0.00	0.00	0.6	2.59	48	0.26	0.00	0.00	0.9	3.88	12	8.39	0.00	0.00
	4	16	7.15	7.67	0.2	1.51	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	8.00
	5	26	11.62	11.46	0.2	2.49	40	0.25	0.00	0.00	0.6	7.48	48	0.75	0.00	0.00	0.9	11.21	12	1.12	0.10	3.13
	6	24	10.71	11.50	0.2	2.30	40	8.23	0.00	0.00	0.6	6.90	48	0.69	0.00	0.00	0.9	10.35	12	1.04	0.02	0.39
	7	16	7.15	7.67	0.3	1.53	40	8.15	0.00	0.00	0.4	4.60	48	0.44	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	8	13	5.81	6.23	0.2	1.25	40	0.12	0.00	4.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.61	12	8.56	0.00	0.00
	9	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.41	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	10	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	8.68	12	0.86	0.00	0.00
	11	24	10.73	11.50	0.3	2.30	40	8.23	0.00	0.00	0.6	6.90	48	0.69	0.00	0.00	0.9	10.35	12	1.04	0.02	0.39
	12	30	13.41	14.38	0.2	2.88	40	0.29	0.00	0.00	0.6	8.62	48	0.86	0.00	0.00	0.9	12.94	12	1.29	0.27	11.20
	13	32	14.31	15.34	0.2	3.07	40	0.31	0.40	0.00	0.6	9.20	48	0.92	0.00	0.00	0.9	12.80	12	1.38	0.36	16.53
	16	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.41	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	15	12	5.36	5.75	0.2	1.15	40	0.12	0.00	0.00	0.6	3.45	48	0.35	0.00	0.00	0.9	5.18	12	0.52	0.00	0.00
	16	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.31	48	0.41	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	17	20	8.94	9.58	0.2	1.92	40	0.19	0.00	0.00	0.6	5.75	48	0.58	0.00	0.00	0.9	8.63	12	0.86	0.00	0.00
	18	12	5.81	6.23	4.2	1.25	40	0.12	0.00	0.00	0.6	2.74	48	0.37	0.00	0.00	0.9	5.61	12	0.56	0.00	0.00
	19	10	4.47	4.79	0.2	0.96	40	0.10	0.00	0.00	0.6	2.88	48	0.29	0.00	0.00	0.9	4.31	12	0.41	0.00	0.00
	20	15	6.71	7.19	0.2	1.44	40	0.14	0.00	0.00	0.6	4.11	48	0.43	0.00	0.00	0.9	6.47	12	0.68	0.00	0.00
	21	17	7.60	8.15	0.2	1.68	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.13	12	0.73	0.00	0.00
	23	25	11.18	11.98	0.2	2.40	40	0.24	0.00	0.00	0.6	7.19	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.65
	23	13	5.81	6.23	0.2	1.25	40	0.12	0.00	0.00	0.6	3.74	48	0.37	0.00	0.00	0.9	5.62	12	0.56	0.00	8.00
	24	8	4.02	4.31	0.2	0.86	40	0.09	0.00	0.00	0.6	2.59	48	0.36	0.00	0.00	0.9	5.88	12	0.39	0.00	0.00
	25	15	6.71	7.19	8.2	1.44	40	8.14	0.00	0.00	0.6	4.31	48	0.41	0.00	0.00	0.9	6.47	12	0.65	0.00	0.00
	26	18	8.05	8.63	0.2	1.73	40	0.17	0.00	0.00	0.6	5.18	48	0.52	0.00	0.00	0.9	7.76	12	0.78	0.00	0.00
	27	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	4.90	12	0.69	0.00	0.00
	28	16	7.15	7.67	0.2	1.58	40	0.15	0.00	0.00	0.6	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	29	16	7.15	7.67	0.2	1.53	40	0.15	0.00	0.00	0.4	4.60	48	0.46	0.00	0.00	0.9	6.90	12	0.69	0.00	0.00
	30	17	7.60	8.15	0.2	1.68	40	0.16	0.00	0.00	0.6	4.89	48	0.49	0.00	0.00	0.9	7.33	12	0.73	0.00	0.00
	31	25	11.16	11.98	0.7	2.40	40	0.24	0.00	0.00	0.4	7.19	48	0.72	0.00	0.00	0.9	10.78	12	1.08	0.06	1.65
										0.00						36.01						976.43

IDEM

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: Patrick Coughlin
Duke Energy Indiana, Inc. - Cayuga Generating Stat
1000 E. Main St
Plainfield, IN 46168

DATE: September 5, 2012

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

SUBJECT: Final Decision
Title V
165-32045-00001

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:
R F Klopfstein, Responsible Official
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

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.

Mitchell E. Daniels Jr.
Governor

Thomas W. Easterly
Commissioner

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

TO: Newport Vermillion County Library

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

Subject: **Important Information for Display Regarding a Final Determination**

Applicant Name: Duke Energy Indiana -Cayuga
Permit Number: 165-32045-00001

You previously received information to make available to the public during the public comment period of a draft permit. Enclosed is a copy of the final decision and supporting materials for the same project. Please place the enclosed information along with the information you previously received. To ensure that your patrons have ample opportunity to review the enclosed permit, **we ask that you retain this document for at least 60 days.**

The applicant is responsible for placing a copy of the application in your library. If the permit application is not on file, or if you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185.

Enclosures
Final Library dot 11/30/07

Mail Code 61-53

IDEM Staff	DPABST 9/5/2012 Duke Energy Indiana, Inc. - Cayuga Generating Station 165-32045-00001 (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		Patrick Coughlin Duke Energy Indiana, Inc. - Cayuga Generating Stat 1000 E Main St Plainfield IN 46168 (Source CAATS) (CONFIRM DELIVERY)									
2		RF Klopfstein Station Mgr - Cayuga Gen Station Duke Energy Indiana, Inc. - Cayuga Generating Stat c/o P Coughlin, 1000 E Main St Plainfield IN 46168 *(RO CAATS)*									
3		Cayuga Town Council PO Box 33 Cayuga IN 47928 *(Local Official)*									
4		Vermillion County Health Department 257 Walnut Street Clinton IN 47842-2342 *(Health Department)*									
5		Newport Vermillion County Library P.O Box 100, 385 E. Market St Newport IN 47966-0100 *(Library)*									
6		Vermillion County Commissioners P.O. Box 190 Newport IN 47966 *(Local Official)*									
7		J.P. Roehm PO Box 303 Clinton IN 47842 *(Affected Party)*									
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FACSIMILIE OF PS Form 3877

CAC
IURC Cause No. 44217
Data Request Set No. 2
Received: October 29, 2012

CAC 2.11

Request:

Please see Duke Energy Indiana's responses to CAC 1.45 and CAC 1.47, where the Company explains that, while it did not assume specific details of the proposed lower ozone NAAQS, it did assume a 60-70 ppb 8-hour ozone standard would be finalized with a 2020 compliance timeframe; and see also Duke Indiana's prior response to OUCC 6.16, where the Company supports its decision to install SCRs at Cayuga to comply with MATS as a way of also positioning itself to meet the "reasonably anticipatable" upcoming revision of the 8-hour ozone NAAQS.

a. Please provide the analysis (including any air quality modeling that was performed) that led to the decision to install SCRs at Cayuga.
b. Did the Company analyze the use of SNCR at Cayuga, instead of SCR, to comply with the "reasonably anticipatable" upcoming 8-hour ozone standard?
    i. If so, please provide this analysis.
    ii. If not, please explain why not.
c. Please also explain whether the Company evaluated the use of SCR at Gallagher, instead of SNCR, for compliance with the "reasonably anticipatable" upcoming 8-hour ozone standard.
    i. If so, please provide this analysis.
    ii. If not, please explain why not.

Objection:

Duke Energy Indiana objects to this Request as vague and ambiguous, and the references to "the analysis" and "this analysis" are vague, ambiguous, overbroad, and unduly burdensome. Duke Energy Indiana also objects to subpart (a) of this Request as confusing and duplicative of prior discovery requests that have already sought the Company's modeling and analyses relating to this proceeding.

Response:

Subject to and without waiving the foregoing general and specific objections, Duke Energy Indiana states as follows:

a. "The analysis that led to the decision to install SCRs at Cayuga" is that presented in support of the Company's Phase 2 Environmental Compliance Plan at issue in this proceeding. Therefore, please see the direct testimony as filed and data request responses provided by Duke Energy Indiana in this proceeding.

b. No.
   i. N/A
   ii. Please see Duke Energy Indiana's prior response to OUCC 9.13.

c. Yes, Duke Energy Indiana included the application of SCR technology at Gallagher Station in the Engineering Screening Analysis.
   i. Please see Duke Energy Indiana's prior response to CAC 1.62.
   ii. N/A

Witness: Joseph A. Miller, Jr.

CAC
IURC Cause No. 44217
Data Request Set No. 2
Received: October 29, 2012

CAC 2.23

Request:

Please refer to page 12, lines 4-23 of the Direct Testimony of Robert Fleck.

a. Was the Aurora model used stochastically to determine wholesale power prices?
    i. If yes, please provide any and all correlations between variables that drive the outcome, i.e. demand, coal prices, natural gas prices, CO2 prices, etc.
    ii. If yes, how was the "fundamental forecast" determined from the range of outcomes generated by Aurora? For example, is the fundamental forecast the average of all the outcomes? The median?
b. How were the energy and peak demand inputs to Aurora determined?

Response:

a. No. Aurora was used deterministically to derive marginal energy prices.

b. Wood Mackenzie utilizes a proprietary econometric (top down) electric sector demand forecasting model, which builds off of historical demand patterns and incorporates forward looking assumptions about GDP growth, as well as observable trends like declining electric intensity and increasing investments in energy efficiency.

Witness: Robert W. Fleck

CAC
IURC Cause No. 44217
Data Request Set No. 2
Received: October 29, 2012

CAC 2.25

Request:

Please refer to page 20, lines 6-12 of the Direct Testimony of Robert Fleck.

a. Please explain the methodology by which the projection of 5.1 GW of coal-fired generation coming online between 2012 and 2015 was derived.
b. Please provide the names of the units and their associated capacities that Wood Mackenzie expects to come online in East North Central between 2012 and 2015, totaling 1.4 GW.
c. Please explain the methodology by which the projection of 49.3 GW of coal-fired generation retiring by 2016 was derived.
d. Please provide the names of the units and their associated capacities that Wood Mackenzie expects to retire by 2016, totaling 49.3 GW.
e. Please explain the methodology by which the projection of 57.9 GW of coal-fired generation retiring between 2010 and 2030 was derived.
f. Please provide the names of the units and their associated capacities that Wood Mackenzie expects to retire between 2010 and 2030, totaling 57.9 GW.
g. Were any of Duke Indiana's units included in the retirement projections?
    i. If so, please identify those units.

Response:

a. Wood Mackenzie tracks a list of new generation projects under development and then makes a determination of which projects will be completed and entered into commercial operation.

b. Edwardsport (600 MW) and Unit 2 at Prairie State Energy Campus (800 MW).

c. Wood Mackenzie evaluates the economic viability of each coal unit using several criteria. Wood Mackenzie applies an equipment based standard to determine whether a unit is in compliance with current and projected EPA rules. That requisite suite of emissions controls which would satisfy the emissions requirements varies based on existing controls size of the plant. Next, a cash flow model is developed to assess the economic viability of each unit including the new capital required for environmental compliance. Other factors such as unit age, efficiency, or whether other surviving units are located at the same station are also taken into account and a list of candidates is developed. Some final adjustments are made based on announced plans from the generation owners and whether the unit is needed for grid reliability.

d. See Attachment CAC 2.25-A.

e. Same process as outlined in the response to (c) above.

f. See Attachment CAC 2.25-B.

g. Yes. Gallagher Units 1 & 3 and Wabash River Unit 6.

Witness: Robert W. Fleck

ATTACHMENT CAC 2.25-A

PLANT	FUEL	NET_MW	CLOSEYEAR
Dubuque	COAL	36.8	2013
Milton L Kapp	COAL	212.4	2015
AES Thames	COAL	164.34	2012
Prairie Creek	COAL	0.3	2015
Prairie Creek	COAL	45.5	2015
Prairie Creek	COAL	143.7	2015
Sutherland	COAL	79.4	2015
Southampton Power Station	COAL	63	2013
Riverside	COAL	130	2015
Council Bluffs	COAL	88	2015
Greene County	COAL	243	2015
R Gallagher	COAL	140	2012
R Gallagher	COAL	140	2012
R Gallagher	COAL	140	2012
Wabash River	COAL	318	2015
Frank E Ratts	COAL	122	2015
Frank E Ratts	COAL	123	2015
Dubuque	COAL	28.6	2013
Ames Electric Services Power Plant	COAL	33	2015
Ames Electric Services Power Plant	COAL	70	2015
Fair Station	COAL	23.4	2015
Fair Station	COAL	41	2015
Riverton	COAL	38	2015
Riverton	COAL	54	2015
Tecumseh Energy Center	COAL	74	2015
Tecumseh Energy Center	COAL	130	2015
Big Sandy	COAL	260	2015
Shawnee	COAL	133	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Dale	COAL	23	2015
Dale	COAL	23	2015
Dale	COAL	74	2015
Dale	COAL	75	2015
C P Crane	COAL	190	2015
C P Crane	COAL	195	2015
R Paul Smith Power Station	COAL	87	2015
R Paul Smith Power Station	COAL	28	2015
Mount Tom	COAL	143.6	2015
Salem Harbor	COAL	82	2012
Salem Harbor	COAL	80	2012
Salem Harbor	COAL	149.8	2014

J R Whiting	COAL	102	2015
J R Whiting	COAL	102	2015
J R Whiting	COAL	124	2015
Harbor Beach	COAL	103	2015
River Rouge	COAL	251	2015
River Rouge	COAL	272	2015
St Clair	COAL	151	2015
St Clair	COAL	154	2015
St Clair	COAL	151	2015
Trenton Channel	COAL	110	2015
Trenton Channel	COAL	100	2015
Trenton Channel	COAL	520	2015
Presque Isle	COAL	88	2015
Presque Isle	COAL	88	2015
Presque Isle	COAL	85	2015
Presque Isle	COAL	85	2015
Presque Isle	COAL	85	2015
J B Sims	COAL	10	2014
J B Sims	COAL	72.7	2014
James De Young	COAL	20.5	2015
James De Young	COAL	27	2015
Eckert Station	COAL	38.7	2015
Eckert Station	COAL	40	2015
Eckert Station	COAL	38.5	2015
Eckert Station	COAL	66.5	2015
Eckert Station	COAL	67.6	2015
Eckert Station	COAL	64.8	2015
Erickson Station	COAL	153	2015
Shiras	COAL	11.6	2015
Shiras	COAL	19.5	2015
Shiras	COAL	41	2015
Wyandotte	COAL	10.5	2015
Wyandotte	COAL	22	2015
Wyandotte	COAL	7.5	2015
Wyandotte	COAL	32	2015
Syl Laskin	COAL	55	2015
Syl Laskin	COAL	55	2015
Clay Boswell	COAL	69	2015
Clay Boswell	COAL	69	2015
Black Dog	COAL	175	2013
Hoot Lake	COAL	7.5	2015
Hoot Lake	COAL	59.9	2015
Hoot Lake	COAL	84	2015
Austin Northeast	COAL	29.3	2012
Silver Lake	COAL	24.3	2014
Silver Lake	COAL	58.7	2014
Jack Watson	COAL	230	2015
Jack Watson	COAL	476	2015
Asbury	COAL	193	2015
Asbury	COAL	17	2015
Montrose	COAL	170	2015
Montrose	COAL	164	2015

Montrose	COAL	176	2015
Sibley	COAL	53 8	2015
Sibley	COAL	53.9	2015
Lake Road	COAL	97.4	2015
Blue Valley	COAL	93	2013
James River Power Station	COAL	21	2015
James River Power Station	COAL	21	2015
James River Power Station	COAL	41	2015
James River Power Station	COAL	56	2015
New Madrid	COAL	580	2015
New Madrid	COAL	580	2015
Chamois	COAL	17	2015
Chamois	COAL	49	2015
Lon Wright	COAL	15	2014
Lon Wright	COAL	20	2014
Lon Wright	COAL	85	2015
Sheldon	COAL	105	2015
Sheldon	COAL	120	2015
North Omaha	COAL	78.6	2015
North Omaha	COAL	111	2015
North Omaha	COAL	111	2015
North Omaha	COAL	138.2	2015
North Omaha	COAL	224	2015
Schiller	COAL	47.5	2015
Schiller	COAL	47.9	2015
B L England	COAL	113	2015
B L England	COAL	151	2015
Danskammer Generating Station	COAL	232.2	2015
C R Huntley Generating Station	COAL	80	2015
Dunkirk Generating Station	COAL	185	2015
Dunkirk Generating Station	COAL	185	2015
E C Gaston	COAL	254	2015
E C Gaston	COAL	256	2015
S A Carlson	COAL	22.5	2015
S A Carlson	COAL	22.5	2015
Cape Fear	COAL	144	2015
Cape Fear	COAL	173	2015
Lee	COAL	77	2013
Lee	COAL	77	2013
Lee	COAL	252	2013
L V Sutton	COAL	97	2013
L V Sutton	COAL	106	2013
L V Sutton	COAL	403	2013
W H Weatherspoon	COAL	49	2012
W H Weatherspoon	COAL	49	2012
W H Weatherspoon	COAL	79	2012
Buck	COAL	128	2015
Buck	COAL	128	2015
Cliffside	COAL	38	2012
Cliffside	COAL	38	2012
Cliffside	COAL	61	2012
Cliffside	COAL	61	2012

Dan River	COAL	67	2012
Dan River	COAL	67	2012
Dan River	COAL	142	2013
Riverbend	COAL	94	2015
Riverbend	COAL	94	2015
Riverbend	COAL	133	2015
Riverbend	COAL	133	2015
R M Heskett	COAL	29.4	2015
R M Heskett	COAL	73.5	2015
Walter C Beckjord	COAL	94	2015
Walter C Beckjord	COAL	94	2015
Walter C Beckjord	COAL	128	2015
Walter C Beckjord	COAL	150	2015
Walter C Beckjord	COAL	238	2015
Walter C Beckjord	COAL	414	2015
Miami Fort	COAL	163	2015
Avon Lake	COAL	92	2014
Eastlake	COAL	132	2014
Eastlake	COAL	240	2014
Eastlake	COAL	597	2014
Conesville	COAL	165	2013
Picway	COAL	95	2015
O H Hutchings	COAL	50	2014
O H Hutchings	COAL	48	2014
O H Hutchings	COAL	60	2014
O H Hutchings	COAL	61	2014
O H Hutchings	COAL	60	2015
O H Hutchings	COAL	57	2015
Niles	COAL	108	2015
Niles	COAL	108	2015
R E Burger	COAL	94	2015
Muskingum River	COAL	190	2015
Muskingum River	COAL	190	2015
Muskingum River	COAL	205	2015
Muskingum River	COAL	205	2015
Hamilton	COAL	25	2015
Hamilton	COAL	51	2014
Orrville	COAL	33	2014
Painesville	COAL	47	2014
Muskogee	COAL	517.3	2015
Muskogee	COAL	515	2015
Barry	COAL	138	2015
Barry	COAL	137	2015
Barry	COAL	249	2015
Barry	COAL	362	2015
Elrama Power Plant	COAL	97	2014
Elrama Power Plant	COAL	97	2014
Elrama Power Plant	COAL	109	2014
Elrama Power Plant	COAL	171	2014
Portland	COAL	158	2015
Portland	COAL	243	2015
Titus	COAL	81	2015

Titus	COAL	81	2015
Titus	COAL	81	2015
Homer City Station	COAL	620	2015
Homer City Station	COAL	614	2015
Shawville	COAL	122	2015
Shawville	COAL	125	2015
Shawville	COAL	175	2015
Shawville	COAL	175	2015
New Castle Plant	COAL	98	2014
New Castle Plant	COAL	98	2014
New Castle Plant	COAL	137	2014
Eddystone Generating Station	COAL	309	2012
Armstrong Power Station	COAL	172	2014
Armstrong Power Station	COAL	172	2014
H B Robinson	COAL	180	2014
W S Lee	COAL	100	2015
W S Lee	COAL	100	2015
W S Lee	COAL	170	2015
Canadys Steam	COAL	105	2014
Canadys Steam	COAL	116	2014
Canadys Steam	COAL	175	2014
Dolphus M Grainger	COAL	85	2015
Dolphus M Grainger	COAL	85	2015
Jefferies	COAL	153	2014
Jefferies	COAL	153	2014
Ben French	COAL	21.6	2014
John Sevier	COAL	176	2012
John Sevier	COAL	176	2013
John Sevier	COAL	176	2013
John Sevier	COAL	176	2013
Johnsonville	COAL	106	2012
Johnsonville	COAL	106	2013
Johnsonville	COAL	106	2013
Johnsonville	COAL	106	2014
Johnsonville	COAL	106	2015
Carbon	COAL	67	2015
Carbon	COAL	105	2015
Clinch River	COAL	230	2015
Clinch River	COAL	230	2015
Clinch River	COAL	230	2015
Glen Lyn	COAL	90	2015
Glen Lyn	COAL	235	2015
Potomac River	COAL	88	2013
Potomac River	COAL	88	2013
Potomac River	COAL	102	2013
Indian River Generating Station	COAL	165	2014
Potomac River	COAL	102	2013
Potomac River	COAL	102	2013
Bremo Bluff	COAL	71	2015
Bremo Bluff	COAL	156	2015
Chesapeake	COAL	111	2015
Chesapeake	COAL	111	2015

Yorktown	COAL	159	2015
Kanawha River	COAL	200	2015
Kanawha River	COAL	200	2015
Philip Sporn	COAL	145	2015
Philip Sporn	COAL	145	2015
Philip Sporn	COAL	145	2015
Philip Sporn	COAL	145	2015
Albright	COAL	73	2014
Albright	COAL	73	2014
Albright	COAL	137	2015
Rivesville	COAL	46	2014
Rivesville	COAL	91	2014
Willow Island	COAL	54	2015
Willow Island	COAL	181	2015
Kammer	COAL	200	2015
Kammer	COAL	200	2015
Kammer	COAL	200	2015
Blount Street	COAL	6.8	2012
Blount Street	COAL	39.2	2012
Blount Street	COAL	22.4	2012
Valley	COAL	133.5	2014
Valley	COAL	133.5	2013
Edgewater	COAL	75.5	2015
Edgewater	COAL	319.5	2015
Nelson Dewey	COAL	112	2015
Nelson Dewey	COAL	111.2	2015
Pulliam	COAL	50.6	2015
Pulliam	COAL	69	2015
Pulliam	COAL	80.9	2015
Pulliam	COAL	127.5	2015
Weston	COAL	60.9	2015
Weston	COAL	80.6	2015
Alma	COAL	19.2	2015
Alma	COAL	19.1	2015
Alma	COAL	18.1	2015
Alma	COAL	51	2015
Alma	COAL	76.9	2015
Endicott Station	COAL	50	2014
W N Clark	COAL	42.5	2014
Arapahoe	COAL	44	2014
Arapahoe	COAL	109	2014
Cherokee	COAL	107	2012
Cherokee	COAL	106	2012
Colbert	COAL	177	2015
Colbert	COAL	177	2015
Colbert	COAL	177	2015
Colbert	COAL	173	2015
Martin Drake	COAL	46	2015
Martin Drake	COAL	77	2015
Martin Drake	COAL	131	2015
Widows Creek	COAL	111	2013
Widows Creek	COAL	111	2014

Widows Creek	COAL	111	2015
Cogentrix of Richmond	COAL	190	2014
Mt Poso Cogeneration	COAL	46.24	2012
McIntosh	COAL	156.5	2015
Welsh	COAL	528	2015
Monticello	COAL	565	2015
Monticello	COAL	565	2015
Rodemacher	COAL	517	2015
Pearl Station	COAL	22	2015
Crystal River	COAL	372	2014
Crystal River	COAL	494	2014
Scholz	COAL	46	2013
Scholz	COAL	46	2013
Lansing Smith	COAL	162	2015
Lansing Smith	COAL	195	2015
Gadsden	COAL	64	2015
Gadsden	COAL	66	2015
Hammond	COAL	112	2015
Hammond	COAL	112	2015
Hammond	COAL	112	2015
Harllee Branch	COAL	266	2014
Harllee Branch	COAL	325	2014
Harllee Branch	COAL	509	2015
Harllee Branch	COAL	507	2015
Jack McDonough	COAL	517	2012
Mitchell	COAL	155	2013
Yates	COAL	99	2013
Yates	COAL	105	2013
Yates	COAL	112	2013
Yates	COAL	135	2013
Yates	COAL	137	2013
Yates	COAL	352	2015
Kraft	COAL	52	2015
Kraft	COAL	101	2015
Kraft	COAL	115	2015
Kraft	COAL	48	2015
Gorgas	COAL	108	2015
Gorgas	COAL	109	2015
Ray D Nixon	COAL	208	2015
E D Edwards	COAL	107	2013
Hutsonville	COAL	75	2015
Hutsonville	COAL	75	2015
Meredosia	COAL	203	2015
Hennepin Power Station	COAL	67	2013
Hennepin Power Station	COAL	215	2014
Vermilion	COAL	99	2013
Vermilion	COAL	64	2013
Wood River	COAL	82	2014
State Line Energy	COAL	197	2012
State Line Energy	COAL	318	2012
Tanners Creek	COAL	145	2015
Tanners Creek	COAL	145	2015

Tanners Creek	COAL	200	2015
Harding Street	COAL	106	2015
Harding Street	COAL	106	2015
Eagle Valley	COAL	62	2015
Eagle Valley	COAL	99	2015
ECAR_CIN_OH_COG	COAL	15.78	2012
ECAR_FE_OH_COG	COAL	14	2012
MAAC_PJMC_PA	COAL	4.2	2014
MAAC_PJME_DE	COAL	11.43	2012
Perry K	COAL	10.23	2012
Riverside (IA)	COAL	5	2014
SERC_PJMW_VP_VA	COAL	4.21	2012

ATTACHMENT CAC 2.25-B

PLANT	FUEL	NET_MW	CLOSEYEAR
Dubuque	COAL	36.8	2013
Milton L Kapp	COAL	212.4	2015
AES Thames	COAL	164.34	2012
Prairie Creek	COAL	0.3	2015
Prairie Creek	COAL	45.5	2015
Prairie Creek	COAL	143.7	2015
Sutherland	COAL	31.1	2016
Sutherland	COAL	79.4	2015
Southampton Power Station	COAL	63	2013
Riverside	COAL	130	2015
Council Bluffs	COAL	88	2015
George Neal North	COAL	515	2027
Greene County	COAL	243	2015
R Gallagher	COAL	140	2012
R Gallagher	COAL	140	2012
R Gallagher	COAL	140	2012
Wabash River	COAL	318	2015
Frank E Ratts	COAL	122	2015
Frank E Ratts	COAL	123	2015
Dubuque	COAL	28.6	2013
Burlington	COAL	191.9	2024
Ames Electric Services Power Plant	COAL	33	2015
Ames Electric Services Power Plant	COAL	70	2015
Fair Station	COAL	23.4	2015
Fair Station	COAL	41	2015
Riverton	COAL	38	2015
Riverton	COAL	54	2015
Tecumseh Energy Center	COAL	74	2015
Tecumseh Energy Center	COAL	130	2015
Quindaro	COAL	72	2026
Big Sandy	COAL	260	2015
Green River	COAL	68	2016
Green River	COAL	95	2016
Tyrone	COAL	71	2016
Cane Run	COAL	155	2016
Cane Run	COAL	168	2016
Cane Run	COAL	240	2016
Shawnee	COAL	133	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Shawnee	COAL	134	2015
Dale	COAL	23	2015
Dale	COAL	23	2015

Dale	COAL	74	2015
Dale	COAL	75	2015
C P Crane	COAL	190	2015
C P Crane	COAL	195	2015
R Paul Smith Power Station	COAL	87	2015
R Paul Smith Power Station	COAL	28	2015
Mount Tom	COAL	143.6	2015
Salem Harbor	COAL	82	2012
Salem Harbor	COAL	80	2012
Salem Harbor	COAL	149.8	2014
B C Cobb	COAL	156	2016
B C Cobb	COAL	156	2016
J C Weadock	COAL	155	2018
J C Weadock	COAL	151	2016
J R Whiting	COAL	102	2015
J R Whiting	COAL	102	2015
J R Whiting	COAL	124	2015
Harbor Beach	COAL	103	2015
River Rouge	COAL	251	2015
River Rouge	COAL	272	2015
St Clair	COAL	151	2015
St Clair	COAL	154	2015
St Clair	COAL	151	2015
Trenton Channel	COAL	110	2015
Trenton Channel	COAL	100	2015
Trenton Channel	COAL	520	2015
Presque Isle	COAL	88	2015
Presque Isle	COAL	88	2015
Presque Isle	COAL	85	2015
Presque Isle	COAL	85	2015
Presque Isle	COAL	85	2015
J B Sims	COAL	10	2014
J B Sims	COAL	72.7	2014
James De Young	COAL	10.5	2022
James De Young	COAL	20.5	2015
James De Young	COAL	27	2015
Eckert Station	COAL	38.7	2015
Eckert Station	COAL	40	2015
Eckert Station	COAL	38.5	2015
Eckert Station	COAL	66.5	2015
Eckert Station	COAL	67.6	2015
Eckert Station	COAL	64.8	2015
Erickson Station	COAL	153	2015
Shiras	COAL	11.6	2015
Shiras	COAL	19.5	2015
Shiras	COAL	41	2015
Wyandotte	COAL	10.5	2015
Wyandotte	COAL	22	2015
Wyandotte	COAL	7.5	2015
Wyandotte	COAL	32	2015
Syl Laskin	COAL	55	2015
Syl Laskin	COAL	55	2015

Clay Boswell	COAL	69	2015
Clay Boswell	COAL	69	2015
Black Dog	COAL	107	2016
Black Dog	COAL	175	2013
Hoot Lake	COAL	7.5	2015
Hoot Lake	COAL	59.9	2015
Hoot Lake	COAL	84	2015
Austin Northeast	COAL	29.3	2012
Silver Lake	COAL	24.3	2014
Silver Lake	COAL	58.7	2014
Jack Watson	COAL	230	2015
Jack Watson	COAL	476	2015
Asbury	COAL	193	2015
Asbury	COAL	17	2015
Montrose	COAL	170	2015
Montrose	COAL	164	2015
Montrose	COAL	176	2015
Sibley	COAL	53.8	2015
Sibley	COAL	53.9	2015
Lake Road	COAL	97.4	2015
Meramec	COAL	120	2022
Meramec	COAL	120	2022
Meramec	COAL	268	2022
Meramec	COAL	347	2022
Blue Valley	COAL	93	2013
James River Power Station	COAL	21	2015
James River Power Station	COAL	21	2015
James River Power Station	COAL	41	2015
James River Power Station	COAL	56	2015
New Madrid	COAL	580	2015
New Madrid	COAL	580	2015
Chamois	COAL	17	2015
Chamois	COAL	49	2015
Lon Wright	COAL	15	2014
Lon Wright	COAL	20	2014
Lon Wright	COAL	85	2015
Sheldon	COAL	105	2015
Sheldon	COAL	120	2015
North Omaha	COAL	78.6	2015
North Omaha	COAL	111	2015
North Omaha	COAL	111	2015
North Omaha	COAL	138.2	2015
North Omaha	COAL	224	2015
Schiller	COAL	47.5	2015
Schiller	COAL	47.9	2015
B L England	COAL	113	2015
B L England	COAL	151	2015
Four Corners	COAL	170	2017
Four Corners	COAL	170	2017
Four Corners	COAL	220	2017
Danskammer Generating Station	COAL	232.2	2015
C R Huntley Generating Station	COAL	80	2015

Dunkirk Generating Station	COAL	185	2015
Dunkirk Generating Station	COAL	185	2015
E C Gaston	COAL	254	2015
E C Gaston	COAL	256	2015
S A Carlson	COAL	22.5	2015
S A Carlson	COAL	22.5	2015
Cape Fear	COAL	144	2015
Cape Fear	COAL	173	2015
Lee	COAL	77	2013
Lee	COAL	77	2013
Lee	COAL	252	2013
L V Sutton	COAL	97	2013
L V Sutton	COAL	106	2013
L V Sutton	COAL	403	2013
W H Weatherspoon	COAL	49	2012
W H Weatherspoon	COAL	49	2012
W H Weatherspoon	COAL	79	2012
Buck	COAL	128	2015
Buck	COAL	128	2015
Cliffside	COAL	38	2012
Cliffside	COAL	38	2012
Cliffside	COAL	61	2012
Cliffside	COAL	61	2012
Dan River	COAL	67	2012
Dan River	COAL	67	2012
Dan River	COAL	142	2013
Riverbend	COAL	94	2015
Riverbend	COAL	94	2015
Riverbend	COAL	133	2015
Riverbend	COAL	133	2015
R M Heskett	COAL	29.4	2015
R M Heskett	COAL	73.5	2015
Walter C Beckjord	COAL	94	2015
Walter C Beckjord	COAL	94	2015
Walter C Beckjord	COAL	128	2015
Walter C Beckjord	COAL	150	2015
Walter C Beckjord	COAL	238	2015
Walter C Beckjord	COAL	414	2015
Miami Fort	COAL	163	2015
Avon Lake	COAL	92	2014
Eastlake	COAL	132	2014
Eastlake	COAL	240	2014
Eastlake	COAL	597	2014
Conesville	COAL	165	2013
Picway	COAL	95	2015
O H Hutchings	COAL	50	2014
O H Hutchings	COAL	48	2014
O H Hutchings	COAL	60	2014
O H Hutchings	COAL	61	2014
O H Hutchings	COAL	60	2015
O H Hutchings	COAL	57	2015
Niles	COAL	108	2015

Niles	COAL	108	2015
R E Burger	COAL	94	2015
Muskingum River	COAL	190	2015
Muskingum River	COAL	190	2015
Muskingum River	COAL	205	2015
Muskingum River	COAL	205	2015
Hamilton	COAL	25	2015
Hamilton	COAL	51	2014
Orrville	COAL	33	2014
Painesville	COAL	47	2014
Muskogee	COAL	517.3	2015
Muskogee	COAL	515	2015
Barry	COAL	138	2015
Barry	COAL	137	2015
Barry	COAL	249	2015
Barry	COAL	362	2015
Elrama Power Plant	COAL	97	2014
Elrama Power Plant	COAL	97	2014
Elrama Power Plant	COAL	109	2014
Elrama Power Plant	COAL	171	2014
Portland	COAL	158	2015
Portland	COAL	243	2015
Titus	COAL	81	2015
Titus	COAL	81	2015
Titus	COAL	81	2015
Homer City Station	COAL	620	2015
Homer City Station	COAL	614	2015
Shawville	COAL	122	2015
Shawville	COAL	125	2015
Shawville	COAL	175	2015
Shawville	COAL	175	2015
New Castle Plant	COAL	98	2014
New Castle Plant	COAL	98	2014
New Castle Plant	COAL	137	2014
Eddystone Generating Station	COAL	309	2012
Armstrong Power Station	COAL	172	2014
Armstrong Power Station	COAL	172	2014
H B Robinson	COAL	180	2014
W S Lee	COAL	100	2015
W S Lee	COAL	100	2015
W S Lee	COAL	170	2015
Canadys Steam	COAL	105	2014
Canadys Steam	COAL	116	2014
Canadys Steam	COAL	175	2014
Dolphus M Grainger	COAL	85	2015
Dolphus M Grainger	COAL	85	2015
Jefferies	COAL	153	2014
Jefferies	COAL	153	2014
Ben French	COAL	21.6	2014
John Sevier	COAL	176	2012
John Sevier	COAL	176	2013
John Sevier	COAL	176	2013

John Sevier	COAL	176	2013
Johnsonville	COAL	106	2012
Johnsonville	COAL	141	2018
Johnsonville	COAL	106	2013
Johnsonville	COAL	106	2013
Johnsonville	COAL	106	2014
Johnsonville	COAL	106	2015
Johnsonville	COAL	106	2016
Johnsonville	COAL	141	2016
Johnsonville	COAL	141	2016
Johnsonville	COAL	141	2018
Carbon	COAL	67	2015
Carbon	COAL	105	2015
Clinch River	COAL	230	2015
Clinch River	COAL	230	2015
Clinch River	COAL	230	2015
Glen Lyn	COAL	90	2015
Glen Lyn	COAL	235	2015
Potomac River	COAL	88	2013
Potomac River	COAL	88	2013
Potomac River	COAL	102	2013
Indian River Generating Station	COAL	165	2014
Potomac River	COAL	102	2013
Potomac River	COAL	102	2013
Bremo Bluff	COAL	71	2015
Bremo Bluff	COAL	156	2015
Chesapeake	COAL	156	2016
Chesapeake	COAL	111	2015
Chesapeake	COAL	111	2015
Chesapeake	COAL	217	2016
Yorktown	COAL	159	2015
Transalta Centralia Generation	COAL	702.5	2021
Transalta Centralia Generation	COAL	702.5	2026
Kanawha River	COAL	200	2015
Kanawha River	COAL	200	2015
Philip Spom	COAL	145	2015
Philip Spom	COAL	145	2015
Philip Spom	COAL	145	2015
Philip Spom	COAL	145	2015
Albright	COAL	73	2014
Albright	COAL	73	2014
Albright	COAL	137	2015
Rivesville	COAL	46	2014
Rivesville	COAL	91	2014
Willow Island	COAL	54	2015
Willow Island	COAL	181	2015
Kammer	COAL	200	2015
Kammer	COAL	200	2015
Kammer	COAL	200	2015
Blount Street	COAL	6.8	2012
Blount Street	COAL	39.2	2012
Blount Street	COAL	22.4	2012

Valley	COAL	133.5	2014
Valley	COAL	133.5	2013
Edgewater	COAL	75.5	2015
Edgewater	COAL	319.5	2015
Nelson Dewey	COAL	112	2015
Nelson Dewey	COAL	111.2	2015
Pulliam	COAL	50.6	2015
Pulliam	COAL	69	2015
Pulliam	COAL	80.9	2015
Pulliam	COAL	127.5	2015
Weston	COAL	60.9	2015
Weston	COAL	80.6	2015
Alma	COAL	19.2	2015
Alma	COAL	19.1	2015
Alma	COAL	18.1	2015
Alma	COAL	51	2015
Alma	COAL	76.9	2015
E J Stoneman Station	COAL	15	2023
Endicott Station	COAL	50	2014
W N Clark	COAL	42.5	2014
Arapahoe	COAL	44	2014
Arapahoe	COAL	109	2014
Cherokee	COAL	107	2012
Cherokee	COAL	106	2012
Cherokee	COAL	152	2016
Cherokee	COAL	352	2018
Colbert	COAL	177	2015
Colbert	COAL	177	2015
Colbert	COAL	177	2015
Colbert	COAL	173	2015
Valmont	COAL	186	2018
Martin Drake	COAL	46	2015
Martin Drake	COAL	77	2015
Martin Drake	COAL	131	2015
Widows Creek	COAL	111	2013
Widows Creek	COAL	111	2014
Widows Creek	COAL	111	2015
Widows Creek	COAL	111	2016
Cogentrix of Richmond	COAL	190	2014
Mt Poso Cogeneration	COAL	46.24	2012
Boardman	COAL	585	2021
McIntosh	COAL	156.5	2015
Welsh	COAL	528	2015
Monticello	COAL	565	2015
Monticello	COAL	565	2015
J T Deely	COAL	385	2018
J T Deely	COAL	440	2018
Rodemacher	COAL	517	2015
Pearl Station	COAL	22	2015
Crystal River	COAL	372	2014
Crystal River	COAL	494	2014
Scholz	COAL	46	2013

Scholz	COAL	46	2013
Lansing Smith	COAL	162	2015
Lansing Smith	COAL	195	2015
Gadsden	COAL	64	2015
Gadsden	COAL	66	2015
Hammond	COAL	112	2015
Hammond	COAL	112	2015
Hammond	COAL	112	2015
Harllee Branch	COAL	266	2014
Harllee Branch	COAL	325	2014
Harllee Branch	COAL	509	2015
Harllee Branch	COAL	507	2015
Jack McDonough	COAL	517	2012
Mitchell	COAL	155	2013
Yates	COAL	99	2013
Yates	COAL	105	2013
Yates	COAL	112	2013
Yates	COAL	135	2013
Yates	COAL	137	2013
Yates	COAL	352	2015
Kraft	COAL	52	2015
Kraft	COAL	101	2015
Kraft	COAL	115	2015
Kraft	COAL	48	2015
Gorgas	COAL	108	2015
Gorgas	COAL	109	2015
Ray D Nixon	COAL	208	2015
E D Edwards	COAL	107	2013
Hutsonville	COAL	75	2015
Hutsonville	COAL	75	2015
Meredosia	COAL	203	2015
Hennepin Power Station	COAL	67	2013
Hennepin Power Station	COAL	215	2014
Vermilion	COAL	99	2013
Vermilion	COAL	64	2013
Wood River	COAL	82	2014
State Line Energy	COAL	197	2012
State Line Energy	COAL	318	2012
Tanners Creek	COAL	145	2015
Tanners Creek	COAL	145	2015
Tanners Creek	COAL	200	2015
Harding Street	COAL	106	2015
Harding Street	COAL	106	2015
Eagle Valley	COAL	43	2019
Eagle Valley	COAL	56	2019
Eagle Valley	COAL	62	2015
Eagle Valley	COAL	99	2015
ECAR_CIN_OH_COG	COAL	15.78	2012
ECAR_FE_OH_COG	COAL	14	2012
ECAR_MECS_MT_MI_COG	COAL	8	2026
MAAC_PJMC_PA	COAL	4.2	2014
MAAC_PJME_DE	COAL	11.43	2012

MAAC_PJMNW_PA	COAL	9.74	2026
MAIN_ALTW_IA	COAL	29	2022
MAIN_NI_IL	COAL	1.85	2022
MAIN_SMAIN_MO	COAL	2	2018
MAPP_US_E_MI	COAL	1.58	2021
MAPP_US_E_WI	COAL	5	2018
Perry K	COAL	10.23	2012
Riverside (IA)	COAL	5	2014
SERC_PJMW_VP_VA	COAL	4.21	2012
SERC_SOU_GA	COAL	5.5	2020
SERC_TVA_TN	COAL	11	2017
SERC_VACAR_NC	COAL	4	2017

OUCC
IURC Cause No. 44217
Data Request Set No. 7
Received: October 3, 2012

OUCC 7.2

Request:

Please provide the estimated useful life, in number of years, of the individual environmental control equipment (i.e. SCR, DSI and ACI systems) for each of the generating units in Cayuga, Gibson and Gallagher facilities.

Response:

Based on the Company's most recent depreciation study, as filed in Cause No. 43114 IGCC 4S1, the estimated retirement dates for the specific units that the environmental equipment will be installed on are as follows:

- Cayuga Unit 1 2035
- Cayuga Unit 2 2037
- Gibson Unit 1 2041
- Gibson Unit 2 2040
- Gibson Unit 3 2043
- Gibson Unit 4 2044
- Gibson Unit 5 2047
- Gallagher Unit 2 2023
- Gallagher Unit 4 2026

The environmental control equipment proposed in this proceeding is expected to last until the units are retired.

Witness: Kent Freeman / Joseph A. Miller, Jr.

TESTIMONY OF ROBERT W. FLECK
VICE PRESIDENT OF GAS AND POWER CONSULTING, AMERICAS
WOOD MACKENZIE, INC.
ON BEHALF OF DUKE ENERGY INDIANA, INC.
CAUSE NO. 44217 BEFORE THE
INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert W. Fleck and my business address is 5847 San Felipe, Suite 1000, Houston, TX 77057.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Wood Mackenzie, Inc. as the Vice President of Gas and Power Consulting, Americas.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I graduated from the University of Massachusetts in 1974 with a BA in education. After 8 years in education, I entered the natural gas industry via employment at Commonwealth Gas Company, a local distribution company in Massachusetts.

I have nearly 30 years' experience in the US natural gas markets, North American energy markets and industry strategy. Prior to joining Wood Mackenzie, I was a Director with the Cambridge Energy Research Associates where I analyzed North American gas market trends, including liquefied natural gas ("LNG") market development. I also spent three years in the retail energy business in the Northeast and 15 years with Commonwealth Gas Company of Cambridge, Massachusetts (now NStar) in the gas supply and regulatory department. As part of my responsibilities in the gas supply and regulatory department, I was responsible for the Commonwealth Gas Company's gas price forecasts and our IRP filings with the Massachusetts regulators. I also became active in federal regulatory proceedings that involved our various pipeline contracts. This lead to my being involved in the restructuring proceedings at the Federal Energy Regulatory Commission ("FERC") during the FERC Orders 436/636 era, resulting in major changes in the regulation of interstate pipelines, and was a founding member of the executive committee for the Gas Industry Standards Board. During the 1988 to 1996 timeframe, my primary responsibilities in the proceedings at the FERC included representing the New England pipeline customers and, along with legal counsel, undertaking the review and negotiation of interstate pipeline tariffs, including cost of service, rates of return, depreciation, operating costs and the resulting rates for use on the pipelines, as well as general terms and conditions for utilizing pipeline services.

Q. **HAVE YOU TESTIFIED BEFORE ANY OTHER REGULATORY BODIES?**

A. Yes, I have testified before the FERC, the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the US Department of Energy, and I am currently sponsoring testimony before the National Energy Board of Canada. I have also provided evidence in many other proceedings across the US and Canada.

Q. **FOR WHOM ARE YOU PROVIDING TESTIMONY?**

A. I am providing testimony on behalf of Duke Energy Indiana, Inc. ("Duke Energy Indiana").

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?**

A. The purpose of my testimony is to describe the process used by Wood Mackenzie to develop its long-term price forecasts for natural gas, power, and coal in the North America markets, and to describe how those processes were utilized in the development of the forecast supplied to Duke Energy ("Duke Fundamental Forecast") used in this filing.

II. WOOD MACKENZIE'S FORECASTING EXPERIENCE IN THE NORTH AMERICAN ENERGY INDUSTRY

Q. PLEASE DESCRIBE WOOD MACKENZIE'S FORECASTING EXPERTISE IN THE NORTH AMERICAN ENERGY INDUSTRY.

A. Wood Mackenzie is a global energy research and consulting company with headquarters located in Edinburgh, Scotland. We have key offices in London, Boston, Houston, Annapolis, New York, Calgary, Sidney, Singapore and Beijing. Wood Mackenzie has studied the energy business for nearly 40 years, providing research and consulting to every major energy company in the world. Individual members of our North American gas and power teams have 20 to 30-plus years of experience in the industry. The North American coal team is essentially the former Hill & Associates team, which was acquired by Wood Mackenzie in 2007. On its own and as part of Wood Mackenzie, Hill & Associates has been evaluating the North American coal industry and providing forecasts of coal prices since 1981.

Our gas, coal and power forecasts have been, and continue to be, used by many utilities, pipelines, and coal companies throughout the United States and Canada, as well as by the major oil and gas companies of the world. In addition, many small to medium sized producers, governments, regulators and banks rely on Wood Mackenzie forecasts for investment and due diligence purposes, resource and infrastructure investment such as LNG regasification and liquefaction, pipeline acquisitions and investments, coal mine acquisition and development, and power plant generation acquisitions and investments. We have specialized research teams who analyze the North American natural gas, power and coal markets, the global natural gas and coal markets, and the global LNG value chain (which impacts the North American gas markets) in support of our subscription research products. Our long term forecasts are updated every six months and published to our client subscribers to incorporate the ever-changing energy markets environment.

Q. PLEASE NAME SOME OTHER CLIENTS OF WOOD MACKENZIE THAT RELY ON YOUR NATURAL GAS, POWER, AND COAL FORECASTS.

A. Wood Mackenzie advises many of the world's major energy companies, including Exxon/Mobil, Chevron, BP, Shell, BG, Nexen, Qatar Petroleum, PETRONAS, PEMEX, CFE, TransCanada, Williams, El Paso Corporation, Mid American Energy, Xcel Energy, CenterPoint Energy, Northeast Utilities, Pacific Gas and Electric, Sempra, Peabody Energy, Arch Coal, Alpha Natural Resources, BHP Billiton, Anglo American and Teck Resources. We also advise several regulatory bodies, including the Alberta Department of Energy, the Department of Natural Resources for Newfoundland and Labrador, the State of Alaska, and SENER (Mexico).

Q. FOR WHAT PURPOSES DO WOOD MACKENZIE'S CLIENTS RELY ON YOUR FORECASTS?

A. Our clients use our forecasts of various energy commodities for many purposes, including internal long term procurement planning, investment evaluations, due diligence processes, regulatory filings, strategic planning processes, benchmarking, and transaction and investment support, as well as other purposes specific to each company's needs. Companies who have used our forecasts in the past for regulatory proceedings include TransCanada, PG & E, Vectren, Otter Tail Power and Excel (CO).

Q. WHAT RELATIONSHIP DOES WOOD MACKENZIE HAVE WITH DUKE ENERGY INDIANA?

A. Wood Mackenzie has worked with Duke Energy Corporation for the past 3 years assisting in the development of the annual Duke Fundamental Forecast. This forecast is used throughout the Duke Energy organization, including Duke Energy Indiana, in the preparation of internal budgeting, capital planning, and any regulatory filings that may be undertaken. The use of this forecast provides the entire Duke Energy organization with a consistent set of planning assumptions for whatever task they are charged with undertaking.

III. THE WOOD MACKENZIE FORECAST

Q. HOW DOES WOOD MACKENZIE PREPARE ITS NATURAL GAS AND COAL PRICE FORECASTS?

A. Each Wood Mackenzie forecast of energy prices is prepared using sophisticated tools to integrate all energy markets globally and those unique to the region and fuel being forecast. The general process used within Wood Mackenzie for all its forecasts is an iterative, interactive process which requires integration of all of its energy research teams globally. Our economics team establishes key economic variables such as GDP for each country as well as global average GDP, country inflation rates, and currency exchange rates. Global oil, natural gas, LNG, power, and coal forecasts are developed using a fundamentals-based, bottom up approach that looks at nearly every supply and demand source for each commodity around the globe. Supply potential and production costs are evaluated by regional upstream teams for each commodity, by country and region. Supply potential and costs are evaluated on a play by play (mine by mine, plant by plant) basis which cover all the key resources within a region (such as North America).

Forecasts of demand for each commodity are similarly developed by regional teams who forecast using historical trends for each customer class and incorporate the GDP forecast, competing fuels, imports and exports, transportation / transmission / shipping costs and capacity and any general industry changes such as carbon legislation or increased use of renewables or conservation. Each commodity market is then balanced between supply and demand to develop an initial price forecast for each commodity within each region using sophisticated linear forecasting models and a rolling 15 year normal weather pattern. The results are then put into a feedback loop for iteration among commodities and regions until all regional and global forecasts reach convergence among supply, demand and price. The forecasting cycle takes several months and is initiated immediately after issuance of the then current forecast. A detailed description of Wood Mackenzie's forecasting process is included in Petitioner's Exhibit H-1.

Q. **WHAT ARE SOME OF THE GENERAL ASSUMPTIONS USED IN THE WOOD MACKENZIE FORECAST?**

A. General assumptions include items such as US GDP, rate of inflation (for purposes of calculating nominal prices, as all Wood Mackenzie's models assume REAL pricing) natural gas and coal cost curves and transportation tariffs or rates. The Global oil price from Wood Mackenzie's oil price forecast is maintained, as are the levels of North American LNG imports or exports.

Q. **WHAT ENVIRONMENTAL RULE ASSUMPTIONS HAVE BEEN USED IN THE WOOD MACKENZIE FORECAST?**

A. The Environmental Protection Agency ("EPA") has promulgated, or proposes to promulgate, several regulations that are projected to affect the Wood Mackenzie Forecast. The regulatory issues include:

Cross State Air Pollution Rule ("CSAPR"): The Wood Mackenzie Forecast assumes the regional cap and trade programs for SO_2 and NOx as promulgated by the EPA on July 6, 2011. The analysis was completed prior to the December 30, 2011 stay of CSAPR issued by the D.C. Circuit Court, so the forecast assumes CSAPR starting in 2012. All plants are assigned to appropriate pollutant Groups (SO_2 Group 1 or 2, Seasonal and/or Annual NOx and State level SO_2 and NOx groups). At the larger Group level, emissions are capped at the sum of allocations. At the State level, emissions are capped at the sum of state allocations plus the assurance limits. Seasonal NOx emissions are annualized, weighted by recent generation trends. The most restrictive rate (annual or seasonal) is used to establish the appropriate emissions caps.

Mercury and Air Toxics Standards ("MATS") (formerly called Utility MACT): The Wood Mackenzie Forecast uses the guidance from the EPA standards as proposed on March 16, 2011. The official compliance date for MATS was expected to occur in 2015. However, we assumed that the EPA would exercise its discretionary one year delay to provide additional time for appropriate controls, grid/transmission improvements, and additional replacement capacity to be constructed. Therefore, units without sufficient controls were not forced to retire in 2015. Implementation of MATS in the forecast assumes a combination of emission rate restrictions and equipment-based standards:

- Hg rates are limited by boiler type as proposed.
- An SO_2 proxy is used in lieu of acid gas (0.2lbs/mmbtu for scrubbed units, 0.4lbs for Dry Sorbent Injection ("DSI")).

- Unscrubbed plants are predetermined with regard to the potential to build wet scrubbing or DSI based on size and coal rank (smaller plants and/or those with the potential to burn Powder River Basin ("PRB") coal are preset with the DSI option)
- Particulate Matter ("PM") (and Hazardous Air Pollutants ("HAPs") are assumed to be controlled by existing and/or upgrades as required by Hg control. Plants that chose to install DSI and burn bituminous coal are required to add Fabric Air Filters ("FAF") and Activated Carbon Injection ("ACI").

Coal Combustion Residuals: The Wood Mackenzie Forecast assumes that plants with wet systems will need to convert to dry systems by 2017 but existing impoundments, for the most part, will not have to be remediated.

Clean Water Act 316(b): The Wood Mackenzie Forecast did not specifically model this rule except for forcing retirement of individual units in California.

National Ambient Air Quality Standards ("NAAQS") – 8hr Ozone: The Wood Mackenzie Forecast assumes that emissions clean-up equipment runs continuously.

NAAQS – $PM_{2.5}$: The Wood Mackenzie Forecast assumes that emissions clean-up equipment runs continuously.

NAAQS – SO_2: The Wood Mackenzie Forecast assumes that emissions clean-up equipment runs continuously.

Green House Gas ("GHG") Tailoring Rule/CO_2: The Wood Mackenzie Forecast assumes that the EPA does not impose significant CO_2 emission restrictions on the existing or under construction coal fleet or on existing or new gas-fired generation associated with the Tailoring Rule. However, the Forecast assumes that there will eventually be some national effort to reduce GHG emissions that is reflected as a tax on Electric Generating Unit ("EGU") CO_2 emissions at a rate of US$14/metric tonne (2011 real dollars) escalated at 5% real beginning in 2022.

Q. WHAT OTHER KEY ASSUMPTIONS HAVE BEEN USED IN THE WOOD MACKENZIE FORECAST?

A. Environmental and safety concerns are assumed to not significantly alter the view that shale gas development will continue at a rapid pace, keeping North America with an abundance of natural gas. We also assume that the Fukushima disaster will not significantly alter the retirement of US nuclear plants, or plans to build new facilities. Additionally, we assume that no new "break through" technology will dramatically alter the energy landscape from what Wood Mackenzie forecasts.

We assume that there will not be an outright ban on surface mining in Appalachia although the cost to develop and operate new mines has been adjusted to reflect the limited use of valley fill as a mining technique.

With regard to renewables, the Wood Mackenzie forecast assumes that renewables will be added as needed to meet renewable energy portfolio standards.

Q. WHAT ABOUT HYDRAULIC FRACKING OF GAS WELLS? HOW HAVE RECENT CONCERNS BEEN INCORPORATED INTO THE FORECAST?

A. Wood Mackenzie believes that hydraulic fracking will continue to be used in the natural gas industry, much as it has for over 60 years. Due to the increased use of fracking in shales, especially in the Marcellus shale in Pennsylvania where there is a higher population density than most traditional drilling regions, there has been an increased focus on the practice by the public. This is likely to result in more stringent rules governing the use of fracking near major population centers as well as the use of certain chemicals and the use of and disposal of water. We believe that these results will add some costs to the production of shale gas (and oil), but will not stop the use of fracking or reduce the ability to produce enough reasonably priced gas to meet current and future gas demand.

Q. PLEASE EXPLAIN THE KEY DRIVERS THAT SUPPORT EACH OF THE PRICE RESULTS FOR NATURAL GAS, COAL, AND POWER.

A. The processes for determining each of the price forecasts is described earlier in my testimony and in Petitioner's Exhibit H-1, but I will describe a bit more of the detail that drives each price forecast. The actual results of the process are addressed later in my testimony.

Natural gas prices are driven by the fundamentals of supply and demand. A few years ago, there was an apparent shortage of natural gas being produced in North America and prices were expected to follow global oil prices to attract LNG cargoes into North America. The reason for this was that globally, gas prices are closely tied to the alternative fuel, which is generally oil. The current reality is significantly different, as, over the past several years, producers in North America have "cracked the code" for economically extracting natural gas from shale formations. These formations have been known since the mid-1800s but have not been economic to develop. Gas prices in the forecast are essentially being set by the cost of the "last Mcf" produced. We have developed cost curves for each of the gas producing formations in North America, as well as regions that are currently too costly to be produced or further developed at this time. These cost curves take into account the costs of drilling, fracking, completing, and an internal rate of return (assumed minimally at 12%). Additionally, the value of Natural Gas Liquids ("NGLs") that may be "co-produced" with the gas stream has a market value. Production from areas that contain significant NGLs or oil has the value of those products credited against the cost of gas produced, thereby effectively reducing the cost of the gas and allowing production to continue even at very low price levels. When the iterative process of demand and supply balancing is completed, the resulting level of supply to meet demand is determined and the cost of that last unit of gas required essentially sets the price, adjusted regionally for distance to the Henry Hub and local pipeline constraints.

Coal prices are also determined based on the fundamentals of supply and demand. Supply and demand fundamentals for coal are entered into Wood Mackenzie's proprietary PRISM model including detailed supply curves for 71 bituminous, 11 sub-bituminous, 15 lignite, and 4 imported coal types plus petcoke and coal refuse. The coal supply curves are based on mine-by-mine analysis of 1,400 plus US and Latin American mining operations including estimates of mining cost, production capacity, coal quality and reserves. Demand is determined in a dispatch model of the interconnected US/Canada/Mexico electricity grid that is constrained by the environmental restrictions outlined in the response to a previous question. PRISM determines the least cost solution to meeting electricity demand while complying with environmental limits. Coal-fired EGUs represented in the model are able to choose from numerous coal types based on delivered cost, including the impact on plant operations and environmental restrictions, while simultaneously competing with other dispatchable generating assets. PRISM can be constrained by a variety of environmental restrictions including unit level emission rate limits, regional and/or national cap and trade programs or emissions taxes. In resolving the least cost solution, PRISM can switch coals and/or install clean-up equipment or redispatch the electricity grid as needed to conform to environmental restrictions. The solution provides a balance of coal and emissions demand and supply, resulting in prices for each of the coal types outlined above and any emissions constrained under a cap-and-trade program.

Wholesale power prices are driven and determined using the EPIS Aurora XMP® ("Aurora") model, a chronological, unit-commitment dispatch model. Aurora performs a simulation of hourly commitment and merit-order economic dispatch of incremental supply sources required to meet hourly power demand under certain system constraints, such as transmission import/export capability and power plant operational limitations. Ultimately, the hourly wholesale power prices are set by the marginal resource required to meet the final megawatt of demand. The types of marginal resources can vary by region and by the time of day and year. Historically and currently, Indiana and its surrounding power markets tend to have marginal power prices set by coal resources for a large number of hours, particularly during off-peak hours and non-summer months when power demand is lower than during on-peak and summer periods. However, natural gas resources are expected to increasingly set prices as the expectation for gas-fired generation to replace coal retirements and meet load growth change the dispatch intersection of supply and demand. This trend is being observed throughout North America, especially in places where coal is often the marginal resource.

The forecast for delivered coal and natural gas prices has rapidly become the single biggest driver for wholesale power prices, outside of the supply/demand balance. Beyond fuel prices, other variable costs that are incorporated in power plant dispatch decisions will impact prices. Beyond 2020, the forecast incorporates a federal carbon pricing regime which has a direct impact to dispatch economics and the marginal cost of production. By imposing an incremental cost of carbon emissions, the dispatch cost of the marginal resource, whether coal or natural gas, will increase accordingly based on the underlying cost curves.

The forecast of wholesale power prices is determined using the Aurora model. "Zones" or aggregations of supply and demand are employed with transmission path ratings reflecting inter-zonal transfer capabilities and certain power plant operational limitations (e.g. minimum load, up/down times, start costs, etc.). This determines the economic dispatch of local resources as well as market imports and exports as needed to balance overall supply and demand in the most efficient economic manner.

IV. THE 2012 DUKE FUNDAMENTAL FORECAST

Q. DID YOU USE THE SAME PROCESSES AS DISCUSSED ABOVE TO DEVELOP THE DUKE FUNDAMENTAL FORECAST?

A. Essentially, yes. The Duke Fundamental Forecast is based on the Wood Mackenzie Long Term View, modified to incorporate specific assumptions provided to our team by Duke Energy. We only iterate with our North America models for Duke Energy, saving time and expense. Duke Energy generally does not change variables that would impact the global models.

Assumptions Duke Energy may ask us to incorporate include variations in timing or magnitude of environmental policy, such as a federally mandated carbon tax, state renewable energy requirement compliance levels, which leads to the amount of renewable energy expected, especially within the Duke Energy service areas, and certain new build assumptions such as new nuclear facilities (or retirements of nuclear), which in turn have impacts on coal plant utilization and retirements and therefore, coal prices and gas prices.

Q. PLEASE DESCRIBE THE ASSUMPTION CHANGES PROVIDED BY DUKE ENERGY.

A. The major assumption changes are as follows:

- CSAPR: The October 6, 2011 revisions to the rule were included.
- MATS: Rather than assuming a blanket one year delay to 2016, the Duke Fundamental Forecast assumes that the additional year to comply is granted only if a plant intends to install controls. If not, the unit is retired in 2015.
- Coal Combustion Residuals: The Duke Fundamental Forecast assumes that compliance will occur by 2018.
- Clean Water Act 316(b): The Duke Fundamental Forecast assumes compliance with EPA's 316(b) Clean Water Act proposal of March 28, 2011, for Best Technology Available to be employed for once-through cooling. This included a one-time capital charge of US$10/kW (2011 real) for units without closed loop cooling, which only impacted retirement decisions.
- GHG/CO_2: The Duke Fundamental Forecast assumes that the CO_2 tax was set at US$15/metric tonne (2009 real dollars) escalated at 6% real beginning in 2020.
- Generic New Nuclear Units: The Duke Fundamental Forecast included a delayed and reduced entry of generic nuclear generation facilities in the long term, but did not change the assumptions for the Wood Mackenzie identified nuclear units (e.g., Watts Bar, VC Summer, and Vogtle). This resulted in a 4 GW lower projection of nuclear capacity across the United States than the Wood Mackenzie case. Most of the assumed generic new nuclear capacity builds are located in the Southeast region of the US.

- Renewables: Duke Energy increased the amount of solar generation in North Carolina based on trends already documented in the pipeline specific to the North Carolina tax credit.
- Inflation Rate: Duke Energy assumes a flat 2.3% general inflation rate, while Wood Mackenzie assumes higher inflation in the near term and lower inflation in the long term. However, these differences only impact the translation to nominal dollars after the forecast has been produced because Wood Mackenzie's models assume REAL pricing in 2011 dollars, as discussed previously.

Q. ARE THE MODIFICATIONS THAT WERE PROVIDED BYDUKE ENERGY REASONABLE IN YOUR OPINION?

A. Yes. Our North America model is used for a variety of industries. The modifications proposed by Duke Energy are reasonable variations of the Wood Mackenzie Long Term View.

Q. DID DUKE ENERGY MAKE ANY CHANGES TO WOOD MACKENZIE'S UPSTREAM GAS MODELING OR ASSUMPTIONS?

A. No.

V. <u>FORECAST RESULTS</u>

Q. PLEASE PROVIDE A SUMMARY OF THE DUKE FUNDAMENTAL FORECAST RESULTS.

A. The key results from the Duke Fundamental Forecast are demand for power, by fuel type and fuel prices. These translate into overall demand for each fuel type and ultimately drive each fuel type price, which in turn determine power prices. I will address each of these results individually.

Q. PLEASE BEGIN BY DESCRIBING THE OVERALL DEMAND FOR POWER IN NORTH AMERICA AND SPECIFIC TO THIS CASE, DEMAND FOR POWER IN DUKE ENERGY INDIANA'S SERVICE TERRITORY.

A. We expect US level aggregate electric demand to grow by 1.04% on average during the period 2012 – 2030. We assume that energy efficiency gains would save just under 9% of electric demand (TWh) by 2030. Specifically, energy efficiency impacts are expected to slow down average demand growth from 1.5% per annum ("p.a.") to 1% p.a. This results in an outlook that is significantly below the historical average growth of 2% p.a.

We expect demand growth in Duke Energy Indiana's service territory to be around 0.9% p.a., effectively an 18% - 19% growth in sales by 2030 over current levels.[1]

Q. WHAT IS THE OVERALL CAPACITY FUEL MIX, OVER TIME, FOR NORTH AMERICA AND FOR DUKE ENERGY INDIANA'S SERVICE TERRITORY?

A. The largest portion of the North American electric generating capacity today is fueled by natural gas, at 36.7% of total capacity, followed by coal, at 28.4% of the total. The balance is from nuclear (9.9%), hydro (14.4%), renewables and "other" (6.1%) and oil (4.5%). By 2020 Gas has increased to 38.3% of the total capacity while coal decreases to 22.1%. Renewable and other sources increase to 11.7%. The trend continues such that

[1] Because Duke Energy did not change any of Wood Mackenzie's load forecast variables in the development of the Duke Fundamental Forecast, there are likely differences between Duke Energy Indiana's internal load forecast and the load growth in the Duke Fundamental Forecast.

by 2030 gas capacity represents 41.0% of the total, coal decreases to 19.4% and renewables et al. continue to grow to 15.3%.

The corresponding capacity numbers for the Reliability First Corporation region are more heavily dependent on coal, which comprises 46% of total capacity followed by natural gas at 28%. Nuclear represents 15% of available capacity with the balance coming from oil (6%), renewable (4%) and hydro (3%). It is anticipated in the forecast that this capacity mix will move towards the national mix, with gas slightly higher than coal (37% and 35% respectively), nuclear falling slightly to 13% followed by renewable (9%), oil (4%), and hydro (3%).

Q. WHAT IS THE OVERALL ENERGY FUEL USE MIX, OVER TIME, FOR NORTH AMERICA AND FOR DUKE ENERGY INDIANA'S SERVICE TERRITORY?

A. Actual energy production by fuel type differs significantly from the generation capacity mix. The North America fuel use mix is heavily weighted today by coal at 34.8% followed by gas (27.8%) and nuclear (19.3%). Hydro (12.9%), renewables and other (5.0%) and oil (0.2%) round out the mix. By 2020 use of the gas facilities is expected to increase to represent 30.5% electricity generated while coal declines to 30.5%. Renewables grow to 8.6% of the total. The trend continues to 2030 with gas representing 36% of actual electric energy production, coal dropping to 24.7% and renewables increasing to 11.2%.

The corresponding energy production results for the Reliability First Corporation region show coal to be the predominant generator of electricity in 2012 at 50% followed by nuclear (20%) and gas (19%). Renewables and other are distant at 3%. We expect coal use to be lowered slightly to 46% in 2020 and 40% by 2030. Gas increases to 23% and 29%, respectively, for the same timeframes, while nuclear increases to 26% in 2020 and then drops to 24% by 2030.

Q. PLEASE DESCRIBE THE RESULTING GAS DEMAND AND PRICES FOR NORTH AMERICA AND THE REGION THAT INCLUDES DUKE ENERGY INDIANA'S SERVICE TERRITORY.

A. Natural gas demand in North America, assuming "normal" weather conditions, rises from 78.8 Bcfd today to 90.8 Bcfd in 2020 and 104.5 Bcfd by 2030. The generation sector's use of natural gas is the primary driver of this growth, increasing from 25.9 Bcfd today to 31.1 Bcfd in 2020 and 39.4 Bcfd in 2030.

The East North Central census region, which includes Indiana, will see gas demand grow from 10.6 Bcfd today to 12.9 Bcfd in 2030. Gas demand for generation increases from 2.0 Bcfd today to 3.8 Bcfd in 2030.

Gas prices at the Henry Hub rise from today's depressed prices to **<CONFIDENTIAL** [redacted] **<CONFIDENTIAL>** by 2020 and to **<CONFIDENTIAL** [redacted] **<CONFIDENTIAL>** by 2030, essentially reflecting the higher costs of producing the marginal volume of gas required. The impact on the North Central region, using Chicago as a proxy, has basis relative to the Henry Hub going from **<CONFIDENTIAL>** [redacted] **<CONFIDENTIAL>** in 2012 to **<CONFIDENTIAL>** [redacted] **<CONFIDENTIAL>** by 2030 due to the increases in shale production in the Marcellus, which pushes back Rockies gas and western Canadian gas. This results in prices of approximately **<CONFIDENTIAL>** [redacted] **<CONFIDENTIAL>**

average for 2012, <CONFIDENTIAL> [redacted] <CONFIDENTIAL> in 2020 and <CONFIDENTIAL> [redacted] <CONFIDENTIAL> by 2030.

Q. PLEASE DESCRIBE THE RESULTING COAL DEMAND AND RESULTING PRICES FOR NORTH AMERICA AND THE REGION THAT INCLUDES DUKE ENERGY INDIANA'S SERVICE TERRITORY.

A. The demand for coal in electric generation is forecast to be adversely effected by the slow growth of the US economy, competition from natural gas and the retirement of a significant portion of the coal fleet due to the unfavorable economics of complying with existing and proposed federal environmental regulations. We forecast that the demand for thermal coal by US electricity generators will decline about 8% from 2011 to 864 million short tons ("mst") in 2012. Between 2012 and 2015 demand will grow to 890 mst before declining to 829 mst in 2020 and reaching 700 mst by 2030. Regional demand in the East North Central ("ENC") Census Region will decline about 8.6% to 201 mst in 2012.

ENC regional demand will continue to decline throughout the forecast to 197 mst by 2015, 187 mst by 2020, and 164 mst by 2030. Coal prices will generally decline with the decreased demand through 2018. However, beyond 2018 the growing demand for US coal in international markets will act to raise prices. Representative coal prices (FOB mine), in constant 2011 US dollars per ton, are forecast as follows:

<CONFIDENTIAL>

	2011	2012	2015	2020	2030
CAPP 12,500 btu 1.6#SO2 CSX price	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NAPP 13,200 btu 3.4#SO2 price	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ILB 11,800 btu 4.8#SO2 price	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PRB 8,800 btu 0.8#SO2 price	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

<CONFIDENTIAL>

Q. ARE THERE ANY OTHER KEY RESULTS THAT CAME OUT OF THE FORECAST PROCESS SUCH AS LEVEL OF RETIREMENTS AND NEW BUILD FOR GENERATION?

A. Yes. We project that 5.1 GWs of coal-fired generation, including 1.4 GWs in East North Central, will come on line between 2012 and 2015. Additional coal demand during the same period of time is expected to reach 22.2 mst. In counter point, we project that 57.9 GWs of coal fired capacity will retire between 2010 and 2030 with 49.3 GWs retiring by 2016, the presumed compliance date for the EPA's MATS regulations. In the ENC, 13.3 GWs of coal-fired generation will retire by the end of the forecast period, with 12.5 GWs of these retirements occurring by 2016.

Q. ARE THERE ANY COMMENTS ON EMISSIONS COSTS RESULTING FROM THE FORECAST?

A. As discussed earlier, this forecast assumes that CSAPR, as revised October 6, 2011, would come into effect on January 1, 2012. CSAPR includes provisions for four distinct Allowance markets including Group 1 SO_2, Group 2 SO_2, Annual NOx and Seasonal NOx. The region in which the Duke Energy Indiana plants reside will be subject to providing Group 1 SO_2, Annual NOx and Seasonal NOx Allowances to offset emissions.

We project that Group 1 SO_2 Allowances will range between **<CONFIDENTIAL>** [redacted] **<CONFIDENTIAL>** per short ton in constant 2011 US dollars between 2012 and 2015. After 2015, the retirement of a significant portion of the coal fleet will make an excess supply of allowances available such that SO_2 Allowance costs will be nominally $0. We estimate that existing and planned controls for NOx, along with additional state level restrictions built into the CSAPR rules will result in an excess supply of Annual and Seasonal NOx Allowances such that the price will be nominally $0[2].

Q. WAS PETITIONER'S EXHIBIT II-1 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

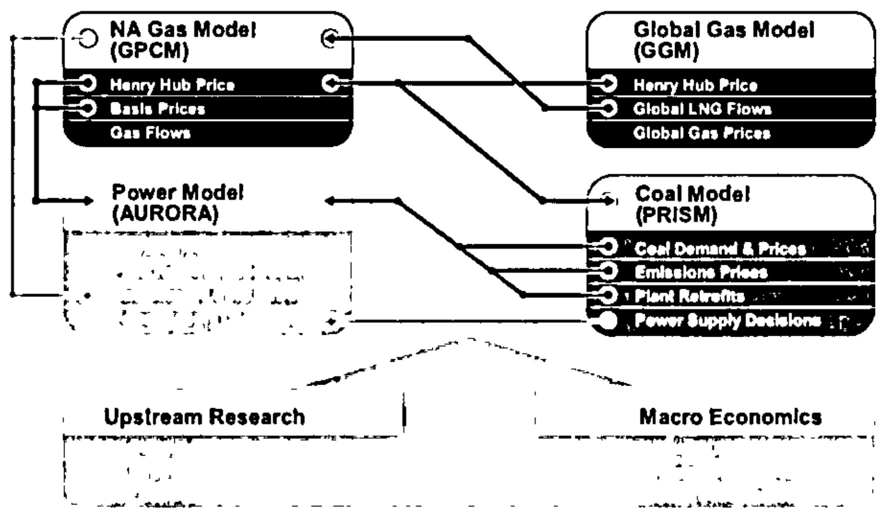
A. Yes, it does.

[2] Duke Energy slightly modified the SO_2 and NOx allowance prices in the Duke Fundamental Forecast by assuming a small minimum floor price.

Analytic Methodology and Process

Wood Mackenzie's North American research and analytical tools are integrated to generate a consistent story around the fuels and energy value chains that we cover. It includes a detailed bottom-up view as well as a global perspective.

North American Integrated Modelling



North American Natural Gas Supply

Wood Mackenzie's North America gas supply services cover the following major supply regions, further broken out into granular resource basins/areas:

- Federal Offshore Gulf of Mexico (GoM)
  - Shallow
  - Deepwater
- Gulf Coast
  - Texas/Louisiana Gulf Coast Basin
  - East Texas-ARKLA-MS-AL-FL Salt basins
  - Black Warrior Basin
- Midcontinent
  - Anadarko Basin
  - Arkoma Basin
  - Forest City/Cherokee basins
  - Salina Basin
- Rocky Mountains
  - Powder River Basin
  - Green River Basin
  - Uinta-Piceance Basin

  - Raton Basin
  - Wind River Basin
  - Denver-Julesburg Basin
  - Williston Basin
  - Northern Great Plains
  - Paradox Basin
  - Big Horn Basin
- San Juan
- Southwest
  - Permian Basin
  - Fort Worth Basin
- Northeast
  - Appalachian Basin
  - Michigan Basin
  - Illinois Basin
- West Coast
  - San Joaquin Basin
  - Sacramento Basin
  - Federal Offshore California
- Alaska
- Canada
  - Western Canada Sedimentary Basin (Alberta, Saskatchewan, British Columbia)
  - East Coast Canada
  - Arctic Canada
- Mexico
  - Northern Region
  - South West Marine Region
  - North East Marine Region
  - Southern Region

Supply from these regions is further subdivided into resource types in terms of conventional versus unconventional resources (tight gas, shale gas, and coalbed methane).

North America Gas Supply Regions

Wood Mackenzie's North America gas supply data that is used in our models benefit from the leveraged research covered by upstream research services. Traditional Wood Mackenzie upstream research comprises asset-by-asset analyses (Deepwater GoM & North America Frontier services). Regional basin/play focused company analyses are utilized for the US Lower 48 (Rockies, San Juan, Gulf Coast and Midcontinent) and the Western Canadian Sedimentary Basin (WCSB). Additional analyses & insights studies for regions not currently covered by upstream research services are gained through Wood Mackenzie's North America Gas Research Service (NAGS) and proprietary multi-client/consulting studies.
The Lower 48 upstream analysis considers details of operator activity in each region including acreage positions, well spacing, capital and rig commitments, drilling plans and corporate strategy to develop a production forecast. Using the drilling forecasts for operators at a granular play level and well type curves for each play based on historical well performance, production forecasts are developed at a play level. Production forecasts for the individual operators/plays are aggregated to develop basin and region level forecasts.

Structure of Wood Mackenzie's US Lower 48 Upstream Research Services for Each Region

The upstream research services derive gas reserves estimates based on Wood Mackenzie's future production forecast for each basin and region. As such the reserve estimates and production forecasts are broadly equivalent to proved plus probable (P+ P or 2P) reserves and production. We take this approach, because a development based on a 2P reserve case is believed to represent the 'most likely' future outcome for each asset. For those assets where reserve upside is known to exist, Wood Mackenzie's North America Gas Service models further upside potential (Reserve growth & Yet-to-finds) based on exploratory data and insights leveraged through the upstream research services. Production resulting from further upside potential can be aggregated through time to approximate a 3P reserve estimate. Wood Mackenzie believes, that this methodology and classification of production and reserves most accurately reflects the supply deliverability across various supply regions.

Wood Mackenzie's 2P reserve estimates include all those fields regarded as commercial: fields in production or under development as well as fields which Wood Mackenzie classes as 'Probable Developments'. It should be noted that in many cases Wood Mackenzie will class a discovery as a Probable Development before a company has booked the reserves under the applicable stock exchange rules, for example the SEC in the US. This is particularly true for unconventional gas plays, where Wood Mackenzie may classify as commercial before a gas sales contract has been agreed. In light of this, and the fact that SEC/Annual Report figures generally report proved (1P) reserves, Wood Mackenzie's published entitlement reserves are likely to exceed SEC reported reserves.

North American Natural Gas Markets

Our analytical process utilizes the Gas Pipeline Competition Model® ("GPCM") as the engine for analyzing the effects of shifts in supply and demand throughout North America they relate to prices, pipeline flows and basis. GPCM is a commercially available product, complete with its own data set. Wood Mackenzie does not use the standard data set included in this model, however. Instead, Wood Mackenzie uses its own analysis to populate the supply and demand data within this model, as well as the supply and demand elasticity assumptions. Wood Mackenzie has also spent many years improving and enhancing the infrastructure data within GPCM and has calibrated model results to ensure accurate reflection of real infrastructure operating capability as well as assumptions regarding pipeline and storage system expansions. Wood Mackenzie's GPCM model now includes over 200 separate pipelines (including new systems), more than 400 demand nodes, 94 separate supply areas, and more than 1,000 separate pipeline interconnects. This proprietary data is developed within Wood Mackenzie, taking advantage of Wood Mackenzie's unique capabilities, including:

- Extensive upstream research teams focusing on all major producing basins in North America.

- Midstream expertise, including 5+ decades of direct collective experience by team members in the natural gas pipeline and utility sectors.

- Decades of experience in analysis of demand patterns in each sector of the North American gas marketplace.

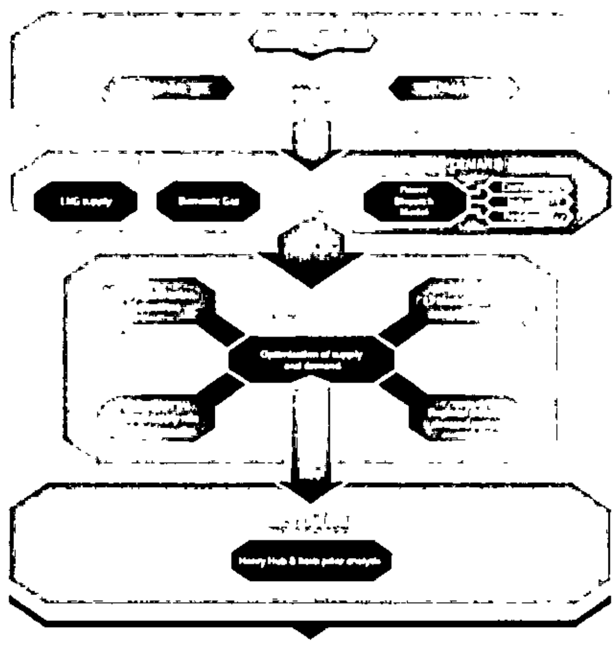
- Unparalleled expertise in global LNG market dynamics, including extensive advisory and analytic work in the Pacific basin market.

- Global oil markets analysis, headed by Ann-Louise Hittle, and making use of Wood Mackenzie's field by field, detailed view of global oil supply potential. This is among the most rigorous analyses of global oil supply potential available in the world.

Insights from each of these specialized areas of Wood Mackenzie analysis are used as critical inputs into the GPCM model.

GPCM is a linear-programming model that reconciles supply, demand, price and flows throughout the North American gas marketplace and infrastructure set. Pricing differentials across a given pipeline zone in GPCM are proportionate to the load factor across that pipeline zone, with higher throughput leading to increasing pricing differentials. Price differentials increase exponentially at very high load factors. This function (which can vary by zone depending on variable charges and fuel rates) enables current and future constraints in the pipeline/storage grid to be identified, and prices and basis differentials to be derived under varying future natural gas market conditions and assumptions.

The GPCM model also enables a comparison of expenditures by customer classes within a state under varying sensitivities for LNG imports (and other factors). This process of analysis of the North American natural gas market is illustrated in the figure below:



The rigorous and comprehensive process assures full integration of data and inclusion of insights from each individual team in all model runs. The specific data and forecasts behind each run are made available to our Clients, assuring total transparency. The experts of each service/component of the energy value chain are made available to Clients for further discussion or explanation as the Clients desires.

North American Power Supply and Demand

Wood Mackenzie's fundamental power analysis leverages our internal proprietary data with a highly integrated approach to ultimately balance the fundamentals across the energy value chain. The proprietary demand and supply assumptions, along with fuel and emissions pricing are simulated to project the marginal cost of production subject to numerous system constraints.

Fundamental Power Forecast Overview

Wood Mackenzie utilizes the Aurora XMP® production cost simulation tool for energy price forecasting in the North America power markets. Using Aurora XMP®, Wood Mackenzie performs a focused, plant-by-plant analysis on an hourly basis against hourly demand projections for every modeled power market zone, taking into account power plant operational characteristics and inter-zonal transmission constraints. Currently, Wood Mackenzie has broken the North American market into more than 85 power market zones, reflecting the major inter-zonal transmission constraints. Energy market clearing prices are set at an hourly level using least cost dispatch based on generating unit marginal cost of production and operational characteristics. Zonal energy flows (imports and exports) are determined based on a combination of least cost dispatch and inter-zonal transmission path ratings.

Wood Mackenzie's fundamental analysis of the power markets is based on our proprietary North American power market supply and demand assumptions. These assumptions have been refined over the past five years relying the on knowledge and expertise of the NAPS team as well as input from NAPS clients that include many major industry players. Below is a description of the major forecast assumptions developed by Wood Mackenzie and continuously updated and within our simulation dataset.

Power plant cost and technical characteristics have been developed and are continuously being updated based on historical unit performance reports (e.g. EPA CEMS and EIA reports) and typical generator characteristics given plant age, technology and manufacturer. Such characteristics include power plant location, fuel type, size, efficiency/heat rates, variable operating and maintenance (O&M) costs, emission rates, planned maintenance and forced outage rates, ramp rates, start costs and fixed O&M costs.

Named power plant entry and retirement assumptions are being updated on a frequent basis based on continuous tracking of industry publications, regulatory permitting progress, ISO and RTO planning information, power plant developer and plant owner announcements related to new plant additions and old plant shutdowns or mothballs.

Long-term Generic power plant retirements determined by an evaluation of the plant's age, efficiency and expected economic performance.

Long-term generic plant additions based on the regulatory drivers (renewable portfolio standards) and financial incentives (loan guarantees, tax credits, feed-in tariffs) promoting certain generation alternatives such as renewable and nuclear generators; plant economics by region and technology; and regional/sub-regional reliability (reserve margin) requirements.

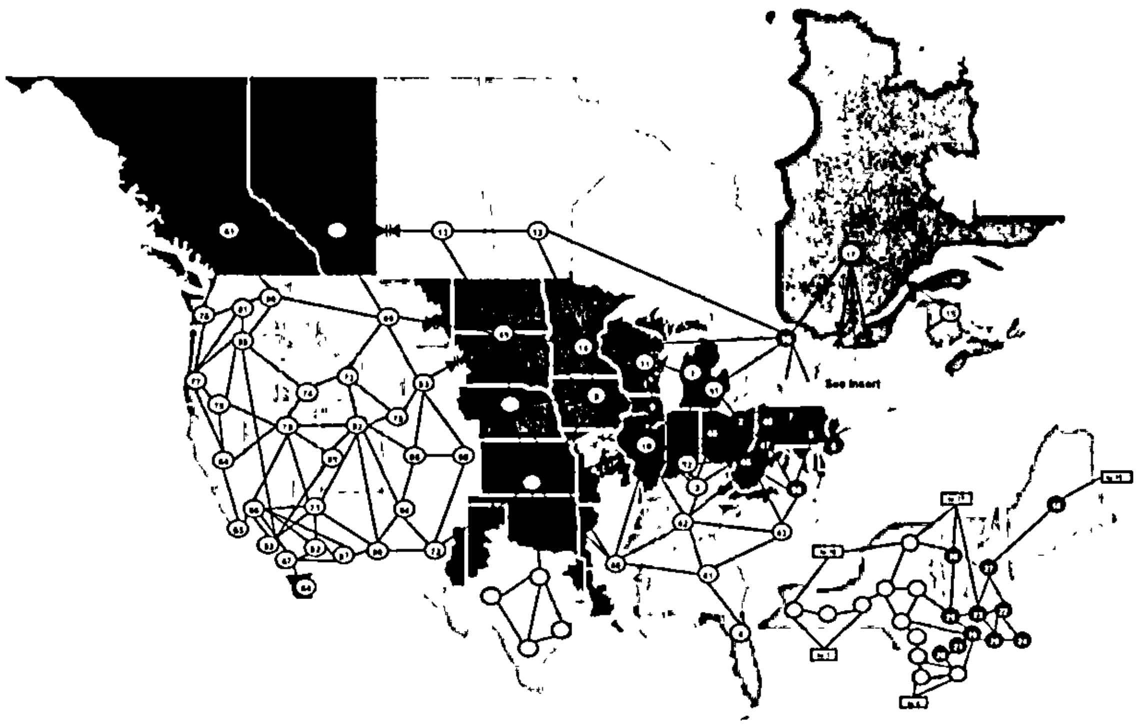
Short-term and long-term power demand forecasts by power zone based on a combination of a proprietary demand forecast model projecting monthly energy and peak demand and hourly load shapes calculated from actual historical hourly loads reported by load serving entities (LSEs). Long-term annual energy and peak demand forecasts are updated twice a year and short-term projections on a quarterly basis reflecting Wood Mackenzie's current economic growth and GDP assumptions and recent demand trends. Electricity demand forecasts are also adjusted based on our estimates of incremental energy efficiency and demand response based on our extensive research and analysis of ISO/RTO reports, provincial, state and LSE initiatives and other relevant sources.

Inter-zonal transmission path ratings, wheeling rates and losses are estimated utilizing information from ISOs, RTOs, transmission coordination groups, transmission system coordinators and transmission owner OASIS websites. Transmission expansion assumptions are determined based on an evaluation of development activity in light of ISO/RTO transmission planning efforts, regulatory permitting and construction progress. Wood Mackenzie also frequently evaluates the zonal configuration topology for the North American power markets to reflect major inter-zonal transmission congestion, mostly affecting power prices for major hubs and zones.

Natural gas, oil and coal fuel prices and emission allowance price projections based on the results of our integrated and iterative multi-commodity modeling of the North American and global energy markets.

NAPS simulation of the North American power markets within Aurora XMP® utilizing our proprietary data and assumptions represents the foundation for electricity price forecasting as well as fuel demand and generation mix inputs for the North American gas and coal models impacting Wood Mackenzie's analysis of the entire energy value chain across the globe. In turn, the assumptions used by NAPS remain consistent with our integrated view of the North American and global energy markets.

Wood Mackenzie's North America Zonal Power Market Configuration



Energy and Capacity Price Determination

Wood Mackenzie's North America Power Service applies a two-part price forecasting approach independently estimating the value of energy and capacity within each simulated power market area. Below is a general description of this two-part forecast methodology:

Energy prices ara calculated within Aurora XMP® for avery hour during the simulated study period based on the short-term marginal cost of production of the unit setting the price- including variable O&M, fuel, emission and start costs

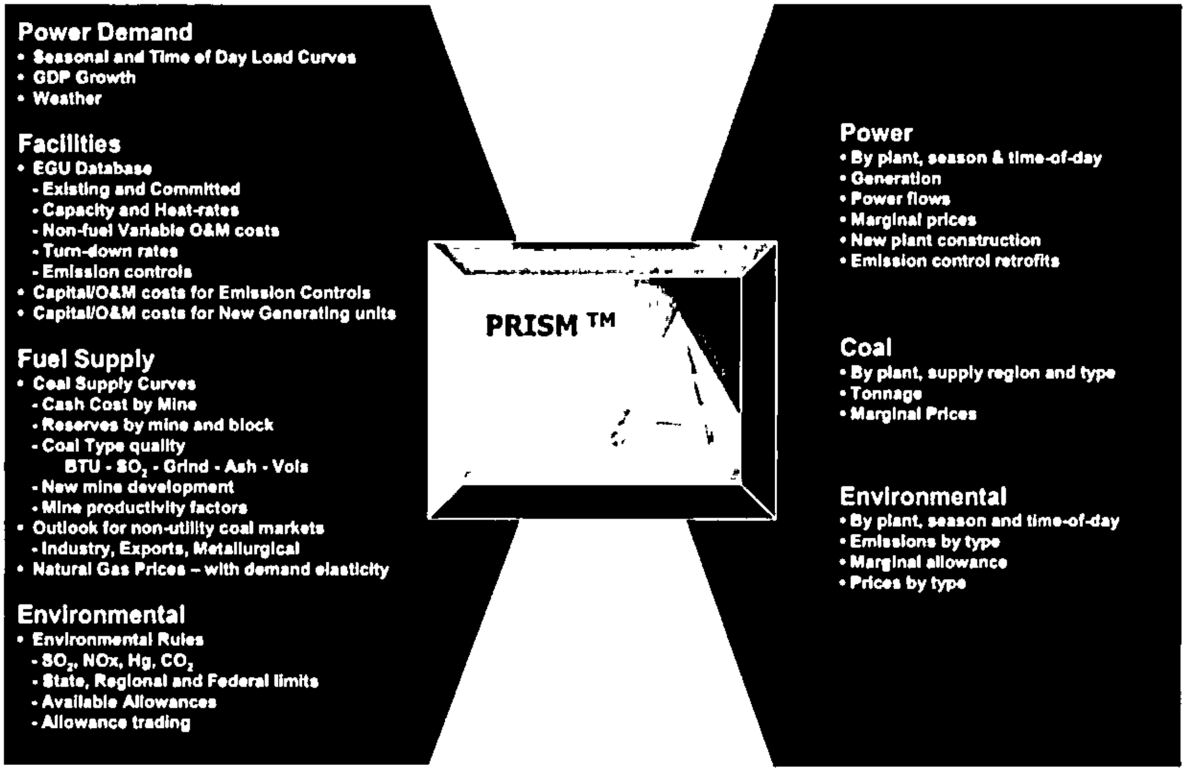
Capacity prices are estimated using Wood Mackenzie proprietary tools assuming that es electricity demand grows to absorb the excess supply, power markets will provide (from a combination of energy and capacity prices) sufficient economic signals to induce the required new generation entry. The level of new entry cost compensation is assumed to decline as reserve margins grow above target reliability levels Wood Mackenzie's projacted capacity prices represant capacity values that generators typically extract from a combination of bid mark-ups in energy markets under scarcity conditions, organized installed cepacity (ICAP) markets and capacity peyments in bilateral power purchase agreements (PPAs).

PRISM ™ Model

In addition to the Aurora model, Wood Mackenzie's coal team uses the PRISM model to evaluate the impact of emissions. This model also produces coal demand and gas demand for the industry which provides another check on internal consistency of our processes.

Model Diagram

The primary objective of the PRISM™ Coal and Power Model is to meet the nation's electricity demand at the lowest possible cost while remaining within emissions caps. The model has several ways of accomplishing this, including fuel switching, choosing to run one plant over another, and/or adding cleanup equipment or new generation.



INPUT **OUTPUT**

The diagram above summarizes the components used in developing demand, supply, and price projections. The projection of coal demand for electrical generation combines a top-down (meeting electrical demand) approach with a bottom-up, or micro, analysis. The beginning point in the bottom-up analysis of demand entails developing detailed information on all existing power generating plants, including data on their current coal utilization, specifications, emissions control processes, regulatory limits, future plans, etc. This plant database includes or accounts for all known Electric Generating Unit (EGU) facilities, regardless of size and is coordinated with the database developed by the North American Power Service as discussed above. We combine many of the small municipal plants and carry their combined capacity and future coal use. In many cases, the list of plants is broken down to unit groupings to separate units that currently scrub or use different coal types from other units at the same plant. Projected additions to coal-fired capacity are treated similar to existing plants.

We populate 100 103 individual coal supply curves that vary by originating basin and quality. Each supply curve is linked to each EGU by stipulating an appropriate transportation cost. The optimization function selects the optimal coal source subject to the environmental and operating restrictions placed upon the EGU. The resulting selections then determine the cost of generating electricity, as well as the pollutant emission rates.

The availability of coal types into specific plants is based upon present usage patterns on a unit-by-unit basis, announced plans for fuel switching, and our judgment of which additional coals seem likely fuel candidates. The coal supply curves are built up from the hundreds of detailed cost estimates we have generated for over 1,000 mines across the United States. These curves are updated on an annual basis.

We utilize forecasts of regional growth in demand for electricity, developed by Wood Mackenzie's *North America Power Service* in the current release of their long term view, which uses the Aurora model, as described above. This regional electricity demand, as well as the fundamental unit by unit and control zone structure of the North American electricity grid developed by the Power Service is then fed into the PRISM model. In addition, we impose existing and proposed environmental restrictions on the operations of the EGUs. Depending upon which case we are modelling, more or less power will be required from individual coal-fired plants, and these requirements are translated into demand for specific types of coal. Projections of industrial steam coal use and exports of steam coal are then added to utility coal demand, resulting in total US steam coal demand for each of the 100 coal types defined in the model.

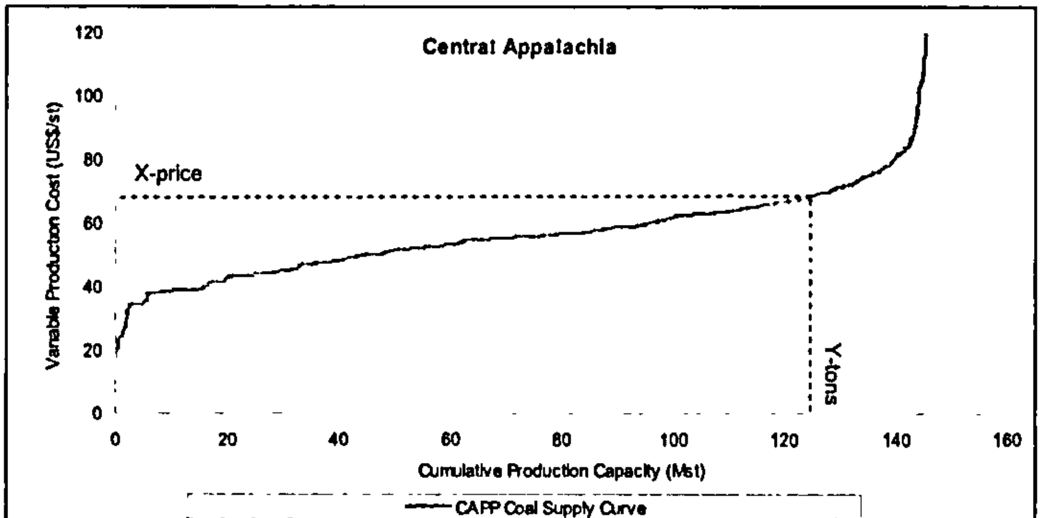
Existing plant cleanup equipment is updated on an annual basis. We then supplement this data with announcements of equipment that will be installed in the future (usually within 10 years). This currently installed and announced cleanup equipment structure is important because the model considers only the operating cost for such equipment in arriving at the optimal solution (i.e. capital costs are considered "sunk" in the case of existing and announced equipment). The model also has the ability to add cleanup equipment if it is economically justified, e.g. if the cost of adding a scrubber is less than the cost of other options available to meet the electricity demand and remain within the SO_2 emission limit. In the case of optimizing equipment retrofits, the model considers the capital cost for such equipment as well as the operating cost in determining the best option. However, the cost of capital is amortised over a 20 year period and only the first year's capital cost is considered in the model decision. In subsequent years, the model only considers the operating costs for this equipment.

PRISM is designed to emulate a variety of environmental regulatory schemes including unit by unit emission rates, regional and national cap and trade programs and/or emissions taxes. Unit by unit emission rates are a part of the profile of each coal plant and are required to be met using a combination of coal supply and clean-up equipment choices during every hour of operation. Each unit is also assigned to one or more regional or national cap and trade programs for each pollutant as appropriate. The cap on emissions for each region and pollutant is an input into the model. PRISM then can optimize coal choices, clean-up equipment operation or build, and dispatch while meeting the emissions caps. PRISM outputs emission allowance prices for each capped pollutant based on the cost of choices required to meet the given cap. Emissions taxes are considered in the cost of dispatch.

In considering coal choice decisions at EGUs we take into account the potential for coal related operational restrictions. For instance, a plant designed for high btu eastem bituminous coal will not normally be able to switch to sub-bituminous coal without incurring operational and capital expense. We take this into account when considering potential fuel switches and have developed switching penalties where appropriate. Penalties for converting a coal-fired plant to PRB coal (where such penalties are appropriate) are applied when a plant first takes PRB coal and incrementally as the plant bums more PRB coal. Once a plant has switched to 100% PRB coal in the model, the capital portion of the penalties no longer exists. Of course, any plant that is already handling and buming 100% PRB coal or has announced a switch to PRB coal is exempt from the application of usage penalties. In the case of announced switches to PRB, the plant would be subject to PRB penalties, if the model chooses to bum PRB coal at that plant prior to the year of announcement.

Mining Cost Supply Curves

The supply curves relating mining costs to production capacity are built up from mine-by-mine estimates of cash operating costs for all currently operating mines in the country. Much of the information on costs, qualities, and reserves is taken from the detailed county-by-county studies of coal supply that we publish annually. Costs for all active mines are estimated using models we have developed. Mine Safety and Health Administration (MSHA) databases provide information on active mines, production, employees, and man-hours worked, from which we calculate productivity. This base is supplemented with information from mine interviews concerning work schedules, equipment, percentages of washed coal, and trucking distances. In instances where trucking distances are not obtained by interviews, we measure the distance between the mine and the preparation plant via the most logical road. Costs for potential mines on undeveloped properties are estimated by comparing costs of similar active operations located nearby.
Mining Cost Supply Curve Example



Source Wood Mackenzie Coal Market Service

The market clearing price for any coal is determined by the relationship between the final converged demand and the cost-supply curve for that coal in the model. Referring to the chart above, this is demonstrated by the intersection of the vertical dashed line and the horizontal dashed line representing a hypothetical Y/million ton steam coal demand at a "market clearing" coal price of under $X/price per short ton.

This marginal price is reported from the model as the market price for each coal type. In some regions, this price represents the cash cost of the marginal producer. In other regions, the PRB for instance, this price is well above the cash cost of the marginal producer and represents the value of an additional ton of this coal type to the marketplace.

Each mine in our mine curves also includes an estimate of the remaining recoverable reserves. As the modelling process steps through the years, the reserves at each cost step (below the marginal price) are reduced by the mine's capacity.

We address the development of new mine reserves in two basic ways:

Identified undeveloped reserve blocks are generally entered as an individual mine with no initial capacity; and

Identified and generic reserves are entered with existing mines with capacity additions.

In both cases, the model will activate the new reserves only if the following are true:

There are at least seven years of reserves remaining at the new capacity;

The marginal price of the particular coal type exceeds the operating cost by at least a pre-determined "trigger" level; and

Opening the particular reserve is part of the overall optimal solution.

The mine triggers used in the model are roughly based on the margin (over cash operating cost) required to realize a 20% to 25% return on investment. We have elected to use relatively high hurdle rates for two reasons:

Our model does not guarantee the rate of return as mine pricing reverts to incremental costs in succeeding years; and

Uncertainty, consolidation, and more sophisticated financing require a healthy respect for the inherent risk in coal mining

The bottom line is that in the model, there is a balancing act which mirrors what happens in the real world. In this balancing act, any shortening of a mine curve (due to exhaustion of reserves at individual mines, for example, or due to some governmental restriction on mining capacity) will likely lead to somewhat higher prices as demand hits higher on the shorter curve. These higher prices cause more steps on the cost curve to "see" an acceptable Return On Investment (ROI), leading to capacity expansion for that step – if any is available. That expansion tends to drive prices back down.

There are two secondary methods by which capacity is added into the mine curves within the model. First, one of the inputs to the model is an assumption of future productivity growth for each of the 100 types of coal. This productivity assumption is important to capacity since a mine producing 1.0 million tons per year (mmtpy) and experiencing a 10% gain in tons per man-hour could either produce 1.1 mmtpy with the same workforce after the productivity gain, or it could lay off approximately 9% of its workforce (1/110% = 91%) and produce the same 1.0 mmtpy with fewer workers. In the first case, we have a productivity-induced capacity increase. One of the model inputs involves our projection of what proportion of productivity gain goes toward capacity increase versus workforce reduction, and although the calculations are somewhat complicated, it works out that less than half of the productivity gain is going toward capacity in the model runs. Second, there is a well-established pattern in the coalfields of mines running at their maximum capacity making small capacity gains (usually through equipment upgrades), even if the true ROI economics are not there to justify this "smaller than major expansion" level of capacity investment. Accordingly, we have a test in the model which determines whether a step was 100% used in the previous year and has at least seven years of reserve life. If both of these conditions are met, then the mine capacity is very slightly stretched for that step (of the order of 1-2%) to reflect this real world phenomenon.

Both of these secondary capacity effects (productivity and stretch) are allowed to occur before making the economic "margin" test for bringing on major new expansion capital at a mine. The net effect is that a small amount of the "major capital" capacity expansion may be forestalled by the lesser amount of "creep" in capacity that occurs due to productivity gains and the stretch described above.

Electricity

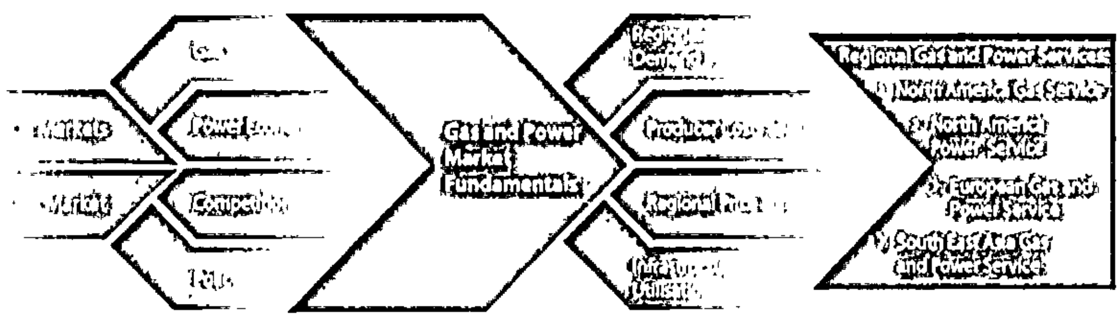
The aspect of our detailed coal modelling which makes it unique is the fact that we simultaneously determine the electric plant dispatch changes due to each coal switch and environmental regulation. Our model uses input data on unit-by-unit generating cost projections, load profiles, seasonal electricity demand patterns, regional electricity growth rates, plans for new units, competitive costs of gas and coal-fired generation, etc. This input data is coordinated with the fundamental unit by unit and electricity grid structure data used by the North American Power Service to assure consistency throughout the North American Coal, Gas and Power Services.

We also bid the cost of emissions at the market clearing price of allowances into the dispatch cost for use in the electric portion of the integrated model.

Global Gas and Coal Influences Wood Mackenzie's North American Research Services

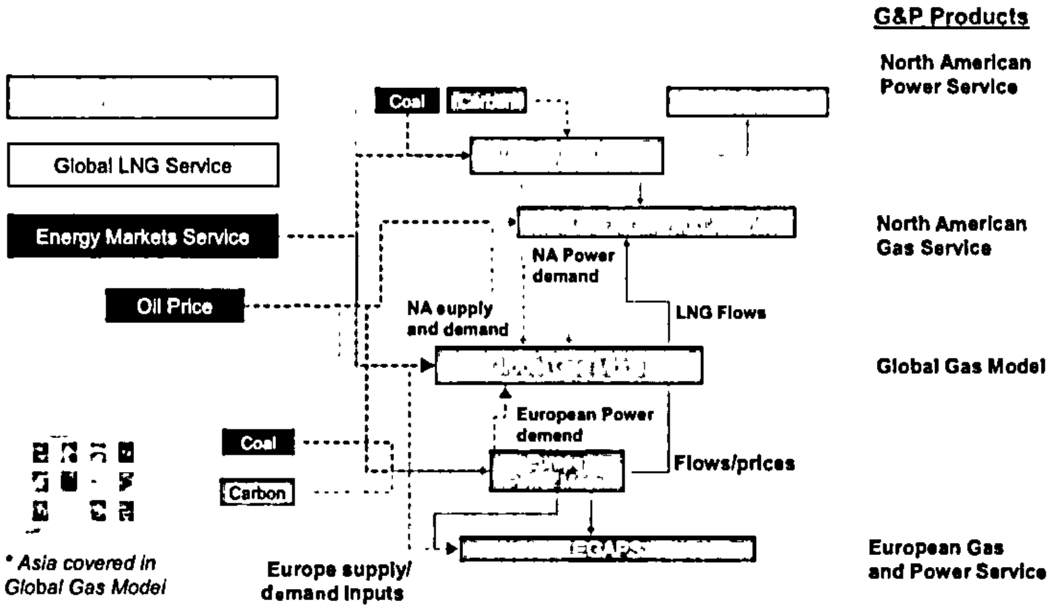
Wood Mackenzie's established research suite provides a global perspective on oil price dynamics, an in-depth analysis of current and future upstream assets production profiles and costs, key evolution of global LNG trade and the competitive and policy environment at a regional and national level. This coverage allows us to have a more robust outlook for regional gas and power markets. In addition, the global reach of our coal services provides similar insight on the needs for North America coals in the global arena, which can have an impact, especially on certain coal basins, on the price expected for certain types of coal. Demand competition for those coals, depending on the supply and exit infrastructure, can impact coal prices to certain generating facilities in North America that are dependent on those specific coals.

Using our proprietary Global Gas Model and our global coal research allows us to provide unique insight into how the inter-connected regional gas, coal and power markets impact upon each other.



Our models and products are integrated and inter-dependent on one another in the development of the WoodMac Long Term View. We do not anticipate a need to run any Global Gas Model sensitivities as part of this assignment.

Global Gas & Power - Integrated Models & Products



VERIFICATION

I hereby verify under the penalties of perjury that the foregoing representations are true to the best of my knowledge, information and belief.

Signed: Robert W. Fleck
Robert W. Fleck

Dated: 6-28-12