SO_2 - 2.75 # / MMBtu

4-17-09

April 17, 2009

Ms. Caroline Shine
Air Resources Program Administrator
Florida Department of Environmental Protection
Central District Office
3319 Maguire Blvd, Suite 232
Orlando, FL 32803-3767

RE: ***Air Construction Permit Application***
Reliant Energy – Indian River
Air Operation Permit No. 0090196-005-AV

Dear Ms. Shine,

The Reliant Energy (Reliant) Indian River Plant (the "Facility") submitted an air construction permit application via the Florida Department of Environmental Protection's (FDEP's) Electronic Permit Submittal and Processing (EPSAP) system. The permit application was submitted for correction of the hourly heat input limits for two (2) of the facility's three (3) fossil fuel steam boilers, specifically for Emission Unit ID Nos. 001 and 003 (Boilers 1 and 3).[1] The EPSAP permit application number for this submittal is #2048-1.

Reliant is submitting this construction permit application following the meeting between Reliant and FDEP on November 18, 2008, and in response to a letter from the FDEP dated October 5, 2006, both of which indicated that changes to the heat input limits and compliance demonstration methodology associated with the boilers at the facility could not be accomplished by revision of the Title V operating permit alone and would require submittal of an air construction permit application. As requested, Reliant is also submitting an attachment to this letter including the analysis demonstrating that this requested change will not be subject to major New Source Review (NSR) or Prevention of Significant Deterioration (PSD) permitting.

HEAT INPUT LIMIT HISTORY

The heat input limits listed in Condition A.1 of the current Title V permit, provided in Table 1, originated from a letter sent by the previous owner of the facility, Orlando Utilities Commission

[1] Reliant is not requesting a change to the heat input limits for Emission Unit 002 (Boiler 2) in this application. The heat input rates listed in the current permit are appropriate for the peak capacity of Boiler 2.

(OUC), to the FDEP Central District Office on July 24, 1975.[2] In this letter OUC calculated the heat input for each boiler based on the provided contract data, assuming the units were firing oil. OUC additionally stated that heat inputs would be approximately 4% higher on all three units if natural gas were fired. The heat input ratings provided in this letter are the same as those listed in Condition A.1 of the current Title V permit. These ratings are referred to as the guaranteed maximum continuous rating (MCR) and are representative of what the units were designed to accommodate and continuously sustain over the long-term.

TABLE 1. MAXIMUM OPERATING HEAT INPUT RATE LIMITS IN TITLE V PERMIT

Fuel Type	Boiler 1 (MMBtu/hr)	Boiler 2 (MMBtu/hr)	Boiler 3 (MMBtu/hr)
Natural Gas	865.5	2,248.7	3,208.5
Oil	832.2	2,016.5	3,048.8

In 1991 OUC requested changes to the heat input values through a permit application submitted to the FDEP Central District Office.[3] OUC proposed that the FDEP change the maximum hourly heat input limits to those achieved during overpressure, where heat inputs higher than the MCR and corresponding limits are required for brief time periods. OUC requested that compliance with the hourly heat input limits be demonstrated by a 30-day rolling average hourly heat input. Using a 30-day rolling average hourly heat input based on the MCR would be appropriate and would not result in exceedances of the permitted hourly heat input values as temporary fluctuations and increases in heat input (i.e., overpressure) that are part of normal operation would not average greater than the MCR. The FDEP did not accept OUC's proposed revision and indicated during the November 18, 2008 meeting that this request to change the averaging period would require a construction permit application.

Based on the permit language of the Indian River facility's initial Title V Permit No. 0090196-001-AV, and after Reliant became the owner and operator of the three boilers, Reliant interpreted that the heat input ratings in Condition A.1 of the permit were incorporated for reference purposes only and were not intended as enforceable limits.[4] Following internal correspondence,

[2] B. E. Shoup of OUC sent a letter dated July 24, 1975 to Mr. Charles Collins of the FDEP Central District Office.

[3] Letter sent by R. F. Hicks of OUC to Mr. Alan Zahm, P.E. of the FDEP Central District Office dated February 12, 1991.

[4] Letter sent by J. Derek Furstenworth of Reliant Energy to Ms. Trina Vielhauer of the FDEP Tallahassee Office dated August 23, 2005.

FDEP responded that the agency views the heat input ratings as enforceable limits and that any exceedence of the permitted heat input in Condition A.1 would be a permit violation.[5]

In light of FDEP's interpretation of the listed heat input rating in Condition A.1 of the Title V permit, the current heat input values do not reflect the maximum hourly capacity of the units. The permitted values represent the unit's MCR which only provides an estimate of the heat input that can be continuously sustained by the unit. The units can and always have been able to accommodate higher instantaneous values, as reflected in OUC's 1991 request to the FDEP Central District Office.

Reliant has subsequently made several requests to the FDEP to either have the heat input limits removed or revised. A brief summary of these actions is provided below:

- On August 23, 2005, Reliant submitted a letter to FDEP requesting the removal of the heat input limits on the basis that imposing a one-hour heat input limit does not ensure compliance for a unit that has only rate-based emission limits.
- On April 12, 2006, Reliant submitted a Title V Permit Revision Application formally requesting to either have the heat input limits revised or removed.
- On June 8, 2006, FDEP responded by asking Reliant to provide an estimate of the potential to emit (PTE) increases expected from raising the hourly heat input values. If the expected emissions increases are significant and trigger PSD review, Reliant was also asked to provide a Best Achievable Control Technology (BACT) Analysis for this operation change, or measures to assure PSD applicability does not apply.
- Reliant responded on June 20, 2006 stating that the emission units have not undergone any physical changes or changes in the method of operation and therefore PSD rules do not apply and there is no need to perform a PTE analysis.
- On July 27, 2006, FDEP sent a letter informing Reliant that the request to remove or modify Condition A.1 cannot be accomplished by revision of the Title V permit and requires submittal of an air construction permit and that the emission increases require a review for PSD and a determination of BACT as described in Rule 62-212.400, F.A.C.
- On September 7, 2006, Reliant submitted a letter withdrawing the request to revise the Title V permit and requested instead to add language that would allow compliance with permitted limits based on a daily average.
- On October 5, 2006, FDEP once again responded by asking Reliant to submit a construction permit application with a review for PSD applicability and determination of BACT.

Reliant is responding to FDEP's most recent request and submitting this construction permit application to correct the maximum hourly heat input limits in Condition A.1 of the current Title V permit and to allow Boiler 1 and Boiler 3 to operate at their actual short-term capacity. Also, Reliant is proposing to include a specified compliance demonstration methodology for these heat input limits

[5] Email from Garry Kuberski of the FDEP Central District Office to Amy Deese of Reliant Energy, July 25, 2005.

and to eliminate from the limitations section the "Permitting Note" in the current permit that provides a reference only to stack testing.

Included with this application is an analysis demonstrating that PSD is not applicable to this application to correct the heat input limit, as the Indian River Plant's incremental emissions change will be below the PSD Significant Emissions Rates – please refer to Attachment 1.

THE CURRENT HEAT INPUT LIMITS DO NOT REFLECT MAXIMUM HOURLY CAPACITY

As described in previous correspondence and summarized in the preceding section of this letter, the current permit heat input limits are not accurate for Boilers 1 or 3 as they are based on the MCR, which is a design-guaranteed long-term sustainable rate rather than short term unit capability. The two units are able to achieve higher values on an instantaneous and hourly basis during normal operation. Changes in operations (e.g., load changes) cause large variability in short-term heat input values while the long-term average remains relatively constant. Additionally, as Reliant has previously asserted, a one-hour heat input limit does not ensure compliance for a unit that has only rate-based emission limits [i.e., pounds per million British thermal unit (MMBtu) emission limitations do not require a MMBtu/hr limit to ensure compliance].[6] As a result, Reliant is proposing alternatives to the current permitted hourly heat input limits.

PROPOSED SHORT-TERM HEAT INPUT LIMIT REVISIONS

Reliant is proposing revised short-term heat input rates for Boilers 1 and 3, provided in Table 2. These values are representative of the maximum short-term values that the units were designed to achieve, such as a result of overpressure. It is important to note that these higher ratings will only be reached for brief time periods and do not change the MCR, or the heat input capacity that can be sustained over the long-term.

TABLE 2. PROPOSED MAXIMUM SHORT-TERM OPERATING HEAT INPUT RATE

Fuel Type	Boiler 1 (MMBtu/hr)	Boiler 2 [7] (MMBtu/hr)	Boiler 3 (MMBtu/hr)
Natural Gas	923.3	2,248.7	3,409.7
Oil	890.0	2,016.5	3,250.0

[6] Letter sent by J. Derek Furstenworth of Reliant Energy to Ms. Trina Vielhauer of the FDEP Tallahassee Office dated August 23, 2005.

[7] Reliant is not proposing a change in the heat input limits for Boiler 2. The heat input values listed are equivalent to the current permit limits.

Compliance with these proposed short-term heat input rates will be based on a 3-hr block average, consistent with the reference of the current limits to stack testing. Reliant will ensure that these 3-hr average heat input rates are not exceeded by monitoring the heat input as is currently done for the Acid Rain program. Reliant will verify these proposed maximum short-term heat input rates for both Boilers 1 and 3 on both natural gas and fuel oil through initial performance testing, following FDEP's review of this application.

With the corrected short-term heat input rates proposed above, Reliant requests that the "Permitting Note" following Condition A.1 of the Title V permit be removed. In its place, Reliant requests clarifying permit language based on the compliance demonstration terms outlined above (3-hr block average as measured by certified fuel flow meters) – please refer to Attachment 2.

PROPOSED ANNUAL LIMITS

In addition to hourly heat input limits, Reliant is also requesting maximum annual heat input rates based on MCR (Table 3) to demonstrate that this application will not result in an increase in potential emissions. The maximum annual capacity of the units will not change as a result of the requested short-term heat input rates. This application is simply to correct mis-assigned short-term capacities. These limits were informally presented to Garry Kuberski of FDEP in July 2005, who subsequently recommended that Reliant request a permit modification.[8]

TABLE 3. PROPOSED MAXIMUM ANNUAL OPERATING HEAT INPUT RATE[9]

Fuel Type	Boiler 1 (MMBtu/yr)	Boiler 2 (MMBtu/yr)	Boiler 3 (MMBtu/yr)
Natural Gas	7,270,200	18,889,080	26,951,400
Oil	6,990,480	16,938,600	25,609,920

With these proposed revisions to the heat input limitations listed in the Title V permit, Reliant has prepared suggested edits to the specific permit conditions as an attachment to this letter.

[8] Email correspondence between Reliant and Garry Kuberski of FDEP in July 2005.

[9] Maximum annual operating rate is calculated by multiplying the currently permitted heat input rates in Table 1 by 8,400 hours per year of operation (Condition A.4 of the current Title V Permit).

REGULATORY APPLICABILITY

In response to FDEP's October 25, 2006 letter requesting that Reliant submit an air construction permit application including a review for PSD and determination of BACT, Reliant has included as an attachment to this letter a New Source Review applicability analysis.[10] It should be emphasized that this request is not the result of a physical change or change in the method of operation. The units have always been capable of operating above the heat input values currently referenced in Condition A.1 of the Title V permit, as these limits only represent the maximum *continuous* rating and are not representative of the short-term heat input that can be reached during normal operation. Reliant recognizes that the request for revising the heat input limits is interpreted by FDEP to be a "modification" to those sources per Florida Administrative Code (F.A.C.) 62-204.200 (Definitions). This interpretation requires the submission of a construction permit application to facilitate the permit condition changes.

Thank you for your consideration of this matter. If you have any questions or comments about the information included in this submittal, please do not hesitate to contact me at (321) 264-4598.

Sincerely,

Dennis Shaulis
Indian River Plant General Manager

Attachments

cc: Trina Vielhauer, Bureau Chief – FDEP Tallahassee
Jeff Koerner, NSR Administrator – FDEP Tallahassee
Ms. Michelle Duncan, Reliant Energy
Trinity Consultants

[10] Letter sent by Mr. A. A. Linero of FDEP to Mr. Terry Gish of Reliant Energy dated October 5, 2006.

ATTACHMENT 1: NEW SOURCE REVIEW APPLICABILITY ANALYSIS

This attachment provides an analysis of the proposed short-term heat input limit revisions for Boilers 1 and 3 located at Reliant Energy's (Reliant) Indian River Plant (the "Facility") with respect to determining applicability of New Source Review (NSR) permitting requirements for Prevention of Significant Deterioration (PSD). An assessment is included herein to support the applicability determination made by Reliant that this proposed revision is not subject to PSD permitting requirements, and thus neither requires a PSD air dispersion modeling demonstration nor a Best Available Control Technology (BACT) analysis.

This section reviews the pre-construction permitting requirements in regard to major NSR and its applicability to the proposed short-term heat input revisions. Additionally, a discussion of the permit application requirements is provided herein.

Reliant recognizes that the request for revising the heat input limits is interpreted by Florida Department of Environmental Protection (FDEP) to be a "modification" to those sources per Rule 62-204.200, Florida Administrative Code (F.A.C.) - *Definitions*, which specifies the following:

> A "modification" includes "any physical change in, change in the method of operation of, or addition to a facility which would result in an increase in the actual emissions of any air pollutant subject to regulation under the Act, including any not previously emitted, from any emissions unit or facility." In addition, "for any pollutant that is specifically regulated by the EPA under the Clean Air Act, a change in the method of operation shall not include an increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975."

The historical developments related to these hourly heat input limits are presented in the attached cover letter. Reliant wishes to remind the Department that these hourly limits were initially established in pre-Title V air operation permits issued to the previous owner and operator of the Indian River Generating Station (Orlando Utilities Commission) using the data that were not representative of maximum hourly operational performance. However, Reliant also recognizes that the F.A.C. does not provide a mechanism for changing incorrectly-established permit limits other than through the submittal of a pre-construction permit application that includes the following NSR applicability analysis.

NEW SOURCE REVIEW APPLICABILITY

Federal permitting programs include requirements for construction of new sources or modification of existing sources under NSR. NSR requires that construction of new emission sources or modifications to existing emission sources be evaluated to determine if both a (i) significant emissions increase and (ii) significant net emission increases results. Two distinct NSR permitting programs apply depending on whether the facility is located in an attainment or nonattainment area for a particular pollutant; nonattainment NSR (NNSR) permitting is required for facilities located in nonattainment areas, while PSD permitting is required for facilities located in attainment areas.

For the most part, the FDEP has adopted the federal NSR permitting program as promulgated in Chapter 62-212, F.A.C. and FDEP has full authority to implement this program through its U.S. EPA-authorized State Implementation Plan (SIP).

The facility is located in Brevard County which is designated by U.S. EPA as "unclassifiable/ attainment" for all pollutants.[1] Therefore, the facility is not subject to NNSR permitting requirements for any criteria pollutants. The facility is potentially subject to PSD permitting requirements.

Major Source Status at the Facility

F.A.C. Rule 62-212.400(3)(b) lists the PSD source categories with a 100 tpy "major" source threshold. Fossil fuel-fired steam electric plants of more than 250 MMBtu/hr heat input are on this list of the 28 source categories identified. Therefore, the facility is subject to a 100 tpy threshold (e.g. - PM_{10}, $PM_{2.5}$, SO_2, CO, NO_2, VOC) for classification as a PSD major source. Because the facility's potential emissions are greater than 100 tpy for PM_{10}, $PM_{2.5}$, SO_2, CO, NO_2, and VOC it is considered an existing major source with respect to the PSD program.

Establishing Applicability of PSD and NSR

If a source will undergo a physical change or change in the method of operation, the applicant must review that project to determine if the project also results in an increase in the actual emissions of any air pollutant. The magnitude of the emissions increase determines whether the change is considered to be a "modification" or "major modification." Rule 62-204.200, F.A.C. - *Definitions* specifies the following:

> A "major modification" is "any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a PSD pollutant and a significant net emissions increase of that pollutant from the major stationary source." In addition, "a physical change or change in the method of operation shall not include an increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975."

If a significant net emissions increase results, then PSD permitting is required. It is important to recall that the boilers have always had the capability to achieve a higher heat input, on a short-term basis, than the hourly limits in Emission Units Condition A.1 of the current Title V permit. No physical change is necessary to achieve the proposed heat inputs.

A significant net emissions increase is defined as a net emissions increase resulting from a physical change or change in the method of operation at a major source that exceeds the

[1] 40 CFR §81.310.

established Significant Emission Rate (SER) for that pollutant. Because the facility is currently a major source with respect to PSD, the SER for PSD pollutants are listed in the following table.[2]

TABLE A1. PSD SIGNIFICANT EMISSION RATES

Pollutant	SER (tons/yr)
PM	25
PM_{10}	15
$PM_{2.5}$	10
SO_2	40
VOC	40
NO_x	40
CO	100

Per Rule 62-210.200, F.A.C. – *Definitions*, (280)(b), the SER also means:

> "...for the pollutants listed above in paragraph (a), any emissions rate or any net emissions increase associated with a major stationary source or major modification which would construct within 10 kilometers of a Class I area and have an impact on such area equal to or greater than 1 μg/m3, 24-hour average."

There are no Class I areas within 10 kilometers of the Indian River Plant. The nearest Class I area is the Chassahowitzka National Wilderness Area, with the closest point approximately 170 kilometers from the Plant.

The current Title V air operation permit includes short-term heat input limits (MMBtu/hr) and annual operating hours limits for Boilers 1 and 3 based on rated MCR. Consequently, Boilers 1 and 3 are by extension also subject to implied annual heat input limits (MMBtu/yr). Per the attached cover letter, Reliant is requesting that the existing, implied annual emissions limits be established as permit conditions so that there are no concerns that the requested change would increase the potential to emit (PTE) of the facility. The requested revisions to the short-term heat input limit will simply allow the units to have higher short-term fluctuations in heat input that results from normal operation. The objective of the PSD applicability analysis is to (i) identify the change in annual emissions of the aforementioned PSD pollutants that is projected to occur as a result of the project (i.e., the increase in the hourly heat input limits for Boilers 1 and 3) and (ii)

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[2] Per Rule 62-210.200, F.A.C. – *Definitions*, (280) – "Significant Emissions Rate" - Although these regulations also list established SERs for fluorides (other than HF because HF is a hazardous air pollutant that is regulated separately under Section 112 of the Clean Air Act), hydrogen sulfide, reduced sulfur compounds and total reduced sulfur, there are no EPA-published (e.g., AP-42) emission factors for these constituents for the oil / gas-fired boiler industry sector. Consequently, it is expected that emissions of these constituents are negligible. Although these regulations also list SERs for sulfuric acid mist, lead and mercury, the EPA-published emission factors for these constituents (if available) are at least a factor of 100 less than the emission factors for the constituents included in Table 1. Consequently, it is expected that emissions of sulfuric acid mist, lead and mercury are also negligible.

determine if the change in annual emissions results in both a significant emissions increase and a significant net emissions increase. If the project does not satisfy the criteria of a "major modification," then PSD permitting requirements do not apply per Rule 62-212.400(2), F.A.C. – *Applicability*, which specifies the following:

> "The requirements of subsections 62-212.400(4) through (12), F.A.C., apply to the construction of any new major stationary source or the major modification of any existing major stationary source."[3]

Rule 62-212.400(2)(a)1., F.A.C. requires that the PSD applicability analysis be conducted using the Baseline Actual-to-Projected Actual Applicability Test for Modifications at Existing Emissions Units. If the difference between the Projected Actual Emissions and the Baseline Actual Emissions equals or exceeds the SER for that pollutant, then the emissions change is considered to be significant. Rule 62-210.200, F.A.C., defines Baseline Actual Emissions and Projected Actual Emissions for the purposes of this analysis as follows:

> (36) "Baseline Actual Emissions" and "Baseline Actual Emissions for PAL" – The rate of emissions, in tons per year, of a PSD pollutant, as follows:
>
> > (a) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding the date a complete permit application is received by the Department.
> >
> > > 3. For a PSD pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used for each PSD pollutant.
>
> (250) "Projected Actual Emissions" – The maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a PSD pollutant in any one of the 5 years following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that PSD pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source. One year is one 12-month period. In determining the projected actual emissions, the Department:
>
> > (a) Shall consider all relevant information, including historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans or orders, including consent

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[3] These regulatory citations include the requirements to conduct air dispersion modeling and a best available control technology analysis, should the project be considered a "major modification," as requested in the referenced correspondence in the cover letter attached to this analysis.

orders; and

(b) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups and shutdowns; and

(c) Shall exclude that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are also unrelated to the particular project including any increased utilization due to product demand growth.

Clause (c) under "Projected Actual Emissions" is widely known as the demand growth exclusion. The requested short-term heat input revisions are not related to any possible future increase in boiler utilization due to an increased number of days of operation demand.

ANNUAL EMISSIONS CHANGES DUE TO THE REVISED SHORT-TERM HEAT INPUT LIMITS

The requested revisions to the short-term heat input will simply allow the units to have higher short-term fluctuations in heat input as a result of normal operation – these requested changes are summarized below:

TABLE A2. INCREMENTAL CHANGE IN REVISED SHORT-TERM HEAT INPUT LIMITS

Unit / Fuel	Current Limits (MMBtu/hr)	Requested Limits (MMBtu/hr)	Change (MMBtu/hr)
Boiler 1			
Oil\	832.2	890.0	57.8
Natural Gas	865.5	923.3	57.8
Boiler 3			
Oil	3,048.8	3,250.0	201.2
Natural Gas	3,208.5	3,409.7	201.2

Long-term heat input is requested to be memorialized in a new permit condition based on the short-term heat input limits found in the current Title V permit. The only difference in future actual emissions not associated with demand growth may be a result of the small increase in heat input allowed by the requested change in short-term heat input limits.

A conservative analysis for how the short-term heat input revision may impact future emissions on an annual basis is to consider any incremental emissions that may result from the difference between the short-term heat input limits of the current Title V permit and the requested short-term heat input limits. Outside of this incremental operational change, any additional annual emissions increase would be attributed to demand growth, or emissions that could have been accommodated prior to this requested revision. As noted earlier, Rule 62-212.400(2)(a)1., F.A.C. requires that the PSD applicability analysis be conducted using the Baseline Actual-to-Projected Actual

Applicability Test for Modifications at Existing Emissions Units, where the Projected Actual Emissions excludes "that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions and that are also unrelated to the particular project including any increased utilization due to product demand growth." The data and methodologies used to calculate the (i) Baseline Actual Emissions (BAE), (ii) Projected Actual Emissions (PAE) and (iii) the portion of the unit's emissions following the project that an existing unit could have accommodated during the baseline period and are unrelated to the project (i.e., emissions that could have occurred in excess of the BAE [e.g., resulting from increased annual utilization] but are unrelated to the project, denoted as X) are presented in the tables included in Attachment 3. In summary, the BAE, PAE and X were calculated as follows:

The baseline actual emissions represent the combined annual rate (tpy) at which Boilers 1 and 3 actually emitted each listed PSD pollutant during the 2004-2005 consecutive 24-month period (Rules 62-210.200(36) and 62-212.400(2)(a)(1), F.A.C.), as obtained from the facility's Annual Operating Reports. The 2004-2005 period represents the maximum emissions over a consecutive 24-month period in the last five years, summing emissions from natural gas and Nos. 2 and 6 fuel oil combustion from both boilers.

The projected actual emissions were conservatively estimated by summing the following:

1. Annual emissions resulting from the combined operation of both Boilers 1 and 3 at their respective maximum capacity under its physical and operational design (maximum continuous rating for annual operation) including any operational limitations or limits in the permit (the minimum operation of either the equivalent availability factor [EAF], by boiler, or the 8,400 hours per year permit limit), [4] and
2. Annual emissions resulting from the incremental operation of both Boilers 1 and 3 at the requested revised heat input limits (short-term maximum heat input).

The portion of the unit's emissions following the project that an existing unit could have accommodated during the baseline period and are unrelated to the project (i.e., emissions that could have occurred in excess of the BAE but are unrelated to the project, denoted as X) were calculated as the difference between the (i) total emissions that an existing unit could have accommodated during the baseline period that are unrelated to the project (denoted as ECHA) and (ii) BAE. The ECHA was conservatively estimated per the criteria presented in Item No. 1 above.

[4] The physical and operation design on an annual basis and the limitations of annual operation will remain the same for each boiler before and after the requested permit revision. The EAF is the ratio of the Unit's available service hours to the total number of hours in the period. The EAF incorporates "derates" (i.e., reductions in electrical generation capacity) to the Unit that result from seasonal, maintenance and forced / unplanned outages.

Mathematically, the annual emissions change due to the project (Δ) is calculated as follows:

$$\Delta = (PAE - X) - BAE$$
$$\Delta = (PAE - [ECHA - BAE]) - BAE$$
$$\Delta = (PAE - ECHA)$$

A summary of the results of the PSD applicability analysis is presented in the following table:

TABLE A3. PSD ANNUAL EMISSIONS ANALYSIS

PSD Pollutant	Baseline Actual Emissions (BAE)[5] (tpy)	Projected Actual Emissions (PAE)[6] (tpy)	Emissions That Could Have Been Accommodated (ECHA)[7] (tpy)	Difference (Δ) (tpy)	SER (tpy)	PSD Applicability (Y/N)
PM	184	1,425	1,424	1	25	N
PM_{10}	184	1,425	1,424	1	15	N
$PM_{2.5}$	184	1,425	1,424	1	10	N
SO_2	4,448	39,186	39,147	39	40	N
VOC	15	97.5	97.4	< 1	40	N
NO_X	1,208	5,536	5,530	6	40	N
CO	113	468.7	468.3	< 1	100	N

With this incremental delta in emissions, which are the result of the revised short-term heat input limits, the annual emissions attributable to this proposed revision will be maintained below the PSD Significant Emission Rates (SERs) for each fuel type in each boiler, combined.

In addition, based on the emission factors used, SO_2 is the limiting pollutant when firing oil, whereas NO_X is the limiting pollutant when firing gas. Reliant will track actual operation above the current heat input limits and ensure that actual emissions (based on the actual heat input rate achieved and the fuel composition, as-fired) from both boilers remain below the significant emission rates for SO_2 and NO_X.

[5] Represents the sum of emissions from Boilers 1 and 3 from both fuels combusted (natural gas and No. 6 oil).

[6] Worst case projected actual emissions of all pollutants occur while firing No. 6 fuel oil.

[7] The physical and operation design (maximum continuous rating for annual operation) and the limitations of annual operation (8,400 hours per year) will remain the same for each boiler before and after the requested permit change.

PSD Analysis Summary

Because Reliant does not expect to realize a significant increase in annual emissions from the proposed project, this application is not subject to PSD permitting requirements (dispersion modeling or BACT). Detailed calculations are provided in Attachment 3.

COMPLIANCE ASSURANCE

As discussed previously, Reliant will monitor actual operation above the current short-term heat input limits to assure compliance with the revised heat input limits and to ensure that actual emissions (based on the actual heat input rate achieved and the fuel composition, as-fired) from both Boilers 1 and 3 remain below the significant emission rates for SO_2 and NO_X.

Compliance With Revised Short-Term Heat Input Limits

Reliant will determine compliance with the revised short-term heat input limits over a 3-hour block average.[8] For example, when firing natural gas only in Boiler 1, compliance will be demonstrated when the actual measured natural gas heat input by the data acquisition and handling system (DAHS) is less than or equal to 923.3 MMBtu/hr - on a 3-hour block average. Similarly, if co-firing oil and gas within a 3-hour block, the percent of actual heat input to the fuel-specific heat input limit will be summed for both natural gas and oil. If less than or equal to 100% on a 3-hr block average, permit compliance will be demonstrated.

Monitoring of Incremental Emissions

In addition to determining compliance with the new short-term heat input limits, the incremental emissions will need to be monitored, summed on an annual basis, and compared with the SER for NO_X and SO_2, respectively. Reliant will continuously monitor fuel-specific heat input for Boilers 1 and 3. The difference between the actual 3-hour block average heat input and the current short-term heat input limits will be used to determine the incremental emissions increase.

For example, if the actual heat input on a 3-hour block average from combustion of natural gas only exceeds 100% of the current permit limit (i.e., greater than 865.5 MMBtu/hr for Boiler 1), then the difference between the actual heat input and the current permit limit (865.5 MMBtu/hr) will be used to calculate the incremental emissions based on the actual NO_X and SO_2 emissions rate for the period.

Similarly, if Boiler 1 or Boiler 3 co-fires gas and oil within a 3-hour block average and the combined average heat input rate is greater than the calculated limit (as outlined in the previous compliance section), the incremental emissions for NO_X will be determined from the measured NO_X emissions rate and the combined total heat input from both fuels, less the current permit heat input limit. The incremental SO_2 emissions will be determined for each fuel individually, per existing monitoring protocol. The amount of incremental short-term heat input over the current limits will be based on the percent of total heat input attributed to that fuel.

The incremental emissions will be summed and recorded on a 12-month rolling basis. Reliant intends to monitor and limit the incremental emissions to levels below the respective SERs. The incremental emissions will be reported annually to FDEP as 12-month rolling totals. Reliant will report if the incremental emissions of any pollutant listed in Table A3 exceeds the applicable SER

[8] The first 3-hour block average of each calendar day will begin at midnight and end at 2:59 am. The subsequent 3-hour block average will begin at 3:00 am and end at 5:59 am, and so on.

and understands that the unit may be subject to NSR permitting requirements upon exceeding the SER.

ATTACHMENT 2: SUGGESTED PERMIT CONDITION LANGUAGE

The requested permit language changes are identified below, with added text included in bold italic font style and removed text identified in bold strikethrough text.

Reliant Proposed Change #1 (Title V Permit – page 6)

A.1. Permitted Capacity. The maximum ***short-term*** operating heat input rate is as follows:

Unit No.	Fuel Type	MMBtu/hr
1	Natural Gas	**~~865.5~~** ***923.3***
1	Oil	**~~832.2~~** ***890.0***
2	Natural Gas	2,248.7
2	Oil	2,016.5
3	Natural Gas	**~~3208.5~~** ***3,409.7***
3	Oil	**~~3048.8~~** ***3,250.0***

The maximum annual operating heat input rate is as follows:

Unit No.	***Fuel Type***	***MMBtu/yr***
1	***Natural Gas***	***7,270,200***
1	***Oil***	***6,990,480***
2	***Natural Gas***	***18,889,080***
2	***Oil***	***16,938,600***
3	***Natural Gas***	***26,951,400***
3	***Oil***	***25,609,920***

Additionally, on specification used oil may be fired at the rate of the lesser of:

a. Up to 1.5 million gallons per year; or
b. The equivalent heat input of 10 percent or less of the permitted heat input of No. 6 Fuel Oil while combusting either No. 6 Fuel Oil or Natural Gas.

{Permitting note: See Specific Condition A.38}
[Rules 62-4.160(2), 62-210.200 {PTE}, and 62-296.405, F.A.C.]

~~{Permitting note: The heat input limitations have been placed in the permit to identify the capacity of each emissions unit for purposes of confirming that emissions testing is conducted within 90-100 percent of the emissions unit's rated capacity (or to limit future operation to 110 percent of the test load), to establish appropriate limits and to aid in determining future rule applicability.~~ }
~~[Rule 62-4.160(2), and Rule 62-297.310(2), F.A.C.]~~

Reliant Proposed Additional Condition #1

In order to demonstrate compliance with Condition A.1. the permittee shall maintain records of the hourly heat input for each unit. These records shall include at a minimum the following information:

a. Emission Unit ID
b. Fuel Type
c. Hourly heat input (MMBtu)

Compliance with the short-term operating heat input rate in Condition A.1. will be demonstrated by 3-hour block averages as measured by certified fuel flow meters. In addition, the permittee shall maintain records of the rolling 12 month total heat input for each unit when burning gas and oil to demonstrate compliance with the annual heat input limits in Condition A.1.

Reliant Proposed Additional Condition #2

In order to demonstrate that annual emissions of NO_x and SO_2 from operation of Boiler 1 and Boiler 3 at the revised short-term operating heat input rate in Condition A.1. remain below the PSD significant emission rates, the permittee shall maintain records of:

a. *Incremental emissions of NO_X and SO_2 based on the actual heat input achieved and the fuel composition as-fired when Boiler 1 operates above 865.5 MMBtu/hr while firing natural gas and 832.2 MMBtu/hr while firing oil*
b. *Incremental emissions of NO_X and SO_2 based on the actual heat input achieved and the fuel composition as-fired when Boiler 3 operates above 3,208.5 MMBtu/hr while firing natural gas and 3,048.8 MMBtu/hr while firing oil.*

ATTACHMENT 3: DETAILED CALCULATIONS

Past Actual Emissions

Pollutant	2004-2005 (tons)[1,2] No. 6 Fuel Oil	No. 2 Fuel Oil	Natural Gas	2005-2006 (tons)[1,2] No. 6 Fuel Oil	No. 2 Fuel Oil	Natural Gas	2006-2007 (tons)[1,2] No. 6 Fuel Oil	No. 2 Fuel Oil	Natural Gas
EU001									
PM	48.73	0.01	0.74	34.94	0.01	0.79	11.56	0.02	1.72
PM_{10}	48.73	0.01	0.74	34.94	0.01	0.79	11.56	0.02	1.72
$PM_{2.5}$	48.73	0.01	0.74	34.94	0.01	0.79	11.56	0.02	1.72
SO_2	921.4	0.10	0.34	645.7	0.10	0.34	231.8	0.12	0.14
VOC	4.74	0.00	0.54	3.40	0.00	0.57	1.13	0.00	1.24
NO_X	249.2	0.31	26.20	176.2	0.30	27.50	57.2	0.20	41.50
CO	22.78	0.04	2.33	16.36	0.04	2.49	5.43	0.29	5.43
EU003									
PM	315.16	0.00	3.82	151.43	0.00	5.68	56.48	0.00	6.59
PM_{10}	315.16	0.00	3.82	151.43	0.00	5.68	56.48	0.00	6.59
$PM_{2.5}$	315.16	0.00	3.82	151.43	0.00	5.68	56.48	0.00	6.59
SO_2	7,972.2	0.00	1.85	3,601.7	0.00	1.94	1,322.4	0.00	0.50
VOC	22.25	0.00	2.76	18.82	0.00	4.11	7.05	0.00	4.77
NO_X	1,981.5	0.00	158	819.8	0.00	181	297.0	0.00	159
CO	188.00	0.00	12.05	90.47	0.00	17.93	33.89	0.00	20.80

1. Emissions were obtained from the Indian River facility's past Annual Operating Reports. The annual emissions for calendar year 2008 were not available at the time of this analysis. Reliant is conservatively assuming that the maximum emissions did not occur in 2008.
2. Represents the sum of emissions for each consecutive set of years by fuel type.

Baseline Actual Emissions

Pollutant	2004-2005 (tons)[1,3]	2005-2006 (tons)[1,3]	2006-2007 (tons)[1,3]	Baseline Actuals Emissions[2] (tpy)
TSP	368	193	76	184
PM_{10}	368	193	76	184
$PM_{2.5}$	368	193	76	184
SO_2	8,896	4,250	1,555	4,448
VOC	30.3	26.9	14.2	15.1
NO_X	2,415	1,205	555	1,208
CO	225	127	66	113

1. Represents the sum of emissions for Boilers 1 and 3 for each consecutive set of years for all fuel types (Nos. 6 and 2 fuel oil and natural gas).
2. Baseline actual emissions (tpy) for each pollutant are equal to the total emissions from a 24-consecutive month period within the last five years divided by two (to determine tons per year).
3. Emissions were calculated based on the Indian River facility's past Annual Operating Reports.

Indian River Annual Operating Report Data 2007

Pollutant	EU001 Annual Emissions by Fuel No. 6 Fuel Oil (tpy)	EU001 No. 2 Fuel Oil (tpy)	EU001 Natural Gas (tpy)	EU003 Annual Emissions by Fuel No. 6 Fuel Oil (tpy)	EU003 No. 2 Fuel Oil (tpy)	EU003 Natural Gas (tpy)
PM	4.07	0.0108	1.30	20.62	0	3.45
PM_{10}	4.07	0.0108	1.30	20.62	0	3.45
$PM_{2.5}$	4.07	0.0108	1.30	20.62	0	3.45
SO_2	81.2	0.0763	0.11	489.4	0	0.28
VOC	0.40	0.0014	0.94	2.58	0	2.50
NO_X	20.1	0.1296	30.3	98.4	0	77.1
CO	1.92	0.27	4.11	12.41	0	10.89

Pollutant	EU001 Emission Factors No. 6 Fuel Oil[1,2] (lb/Mgal)	EU001 No. 2 Fuel Oil[1] (lb/Mgal)	EU001 Natural Gas[3] (lb/MMscf)	EU003 Emission Factors No. 6 Fuel Oil[1,2] (lb/Mgal)	EU003 No. 2 Fuel Oil[1] (lb/Mgal)	EU003 Natural Gas[3] (lb/MMscf)
PM	10.6	2	7.6	8.31	2	7.6
PM_{10}	10.6	2	7.6	8.31	2	7.6
$PM_{2.5}$	10.6	2	7.6	8.31	2	7.6
SO_2	DAHS	14.13	DAHS	DAHS	14.13	DAHS
VOC	1.04	0.252	5.5	1.04	0.252	5.5
NO_X	DAHS	24	DAHS	DAHS	24	DAHS
CO	5	5	24	5	5	24

1. AP-42 Table 1.3-1, 1.3-3, unless otherwise noted.
2. Emission factors for PM, PM_{10}, and $PM_{2.5}$ were derived from stack tests for No. 6 Fuel Oil Firing.
3. AP-42 Table 1.4-1, 1.4-2.

Indian River Annual Operating Report Data 2006

Pollutant	EU001 Annual Emissions by Fuel No. 6 Fuel Oil (tpy)	EU001 No. 2 Fuel Oil (tpy)	EU001 Natural Gas (tpy)	EU003 Annual Emissions by Fuel No. 6 Fuel Oil (tpy)	EU003 No. 2 Fuel Oil (tpy)	EU003 Natural Gas (tpy)
PM	7.49	0.006	0.42	35.86	0	3.14
PM_{10}	7.49	0.006	0.42	35.86	0	3.14
$PM_{2.5}$	7.49	0.006	0.42	35.86	0	3.14
SO_2	150.6	0.0423	0.03	833.0	0	0.22
VOC	0.73	0.0008	0.30	4.47	0	2.27
NO_X	37.1	0.0719	11.2	198.6	0	81.9
CO	3.52	0.015	1.32	21.48	0	9.91

Pollutant	EU001 Emission Factors No. 6 Fuel Oil[1,2] (lb/Mgal)	EU001 No. 2 Fuel Oil[1] (lb/Mgal)	EU001 Natural Gas[3] (lb/MMscf)	EU003 Emission Factors No. 6 Fuel Oil[1,2] (lb/Mgal)	EU003 No. 2 Fuel Oil[1] (lb/Mgal)	EU003 Natural Gas[3] (lb/MMscf)
PM	10.6	2	7.6	8.31	2	7.6
PM_{10}	10.6	2	7.6	8.31	2	7.6
$PM_{2.5}$	10.6	2	7.6	8.31	2	7.6
SO_2	DAHS	14.13	DAHS	DAHS	14.13	DAHS
VOC	1.04	0.252	5.5	1.04	0.252	5.5
NO_X	DAHS	24	DAHS	DAHS	24	DAHS
CO	5	5	24	5	5	24

1. AP-42 Table 1.3-1, 1.3-3, unless otherwise noted.
2. Emission factors for PM, PM_{10}, and $PM_{2.5}$ were derived from stack tests for No. 6 Fuel Oil Firing.
3. AP-42 Table 1.4-1, 1.4-2.

Indian River Annual Operating Report Data 2005

Pollutant	EU001 Annual Emissions by Fuel No. 6 Fuel Oil (tpy)	EU001 No. 2 Fuel Oil (tpy)	EU001 Natural Gas (tpy)	EU003 Annual Emissions by Fuel No. 6 Fuel Oil (tpy)	EU003 No. 2 Fuel Oil (tpy)	EU003 Natural Gas (tpy)
PM	27.45	0.0083	0.37	115.57	0	2.54
PM_{10}	27.45	0.0083	0.37	115.57	0	2.54
$PM_{2.5}$	27.45	0.0083	0.37	115.57	0	2.54
SO_2	495.1	0.0584	0.31	2,769	0	1.72
VOC	2.67	0.001	0.27	14.35	0	1.84
NO_X	139.1	0.2326	16.3	621.2	0	99.1
CO	12.84	0.0207	1.17	68.98	0	8.02

Pollutant	EU001 Emission Factors No. 6 Fuel Oil[1,2] (lb/Mgal)	EU001 No. 2 Fuel Oil[1] (lb/Mgal)	EU001 Natural Gas[3] (lb/MMscf)	EU003 Emission Factors No. 6 Fuel Oil[1,2] (lb/Mgal)	EU003 No. 2 Fuel Oil[1] (lb/Mgal)	EU003 Natural Gas[3] (lb/MMscf)
PM	10.6	2	7.6	8.31	2	7.6
PM_{10}	10.6	2	7.6	8.31	2	7.6
$PM_{2.5}$	10.6	2	7.6	8.31	2	7.6
SO_2	DAHS	14.13	DAHS	DAHS	14.13	DAHS
VOC	1.04	0.252	5.5	1.04	0.252	5.5
NO_X	DAHS	24	DAHS	DAHS	24	DAHS
CO	5	5	24	5	5	24

1. AP-42 Table 1.3-1, 1.3-3, unless otherwise noted.
2. Emission factors for PM, PM_{10}, and $PM_{2.5}$ were derived from stack tests for No. 6 Fuel Oil Firing.
3. AP-42 Table 1.4-1, 1.4-2.

Indian River Annual Operating Report Data 2004

Pollutant	EU001 Annual Emissions by Fuel No. 6 Fuel Oil (tpy)	EU001 No. 2 Fuel Oil (tpy)	EU001 Natural Gas (tpy)	EU003 Annual Emissions by Fuel No. 6 Fuel Oil (tpy)	EU003 No. 2 Fuel Oil (tpy)	EU003 Natural Gas (tpy)
PM	21.28	0.0064	0.37	199.59	0	1.28
PM_{10}	21.28	0.0064	0.37	199.59	0	1.28
$PM_{2.5}$	21.28	0.0064	0.37	199.59	0	1.28
SO_2	426.3	0.0454	0.03	5,203	0	0.13
VOC	2.07	0.0008	0.27	7.90	0	0.92
NO_X	110.1	0.0771	9.9	1360.3	0	58.9
CO	9.94	0.0161	1.17	119.01	0	4.03

Pollutant	EU001 Emission Factors No. 6 Fuel Oil[1,2] (lb/Mgal)	EU001 No. 2 Fuel Oil[1] (lb/Mgal)	EU001 Natural Gas[3] (lb/MMscf)	EU003 Emission Factors No. 6 Fuel Oil[1,2] (lb/Mgal)	EU003 No. 2 Fuel Oil[1] (lb/Mgal)	EU003 Natural Gas[3] (lb/MMscf)
PM	10.6	2	7.6	8.31	2	7.6
PM_{10}	10.6	2	7.6	8.31	2	7.6
$PM_{2.5}$	10.6	2	7.6	8.31	2	7.6
SO_2	DAHS	14.13	DAHS	DAHS	14.13	DAHS
VOC	1.04	0.252	5.5	1.04	0.252	5.5
NO_X	DAHS	24	DAHS	DAHS	24	DAHS
CO	5	5	24	5	5	24

1. AP-42 Table 1.3-1, 1.3-3, unless otherwise noted.
2. Emission factors for PM, PM_{10}, and $PM_{2.5}$ were derived from stack tests for No. 6 Fuel Oil Firing.
3. AP-42 Table 1.4-1, 1.4-2.

Indian River Annual Operating Report Data 2003

Pollutant	EU001 Annual Emissions by Fuel No. 6 Fuel Oil (tpy)	EU001 No. 2 Fuel Oil (tpy)	EU001 Natural Gas (tpy)	EU003 Annual Emissions by Fuel No. 6 Fuel Oil (tpy)	EU003 No. 2 Fuel Oil (tpy)	EU003 Natural Gas (tpy)
PM	49.18	0.016	0.71	175.32	0	6.87
PM_{10}	49.18	0.016	0.71	175.32	0	6.87
$PM_{2.5}$	49.18	0.016	0.71	175.32	0	6.87
SO_2	853.2	0.1133	0.01	5,200	0	0.58
VOC	3.35	0.002	5.14	22.26	0	4.97
NO_X	103.2	0.1924	15.9	685.0	0	153.6
CO	13.13	0.0401	2.24	107.04	0	21.69

Pollutant	EU001 Emission Factors No. 6 Fuel Oil[1,2] (lb/Mgal)	EU001 No. 2 Fuel Oil[1] (lb/Mgal)	EU001 Natural Gas[3] (lb/MMscf)	EU003 Emission Factors No. 6 Fuel Oil[1,2] (lb/Mgal)	EU003 No. 2 Fuel Oil[1] (lb/Mgal)	EU003 Natural Gas[3] (lb/MMscf)
PM	15.25	2	7.6	8.19	2	7.6
PM_{10}	15.25	2	7.6	8.19	2	7.6
$PM_{2.5}$	15.25	2	7.6	8.19	2	7.6
SO_2	DAHS	14.13	DAHS	DAHS	14.13	DAHS
VOC	1.04	0.252	5.5	1.04	0.252	5.5
NO_X	32	24	170	32	24	170
CO	5	5	24	5	5	24

1. AP-42 Table 1.3-1, 1.3-3, unless otherwise noted.
2. Emission factors for PM, PM_{10}, and $PM_{2.5}$ were derived from stack tests for No. 6 Fuel Oil Firing.
3. AP-42 Table 1.4-1, 1.4-2.

Inidan River Annual Operating Report Data 2002

Pollutant	EU001 Annual Emissions by Fuel No. 6 Fuel Oil (tpy)	EU001 No. 2 Fuel Oil (tpy)	EU001 Natural Gas (tpy)	EU003 Annual Emissions by Fuel No. 6 Fuel Oil (tpy)	EU003 No. 2 Fuel Oil (tpy)	EU003 Natural Gas (tpy)
PM	32.03	0.03	2.82	79.46	0	11.42
PM_{10}	32.03	0.03	2.82	79.46	0	11.42
$PM_{2.5}$	32.03	0.03	2.82	79.46	0	11.42
SO_2	464.6	0.2119	0.30	3,042	0	1.00
VOC	2.45	0.0038	2.04	16.92	0	8.26
NO_X	142.2	0.3598	72.6	830.6	0	231.7
CO	11.79	0.075	8.92	81.35	0	36.06

Pollutant	EU001 Emission Factors No. 6 Fuel Oil[1,2] (lb/Mgal)	EU001 No. 2 Fuel Oil[1] (lb/Mgal)	EU001 Natural Gas[3] (lb/MMscf)	EU003 Emission Factors No. 6 Fuel Oil[1,2] (lb/Mgal)	EU003 No. 2 Fuel Oil[1] (lb/Mgal)	EU003 Natural Gas[3] (lb/MMscf)
PM	13.58	2	7.6	4.88	2	7.6
PM_{10}	13.58	2	7.6	4.88	2	7.6
$PM_{2.5}$	13.58	2	7.6	4.88	2	7.6
SO_2	DAHS	14.13	DAHS	DAHS	14.13	DAHS
VOC	1.04	0.252	5.5	1.04	0.252	5.5
NO_X	DAHS	24	DAHS	DAHS	24	DAHS
CO	5	5	24	5	5	24

1. AP-42 Table 1.3-1, 1.3-3, unless otherwise noted.
2. Emission factors for PM, PM_{10}, and $PM_{2.5}$ were derived from stack tests for No. 6 Fuel Oil Firing.
3. AP-42 Table 1.4-1, 1.4-2.

EU001 Steam Generating Boiler

Maximum No. 6 Fuel Oil Usage	39,640	mgal/yr
	5.48	mgal/hr
Sulfur Content of Fuel	2.5	%
No. 6 Fuel Oil Heating Value	152	MMBtu/mgal
Maximum No. 2 Fuel Oil Usage	43,347	mgal/yr
	5.99	mgal/hr
Sulfur Content of Fuel	0.5	%
No. 2 Fuel Oil Heating Value	139	MMBtu/mgal
Maximum Natural Gas Usage	6,020	MMscf/yr
	0.83	MMscf/hr
Natural Gas Heating Value	1,041	Btu/scf
Limited Short-term Rating of Boiler (Oil)	832.2	MMBtu/hr
Limited Short-term Rating of Boiler (Gas)	865.5	MMBtu/hr
Maximum Continuous Rating of Boiler (Oil)	832.2	MMBtu/hr
Maximum Continuous Rating of Boiler (Gas)	865.5	MMBtu/hr
Maximum Operation	8,400	hr/yr
Equivalent Availability Factor (EAF)	82.65	%
Annual Heat Input (Oil)	6,025,245	MMBtu/yr
Annual Heat Input (Gas)	6,266,341	MMBtu/yr

1. The annual heat input was calculated as the lesser of:
   The product of the boiler MCR and the maximum permitted operation (8400 hr/yr);
   The product of the boiler MCR and the EAF (at 8760 hr/yr).
2. Hourly fuel usage was calculated by dividing the short-term boiler capacity by the heating value of the fuel.
3. Heating values for No. 6 and No. 2 fuel oil were obtained from the 2007 AOR.
4. Heating value for natural gas represents the average heating value of natural gas fired at the Indian River facility from January 2002 through October 2008. Supplied by Florida Gas Transmission (Brooker Chromatograph).
5. Sulfur content of No. 6 fuel oil based on Condition A.10. of Title V Air Operation Permit No. 0090196-008-AV.
6. EAF based on 2004 for Unit No. 1.

Emissions That Could Have Been Accommodated for EU001[1]

Pollutant	No. 6 Fuel Oil Emission Factor		Ref.	(tpy)	Natural Gas Emission Factor		Ref.	(tpy)
PSD Regulated Pollutants								
PM	0.1	lb/MMBtu	2	301	7.6	lb/MMscf	5	23
PM_{10}	0.1	lb/MMBtu	2	301	7.6	lb/MMscf	5	23
$PM_{2.5}$	0.1	lb/MMBtu	2	301	7.6	lb/MMscf	5	23
SO_2	2.75	lb/MMBtu	2	8,285	0.6	lb/MMscf	5	2
VOC	1.04	lb/10^3 gal	3	21	5.5	lb/MMscf	5	17
NO_X	0.409	lb/MMBtu	4	1,232	0.116	lb/MMbtu	6	363
CO	5	lb/10^3 gal	3	99	24	lb/MMscf	5	72

[1] This table presents the calculations of Emissions That Could Have Been Accommodated prior to this request for revised short-term heat input limits. The annual emissions that could have been accomodated prior to this requested change are based on operating at the MCR for the duration of the equivalent activity factor for the boiler, or the permitted hours of operation, whichever is less.

[2] Emission factor based on the emission rate limits in Section III.A. of the Title V Air Operation Permit No. 0090196-008-AV

[3] Emission factors for large boilers (> 100 MMBtu/hr), tangential firing from AP-42, Section 1.3 - Fuel Oil Combustion, Table 1.3-1 (9/98).

[4] Based on site specific data for Boiler 1 while firing only oil in Feburary, July, September and October 2006. Represents average NO_x in lb/MMBtu.

[5] Emission factors for Tangential-Fired boilers (All Sizes) from AP-42, Section 1.4 - Natural Gas Combustion (7/98).
PM emission factor includes filterable and condensable fractions. Although the 0.1 lb of PM/MMBtu emission rate limit in Section III.A. of the Title V Air Operation Permit No. 0090196-008-AV applies during gas combustion as well, Reliant has applied the AP-42 factor to represent PM emissions that could have been accomodated from gas combustion.

[6] Based on site specific data for Boiler 1 while firing only gas in October 2006. Represents average NO_x emissions in lb/MMBtu.

EU003 Steam Generating Boiler

Maximum No. 6 Fuel Oil Usage	147,664 mgal/yr 20.06 mgal/hr
Sulfur Content of Fuel	2.5 %
No. 6 Fuel Oil Heating Value	152 MMBtu/mgal
Maximum No. 2 Fuel Oil Usage	161,475 mgal/yr 21.93 mgal/hr
Average Sulfur Content of Fuel	0.5 %
No. 2 Fuel Oil Heating Value	139 MMBtu/mgal
Maximum Natural Gas Usage	22,690 MMscf/yr 3.08 MMscf/hr
Natural Gas Heating Value	1,041 Btu/scf
Limited Short-term Rating of Boiler (Oil)	3,048.8 MMBtu/hr
Limited Short-term Rating of Boiler (Gas)	3,208.5 MMBtu/hr
Maximum Continuous Rating of Boiler (Oil)	3,048.8 MMBtu/hr
Maximum Continuous Rating of Boiler (Gas)	3,208.5 MMBtu/hr
Maximum Operation	8,400 hr/yr
Equivalent Availability Factor (EAF)	84.04 %
Annual Heat Input (Oil)	22,444,973 MMBtu/yr
Annual Heat Input (Gas)	23,620,669 MMBtu/yr

1. The annual heat input was calculated as the lesser of:
   The product of the boiler MCR and the maximum permitted operation (8400 hr/yr);
   The product of the boiler MCR and the EAF (at 8760 hr/yr).
2. Hourly fuel usage was calculated by dividing the short-term boiler capacity by the heating value of the fuel.
3. Heating values for No. 6 and No. 2 fuel oil were obtained from the 2007 AOR.
4. Heating value for natural gas represents the average heating value of natural gas fired at the Indian River facility from January 2002 through October 2008. Supplied by Florida Gas Transmission (Brooker Chromatograph).
5. Sulfur content of No. 6 fuel oil based on Condition A.10. of Title V Air Operation Permit No. 0090196-008-AV.
6. EAF based on 2004 for Unit No. 3.

Emissions That Could Have Been Accommodated for EU003[1]

Pollutant	No. 6 Fuel Oil Emission Factor		Ref.	(tpy)	Natural Gas Emission Factor		Ref.	(tpy)
PSD Regulated Pollutants								
PM	0.1	lb/MMBtu	2	1,122	7.6	lb/MMscf	5	86
PM_{10}	0.1	lb/MMBtu	2	1,122	7.6	lb/MMscf	5	86
$PM_{2.5}$	0.1	lb/MMBtu	2	1,122	7.6	lb/MMscf	5	86
SO_2	2.75	lb/MMBtu	2	30,862	0.6	lb/MMscf	5	7
VOC	1.04	$lb/10^3$ gal	3	77	5.5	lb/MMscf	5	62
NO_X	0.383	lb/MMBtu	4	4,298	0.198	lb/MMBtu	6	2338
CO	5	$lb/10^3$ gal	3	369	24	lb/MMscf	5	272

[1] This table presents the calculations of Emissions That Could Have Been Accommodated prior to this request for revised short-term heat input limits. The annual emissions that could have been accomodated prior to this requested change are based on operating at the MCR for the duration of the equivalent activity factor for the boiler, or the permitted hours of operation, whichever is less.

[2] Emission factor based on the emission rate limits in Section III.A. of the Title V Air Operation Permit No. 0090196-008-AV

[3] Emission factors for large boilers (> 100 MMBtu/hr), tangential firing from AP-42, Section 1.3 - Fuel Oil Combustion, Table 1.3-1 (9/98).

[4] Based on site specific data for Boiler 3 while firing only oil in August 2006. Represents average NO_x emissions in lb/MMBtu.

[5] Emission factors for Tangential-Fired boilers (All Sizes) from AP-42, Section 1.4 - Natural Gas Combustion (7/98). PM emission factor includes filterable and condensable fractions. Although the 0.1 lb of PM/MMBtu emission rate limit in Section III.A. of the Title V Air Operation Permit No. 0090196-008-AV applies during gas combustion as well, Reliant has applied the AP-42 factor to represent PM emissions that could have been accomodated from gas combustion.

[6] Based on site specific data for Boiler 3 while firing only gas in June 2005. Represents average NO_x emissions in lb/MMBtu.

EU001 Steam Generating Boiler

Maximum No. 6 Fuel Oil Usage	39,640 mgal/yr 5.86 mgal/hr
Sulfur Content of Fuel	2.5 %
No. 6 Fuel Oil Heating Value	152 MMBtu/mgal
Maximum No. 2 Fuel Oil Usage	43,347 mgal/yr 6.40 mgal/hr
Sulfur Content of Fuel	0.5 %
No. 2 Fuel Oil Heating Value	139 MMBtu/mgal
Maximum Natural Gas Usage	6,020 MMscf/yr 0.89 MMscf/hr
Natural Gas Heating Value	1,041 Btu/scf
Maximum Short-term Rating of Boiler (Oil)	890.0 MMBtu/hr
Maximum Short-term Rating of Boiler (Gas)	923.3 MMBtu/hr
Maximum Continuous Rating of Boiler (Oil)	832.2 MMBtu/hr
Maximum Continuous Rating of Boiler (Gas)	865.5 MMBtu/hr
Maximum Operation	8,400 hr/yr
Equivalent Availability Factor (EAF)	82.65 %
Annual Heat Input (Oil)	6,025,245 MMBtu/yr
Annual Heat Input (Gas)	6,266,341 MMBtu/yr

1. The annual heat input was calculated as the lesser of:
   The product of the boiler MCR and the maximum permitted operation (8400 hr/yr);
   The product of the boiler MCR and the EAF (at 8760 hr/yr).
2. Hourly fuel usage was calculated by dividing the short-term boiler capacity by the heating value of the fuel.
3. Heating values for No. 6 and No. 2 fuel oil were obtained from the 2007 AOR.
4. Heating value for natural gas represents the average heating value of natural gas fired at the Indian River facility from January 2002 through October 2008. Supplied by Florida Gas Transmission (Brooker Chromatograph).
5. Sulfur content of No. 6 fuel oil based on Condition A.10. of Title V Air Operation Permit No. 0090196-008-AV.
6. EAF based on 2004 for Unit No. 1.

Projected Actual Emissions Not Attributed to Revised Heat Input for EU001[1]

Pollutant	No. 6 Fuel Oil Emission Factor		Ref.	(tpy)	Natural Gas Emission Factor		Ref.	(tpy)
PSD Regulated Pollutants								
PM	0.1	lb/MMBtu	2	301	7.6	lb/MMscf	5	23
PM_{10}	0.1	lb/MMBtu	2	301	7.6	lb/MMscf	5	23
$PM_{2.5}$	0.1	lb/MMBtu	2	301	7.6	lb/MMscf	5	23
SO_2	2.75	lb/MMBtu	2	8,285	0.6	lb/MMscf	5	2
VOC	1.04	lb/10^3 gal	3	21	5.5	lb/MMscf	5	17
NO_X	0.409	lb/MMBtu	4	1,232	0.116	lb/MMBtu	6	363
CO	5	lb/10^3 gal	3	99	24	lb/MMscf	5	72

[1] This table presents the calculations for the portion of the Projected Actual Emissions not attributed to the revised short-term heat input limits. The annual emissions rate is based on the sustained operation at the maximum continuous rating of the boiler (current heat input limits) for the duration of the equivalent activity factor for the boiler, or the permitted hours of operation, whichever is less.

[2] Emission factor based on the emission rate limits in Section III.A. of the Title V Air Operation Permit No. 0090196-008-AV

[3] Emission factors for large boilers (> 100 MMBtu/hr), tangential firing from AP-42, Section 1.3 - Fuel Oil Combustion, Table 1.3-1 (9/98).

[4] Based on site specific data for Boiler 1 while firing only oil in Feburary, July, September and October 2006. Represents average NO_x in lb/MMBtu.

[5] Emission factors for Tangential-Fired boilers (All Sizes) from AP-42, Section 1.4 - Natural Gas Combustion (7/98). PM emission factor includes filterable and condensable fractions. Although the 0.1 lb of PM/MMBtu emission rate limit in Section III.A. of the Title V Air Operation Permit No. 0090196-008-AV applies during gas combustion as well, Reliant has applied the AP-42 factor to represent projected actual PM emissions from gas combustion.

[6] Based on site specific data for Boiler 1 while firing only gas in October 2006. Represents average NO_x emissions in lb/MMBtu.

EU003 Steam Generating Boiler

Maximum No. 6 Fuel Oil Usage	147,664	mgal/yr
	21.38	mgal/hr
Sulfur Content of Fuel	2.5	%
No. 6 Fuel Oil Heating Value	152	MMBtu/mgal
Maximum No. 2 Fuel Oil Usage	161,475	mgal/yr
	23.38	mgal/hr
Average Sulfur Content of Fuel	0.5	%
No. 2 Fuel Oil Heating Value	139	MMBtu/mgal
Maximum Natural Gas Usage	22,690	MMscf/yr
	3.28	MMscf/hr
Natural Gas Heating Value	1,041	Btu/scf
Maximum Short-term Rating of Boiler (Oil)	3,250.0	MMBtu/hr
Maximum Short-term Rating of Boiler (Gas)	3,409.7	MMBtu/hr
Maximum Continuous Rating of Boiler (Oil)	3,048.8	MMBtu/hr
Maximum Continuous Rating of Boiler (Gas)	3,208.5	MMBtu/hr
Maximum Operation	8,400	hr/yr
Equivalent Availability Factor (EAF)	84.04	%
Annual Heat Input (Oil)	22,444,973	MMBtu/yr
Annual Heat Input (Gas)	23,620,669	MMBtu/yr

1. The annual heat input was calculated as the lesser of:
   The product of the boiler MCR and the maximum permitted operation (8400 hr/yr);
   The product of the boiler MCR and the EAF (at 8760 hr/yr).
2. Hourly fuel usage was calculated by dividing the short-term boiler capacity by the heating value of the fuel.
3. Heating values for No. 6 and No. 2 fuel oil were obtained from the 2007 AOR.
4. Heating value for natural gas represents the average heating value of natural gas fired at the Indian River facility from January 2002 through October 2008. Supplied by Florida Gas Transmission (Brooker Chromatograph).
5. Sulfur content of No. 6 fuel oil based on Condition A.10. of Title V Air Operation Permit No. 0090196-008-AV.
6. EAF based on 2004 for Unit No. 3.

Projected Actual Emissions Not Attributed to Revised Heat Input for EU003[1]

Pollutant	No. 6 Fuel Oil Emission Factor		Ref.	(tpy)	Natural Gas Emission Factor		Ref.	(tpy)
PSD Regulated Pollutants								
PM	0.1	lb/MMBtu	2	1,122	7.6	lb/MMscf	5	86
PM_{10}	0.1	lb/MMBtu	2	1,122	7.6	lb/MMscf	5	86
$PM_{2.5}$	0.1	lb/MMBtu	2	1,122	7.6	lb/MMscf	5	86
SO_2	2.75	lb/MMBtu	2	30,862	0.6	lb/MMscf	5	7
VOC	1.04	lb/10^3 gal	3	77	5.5	lb/MMscf	5	62
NO_X	0.383	lb/MMBtu	4	4,298	0.198	lb/MMBtu	6	2,338
CO	5	lb/10^3 gal	3	369	24	lb/MMscf	5	272

[1] This table presents the calculations for the portion of the Projected Actual Emissions not attributed to the revised short-term heat input limits. The annual emissions rate is based on the sustained operation at the maximum continuous rating of the boiler (current heat input limits) for the duration of the equivalent activity factor for the boiler, or the permitted hours of operation, whichever is less.

[2] Emission factor based on the emission rate limits in Section III.A. of the Title V Air Operation Permit No. 0090196-008-AV

[3] Emission factors for large boilers (> 100 MMBtu/hr), tangential firing from AP-42, Section 1.3 - Fuel Oil Combustion, Table 1.3-1 (9/98).

[4] Based on site specific data for Boiler 3 while firing only oil in August 2006. Represents average NO_x emissions in lb/MMBtu.

[5] Emission factors for Tangential-Fired boilers (All Sizes) from AP-42, Section 1.4 - Natural Gas Combustion (7/98). PM emission factor includes filterable and condensable fractions. Although the 0.1 lb of PM/MMBtu emission rate limit in Section III.A. of the Title V Air Operation Permit No. 0090196-008-AV applies during gas combustion as well, Reliant has applied the AP-42 factor to represent projected actual PM emissions from gas combustion.

[6] Based on site specific data for Boiler 3 while firing only gas in June 2005. Represents average NO_x emissions in lb/MMBtu.

SO2

6409 MMBtu/yr x $\frac{2.75}{2000}$ = 8.8

98,084 x $\frac{.6}{2000}$ =

.03

8.83 #1

E/12-4-08

F/os

EU001 Steam Generating Boiler

Incremental No. 6 Fuel Oil Usage	42	mgal/yr
	0.38	mgal/hr
Sulfur Content of Fuel	2.5	%
No. 6 Fuel Oil Heating Value	152	MMBtu/mgal
Maximum No. 2 Fuel Oil Usage	46	mgal/yr
	0.42	mgal/hr
Sulfur Content of Fuel	0.5	%
No. 2 Fuel Oil Heating Value	139	MMBtu/mgal
Maximum Natural Gas Usage	94	MMscf/yr
	0.06	MMscf/hr
Natural Gas Heating Value	1,041	Btu/scf
Maximum Short-term Rating of Boiler (Oil)	890.0	MMBtu/hr
Maximum Short-term Rating of Boiler (Gas)	923.3	MMBtu/hr
Maximum Continuous Rating of Boiler (Oil)	832.2	MMBtu/hr
Maximum Continuous Rating of Boiler (Gas)	865.5	MMBtu/hr
Incremental Annual Heat Input (Oil)	6,409	MMBtu/yr
Incremental Annual Heat Input (Gas)	98,084	MMBtu/yr

1. The incremental annual heat input was calculated from the incremental increase in the short-term heat input limits (the difference between the short-term boiler capacity and the MCR) and an estimate of the annual operation at these revised heat inputs. This estimate identifies the portion of annual operation that can be attributed to the revised heat input limits.
2. Incremental hourly fuel usage was calculated by dividing the difference between the short-term boiler capacity and the MCR by the heating value of the fuel.
3. Heating values for No. 6 and No. 2 fuel oil were obtained from the 2007 AOR.
4. Heating value for natural gas represents the average heating value of natural gas fired at the Indian River facility from January 2002 through October 2008. Supplied by Florida Gas Transmission (Brooker Chromatograph).
5. Sulfur content of No. 6 fuel oil based on Condition A.10. of Title V Air Operation Permit No. 0090196-008-AV.

5 yr Avg Emission Factor then Apply to 2 yr Period

Need 3 hr Rolling Avg Above 0/1 Ratio

61 C - 58 mmBtu/hr

57.2 / 139

~~.42 gal/hr~~

5

37k gal/hr

Projected Actual Emissions Due to Revised Heat Input Limit for EU001[1]

Pollutant	No. 6 Fuel Oil Emission Factor		Ref.	(tpy)	Natural Gas Emission Factor		Ref.	(tpy)
PSD Regulated Pollutants								
PM	0.1	lb/MMBtu	2	0.3	7.6	lb/MMscf	5	0.4
PM_{10}	0.1	lb/MMBtu	2	0.3	7.6	lb/MMscf	5	0.4
$PM_{2.5}$	0.1	lb/MMBtu	2	0.3	7.6	lb/MMscf	5	0.4
SO_2	2.75	lb/MMBtu	2	8.8	0.6	lb/MMscf	5	0.03
VOC	1.04	lb/10^3 gal	3	0.02	5.5	lb/MMscf	5	0.3
NO_X	0.409	lb/MMBtu	4	1.3	0.116	lb/MMBtu	6	5.7
CO	5	lb/10^3 gal	3	0.1	24	lb/MMscf	5	1.1

[1] This table presents the calculations for the portion of the Projected Actual Emissions that can be attributed to the revised short-term heat input limits. The annual emissions due to the revised heat input limit is based on the incremental difference in the projected maximum short-term rating of the boiler for each fuel and the MCR (at the current heat input limits).
The emissions presented in this table are the estimated incremental annual emissions attributed to the revised heat input for Boiler 1 only. Boiler 1 and 3's individual contribution to the total incremental emissions has been estimated assuming that both boilers will operate for the same duration. Reliant will track the actual incremental emissions from both boilers combined.

[2] Emission factor based on the emission rate limits in Section III.A. of the Title V Air Operation Permit No. 0090196-008-AV

[3] Emission factors for large boilers (> 100 MMBtu/hr), tangential firing from AP-42, Section 1.3 - Fuel Oil Combustion, Table 1.3-1 (9/98).

[4] Based on site specific data for Boiler 1 while firing only oil in Feburary, July, September and October 2006. Represents average NO_x in lb/MMBtu.

[5] Emission factors for Tangential-Fired boilers (All Sizes) from AP-42, Section 1.4 - Natural Gas Combustion (7/98).
PM emission factor includes filterable and condensable fractions. Although the 0.1 lb of PM/MMBtu emission rate limit in Section III.A. of the Title V Air Operation Permit No. 0090196-008-AV applies during gas combustion as well, Reliant has applied the AP-42 factor to represent projected actual PM emissions from gas combustion.

[6] Based on site specific data for Boiler 1 while firing only gas in October 2006. Represents average NO_x emissions in lb/MMBtu.

EU003 Steam Generating Boiler

Incremental No. 6 Fuel Oil Usage	147 mgal/yr
	1.32 mgal/hr
Sulfur Content of Fuel	2.5 %
No. 6 Fuel Oil Heating Value	152 MMBtu/mgal
Maximum No. 2 Fuel Oil Usage	161 mgal/yr
	1.45 mgal/hr
Sulfur Content of Fuel	0.5 %
No. 2 Fuel Oil Heating Value	139 MMBtu/mgal
Maximum Natural Gas Usage	328 MMscf/yr
	0.19 MMscf/hr
Natural Gas Heating Value	1,041 Btu/scf
Maximum Short-term Rating of Boiler (Oil)	3,250.0 MMBtu/hr
Maximum Short-term Rating of Boiler (Gas)	3,409.7 MMBtu/hr
Maximum Continuous Rating of Boiler (Oil)	3,048.8 MMBtu/hr
Maximum Continuous Rating of Boiler (Gas)	3,208.5 MMBtu/hr
Incremental Annual Heat Input (Oil)	22,311 MMBtu/yr
Incremental Annual Heat Input (Gas)	341,426 MMBtu/yr

1. The incremental annual heat input was calculated from the incremental increase in the short-term heat input limits (the difference between the short-term boiler capacity and the MCR) and an estimate of the annual operation at these revised heat inputs. This estimate identifies the portion of annual operation that can be attributed to the revised heat input limits.
2. Incremental hourly fuel usage was calculated by dividing the difference between the short-term boiler capacity and the MCR by the heating value of the fuel.
3. Heating values for No. 6 and No. 2 fuel oil were obtained from the 2007 AOR.
4. Heating value for natural gas represents the average heating value of natural gas fired at the Indian River facility from January 2002 through October 2008. Supplied by Florida Gas Transmission (Brooker Chromatograph).
5. Sulfur content of No. 6 fuel oil based on Condition A.10. of Title V Air Operation Permit No. 0090196-008-AV.

Projected Actual Emissions Due to Revised Heat Input Limit for EU003[1]

Pollutant	No. 6 Fuel Oil Emission Factor		Ref.	(tpy)	Natural Gas Emission Factor		Ref.	(tpy)
PSD Regulated Pollutants								
PM	0.1	lb/MMBtu	2	1.1	7.6	lb/MMscf	5	1.2
PM_{10}	0.1	lb/MMBtu	2	1.1	7.6	lb/MMscf	5	1.2
$PM_{2.5}$	0.1	lb/MMBtu	2	1.1	7.6	lb/MMscf	5	1.2
SO_2	2.75	lb/MMBtu	2	30.7	0.6	lb/MMscf	5	0.10
VOC	1.04	$lb/10^3$ gal	3	0.1	5.5	lb/MMscf	5	0.9
NO_X	0.383	lb/MMBtu	4	4.3	0.198	lb/MMBtu	6	33.8
CO	5	$lb/10^3$ gal	3	0.4	24	lb/MMscf	5	3.9

[1] This table presents the calculations for the portion of the Projected Actual Emissions that can be attributed to the revised short-term heat input limits. The annual emissions due to the revised heat input limit is based on the incremental difference in the projected maximum short-term rating of the boiler for each fuel and the MCR (at the current heat input limits).
The emissions presented in this table are the estimated incremental annual emissions attributed to the revised heat input for Boiler 3 only. Boiler 1 and 3's individual contribution to the total incremental emissions has been estimated assuming that both boilers will operate for the same duration. Reliant will track the actual incremental emissions from both boilers combined.

[2] Emission factor based on the emission rate limits in Section III.A. of the Title V Air Operation Permit No. 0090196-008-AV

[3] Emission factors for large boilers (> 100 MMBtu/hr), tangential firing from AP-42, Section 1.3 - Fuel Oil Combustion, Table 1.3-1 (9/98).

[4] Based on site specific data for Boiler 3 while firing only oil in August 2006. Represents average NO_x emissions in lb/MMBtu.

[5] Emission factors for Tangential-Fired boilers (All Sizes) from AP-42, Section 1.4 - Natural Gas Combustion (7/98).
PM emission factor includes filterable and condensable fractions. Although the 0.1 lb of PM/MMBtu emission rate limit in Section III.A. of the Title V Air Operation Permit No. 0090196-008-AV applies during gas combustion as well, Reliant has applied the AP-42 factor to represent projected actual PM emissions from gas combustion.

[6] Based on site specific data for Boiler 3 while firing only gas in June 2005. Represents average NO_x emissions in lb/MMBtu.

PSD Annual Emissions Analysis

Pollutant	Baseline Actual Emissions[1,2] (tpy)	Projected Actual Emissions[3,4] (tpy)	Emissions that Could Have Been Accommodated[5] (tpy)	Difference (tpy)	SER (tpy)	PSD Applicability (Y/N)
PM	184	1,425	1,424	1.4	25	N
PM_{10}	184	1,425	1,424	1.4	15	N
$PM_{2.5}$	184	1,425	1,424	1.4	10	N
SO_2	4,448	39,186	39,147	39	40	N
VOC	15	97.5	97.4	0.1	40	N
NO_X	1,208	5,536	5,530	5.6	40	N
CO	113	468.73	468.26	0.5	100	N

1. Represents the sum of emissions from Boilers 1 and 3 from both fuels combusted (gas and No. 6 oil)
2. Basline acutal emissions is the sum of annual average emissions for Boilers 1 and 3 from a consecutive 24-month period (2004-2005 was chosen as it has maximum emissions for all pollutants) per Rule 62-210.200(36), F.A.C.
3. Worst case projected actual emissions of all pollutants occur while firing No. 6 fuel oil
4. Projected actual emissions are the sum of the emissions from:
   a) The operation of both boilers at their respective maximum capacity under its physical and operational design (maximum continuous rating for annual operation) including any operational limitations or limits in the permit (the minimum operation of either the EAF, by boiler, or the 8,400 hours per year permit limit).
   b) The estimated incremental annual operation of both boilers at the requested revised heat input limits (short-term maximum heat input). Reliant will track actual incremental emissions from both boilers combined (and all fuels) to ensure the corresponding SER is not exceeded.
5. The physical and operation design (maximum continuous rating for annual operation) and the limitations of annual operation (8,400 hours per year) will remain the same for each boiler before and after the requested permit change.

RRI Energy

121 Champion Way
Canonsburg, PA 15317

August 24, 2009

Electronic Mail - Received Receipt Requested

Mr. Jeffery F. Koerner, Administrator
New Source Review Section
Florida Department of Environmental Protection
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, FL 32399-2400

RE: **Response to Request for Additional Information**
Project No. 0090196-010-AC
RRI Energy Florida, LLC; Indian River Power Plant
Boiler 1 and 3 Heat Input Increase

Dear Mr. Koerner:

On May 27, 2009 RRI Energy received your Request for Additional Information (RAI) concerning our application for an air construction permit requesting a heat input increase for Boilers 1 and 3 at the Indian River Power Plant. We had a follow-up teleconference with you and Ms. Trina Vielhauer on June 15, 2009 to discuss the specifics of the RAI. For clarity, our responses follow the four (4) questions posed in the RAI.

1. *Provide data supporting the requested short-term heat input rates during normal operation. Please document the total number of hours and the maximum heat inputs realized for each "over-pressure" excursion above the permitted heat input limits for the 2004-2008 baseline emission period. Data from any periods of operation over the permitted capacity should be excluded from the baseline actual emissions.*

As noted in our April 2009 submittal, the current hourly heat input limits were provided to the FDEP Central District Office in 1975 by the Orlando Utilities Commission (OUC), who was the previous owner and operator of the plant. OUC identified these hourly heat inputs as the unit's guaranteed maximum continuous ratings (MCR) which are representative of what the units were designed to accommodate and continuously sustain over the long-term. All boilers are designed to produce steam at a target design temperature and pressure. However, excursions from these values are occasionally realized because boiler operations involve the interaction of many variables such as water-steam circulation, fuel characteristics, firing system and heat input, and heat transfer (reference: <u>Perry's Chemical Engineering Handbook Engineers' Handbook,</u>

Seventh Edition, Section 27 – Energy Resources, Conversion and Utilization). Although these variables are controlled using a variety of devices to be within a specified tolerance, control systems do not operate and the subsequent responses do not occur instantaneously. Consequently, normal boiler operations are characterized by occasional and temporary excursions from the maximum sustainable fuel firing and steam generation rates. Based on operational experience at the Indian River Power Plant, RRI Energy has estimated that excursions from the MCR heat input rates occur about ten percent (10%) of the total annual operational hours for Unit Nos. 1 and 3 during normal boiler operations. However, RRI Energy has been forced to operate Unit Nos. 1 and 3 in a less than normal manner because of the current hourly heat input limits that prohibit occasional and temporary excursions from the maximum sustainable fuel firing rate that are characteristic of normal boiler operations. As such, there were no operating hours included in the baseline period (2004-2009) in which the current heat input limits were exceeded. The operators at Indian River Power Plant monitor the heat inputs and take action to remain below permit limits. It is important to recognize that RRI Energy's request does not include changes to any of the short-term or long-term pollutant emission limits. In fact, RRI Energy has agreed to accept annual heat input limits based on the current short-term heat input limits and annual operational hours limits included in the Title V operating permit. A summary of RRI Energy's request is as follows:

	Unit No. 1		Unit No. 3	
Fuel Type	Current Heat Input Limit (MMBtu/hr)	Requested Heat Input Limit (MMBtu/hr)	Current Heat Input Limit (MMBtu/hr)	Requested Heat Input Limit (MMBtu/hr)
Natural Gas	865.5	923.3	3208.5	3409.7
No. 2 or No. 6 Oil	832.2	890.0	3048.8	3250.0

It is also important to recognize that the boilers have always had the capability to achieve a higher heat input, on a short-term basis, as compared with the current hourly limits and that no physical change is necessary to achieve the proposed heat inputs. Support for this is provided by examining historic electrical capacity tests conducted by the Indian River Power Plant during periods of association with the Southern Electric Reliability Council (SERC). A summary of the capacity test data for Unit Nos. 1 and 3 is presented below:

Indian River Power Plant - Unit 1

Date	Gross Gen (MWH)	Gas Flow (MCFH)	Gas HHV (BTU/MCF)	865 Gas HI (mmBTU/Hr)	Oil Flow (BBLH)	Oil HHV (BTU/BBL)	832 Oil HI (mmBTU/Hr)	Load Limiting Factor	
2/4/1999	83	835			0				
7/15/1999	85	0			137.14			Shortened end turns in generator	
12/10/1997	88.7	845	1026250	867.2	N/A	N/A	N/A	HI Limit	
7/23/1998	84.3	847	1027340	870.2	N/A	N/A	N/A	HI Limit	
3/11/1997	89	825	1038604	856.8 866	N/A	N/A	N/A	HI Limit	
6/15/1997	89.65	839	1045832	877.5	N/A	N/A	N/A	HI Limit	
9/5/1996	91.116	822	1031000	847.5	N/A	N/A	N/A	HI Limit	
12/11/1995	91.203	164	1021000	~~167.4~~	105.7	6281000	663.9	HI Limit	
1/5/1995	94.9	868	1031000	894.9	N/A	N/A	N/A		5% overpressure
8/17/1995	92.42	859	1034000	888.2	N/A	N/A	N/A		5% overpressure
6/10/1994	92.43	862 866	1038000	894.8	N/A	N/A	N/A		5% overpressure
3/28/1994	93.5	878	1035000	908.7	N/A	N/A	N/A		5% overpressure
9/15/1993	91.5	886	1033000	915.2	N/A	N/A	N/A		5% overpressure
1/27/1988	97.6	975			N/A				
1/21/1985	90.3	335	1023000	342.7	108	6333000	684.0	Htr 15 left in service	
6/4/1985	93.57	N/A	N/A	N/A	159	6333000	1006.9		Htr 15 OOS
1/4/1984	95.3	665	1023000	680.3	55	6278000	345.3		Condition with FW Htr 15 out and one level of oil guns
9/23/1984	90.3	N/A	N/A	N/A	140	6275000	878.5		Unit limited due to superhtr tube temp (1015 F) & all FW htrs
3/30/1983	94	666	1023000	681.3	56	6278000	351.6		FW htr 15 OOS
9/7/1983	92	645	1024000	660.5	60.7	6283000	381.4		
4/23/1982	96	660	1026000	677.2	N/A	N/A	N/A		Htr 15 OOS
8/30/1982	94	664	1026000	681.3	49.5	6270000	310.4		Htr 15 OOS
8/28/1981	94	655	1026000	672.0	34.6	6270000	216.9		
3/27/1980	98.444	444.95	1026000	456.5	84.84	6293931	534.0		
3/29/1979	91.9	N/A	N/A	N/A	145.9	6293931	918.3		Max capability limited to 5% overpressure & htr 15 OOS
7/25/1979	93.04	N/A	N/A	N/A	150.1	6277179	942.2		Max capability limited to 5% overpressure & htr 15 OOS

Indian River Power Plant - Unit 3

Date	Gross Gen (MWH)	Gas Flow (MCFH)	Gas HHV (BTU/MCF)	3206 Gas HI (mmBTU/Hr)	Oil Flow (BBLH)	Oil HHV (BTU/BBL)	Oil HI (mmBTU/Hr)	Load Limiting Factor	
1/13/1999	325	0			492				
7/13/1999	334	851			371.4				
2/13/1998	326.3	3275	1028151	3367.2	N/A	N/A	N/A	HI Limit	
8/7/1998	325.5	3112	1026314	3193.9	N/A	N/A	N/A	HI Limit	
1/20/1997	328.1	N/A	N/A	N/A	492	6358000	3128.1	HI Limit	
8/23/1997	323.45	3110	1050371	3266.7	22.28	6285000	140.0	HI Limit	
1/9/1996	332.975	3015	1031000	3108.5	N/A	N/A	N/A		Heater 35 OOS
6/25/1996	323.65	3100	1021000	3165.1	N/A	N/A	N/A		Heater 35 OOS
1/24/1995	336	N/A	N/A	N/A	477.5	6360000	3036.9		Heater 35 OOS
8/1/1994	326.4	3072	1035000	3179.5	N/A	N/A	N/A		
3/28/1994	327.3	3200	1035000	3312.0	N/A	N/A	N/A		
3/10/1993	328	3009	1022000	3075.2	N/A	N/A	N/A		
8/2/1993	327.3	N/A	N/A	N/A	480	6381000	3062.9		
1/21/1985	330.2	N/A	N/A	N/A	534	6333000	3381.8 3048		Max capability limited to VWO 1800 PSIG
6/3/1985	328.4	3450	1023000	3529.4 3200	N/A	N/A	N/A		Max capability limited to VWO 1800 PSIG
1/20/1984	328.9	2200	1023000	2250.6	373.2	6283000	2344.8		Max capability limited to VWO 1800 PSIG
8/31/1984	326.7	3300	1023000	3375.9	N/A	N/A	N/A		Max capability limited to VWO 1800 PSIG
2/9/1983	332.5	912	1025000	934.8	383.9	6283000	2412.0		
8/26/1983	325.7	1913.3	1023000	1957.3	255.6	6278000	1604.7		
3/2/1982	333	915	1026000	938.8	383.6	6270000	2405.2		
7/9/1982	326	2606	1026000	2673.8	59.3	6270000	371.8		
3/31/1981	330	1115	1026000	1144.0	245	6270000	1536.2		
7/14/1981	329.75	1206	1026000	1237.4	238	6270000	1492.3		
2/29/1980	324	1350	1026000	1385.1	337	6302345	2123.9		
6/30/1980	330	890	1026000	913.1	404	6302345	2546.1		
2/13/1979	326.5	776.5	1026000	796.7	358.6	6302345	2260.0		Max capability limited to VWO 1800 PSIG
7/13/1979	322.7	1558.2	1026000	1598.7	243.9	6298917	1536.3		Max capability limited to VWO 1800 PSIG

2. *Please provide the actual annual heat input rates and megawatt-hours from 1999 to 2008. Justify the hours of estimated incremental annual operation for both boilers at the requested increased heat input limits. Please provide the 5 year projection of heat input rates based on actual predicted electrical energy demand.*

Please see the table presented below concerning 1999 to 2008 operational data for the Indian River Power Plant:

Year	Unit No.	Annual Heat Inputs (MMBtu)	Annual Megawatt Hours (Net MWh)	Year	Unit No.	Annual Heat Inputs (MMBtu)	Annual Megawatt Hours (Net MWh)
1999	1	2,178,580	246,500	1999	3	9,688,080	1,074,010
2000	1	1,245,470	105,869	2000	3	8,122,620	744,983
2001	1	1,868,740	160,673	2001	3	8,701,110	829,420
2002	1	1,491,880	124,264	2002	3	8,088,090	725,216
2003	1	1,183,860	97,951	2003	3	8,437,850	758,501
2004	1	710,020	53,217	2004	3	7,639,620	668,163
2005	1	889,540	69,985	2005	3	4,898,310	402,640
2006	1	328,880	21,068	2006	3	2,163,670	184,358
2007	1	471,800	31,598	2007	3	1,691,020	141,462
2008	1	283,920	16,815	2008	3	778,740	57,237

Please refer to the attached NSR Applicability Analysis (Revision No. 1), Section 2.2.1 and Table 14 for information concerning the 5-year projection of maximum annual heat input rates. In summary, RRI Energy is projecting maximum annual heat inputs of 150,000 and 1,600,000 MMBtu for Unit Nos. 1 and 3, respectively. Although RRI Energy acknowledges that these forecasted annual utilizations are lower than the utilizations realized during the baseline period (August 2004 through July 2006), these forecasts are reasonable because RRI Energy expects that the Indian River Power Plant will be utilized to provide peak shaving electrical load service only for the next five year period. As noted earlier, RRI Energy has estimated that excursions from the MCR heat input rates occur ~~about ten percent (10%)~~ of the total annual operational hours for Unit Nos. 1 and 3 during normal boiler operations.

Because RRI Energy is a wholesale energy supplier, production forecasts and bid strategies are considered confidential business material. Consequently, RRI Energy requests that information concerning projected utilizations include in the following ~~analysis by~~ kept confidential by the Department in accordance with Section 403.111, F.S.

3. *Please recalculate the estimated emissions increases expected from the requested higher heat input rates. Compare the projected actual emissions to baseline actual emissions as defined in Rules 62-210.200, 62-210.370, and 62-212.300, F. A. C. Baseline actual emissions must be calculated following the hierarchy and methods in Rule 62-210.370, F. A. C. Projected actual emissions should reflect the expected actual plant operating parameters based on the plant's predicted demand for electrical energy for 5 years after the project. Any site specific emissions data used to estimate projected actual emissions should be based on the five-year average encompassing the period over which the emissions are being computed. Will the predicted increases exceed the significant emissions rates and subject the project to Rule 62-212.400, F. A. C. for the Prevention of Significant Deterioration (PSD) of Air Quality?*

Please refer to the attached NSR Applicability Analysis (Revision No. 1). Baseline actual emissions were calculated using data submitted in the annual operating report (AOR) and in accordance with Rule 62-210.370, F.A.C. The results of the analysis showed that no PSD permitting requirements are applicable to the project for the NSR attainment pollutants.

4. *Submit correct emissions unit pollutant detail information forms for each PSD pollutant. The completed forms must include baseline actual emissions, projected actual emissions, the baseline 24-month period and the projected monitoring period.*

Information concerning the baseline and projected actual emissions are provided in the attached NSR Applicability Analysis (Revision No. 1). RRI Energy understands that updates to the forms are not required in accordance with the telephone conference call between FDEP and RRI Energy conducted on June 15, 2009.

Please resume processing our application as this submittal is a full and complete response to the RAI. If you have questions or concerns related to this submittal, please contact Michelle Duncan at 724-597-8631 or mfduncan@rrienergy.com. We appreciate your time and attention.

Sincerely,

Dennis D. Shaulis/jk

Dennis D. Shaulis
General Manager, Indian River Plant

cc: Gary Mauzy
Keith Schmidt
File

RRI Energy Florida, LLC
Indian River Power Plant – Unit Nos. 1 and 3 – Titusville, Florida
NSR Applicability Analysis for the Requested Increase in the Allowable Hourly Heat Input Rates – Revision No. 1
August 24, 2009

1.0 Introduction

1.1 Background and Summary of the Project

RRI Energy Florida, LLC operates three natural gas / oil-fired electric utility steam generating boilers at its Indian River Plant located in Titusville, Florida. The Indian River Plant is operated under Title V Permit No. 00901196-005-AV issued by the Florida Department of Environmental Protection (FDEP). In April 2009, RRI Energy submitted an air construction permit application requesting an approximate seven percent increase in the permitted hourly heat input for Units Nos. 1 and 3. RRI Energy's request can be summarized as follows:

	Unit No. 1		Unit No. 3	
Fuel Type	Current Heat Input Limit (MMBtu/hr)	Requested Heat Input Limit (MMBtu/hr)	Current Heat Input Limit (MMBtu/hr)	Requested Heat Input Limit (MMBtu/hr)
Natural Gas	865.5	923.3	3208.5	3409.7
No. 2 or No. 6 Oil	832.2	890.0	3048.8	3250.0

RRI Energy is requesting the increases in the hourly heat input limits to allow for periodic boiler operations during overpressure situations, where heat inputs greater than the current limits are required for brief time periods (estimated to be a maximum of ten percent of the total annual operating hours). The historical developments concerning this request were presented in the April 2009 submittal but are not repeated in this submittal. However, RRI Energy once again emphasizes that the boilers have always had the capability to achieve a higher heat input, on a short-term basis, as compared with the current hourly limits and that no physical change is necessary to achieve the proposed heat inputs.

RRI Energy recognizes that the request for revising the heat input limits is considered to be a modification as defined by Rule 62-210.200(205), F.A.C. (Definitions) as presented below:

> *"Modification" – Any physical change in, change in the method of operation of, or addition to a facility which would result in an increase in the actual emissions of any air pollutant subject to regulation under the Act, including any not previously emitted, from any emissions unit or facility.*
>
> *(a) A physical change or change in the method of operation shall not include:*
>
> *1. Routine maintenance, repair, or replacement of component parts of an emissions unit; or*

2. A change in ownership of an emissions unit or facility.

(b) For any pollutant that is specifically regulated by the EPA under the Clean Air Act, a change in the method of operation shall not include an increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975.

(c) For any pollutant that is not specifically regulated by the EPA under the Clean Air Act, a change in the method of operation shall not include an increase in the hours of operation or in the production rate, unless such change would exceed any restriction on hours of operation or production rate included in any applicable Department air construction or air operation permit.

Although the proposed change has the potential to impact emissions of selected pollutants from Unit Nos. 1 and 3, RRI Energy does not expect the project to change fugitive emissions from the facility, and as such, fugitive emissions were excluded from the following analysis.

The affected existing sources and any new sources associated with the project must be evaluated to determine if the modification also satisfies the definition of a "major modification" and thus subjecting the sources to New Source Review (NSR) requirements. This is determined by the evaluating the emissions change resulting from the project in accordance with the requirements of Rule 62-212.400, F.A.C. (Stationary Sources – Preconstruction Review, Prevention of Significant Deterioration [PSD]) for the attainment pollutants and Rule 62-212-500, F.A.C. (Stationary Sources – Preconstruction Review for Nonattainment Areas) for the nonattainment pollutants.

The Indian River Power Plant is located in Brevard County, Florida. According to the current National Ambient Air Quality Standards (NAAQS) attainment designations for the location (40 CFR 81.310), the area is designated as attainment for all criteria pollutants. Consequently, RRI Energy conducted the NSR applicability analysis (Revision No. 1) in accordance with Chapter 62-212.400, F.A.C. for all applicable pollutants.

1.2 NSR Applicability Review

An analysis was conducted to determine if the project satisfies the definition of a "major modification" as specified in Rule 62-210.200(192), F.A.C. as presented below:

> *"Major Modification" –*
>
> *(a) Any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase of a PSD pollutant and a significant net emissions increase of that pollutant from the major stationary source.*
>
> *(b) Any significant emissions increase from any emissions units or net emissions increase at a major stationary source that is significant for volatile organic compounds or nitrogen oxides shall be considered significant for ozone.*
>
> *(c) A physical change or change in the method of operation shall not include:*
>
> *1. Routine maintenance, repair and replacement.*
>
> *6. An increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975.*

Subsections (c)1 through 5, (c)7 through 10 and (d) of this citation are also included but are not repeated here. Per Rule 62-212.400(2)(a), F.A.C., if the proposed project satisfies the definition of a "major modification" for any existing major stationary source, then the project would potentially be subject to PSD permitting requirements promulgated under Rule 62-212.400(4) through (12), F.A.C.

Rule 62-210.200(280), F.A.C. defines a "significant emissions rate" as follows:

> *(a) With respect to any emissions increase or any net emissions increase, or the potential of a facility to emit any of the following pollutants, significant emissions rate means a rate of pollutant emissions that would equal or exceed:*
>
> *1. A rate listed at 40 CFR 52.21(b)(23)(i), adopted by reference at Rule 62-204.800, F.A.C.; specifically, any of the following rates:*
>
> *a. Carbon monoxide: 100 tons per year (tpy);*
> *b. Nitrogen oxides: 40 tpy;*
> *c. Sulfur dioxide: 40 tpy;*
> *d. Particulate matter:*
> *(I) 25 tpy of particulate matter emissions;*
> *(II) 15 tpy of PM10 emissions;*
> *e. Ozone: 40 tpy of volatile organic compounds or nitrogen oxides;*
> *f. Lead: 0.6 tpy;*
> *g. Fluorides: 3 tpy;*
> *h. Sulfuric acid mist: 7 tpy;*

i. Hydrogen sulfide (H2S): 10 tpy;
j. Total reduced sulfur (including H2S): 10 tpy;
k. Reduced sulfur compounds (including H2S): 10 tpy;

Subsections m through o of this citation are also included but are not repeated here.

2. A rate previously listed at Table 62-212.400-2; specifically, Mercury: 0.1 tpy.

(b) Significant emissions rate also means, for the pollutants listed above in paragraph (a), any emissions rate or any net emissions increase associated with a major stationary source or major modification which would construct within 10 kilometers of a Class I area and have an impact on such area equal to or greater than 1 μg/m3, 24-hour average.

(c) For purposes of substances listed in paragraph (d) of the definition of "Regulated Air Pollutant" that do not otherwise have a threshold at paragraph (a) or (b), above, or for which 40 CFR 52.21(b)(50)(iv) prohibits regulation under the prevention of significant deterioration program, "Significant Emissions Rate" shall have the rate specified at 40 CFR 52.21(b)(23)(ii), adopted and incorporated by reference at Rule 62-204.800, F.A.C.

Per subsection (b) above, there are no Class I areas within 10 kilometers of the Indian River Power Plant. The nearest Class I area is the Chassahowitzka National Wildlife Refuge, with the closest point approximately 170 kilometers from the Plant.

The following sections present an emissions analysis conducted to determine if the proposed project would result in an increase in the applicable pollutants that would require the project to obtain a PSD permit.

2.0 PSD Applicability Analysis

Rule 62-212.400(2)(a)1., F.A.C. requires that the PSD applicability analysis be conducted using the Baseline Actual-to-Projected Actual Applicability Test for Modifications at Existing Emissions Units. A significant emissions increase of a PSD pollutant will occur if the difference, or the sum of the differences if more than one emissions unit is involved, between the projected actual emissions and the baseline actual emissions equals or exceeds the significant emissions rate for that pollutant.

A summary of the project emissions analysis is presented in Table 1. The emissions analysis was conducted as described in the following sections.

2.1 Calculation of Baseline Actual Emissions (BAE)

2.1.1 Existing Emissions Units (Units 1 and 3)

The baseline actual emissions for existing emissions units (Units 1 and 3) were calculated in accordance with Rule 62-210.200(36), F.A.C. as summarized below:

> *"Baseline Actual Emissions" and "Baseline Actual Emissions for PAL" – The rate of emissions, in tons per year, of a PSD pollutant, as follows:*
>
> *(a) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding the date a complete permit application is received by the Department.*
>
> *3. For a PSD pollutant, when a project involves multiple emissions units, only one consecutive 24-month period must be used to determine the baseline actual emissions for the emissions units being changed. A different consecutive 24-month period can be used for each PSD pollutant.*

For the purpose of this analysis, RRI Energy evaluated the latest available 60 month (five-year) period from August 2004 through July 2009. Baseline emissions for target regulated NSR pollutants were calculated in accordance with Rule 62-210.370, F.A.C. (Emissions Computation and Reporting) and the annual operating report for the plant as outlined below:

NSR Pollutant	Emissions Calculation Procedure by Fuel Type		
	No. 2 Fuel Oil	No. 6 Fuel Oil	Natural Gas
PM (filterable + condensable components)	EPA AP-42 emission factor	Filterable component: average of emission factors developed during stack test programs Condensable component: EPA AP-42	EPA AP-42 emission factor
PM_{10}	Same as PM	Same as PM	Same as PM
$PM_{2.5}$	Same as PM	Same as PM	Same as PM
SO_2	EPA AP-42 emission factor	Certified CEMs data	Certified CEMs data
NO_x	EPA AP-42 emission factor	Certified CEMs data	Certified CEMs data
CO	EPA AP-42 emission factor	EPA AP-42 emission factor	EPA AP-42 emission factor
VOC	EPA AP-42 emission factor	EPA AP-42 emission factor	EPA AP-42 emission factor

The unit-specific baseline emission factors for the aforementioned NSR pollutants are presented in Table 2. RRI Energy elected to exclude emission estimates for other regulated NSR pollutants such as fluorides (other than HF because HF is a hazardous air pollutant that is regulated separately under Section 112 of the Clean Air Act), hydrogen sulfide, reduced sulfur compounds and total reduced sulfur because there are no EPA-published (e.g., AP-42) emission factors for these constituents for the oil / gas-fired boiler industry sector. Consequently, it is expected that emissions of these constituents are negligible. RRI Energy also elected to exclude emission estimates for other regulated NSR pollutants such as sulfuric acid mist, lead and mercury because the EPA-published emission factors for these constituents (if available) are at least a factor of 100 less than the emission factors for the constituents included in Table 2. Consequently, it is expected that emissions of sulfuric acid mist, lead and mercury are also negligible.

Per Rule 62-210.200(36), F.A.C., the baseline actual emissions were calculated using the same consecutive 24-month period (August 2004 through July 2006) for all pollutants and all affected units. The unit-specific monthly fuel usages for Unit Nos. 1 and 3 for the period August 2004 through July 2009 are presented in Tables 3 and 4, respectively. The unit-specific monthly heat inputs for the period August 2004 through July 2009 are presented in Table 5. The unit-specific monthly emissions for PM, PM_{10}, $PM_{2.5}$, SO_2, NO_x, CO and VOC for the period August 2004 through July 2009 are presented in Tables 6 through 12, respectively. The baseline actual emissions for the existing units are summarized in Table 13.

2.1.2 New Emissions Units

The baseline actual emissions for new emissions units were calculated in accordance with Rule 62-210.200(36), F.A.C. as summarized below:

> *For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will result from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit.*

There are no new emissions units included in the project.

2.1.3 Total Baseline Actual Emissions

The total baseline actual emissions for the project, which were calculated as the sum of the baseline actual emissions from existing emission units and new emissions units (which are zero), are presented in Table 1.

2.2 Calculation of Projected Actual Emissions (PAE) Following Completion of the Project

2.2.1 Existing Emissions Units (Units 1 and 3)

The projected actual emissions for existing emissions units (Units 1 and 3) were calculated in accordance with Rule 62-210.200(250), F.A.C. as summarized below:

> *"Projected Actual Emissions" – The maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a PSD pollutant in any one of the 5 years following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that PSD pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source. One year is one 12-month period. In determining the projected actual emissions, the Department:*
>
> *(a) Shall consider all relevant information, including historical operational data, the company's own representations, the company's expected business activity and the company's highest projections of business activity, the company's filings with the State or Federal regulatory authorities, and compliance plans or orders, including consent orders; and*
>
> *(b) Shall include fugitive emissions to the extent quantifiable and emissions associated with startups and shutdowns; and*
>
> *(c) Shall exclude that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish*

the baseline actual emissions and that are also unrelated to the particular project including any increased utilization due to product demand growth; or

(d) In lieu of using the method set out in paragraphs (a) through (c) above, may be directed by the owner or operator to use the emissions unit's potential to emit, in tons per year.

This definition is nearly identical to that presented in the federal PSD regulations under 40 CFR 52.21(b). Additional guidance concerning the calculation of projected actual emissions was presented in the preamble to 40 CFR 52.21 (Federal Register / Vol. 67, No. 251 / Tuesday, December 31, 2002 / Section II.D, Page 80196). Pertinent text is presented below:

This projection of the unit's annual emissions rate following the change is defined as the 'projected actual emissions'' (see, for example, § 52.21(b)(48)), and will be based on your maximum annual rate in tons per year at which you are projected to emit a regulated NSR pollutant, less any amount of emissions that could have been accommodated during the selected 24-month baseline period and is not related to the change. Accordingly, you will calculate the unit's projected actual emissions as the product of: (1) The hourly emissions rate, which is based on the emissions unit's operational capabilities following the change(s), taking into account legally enforceable restrictions that could affect the hourly emissions rate following the change(s); and (2) the projected level of utilization, which is based on both the emissions unit's historical annual utilization rate and available information regarding the emissions unit's likely post-change capacity utilization. In calculating the projected actual emissions, you should consider both the expected and the highest projections of the business activity that you expect could be achieved and that are consistent with information your company publishes for business-related purposes such as a stockholder prospectus, or applications for business loans. From the initial calculation, you may then make the appropriate adjustment to subtract out any portion of the emissions increase that could have been accommodated during the unit's 24-month baseline period and is unrelated to the change. Once the appropriate subtractions have been made, the final value for the projected actual emissions, in tpy, is the value that you compare to the baseline actual emissions to determine whether your project will result in a significant emissions increase.

For the purposes of this analysis, RRI Energy elected to calculate the "Projected Actual Emissions – Initial Calculation" for the existing emissions units using (i) pollutant–specific emission factors / rates (lb/MMBtu) and (ii) unit-specific annual utilization factors (MMBtu/yr) in any one of the 5 years following the date the unit resumes regular operation after the project. The 10-year forecast period is not applicable to this project because the project does not involve increasing an existing emissions unit's design capacity or its potential to emit of that regulated NSR pollutant and full utilization of the unit is not expected to result in a significant emissions increase or a significant net emissions increase.

The pollutant-specific emission factors / rates used to calculate the "Projected Actual Emissions – Initial Calculation" (maximum projected annual emissions) are presented in Table 14. For purposes of this NSR applicability analysis, RRI Energy assumed that the unit-specific emission factors required to calculate the PAE would be the same as those used to calculate the BAE. The maximum annual unit-specific annual utilization factors / heat inputs used to calculate the "Projected Actual Emissions – Initial Calculation" are also presented in Table 14. Although RRI Energy acknowledges that these forecasted annual utilizations are lower than the utilizations realized during the baseline period, these forecasts are reasonable because RRI Energy expects that the Indian River Power Plant will be utilized to provide peak shaving electrical load service only for the next five year period. The "Projected Actual Emissions – Initial Calculation" for the existing emissions units are presented in Tables 1 and 15.

The emissions attributable to the project from the existing emissions units (Δ) were estimated in consideration of the following (please reference Table 14):

- Unit-specific PAE emission factors
- Unit-specific maximum annual utilizations
- Percentage of the maximum annual operating hours in which the units would operate at the requested higher hourly heat (estimated to be ten percent)

The emissions attributable to the project from the existing emissions units are presented in Table 16.

Mathematically, the "Projected Actual Emissions – Final Value" was calculated in accordance with the aforementioned definitions and EPA guidance as follows:

1. If "PAE – Initial Calculation" ≤ BAE, then
   "PAE – Final Value" = "PAE – Initial Calculation"

2. If "PAE – Initial Calculation" > BAE, then
   "PAE – Final Value" = "PAE – Initial Calculation" – EICHA

   Where EICHA = emissions increase that could have been accommodated during the baseline period but is unrelated to the project

   EICHA = "PAE – Initial Calculation" – BAE - Δ

   Therefore,
   "PAE – Final Value" =
   "PAE – Initial Calculation" – ("PAE – Initial Calculation" – BAE - Δ)

   Or
   "PAE – Final Value" = BAE + Δ

The "Projected Actual Emissions – Final Value" are presented in Table 1.

2.2.2 New Emissions Units

The projected actual emissions for new emissions units were calculated in accordance with Rule 62-210.200(36), F.A.C. as summarized below:

For a new emissions unit, the baseline actual emissions for purposes of determining the emissions increase that will results from the initial construction and operation of such unit shall equal zero; and thereafter, for all other purposes, shall equal the unit's potential to emit.

The projected actual emissions for new emissions sources are presented in Table 16 and in Table 1 with the column header "New Source Potential Emissions." There are no new emissions units included in the project.

2.3 Calculation of the Emissions Increases Due to the Project

2.3.1 Existing Emissions Units (Units 1 and 3)

The emissions increases due to the project for existing emissions units were calculated in accordance with Rule 62-212.400(2)(a)1, F.A.C. as presented below:

Baseline Actual-to-Projected Actual Applicability Test for Modifications at Existing Emissions Units. A significant emissions increase of a PSD pollutant will occur if the difference, or the sum of the differences if more than one emissions unit is involved, between the projected actual emissions and the baseline actual emissions equals or exceeds the significant emissions rate for that pollutant. If a combination of new and existing emissions units is involved, then the major modification shall be determined by the hybrid test for multiple types of emissions units pursuant to subparagraph 62-212.400(2)(a)3., F.A.C.

Mathematically, the operation is conducted as follows:

1. If "PAE – Final Value" $\leq$ BAE, then
   "Existing Units Emissions Increase" = 0

2. If "PAE – Final Value" > BAE, then
   "Existing Units Emissions Increase" = "PAE – Final Value" - BAE

These results are presented in Table 1.

2.3.2 New Emissions Units

The emissions increases due to the project for new emissions units were calculated in accordance with Rule 62-212.400(2)(a)2, F.A.C. as presented below:

Baseline Actual-to-Potential Applicability Test for Construction of New Emissions Units. A significant emissions increase of a PSD pollutant will occur if the difference, or the sum of the differences if more than one emissions unit is involved, between the potential to emit from each new emissions unit following completion of the construction and the baseline actual emissions of these units before the construction equals or exceeds the significant emissions rate for that pollutant. If a combination of new and existing emissions units is involved, then the major modification shall be determined by the hybrid test for multiple types of emissions units pursuant to subparagraph 62-212.400(2)(a)3., F.A.C.

The emissions increases due to the project for new sources are presented in Table 1 with the column header "New Source Potential Emissions." There are no new emissions units included in the project.

2.3.3 Total Emissions Increases Due to the Project

The emissions increases due to the project were calculated as the sum of the emission increases from the existing and new emission sources. These values are presented in Table 1 with the column header "Project Projected Emissions Increase."

2.4 Calculation of the Net Emissions Increases Due to the Project – Attainment NSR Pollutants

For the attainment NSR pollutants (all NSR pollutants at the Indian River Power Plant), the net emissions increases due to the project were calculated in accordance with Rule 62-210.200(210), F.A.C. as summarized below:

(210) "Net Emissions Increase" –
(a) With respect to any PSD pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero (0):

1. The increase in emissions from a particular physical change or change in the method of operation as calculated pursuant to paragraph 62-212.400(2)(a), F.A.C.; and

2. Any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are creditable. Baseline actual emissions for calculating increases and decreases under this subparagraph shall be determined as provided by the definition of "baseline actual emissions", except that subparagraphs (a)3. and (b)4. of such definition shall not apply.

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

1. The date five years before construction on the particular change commences; and

2. The date that the increase from the particular change occurs.

Subsections (c) through (h) of this citation follow but are not repeated here.

The increases and decreases in actual emissions at the existing emissions units that are contemporaneous with the project and otherwise credible are presented Table 1 with the column header "Contemporaneous Emissions Changes – 5-Year Lookback" – there are none associated with this project.

Mathematically, the net emissions increase for the attainment NSR pollutants is calculated as follows:

(Project Projected Emissions Increase) + (Contemporaneous Emissions Change [5-Year Lookback])

The net emissions increases due to the project for attainment NSR pollutants are presented in Table 1 with the column header "Net Emissions Increase Due to the Project."

2.5 Results of the PSD Applicability Analysis

To review, RRI Energy conducted an NSR emission analysis to determine if the project would result in an increase in applicable pollutants that would require the project to obtain a PSD permit. The emissions analysis was conducted in accordance with a template designed to satisfy the requirements under Rule 62-212.400, F.A.C. for the attainment pollutants.

For each attainment NSR pollutant (all NSR pollutants at the Indian River Power Plant), if the (i) Project Projected Emissions Increase and (ii) Net Emissions Increase Due to the Project are both greater than or equal to the applicable significance emissions rate, then the project is subject to PSD permitting requirements. The analysis shows that no PSD permitting requirements are applicable to the project for the NSR attainment pollutants.

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Table 1
Project Emissions Comparison Summary
8/24/2009 (Revision No. 1)

Pollutant	Pollutant Type (PSD or NNSR)	Baseline Actual Emissions[1]	Projected Actual Emissions - Initial Calculaton[2]	Projected Actual Emissions - Final Value[3]	Existing Units Emissions Increase[4]	New Source Potential Emissions[5]	Project Projected Emissions Increase[6]	Contemporaneous Emissions Change - 5-Year Lookback[7]	Net Emissions Increase Due to the Project[8]	NSR Significance Level[9]	Significant Emissions Increase?
		(Tons/yr)	(Tons/yr)	(Tons/yr)	(Tons/yr)	(Tons/yr)	(Tons/yr)	(Tons/yr)	(Tons/yr)	(Tons/yr)	(Yes or No)
Criteria											
PM2.5	PSD	146.5	55.2	55.2	0.0	0.0	0.0	0.0	0.0	15	No
PM10	PSD	146.5	55.2	55.2	0.0	0.0	0.0	0.0	0.0	15	No
SO2	PSD	2821	1024	1024	0.0	0.0	0.0	0.0	0.0	40	No
NOx	PSD	763	275	275	0.0	0.0	0.0	0.0	0.0	40	No
CO	PSD	79.8	28.2	28.2	0.0	0.0	0.0	0.0	0.0	100	No
VOC	PSD	12.9	4.4	4.4	0.0	0.0	0.0	0.0	0.0	40	No
Other (PSD)											
PM	PSD	146.5	55.2	55.2	0.0	0.0	0.0	0.0	0.0	25	No

Notes:

NAp = Not Applicable .

1 Emissions based on maximum annual-averaged emissions from consecutive 24 month period in the last 5 years

2 Projected Actual Emissions from the Existing Emissions Units

3 *Projected Actual Emissions from the Existing Emissions Units excluding any emissions in excess of the baseline actual emissions that could have been accommodated* during the baseline period and are unrelated to the project

4 Existing Units Emissions Increase is equal to Projected Actual Emissions - Final Value minus Baseline Actual Emissions

5 New Source Potential Emissions = potential to emit (PTE)

6 Project Projected Emissions Increase is the sum of Existing Source Emissions Increase and New Source Potential Emissions

7 Emissions changes from projects identified to have occurred in the 5 year contemporaneous period that resulted in a credible emissions change at the facility

The following projects occurred in the contemporaneous period.

Project	Began Operation	Pollutant	Emissions Change (TPY)
None	None	**PM10**	**0.00**
		PM2.5	**0.00**
		SO2	**0.00**
		NOx	**0.00**
		CO	**0.00**
		VOC	**0.00**
		PM	**0.00**

8 Net Emissions Increase Due to the Project is the sum of Project Projected Emissions Increase and Contemporaneous Emissions Change (5-year lookback)

9 Significance Level for PSD

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Table 2
Baseline Actual Emissions Factors
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Year	Unit No.	Fuel Type	PM (lb/M gal)	PM-10 (lb/M gal)	PM-2.5 (lb/M gal)	SO2 (lb/M gal)	NOx (lb/M gal)	CO (lb/M gal)	VOC (lb/M gal)
2004	1	No. 2 Oil	3.3	3.3	3.3	14.13	24	5	0.2
2005	1	No. 2 Oil	3.3	3.3	3.3	14.13	24	5	0.2
2006	1	No. 2 Oil	3.3	3.3	3.3	14.13	24	5	0.2
2007	1	No. 2 Oil	3.3	3.3	3.3	14.13	24	5	0.2
2008	1	No. 2 Oil	3.3	3.3	3.3	6.28	24	5	0.2
2009	1	No. 2 Oil	3.3	3.3	3.3	6.28	24	5	0.2

Year	Unit No.	Fuel Type	PM (lb/M gal)	PM-10 (lb/M gal)	PM-2.5 (lb/M gal)	SO2	NOx	CO (lb/M gal)	VOC (lb/M gal)
2004	1	No. 6 Oil	12.2	12.2	12.2	CEM	CEM	5	0.76
2005	1	No. 6 Oil	12.2	12.2	12.2	CEM	CEM	5	0.76
2006	1	No. 6 Oil	12.2	12.2	12.2	CEM	CEM	5	0.76
2007	1	No. 6 Oil	12.2	12.2	12.2	CEM	CEM	5	0.76
2008	1	No. 6 Oil	12.3	12.3	12.3	CEM	CEM	5	0.76
2009	1	No. 6 Oil	11.2	11.2	11.2	CEM	CEM	5	0.76

Year	Unit No.	Fuel Type	PM (lb/MMscf)	PM-10 (lb/MMscf)	PM-2.5 (lb/MMscf)	SO2	NOx	CO (lb/MMscf)	VOC (lb/MMscf)
2004	1	Natural Gas	7.6	7.6	7.6	CEM	CEM	24	5.5
2005	1	Natural Gas	7.6	7.6	7.6	CEM	CEM	24	5.5
2006	1	Natural Gas	7.6	7.6	7.6	CEM	CEM	24	5.5
2007	1	Natural Gas	7.6	7.6	7.6	CEM	CEM	24	5.5
2008	1	Natural Gas	7.6	7.6	7.6	CEM	CEM	24	5.5
2009	1	Natural Gas	7.6	7.6	7.6	CEM	CEM	24	5.5

Year	Unit No.	Fuel Type	PM (lb/M gal)	PM-10 (lb/M gal)	PM-2.5 (lb/M gal)	SO2 (lb/M gal)	NOx (lb/M gal)	CO (lb/M gal)	VOC (lb/M gal)
2004	3	No. 2 Oil	3.3	3.3	3.3	14.13	24	5	0.2
2005	3	No. 2 Oil	3.3	3.3	3.3	14.13	24	5	0.2
2006	3	No. 2 Oil	3.3	3.3	3.3	14.13	24	5	0.2
2007	3	No. 2 Oil	3.3	3.3	3.3	14.13	24	5	0.2
2008	3	No. 2 Oil	3.3	3.3	3.3	6.28	24	5	0.2
2009	3	No. 2 Oil	3.3	3.3	3.3	6.28	24	5	0.2

Year	Unit No.	Fuel Type	PM (lb/M gal)	PM-10 (lb/M gal)	PM-2.5 (lb/M gal)	SO2	NOx	CO (lb/M gal)	VOC (lb/M gal)
2004	3	No. 6 Oil	9.9	9.9	9.9	CEM	CEM	5	0.76
2005	3	No. 6 Oil	9.9	9.9	9.9	CEM	CEM	5	0.76
2006	3	No. 6 Oil	9.9	9.9	9.9	CEM	CEM	5	0.76
2007	3	No. 6 Oil	9.9	9.9	9.9	CEM	CEM	5	0.76
2008	3	No. 6 Oil	9.1	9.1	9.1	CEM	CEM	5	0.76
2009	3	No. 6 Oil	8.9	8.9	8.9	CEM	CEM	5	0.76

Year	Unit No.	Fuel Type	PM (lb/MMscf)	PM-10 (lb/MMscf)	PM-2.5 (lb/MMscf)	SO2	NOx	CO (lb/MMscf)	VOC (lb/MMscf)
2004	3	Natural Gas	7.6	7.6	7.6	CEM	CEM	24	5.5
2005	3	Natural Gas	7.6	7.6	7.6	CEM	CEM	24	5.5
2006	3	Natural Gas	7.6	7.6	7.6	CEM	CEM	24	5.5
2007	3	Natural Gas	7.6	7.6	7.6	CEM	CEM	24	5.5
2008	3	Natural Gas	7.6	7.6	7.6	CEM	CEM	24	5.5
2009	3	Natural Gas	7.6	7.6	7.6	CEM	CEM	24	5.5

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Table 3
Heat Input (HI) by Fuel Type - Unit No. 1
8/24/2009 (Revision No. 1)

		No. 2 Fuel Oil			No. 6 Fuel Oil			Natural Gas		
YEAR	MONTH	Usage (gal)	HHV (Btu/gal)	% Total HI	Usage (gal)	HHV (Btu/gal)	% Total HI	Usage (Mcf)	HHV (Btu/cf)	% Total HI
2004										
	8	400	138,800	0.2%	131,919	153,405	86.5%	2,971	1,040	13.2%
	9	1,399	138,800	0.1%	1,071,310	152,950	79.9%	39,291	1,041	20.0%
	10	816	138,800	0.1%	586,620	152,950	92.1%	7,271	1,040	7.8%
	11	121	138,800	0.4%	18,056	152,950	73.2%	956	1,040	26.4%
	12	703	138,800	0.1%	476,747	152,950	92.7%	5,399	1,041	7.1%
2005	1	596	138,800	0.3%	143,552	152,950	83.8%	3,995	1,041	15.9%
	2	402	138,800	0.2%	194,724	151,964	91.9%	2,458	1,040	7.9%
	3	849	138,800	0.3%	237,062	154,000	82.4%	7,409	1,040	17.4%
	4	1,273	138,800	0.2%	680,387	153,911	93.0%	7,452	1,031	6.8%
	5	403	138,800	0.1%	74,111	154,000	16.8%	54,693	1,031	83.1%
	6	0	0		0	0		0	0	
	7	1,037	138,800	0.1%	694,094	152,131	95.4%	4,833	1,031	4.5%
	8	729	138,800	0.1%	666,257	153,625	96.7%	3,261	1,041	3.2%
	9	1,440	138,800	0.1%	1,574,264	153,625	97.3%	6,203	1,031	2.6%
	10	220	138,800	0.0%	394,212	153,625	94.5%	3,407	1,031	5.5%
	11	0	0		0	0		0	0	
	12	1,320	138,800	0.2%	477,215	153,625	94.9%	3,613	1,041	4.9%
2006	1	884	138,800	0.3%	258,946	152,627	94.2%	2,249	1,037	5.6%
	2	569	138,800	1.6%	23,314	152,900	72.2%	1,250	1,036	26.2%
	3	0	0	0.0%	0	0	0.0%	195	1,037	100.0%
	4	0	0		0	0		0	0	
	5	0	0		0	0		0	0	
	6	273	138,800	0.4%	61,648	152,097	95.6%	379	1,039	4.0%
	7	679	138,800	0.2%	126,457	152,567	41.3%	26,349	1,035	58.4%
	8	1,473	138,800	0.2%	347,109	152,567	50.3%	50,380	1,035	49.5%
	9	886	138,800	0.4%	151,703	151,914	70.0%	9,456	1,033	29.7%
	10	268	138,800	0.1%	248,070	152,167	71.8%	14,337	1,034	28.2%
	11	959	138,800	0.4%	188,859	152,288	83.5%	5,371	1,031	16.1%
	12	0	0		0	0		0	0	
2007	1	429	138,800	0.4%	87,187	152,624	90.2%	1,333	1,035	9.4%
	2	1,319	138,800	0.5%	195,598	152,336	87.3%	3,986	1,037	12.1%
	3	0	0		0	0		0	0	
	4	228	138,800	0.4%	41,485	152,916	82.8%	1,251	1,031	16.8%
	5	211	138,800	3.8%	0	0	0.0%	713	1,035	96.2%
	6	1,602	138,800	0.6%	1,115	151,863	0.4%	36,538	1,035	99.0%
	7	1,496	138,800	0.2%	32,001	151,462	5.3%	83,444	1,034	94.5%
	8	2,835	138,800	0.2%	394,359	151,379	37.4%	96,077	1,034	62.3%
	9	1,060	138,800	0.3%	0	0	0.0%	46,194	1,034	99.7%
	10	1,621	138,800	0.3%	15,307	151,663	3.0%	72,874	1,030	96.7%
	11	0	0		0	0		0	0	
	12	0	0		0	0		0	0	
2008	1	500	138,800	0.2%	7,474	151,888	2.9%	37,436	1,027	97.0%
	2	84	138,800	0.3%	2,814	149,599	12.2%	2,935	1,027	87.4%
	3	0	0		0	0		0	0	
	4	578	138,800	0.8%	0	0	0.0%	9,674	1,028	99.2%
	5	1,888	138,800	0.6%	0	0	0.0%	44,327	1,031	99.4%
	6	1,133	138,800	0.7%	0	0	0.0%	23,134	1,031	99.3%
	7	806	138,800	0.8%	150	152,223	0.2%	13,732	1,031	99.1%
	8	1,703	138,800	0.7%	22,081	152,223	9.7%	29,961	1,033	89.6%
	9	1,655	138,800	0.4%	193,724	152,941	45.2%	34,459	1,036	54.5%
	10	2,064	138,800	1.0%	0	0	0.0%	26,113	1,034	99.0%
	11	1,030	138,800	0.7%	33,684	152,657	26.9%	13,366	1,036	72.4%
	12	0	0		0	0		0	0	
2009	1	841	138,800	0.3%	54,056	152,657	20.7%	30,507	1,033	79.0%
	2	455	138,800	0.3%	69,837	152,657	45.2%	12,510	1,027	54.5%
	3	948	138,800	1.6%	0	0	0.0%	7,862	1,028	98.4%
	4	1,321	138,800	0.7%	0	0	0.0%	26,090	1,028	99.3%
	5	1,112	138,800	0.3%	46,091	152,908	14.8%	39,371	1,026	84.9%
	6	761	138,800	0.2%	31,332	152,716	10.6%	39,327	1,025	89.2%
	7	1,246	138,800	0.4%	28,713	152,900	10.5%	36,210	1,027	89.1%

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Table 4
Heat Input by Fuel Type - Unit No. 3
8/24/2009 (Revision No. 1)

		No. 2 Fuel Oil			No. 6 Fuel Oil			Natural Gas		
YEAR	MONTH	Usage (gal)	HHV (Btu/gal)	% Total HI	Usage (gal)	HHV (Btu/gal)	% Total HI	Usage (Mcf)	HHV (Btu/cf)	% Total HI
2004										
	8	0	0	0.0%	4,961,743	153,577	92.5%	59,088	1,041	7.5%
	9	0	0	0.0%	4,949,734	153,999	91.9%	64,205	1,041	8.1%
	10	0	0	0.0%	4,768,454	153,999	93.7%	47,497	1,040	6.3%
	11	0	0	0.0%	1,183,109	153,919	89.8%	19,957	1,040	10.2%
	12	0	0	0.0%	1,867,881	153,999	95.5%	13,156	1,041	4.5%
2005	1	0	0	0.0%	2,240,711	153,999	98.0%	6,813	1,041	2.0%
	2	0	0	0.0%	782,173	152,908	94.5%	6,648	1,040	5.5%
	3	0	0	0.0%	853,396	153,150	95.7%	5,598	1,040	4.3%
	4	0	0		0	0		0	0	
	5	0	0	0.0%	2,143	153,150	0.2%	127,261	1,031	99.8%
	6	0	0	0.0%	2,129,023	153,251	44.4%	395,557	1,031	55.6%
	7	0	0	0.0%	4,405,689	152,457	85.2%	113,556	1,031	14.8%
	8	0	0	0.0%	5,925,941	152,164	99.6%	3,265	1,041	0.4%
	9	0	0	0.0%	5,952,304	152,164	100.0%	15	1,041	0.0%
	10	0	0	0.0%	4,634,051	152,164	99.7%	2,307	1,031	0.3%
	11	0	0	0.0%	0	0	0.0%	944	1,041	100.0%
	12	0	0	0.0%	668,516	152,164	93.0%	7,379	1,041	7.0%
2006	1	0	0		0	0		0	0	
	2	0	0	0.0%	596,752	152,699	94.0%	5,655	1,036	6.0%
	3	0	0		0	0		0	0	
	4	0	0		0	0		0	0	
	5	0	0	0.0%	439,565	152,850	34.2%	124,830	1,037	65.8%
	6	0	0	0.0%	1,107,081	152,407	40.4%	239,355	1,039	59.6%
	7	0	0	0.0%	882,894	152,285	46.6%	148,835	1,035	53.4%
	8	0	0	0.0%	3,328,472	152,285	80.7%	117,067	1,035	19.3%
	9	0	0	0.0%	883,052	151,797	57.5%	96,036	1,033	42.5%
	10	0	0	0.0%	1,202,966	151,910	71.2%	71,400	1,034	28.8%
	11	0	0	0.0%	153,008	152,326	50.4%	22,272	1,031	49.6%
	12	0	0		0	0		0	0	
2007	1	0	0	0.0%	0	0	0.0%	59	1,035	100.0%
	2	0	0	0.0%	574,294	152,112	93.4%	5,954	1,036	6.6%
	3	0	0		0	0		0	0	
	4	0	0	0.0%	315,440	151,863	52.3%	42,374	1,031	47.7%
	5	0	0	0.0%	123,490	151,613	16.0%	94,907	1,035	84.0%
	6	0	0	0.0%	321,651	151,863	33.7%	92,685	1,035	66.3%
	7	0	0	0.0%	818,236	151,522	34.8%	224,428	1,034	65.2%
	8	0	0	0.0%	1,162,569	151,345	56.9%	128,999	1,034	43.1%
	9	0	0	0.0%	572,807	152,875	41.4%	119,941	1,034	58.6%
	10	0	0	0.0%	1,074,361	151,454	44.3%	198,475	1,030	55.7%
	11	0	0		0	0		0	0	
	12	0	0		0	0		0	0	
2008	1	0	0	0.0%	261,640	152,081	44.6%	48,030	1,027	55.4%
	2	0	0	0.0%	33,726	152,457	26.5%	13,900	1,027	73.5%
	3	0	0		0	0		0	0	
	4	0	0	0.0%	59,344	152,265	15.6%	47,576	1,028	84.4%
	5	0	0	0.0%	231,108	152,223	27.7%	89,285	1,031	72.3%
	6	0	0	0.0%	56,692	152,265	18.1%	37,960	1,031	81.9%
	7	0	0	0.0%	69,765	152,223	18.3%	45,866	1,031	81.7%
	8	0	0	0.0%	125,667	152,223	18.0%	84,405	1,033	82.0%
	9	0	0	0.0%	1,035,032	152,824	70.7%	63,234	1,036	29.3%
	10	0	0	0.0%	22,668	152,389	16.2%	17,226	1,034	83.8%
	11	0	0	0.0%	152,618	152,306	82.8%	4,656	1,036	17.2%
	12	0	0		0	0		0	0	
2009	1	0	0	0.0%	370,608	152,389	36.2%	96,470	1,033	63.8%
	2	0	0	0.0%	569,994	152,306	45.6%	100,961	1,027	54.4%
	3	0	0	0.0%	0	0	0.0%	11,939	1,028	100.0%
	4	0	0	0.0%	44,264	151,345	5.9%	103,906	1,028	94.1%
	5	0	0	0.0%	104,961	152,641	25.8%	44,956	1,026	74.2%
	6	0	0	0.0%	392,074	152,607	29.3%	140,861	1,025	70.7%
	7	0	0	0.0%	296,313	152,265	24.1%	138,640	1,027	75.9%

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Table 5
Baseline Heat Input (HI) – CEM Measured MMBtu
8/24/2009 (Revision No. 1)

	UNIT 1		UNIT 3		TOTAL	
	HI (MMBtu)	Period end	HI (MMBtu)	Period end	HI (MMBtu)	Period end
Maximum	**703,167**	Aug-06	**4,151,595**	Jul-06	**4,813,973**	Jul-06
Baseline Period	**662,378**	Jul-06	**4,151,595**	Jul-06	**4,813,973**	Jul-06

YEAR	MONTH	HI (MMBtu)	Rolling 24/2	HI (MMBtu)	Rolling 24/2	HI (MMBtu)	Rolling 24/2
2004							
	8	20,981		779,380		800,361	
	9	198,881		785,812		984,693	
	10	90,189		725,198		815,387	
	11	2,740		173,658		176,398	
	12	75,678		284,564		360,242	
2005	1	24,524		342,068		366,592	
	2	30,853		119,951		150,804	
	3	39,428		127,178		166,606	
	4	103,589		0		103,589	
	5	64,237		133,870		198,107	
	6	0		717,003		717,003	
	7	108,354		749,407		857,761	
	8	100,688		848,543		949,231	
	9	235,229		835,347		1,070,576	
	10	59,005		644,990		703,995	
	11	0		1,879		1,879	
	12	67,407		95,040		162,447	
2006	1	39,265		0		39,265	
	2	4,632		73,430		78,062	
	3	145		0		145	
	4	0		0		0	
	5	0		186,467		186,467	
	6	11,428		403,709		415,137	
	7	47,503	**662,378**	275,696	**4,151,595**	323,199	**4,813,973**
	8	102,559	**703,167**	603,482	4,063,646	706,041	4,766,813
	9	32,173	619,813	223,586	3,782,533	255,759	4,402,346
	10	50,616	600,027	247,214	3,543,541	297,830	4,143,568
	11	32,637	614,975	46,433	3,479,929	79,070	4,094,904
	12	0	577,136	0	3,337,647	0	3,914,783
2007	1	14,051	571,900	96	3,166,661	14,147	3,738,560
	2	32,946	572,946	89,398	3,151,384	122,344	3,724,330
	3	0	553,232	0	3,087,795	0	3,641,027
	4	8,250	505,563	88,093	3,131,842	96,343	3,637,404
	5	955	473,922	113,709	3,121,761	114,664	3,595,683
	6	37,883	492,863	127,449	2,826,984	165,332	3,319,847
	7	89,244	483,308	342,550	2,623,556	431,794	3,106,863
	8	157,136	511,532	299,350	2,348,959	456,486	2,860,491
	9	47,882	417,858	202,031	2,032,301	249,913	2,450,159
	10	78,323	427,517	360,027	1,889,820	438,350	2,317,337
	11	0	427,517	0	1,888,880	0	2,316,397
	12	0	393,814	0	1,841,360	0	2,235,174
2008	1	37,917	393,140	72,597	1,877,659	110,514	2,270,798
	2	3,686	392,667	19,306	1,850,597	22,992	2,243,263
	3	0	392,594	0	1,850,597	0	2,243,191
	4	9,815	397,502	55,818	1,878,506	65,633	2,276,007
	5	45,869	420,436	119,689	1,845,117	165,558	2,265,553
	6	23,367	426,406	48,812	1,667,668	72,179	2,094,074
	7	13,489	409,399	49,825	1,554,733	63,314	1,964,131
	8	32,526	374,382	106,359	1,306,171	138,885	1,680,553
	9	64,506	390,549	207,143	1,297,950	271,649	1,688,498
	10	26,344	378,413	20,441	1,184,563	46,785	1,562,976
	11	18,966	371,577	26,383	1,174,538	45,349	1,546,115
	12	0	371,577	0	1,174,538	0	1,546,115
2009	1	39,123	384,113	156,046	1,252,513	195,169	1,636,627
	2	16,832	376,057	187,525	1,301,577	204,357	1,677,633
	3	8,129	380,121	12,400	1,307,777	20,529	1,687,898
	4	26,727	389,359	109,230	1,318,345	135,957	1,707,704
	5	41,943	409,853	58,819	1,290,900	100,762	1,700,754
	6	44,761	413,293	204,447	1,329,399	249,208	1,742,692
	7	40,259	388,800	181,653	1,248,951	221,912	1,637,751

Indian River Power Plant - Unit Nos. 1 and 3
NSR Applicability Analysis
Request for Increase in Allowable Hourly Heat Inputs
Table 6
Baseline PM Emissions
8/24/2009 (Revision No. 1)

	UNIT 1		UNIT 3	
	PM (tons)	Period end	PM (tons)	Period end
Maximum	25.2	Aug-06	122.1	Nov-06
Baseline Period	24.4	Jul-06	122.1	Jul-06

YEAR	MONTH	PM (tons)	Rolling 24/2	PM (tons)	Rolling 24/2
2004					
	8	0.8		24.7	
	9	6.7		24.7	
	10	3.6		23.7	
	11	0.1		5.9	
	12	2.9		9.3	
2005	1	0.9		11.1	
	2	1.2		3.9	
	3	1.5		4.2	
	4	4.2		0.0	
	5	0.7		0.5	
	6	0.0		12.0	
	7	4.3		22.2	
	8	4.1		29.3	
	9	9.6		29.4	
	10	2.4		22.9	
	11	0.0		0.0	
	12	2.9		3.3	
2006	1	1.6		0.0	
	2	0.1		3.0	
	3	0.0		0.0	
	4	0.0		0.0	
	5	0.0		2.6	
	6	0.4		6.4	
	7	0.9	**24.4**	4.9	**122.1**
	8	2.3	**25.2**	16.9	118.2
	9	1.0	22.3	4.7	108.2
	10	1.6	21.3	6.2	99.4
	11	1.2	21.8	0.8	96.9
	12	0.0	20.3	0.0	92.3
2007	1	0.5	20.2	0.0	86.7
	2	1.2	20.2	2.9	86.2
	3	0.0	19.4	0.0	84.1
	4	0.3	17.5	1.7	84.9
	5	0.0	17.2	1.0	85.2
	6	0.1	17.2	1.9	80.1
	7	0.5	15.4	4.9	71.5
	8	2.8	14.7	6.2	59.9
	9	0.2	10.0	3.3	46.9
	10	0.4	9.0	6.1	38.5
	11	0.0	9.0	0.0	38.5
	12	0.0	7.5	0.0	36.8
2008	1	0.2	6.8	1.4	37.5
	2	0.0	6.7	0.2	36.1
	3	0.0	6.7	0.0	36.1
	4	0.0	6.8	0.5	36.3
	5	0.2	6.8	1.4	35.7
	6	0.1	6.7	0.4	32.7
	7	0.1	6.3	0.5	30.5
	8	0.3	5.3	0.9	22.5
	9	1.3	5.4	4.9	22.6
	10	0.1	4.7	0.2	19.6
	11	0.3	4.3	0.7	19.5
	12	0.0	4.3	0.0	19.5
2009	1	0.4	4.2	2.0	20.5
	2	0.4	3.8	2.9	20.5
	3	0.0	3.8	0.0	20.6
	4	0.1	3.7	0.6	20.0
	5	0.4	4.0	0.6	19.8
	6	0.3	4.0	2.3	20.0
	7	0.3	3.9	1.8	18.5

Indian River Power Plant - Unit Nos. 1 and 3
NSR Applicability Analysis
Request for Increase in Allowable Hourly Heat Inputs
Table 7
Baseline PM10 Emissions
8/24/2009 (Revision No. 1)

	UNIT 1		UNIT 3	
	PM10 (tons)	Period end	PM10 (tons)	Period end
Maximum	25.2	Aug-06	122.1	Jul-06
Baseline Period	24.4	Jul-06	122.1	Jul-06

YEAR	MONTH	PM10 (tons)	Rolling 24/2	PM10 (tons)	Rolling 24/2
2004					
	8	0.8		24.7	
	9	6.7		24.7	
	10	3.6		23.7	
	11	0.1		5.9	
	12	2.9		9.3	
2005	1	0.9		11.1	
	2	1.2		3.9	
	3	1.5		4.2	
	4	4.2		0.0	
	5	0.7		0.5	
	6	0.0		12.0	
	7	4.3		22.2	
	8	4.1		29.3	
	9	9.6		29.4	
	10	2.4		22.9	
	11	0.0		0.0	
	12	2.9		3.3	
2006	1	1.6		0.0	
	2	0.1		3.0	
	3	0.0		0.0	
	4	0.0		0.0	
	5	0.0		2.6	
	6	0.4		6.4	
	7	0.9	24.4	4.9	122.1
	8	2.3	25.2	16.9	118.2
	9	1.0	22.3	4.7	108.2
	10	1.6	21.3	6.2	99.4
	11	1.2	21.8	0.8	96.9
	12	0.0	20.3	0.0	92.3
2007	1	0.5	20.2	0.0	86.7
	2	1.2	20.2	2.9	86.2
	3	0.0	19.4	0.0	84.1
	4	0.3	17.5	1.7	84.9
	5	0.0	17.2	1.0	85.2
	6	0.1	17.2	1.9	80.1
	7	0.5	15.4	4.9	71.5
	8	2.8	14.7	6.2	59.9
	9	0.2	10.0	3.3	46.9
	10	0.4	9.0	6.1	38.5
	11	0.0	9.0	0.0	38.5
	12	0.0	7.5	0.0	36.8
2008	1	0.2	6.8	1.4	37.5
	2	0.0	6.7	0.2	36.1
	3	0.0	6.7	0.0	36.1
	4	0.0	6.8	0.5	36.3
	5	0.2	6.8	1.4	35.7
	6	0.1	6.7	0.4	32.7
	7	0.1	6.3	0.5	30.5
	8	0.3	5.3	0.9	22.5
	9	1.3	5.4	4.9	22.6
	10	0.1	4.7	0.2	19.6
	11	0.3	4.3	0.7	19.5
	12	0.0	4.3	0.0	19.5
2009	1	0.4	4.2	2.0	20.5
	2	0.4	3.8	2.9	20.5
	3	0.0	3.8	0.0	20.6
	4	0.1	3.7	0.6	20.0
	5	0.4	4.0	0.6	19.8
	6	0.3	4.0	2.3	20.0
	7	0.3	3.9	1.8	18.5

Indian River Power Plant - Unit Nos. 1 and 3
NSR Applicability Analysis
Request for Increase in Allowable Hourly Heat Inputs
Table 8
Baseline PM2.5 Emissions
8/24/2009 (Revision No. 1)

	UNIT 1		UNIT 3	
	PM2.5 (tons)	Period end	PM2.5 (tons)	Period end
Maximum	25.2	Aug-06	122.1	Jul-06
Baseline Period	24.4	Jul-06	122.1	Jul-06

YEAR	MONTH	PM2.5 (tons)	Rolling 24/2	PM2.5 (tons)	Rolling 24/2
2004					
	8	0.8		24.7	
	9	6.7		24.7	
	10	3.6		23.7	
	11	0.1		5.9	
	12	2.9		9.3	
2005	1	0.9		11.1	
	2	1.2		3.9	
	3	1.5		4.2	
	4	4.2		0.0	
	5	0.7		0.5	
	6	0.0		12.0	
	7	4.3		22.2	
	8	4.1		29.3	
	9	9.6		29.4	
	10	2.4		22.9	
	11	0.0		0.0	
	12	2.9		3.3	
2006	1	1.6		0.0	
	2	0.1		3.0	
	3	0.0		0.0	
	4	0.0		0.0	
	5	0.0		2.6	
	6	0.4		6.4	
	7	0.9	**24.4**	4.9	**122.1**
	8	2.3	**25.2**	16.9	118.2
	9	1.0	22.3	4.7	108.2
	10	1.6	21.3	6.2	99.4
	11	1.2	21.8	0.8	96.9
	12	0.0	20.3	0.0	92.3
2007	1	0.5	20.2	0.0	86.7
	2	1.2	20.2	2.9	86.2
	3	0.0	19.4	0.0	84.1
	4	0.3	17.5	1.7	84.9
	5	0.0	17.2	1.0	85.2
	6	0.1	17.2	1.9	80.1
	7	0.5	15.4	4.9	71.5
	8	2.8	14.7	6.2	59.9
	9	0.2	10.0	3.3	46.9
	10	0.4	9.0	6.1	38.5
	11	0.0	9.0	0.0	38.5
	12	0.0	7.5	0.0	36.8
2008	1	0.2	6.8	1.4	37.5
	2	0.0	6.7	0.2	36.1
	3	0.0	6.7	0.0	36.1
	4	0.0	6.8	0.5	36.3
	5	0.2	6.8	1.4	35.7
	6	0.1	6.7	0.4	32.7
	7	0.1	6.3	0.5	30.5
	8	0.3	5.3	0.9	22.5
	9	1.3	5.4	4.9	22.6
	10	0.1	4.7	0.2	19.6
	11	0.3	4.3	0.7	19.5
	12	0.0	4.3	0.0	19.5
2009	1	0.4	4.2	2.0	20.5
	2	0.4	3.8	2.9	20.5
	3	0.0	3.8	0.0	20.6
	4	0.1	3.7	0.6	20.0
	5	0.4	4.0	0.6	19.8
	6	0.3	4.0	2.3	20.0
	7	0.3	3.9	1.8	18.5

Indian River Power Plant - Unit Nos. 1 and 3
NSR Applicability Analysis
Request for Increase in Allowable Hourly Heat Inputs
Table 9
Baseline SO2 Emissions
8/24/2009 (Revision No. 1)

	UNIT 1		UNIT 3	
	SO2 (tons)	Period end	SO2 (tons)	Period end
Maximum	408.0	Aug-06	2,422.7	Jul-06
Baseline Period	398.4	Jul-06	2,422.7	Jul-06

YEAR	MONTH	SO2 (tons)	Rolling 24/2	SO2 (tons)	Rolling 24/2
2004					
	8	15.7		565.4	
	9	133.6		553.0	
	10	61.7		426.2	
	11	0.8		88.2	
	12	35.1		185.0	
2005	1	14.0		252.8	
	2	18.6		76.7	
	3	20.3		85.6	
	4	65.0		0.0	
	5	6.6		1.0	
	6	0.0		201.9	
	7	69.8		438.9	
	8	64.9		602.8	
	9	161.4		611.6	
	10	38.9		450.5	
	11	0.0		0.0	
	12	35.9		48.4	
2006	1	27.8		0.0	
	2	2.2		38.6	
	3	0.0		0.0	
	4	0.0		0.0	
	5	0.0		38.3	
	6	7.2		97.1	
	7	17.3	**398.4**	83.4	**2,422.7**
	8	34.8	**408.0**	350.1	2,315.1
	9	16.2	349.2	87.6	2,082.4
	10	25.8	331.3	121.4	1,930.0
	11	19.4	340.6	16.9	1,894.4
	12	0.0	323.0	0.0	1,801.8
2007	1	8.6	320.3	0.0	1,675.4
	2	19.8	320.9	56.3	1,665.2
	3	0.0	310.7	0.0	1,622.4
	4	4.1	280.3	31.4	1,638.1
	5	0.0	277.0	9.7	1,642.4
	6	0.0	277.0	23.3	1,553.1
	7	2.1	243.2	77.8	1,372.5
	8	44.2	232.8	122.0	1,132.1
	9	0.0	152.1	57.6	855.1
	10	2.4	133.9	111.6	685.7
	11	0.0	133.9	0.0	685.7
	12	0.0	115.9	0.0	661.5
2008	1	0.8	102.5	16.6	669.7
	2	0.4	101.6	3.3	652.1
	3	0.0	101.6	0.0	652.1
	4	0.0	101.6	5.0	654.6
	5	0.0	101.6	21.2	646.0
	6	0.0	98.0	7.5	601.2
	7	0.0	89.4	4.4	561.7
	8	2.4	73.2	15.2	394.3
	9	16.8	73.5	87.6	394.3
	10	0.0	60.6	1.9	334.5
	11	3.5	52.7	14.0	333.1
	12	0.0	52.7	0.0	333.1
2009	1	4.1	50.4	34.5	350.4
	2	2.2	41.6	52.8	348.6
	3	0.0	41.6	0.0	348.6
	4	0.0	39.6	1.6	333.7
	5	0.9	40.0	8.1	332.9
	6	2.6	41.3	37.6	340.1
	7	2.4	41.5	26.5	314.5

Indian River Power Plant - Unit Nos. 1 and 3
Main Boilers
Request for Increase in Allowable Hourly Heat Inputs
Table 10
Baseline NOx Emissions
8/24/2009 (Revision No. 1)

	UNIT 1		UNIT 3	
	NOx (tons)	Period end	NOx (tons)	Period end
Maximum	120.7	Aug-06	645.1	Jul-06
Baseline Period	117.6	Jul-06	645.1	Jul-06

YEAR	MONTH	NOx (tons)	Rolling 24/2	NOx (tons)	Rolling 24/2
2004					
	8	3.9		155.1	
	9	32.7		136.3	
	10	17.7		131.5	
	11	0.4		32.1	
	12	15.2		47.8	
2005	1	3.8		24.4	
	2	5.0		6.6	
	3	6.8		5.9	
	4	21.1		0.0	
	5	14.2		24.5	
	6	0.0		106.5	
	7	19.7		116.6	
	8	18.2		137.9	
	9	44.8		152.9	
	10	9.6		119.6	
	11	0.0		0.0	
	12	10.5		13.5	
2006	1	6.1		0.0	
	2	0.2		11.7	
	3	0.0		0.0	
	4	0.0		0.0	
	5	0.0		11.8	
	6	0.8		35.5	
	7	4.4	117.6	20.0	645.1
	8	10.2	120.7	70.0	602.6
	9	2.0	105.3	17.7	543.3
	10	8.1	100.5	38.4	496.7
	11	5.2	103.0	6.6	484.0
	12	0.0	95.3	0.0	460.1
2007	1	2.1	94.5	0.0	447.8
	2	6.5	95.2	18.3	453.7
	3	0.0	91.9	0.0	450.7
	4	1.5	82.0	11.2	456.3
	5	0.1	75.0	8.4	448.3
	6	3.7	76.8	12.0	401.1
	7	8.2	71.0	34.7	360.1
	8	18.2	71.0	36.6	309.5
	9	4.6	50.9	19.2	242.7
	10	7.3	49.8	35.0	200.4
	11	0.0	49.8	0.0	200.3
	12	0.0	44.5	0.0	193.6
2008	1	2.4	42.7	6.4	196.8
	2	0.2	42.7	2.0	191.9
	3	0.0	42.7	0.0	191.9
	4	0.5	42.9	4.4	194.1
	5	3.4	44.6	10.0	193.2
	6	1.7	45.1	4.1	177.5
	7	0.8	43.3	3.7	169.3
	8	2.7	39.6	8.7	138.6
	9	6.9	42.0	29.1	144.4
	10	1.5	38.7	1.3	125.8
	11	2.4	37.3	2.8	124.0
	12	0.0	37.3	0.0	124.0
2009	1	2.8	37.7	18.1	133.0
	2	1.6	35.2	23.9	135.8
	3	0.3	35.3	0.8	136.2
	4	1.5	35.4	7.8	134.5
	5	2.8	36.7	5.6	133.1
	6	2.8	36.3	17.7	136.0
	7	2.4	33.4	15.6	126.4

Indian River Power Plant - Unit Nos. 1 and 3
NSR Applicability Analysis
Request for Increase in Allowable Hourly Heat Inputs
Table 11
Baseline CO Emissions
8/24/2009 (Revision No. 1)

	UNIT 1		UNIT 3	
	CO (tons)	Period end	CO (tons)	Period end
Maximum	11.5	Aug-06	68.8	Jul-06
Baseline Period	11.0	Jul-06	68.8	Jul-06

YEAR	MONTH	CO (tons)	Rolling 24/2	CO (tons)	Rolling 24/2
2004					
	8	0.4		13.1	
	9	3.2		13.1	
	10	1.6		12.5	
	11	0.1		3.2	
	12	1.3		4.8	
2005	1	0.4		5.7	
	2	0.5		2.0	
	3	0.7		2.2	
	4	1.8		0.0	
	5	0.8		1.5	
	6	0.0		10.1	
	7	1.8		12.4	
	8	1.7		14.9	
	9	4.0		14.9	
	10	1.0		11.6	
	11	0.0		0.0	
	12	1.2		1.8	
2006	1	0.7		0.0	
	2	0.1		1.6	
	3	0.0		0.0	
	4	0.0		0.0	
	5	0.0		2.6	
	6	0.2		5.6	
	7	0.6	11.0	4.0	68.8
	8	1.5	11.5	9.7	67.1
	9	0.5	10.2	3.4	62.2
	10	0.8	9.8	3.9	57.9
	11	0.5	10.1	0.6	56.6
	12	0.0	9.4	0.0	54.2
2007	1	0.2	9.4	0.0	51.4
	2	0.5	9.4	1.5	51.1
	3	0.0	9.0	0.0	50.0
	4	0.1	8.2	1.3	50.6
	5	0.0	7.8	1.4	50.6
	6	0.4	8.0	1.9	46.5
	7	1.1	7.6	4.7	42.7
	8	2.1	7.9	4.5	37.5
	9	0.6	6.1	2.9	31.5
	10	0.9	6.1	5.1	28.2
	11	0.0	6.1	0.0	28.2
	12	0.0	5.5	0.0	27.3
2008	1	0.5	5.3	1.2	28.0
	2	0.0	5.3	0.3	27.3
	3	0.0	5.3	0.0	27.3
	4	0.1	5.4	0.7	27.7
	5	0.5	5.7	1.6	27.2
	6	0.3	5.7	0.6	24.7
	7	0.2	5.5	0.7	23.0
	8	0.4	5.0	1.3	18.8
	9	0.9	5.2	3.3	18.8
	10	0.3	4.9	0.3	17.0
	11	0.2	4.8	0.4	16.9
	12	0.0	4.8	0.0	16.9
2009	1	0.5	4.9	2.1	18.0
	2	0.3	4.8	2.6	18.5
	3	0.1	4.9	0.1	18.6
	4	0.3	5.0	1.4	18.6
	5	0.6	5.2	0.8	18.3
	6	0.6	5.3	2.7	18.7
	7	0.5	5.0	2.4	17.5

Indian River Power Plant - Unit Nos. 1 and 3
NSR Applicability Analysis
Request for Increase in Allowable Hourly Heat Inputs
Table 12
Baseline VOC Emissions
8/24/2009 (Revision No. 1)

	UNIT 1		UNIT 3	
	VOC (tons)	Period end	VOC (tons)	Period end
Maximum	**1.9**	Jun-09	**11.1**	Jul-06
Baseline Period	**1.8**	Jul-06	**11.1**	Jul-06

YEAR	MONTH	VOC (tons)	Rolling 24/2	VOC (tons)	Rolling 24/2
2004					
	8	0.1		2.0	
	9	0.5		2.1	
	10	0.2		1.9	
	11	0.0		0.5	
	12	0.2		0.7	
2005	1	0.1		0.9	
	2	0.1		0.3	
	3	0.1		0.3	
	4	0.3		0.0	
	5	0.2		0.4	
	6	0.0		1.9	
	7	0.3		2.0	
	8	0.3		2.3	
	9	0.6		2.3	
	10	0.2		1.8	
	11	0.0		0.0	
	12	0.2		0.3	
2006	1	0.1		0.0	
	2	0.0		0.2	
	3	0.0		0.0	
	4	0.0		0.0	
	5	0.0		0.5	
	6	0.0		1.1	
	7	0.1	**1.8**	0.7	**11.1**
	8	0.3	**1.9**	1.6	10.9
	9	0.1	1.6	0.6	10.1
	10	0.1	1.6	0.7	9.5
	11	0.1	1.6	0.1	9.3
	12	0.0	1.5	0.0	8.9
2007	1	0.0	1.5	0.0	8.5
	2	0.1	1.5	0.2	8.5
	3	0.0	1.5	0.0	8.3
	4	0.0	1.3	0.2	8.4
	5	0.0	1.2	0.3	8.4
	6	0.1	1.3	0.4	7.6
	7	0.2	1.3	0.9	7.1
	8	0.4	1.4	0.8	6.4
	9	0.1	1.1	0.5	5.5
	10	0.2	1.1	1.0	5.1
	11	0.0	1.1	0.0	5.1
	12	0.0	1.0	0.0	5.0
2008	1	0.1	1.0	0.2	5.1
	2	0.0	1.0	0.1	5.0
	3	0.0	1.0	0.0	5.0
	4	0.0	1.0	0.2	5.1
	5	0.1	1.1	0.3	5.0
	6	0.1	1.1	0.1	4.5
	7	0.0	1.1	0.2	4.2
	8	0.1	1.0	0.3	3.5
	9	0.2	1.0	0.6	3.5
	10	0.1	1.0	0.1	3.2
	11	0.0	1.0	0.1	3.2
	12	0.0	1.0	0.0	3.2
2009	1	0.1	1.0	0.4	3.4
	2	0.1	1.0	0.5	3.5
	3	0.0	1.0	0.0	3.6
	4	0.1	1.0	0.3	3.6
	5	0.1	1.1	0.2	3.5
	6	0.1	1.1	0.5	3.6
	7	0.1	1.1	0.5	3.4

Indian River Power Plant - Unit Nos. 1 and 3

Request for Increase in Allowable Hourly Heat Inputs
Table 13
Baseline Actual Emissions - Existing Units
8/24/2009 (Revision No. 1)

Pollutant	Unit 1	Unit 3	Total Actual Emissions[1] (Tons/yr)	Total Allowable Emissions[2] (Tons/yr)	Baseline Actual Emissions[3] (Tons/yr)
Criteria					
PM2.5	24.4	122.1	146.5	NAp	146.5
PM10	24.4	122.1	146.5	NAp	146.5
SO2	398	2,423	2,821	44,826	2,821
NOx	118	645	763	NAp	763
CO	11.0	68.8	79.8	NAp	79.8
VOC	1.8	11.1	12.9	NAp	12.9
Other (PSD)					
PM	24.4	122.1	146.5	1630.0	146.5

Notes:

1 Emissions based on maximum annual-averaged emissions from consecutive 24-month period in the last 5 years
Baseline period for each pollutant are shown in the baseline emissions summaries. Actual emissions are shown for the existing sources - Unit Nos. 1 and 3

2 Allowable emissions based on proposed maximum annual heat inputs to the units during oil-firing conditions and short-term emission limits (lb/MMBtu)

Boiler	MMBtu/yr	PM (lb/MMBtu)	SO2 (lb/MMBtu)
1	**6,990,480**	**0.1**	**2.75**
3	**25,609,920**	**0.1**	**2.75**

3 Baseline Actual Emissions are equal to actual or allowable emissions, whichever is lower

Indian River Power Plant - Unit Nos. 1 and 3
NSR Applicability Analysis
Request for Increase in Allowable Hourly Heat Inputs
Table 14
Projected Actual Emissions - Initial Calculation - Emission Factors and Utilization

8/24/2009 (Revision No. 1)

Year	Unit No.	Projected Maximum Annual Heat Input (MMBtu/yr)	Fuel Type	Nominal HHV (Btu/gal or Btu/scf)	Percentage of Projected Max. Annual Heat Input by Fuel Type (%)	Equivalent Annual Fuel Usage by Fuel Type (Mgal/yr or MMscf/yr)	Percentage of Annual Oper. Hours at the Requested Hourly Heat Input (%)	Projected Annual Oper. Hours at the Requested Hourly Heat Input (hrs/yr)	Projected Annual Oper. Hours at the Current Hourly Heat Input (hrs/yr)
Future	1	150,000	No. 2 Oil	139,000	0	0	0	0	0
			No. 6 Oil	153,000	95	931	10	17	153
			Natural Gas	1,040	5	7	0	0	9
Future	3	1,600,000	No. 2 Oil	139,000	0	0	0	0	0
			No. 6 Oil	153,000	95	9,935	10	50	446
			Natural Gas	1,040	5	77	0	0	25

Year	Unit No.	Fuel Type	PM (lb/M gal)	PM-10 (lb/M gal)	PM-2.5 (lb/M gal)	SO2 (lb/M gal)	NOx (lb/M gal)	CO (lb/M gal)	VOC (lb/M gal)
Future	1	No. 2 Oil	3.3	3.3	3.3	14.13	24	5	0.2

Year	Unit No.	Fuel Type	PM (lb/M gal)	PM-10 (lb/M gal)	PM-2.5 (lb/M gal)	SO2 (lb/MMBtu)	NOx (lb/MMBtu)	CO (lb/M gal)	VOC (lb/M gal)
Future	1	No. 6 Oil	12.2	12.2	12.2	1.20	0.35	5	0.76

Year	Unit No.	Fuel Type	PM (lb/MMscf)	PM-10 (lb/MMscf)	PM-2.5 (lb/MMscf)	SO2 (lb/MMBtu)	NOx (lb/MMBtu)	CO (lb/MMscf)	VOC (lb/MMscf)
Future	1	Natural Gas	7.6	7.6	7.6	1.20	0.35	24	5.5

Year	Unit No.	Fuel Type	PM (lb/M gal)	PM-10 (lb/M gal)	PM-2.5 (lb/M gal)	SO2 (lb/M gal)	NOx (lb/M gal)	CO (lb/M gal)	VOC (lb/M gal)
Future	3	No. 2 Oil	3.3	3.3	3.3	14.13	24	5	0.2

Year	Unit No.	Fuel Type	PM (lb/M gal)	PM-10 (lb/M gal)	PM-2.5 (lb/M gal)	SO2 (lb/MMBtu)	NOx (lb/MMBtu)	CO (lb/M gal)	VOC (lb/M gal)
Future	3	No. 6 Oil	9.9	9.9	9.9	1.17	0.31	5	0.76

Year	Unit No.	Fuel Type	PM (lb/MMscf)	PM-10 (lb/MMscf)	PM-2.5 (lb/MMscf)	SO2 (lb/MMBtu)	NOx (lb/MMBtu)	CO (lb/MMscf)	VOC (lb/MMscf)
Future	3	Natural Gas	7.6	7.6	7.6	1.17	0.31	24	5.5

Indian River Power Plant - Unit Nos. 1 and 3

Request for Increase in Allowable Hourly Heat Inputs
Table 15
Projected Actual Emission - Initial Calculation - Existing Units

8/24/2009 (Revision No. 1)

Pollutant	Unit 1	Unit 3	Total Boiler Emissions
Criteria			
PM2.5	5.7	49.5	55.2
PM10	5.7	49.5	55.2
SO2	90	934	1,024
NOx	27	249	275
CO	2.4	25.8	28.2
VOC	0.4	4.0	4.4
Other (PSD)			
PM	5.7	49.5	55.2

Indian River Power Plant - Unit Nos. 1 and 3

Request for Increase in Allowable Hourly Heat Inputs
Table 16
Projected Actual Emissions Attributable to the Project - Existing Units

8/24/2009 (Revision No. 1)

Pollutant	Unit 1	Unit 3	Total Boiler Emissions
Criteria			
PM2.5	0.0	0.3	0.4
PM10	0.0	0.3	0.4
SO2	0.6	5.8	6.4
NOx	0.2	1.5	1.7
CO	0.0	0.2	0.2
VOC	0.0	0.0	0.0
Other (PSD)			
PM	0.0	0.3	0.4

Boiler	Fuel Type	Current Hourly HI (MMBtu/hr)	Requested Hourly HI (MMBtu/hr)
1	Oil	832.3	890.0
1	Natural Gas	865.5	923.3
3	Oil	3048.8	3250.0
3	Natural Gas	3208.5	3409.7

Indian River Power Plant - Unit Nos. 1 and 3

Request for Increase in Allowable Hourly Heat Inputs
Table 17
New Source Potential Emissions
8/24/2009 (Revision No. 1)

Pollutant	None	Total New Source Emissions[1]
Criteria		
PM2.5	0	0
PM10	0	0
SO2	0	0
NOx	0	0
CO	0	0
VOC	0	0
Other (PSD)		
PM	0	0

Notes:

1 Emissions = potential to emit (PTE)