## Exhibit E:
## August 20, 2013, Letter from Tetra Tech to MassDEP
## to MassDEP
## (the "August 20, 2013 Supplement")

**TETRA TECH**

August 20, 2013

Mr. James Belsky, Permit Chief
MassDEP Northeast Region
205B Lowell Street
Wilmington, MA 01887

Re:  Major Comprehensive Plan Application
     Salem Harbor Redevelopment (SHR) Project (Transmittal Number X254064)
     **Additional Information**

Dear Mr. Belsky:

This information is being submitted to respond to technical questions raised by Mr. Cosmo Buttaro with respect to the Major Comprehensive Plan Application (MCPA) submitted on December 21, 2012, and the First and Second Supplements submitted in April and June, 2013. This information is being submitted on behalf of Footprint Power Salem Harbor Development LP ("Footprint"). This technical information includes: (1) GE startup emission data for $SO_2$, (2) rationale and references for the addition of a condensable particulate allowance for the emergency diesel generator and fire pump, (3) references for the emission factors for formaldehyde, HAPs, $H_2SO_4$, Pb, and $CO_2/CO_2e$, (4) proposed BACT limit for GHG on a rolling 12-month basis, (5) sulfur limits for natural gas, (6) particulate emission rates, and (7) spreadsheet correction for the second sheet of Attachment 4 to our August 6 letter.

### (1) GE Startup/Shutdown Emissions for $SO_2$

The startup/shutdown emission estimates for $SO_2$ as provided by GE are as follows:

Cold Start:     2.0 pounds
Warm Start:     1.5 pounds
Hot Start:      0.6 pounds
Shutdown:       0.3 pounds

### (2) Condensable Particulate Emissions for Emergency Engines

As presented in Section 3.0 of the MCPA, Footprint proposed that the Emergency Diesel Generator (EDG) will meet EPA Tier 2 standards and the Emergency Fire Pump (FP) will meet Tier 3 standards, both for off-road diesel engines. This corresponds to the applicable requirements specified in 40 CFR 89, as specified at 310 CMR 7.26(42)(b) and the MassDEP's June 2011 BACT Guidelines.

For particulates, the applicable limit under both Tier 2 and Tier 3 for the relevant engine sizes is 0.2 grams/kW-hr. The particulate testing procedures in 40 CFR 89.112(c) reference the *California Regulations for New 1996 and Later Heavy-Duty Off-Road Diesel Cycle Engines.*

These California requirements then reference the International Standards Organization's (ISO) Test Procedure 8178. A summary of the particulate test procedures in ISO-8178 are found in the report *Test/QA Plan for the Verification Testing of Diesel Exhaust Catalysts, Particulate Filters, and Engine Modification Control Technologies for Highway and Nonroad Use Diesel Engines, EPA Cooperative Agreement No. CR83416901-0, March 2011.* As outlined in ISO-8178, PM mass is determined by filtration of a portion of dilute exhaust. A double dilution technique is used, and filtration occurs with the sample stream controlled to 52°C or less (52°C = 125.6°F). Under EPA Test Method 201A for "filterable" PM, if the filtration temperature exceeds 30°C (= 85°F), then Method 201A specifies that Method 201A may only be used to measure "filterable" particulates, and Method 202 must be used to measure "condensable" particulates. Since the ISO-8178 temperature is higher than 30°C, we therefore have added a condensable particulate emissions allowance based on the AP-42 condensable particulate emission factor. The AP-42 condensable particulate emission factor for large diesel engines (from Table 3.4-2) is 0.0077 lb/MMBtu. This converts to grams/kWhr for the emergency diesel generator as follows (based on a heat rate of (7,400,000 Btu/hr)/(822.4 kW) = 9000 Btu/kWhr):

(0.0077 lb/MMBtu)(9000 Btu/kWhr)(454 grams/lb)/(1,000,000 Btu/MMBtu) = 0.0315 g/kWhr

The factor then used for modeling and potential emissions (for both the EDG and FP) is:

0.2 g/kWhr + 0.0315 g/kWhr = 0.232 g/kWhr

### (3) Emission Factor References

*HAPs (including formaldehyde and lead)*

For the combustion turbines/duct burners, the HAP emission factors as contained in Table 3-6 of the December 2012 MCPA are all based on AP-42, Table 3.1-3 (uncontrolled factors) except for formaldehyde. For formaldehyde, we have assumed that the turbine performance and oxidation catalyst will achieve a nominal 50% reduction from the uncontrolled AP-42 factor, reducing the formaldehyde emission rate from 7.1E-04 lb/MMBtu to 3.5E-04 lb/MMBtu.

For the auxiliary boiler, all the HAP emission factors in Table 3-6 of the December 2012 MCPA are from AP-42, Tables 1.4-3 and 1.4-4.

For the EDG and FP, the organic HAP emissions factors are from AP-42 Tables 3.4-3 and 3.4-4 (EDG) and Table 3.3-2 for the FP. Metals emissions in ULSD for the EDG and FP are based on the paper *Survey of Ultra Trace Metals in Gas Turbine Fuels.* A copy of this paper is provided as Attachment 1. Where trace metals were detected in any of the 13 samples, the average results was used. For metals where none of that metal was detected in any of the thirteen samples, the detection limit was used.

*$H_2SO_4$*

For the combustion turbines/duct burners, the $H_2SO_4$ emissions include an allowance for oxidation of $SO_2$ to $SO_3$ from the turbine combustor, the oxidation catalyst, and the SCR system. $SO_3$ then combines with water vapor to form $H_2SO_4$. Based on data from GE, up to 5% of the fuel sulfur is expected to convert directly to $SO_3$ in the turbine combustor/duct burners. Then, up to 35% of the (remaining) $SO_2$ is expected to convert to $SO_3$ in passing through the oxidation catalyst, and up to an additional 5% of the (remaining) $SO_2$ is expected to convert to $SO_3$ in passing through the SCR system. In terms of $SO_2$, the percentage of the original amount of $SO_2$ remaining as $SO_2$ based on these values $= (0.95)(0.65)(0.95) = 58.7\%$. Therefore, on a molecular basis, up to 41.3% of the $SO_2$ is estimated to convert to $SO_3$. Adjusting for the ratio of the molecular weight of $H_2SO_4{:}SO_2$ (98/64), the potential emissions of $H_2SO_4$ on a mass basis are calculated as:

$(0.0015$ lb/MMBtu $(SO_2))(0.413)(98/64) = 0.00095$ lb/MMBtu, rounded up to 0.001 lb/MMBtu.

For the auxiliary boiler, EDG, and FP, up to 5% of the fuel sulfur is assumed to convert directly to $SO_3$ in the combustion process. Adjusting for the ratio of the molecular weight of $H_2SO_4{:}SO_2$ (98/64), the potential emissions of $H_2SO_4$ on a mass basis are calculated as:

$(0.05)(98/64) = 0.077$; 8% of $SO_2$ is used.

*$CO_2/CO_2e$*

$CO_2$ emissions for both natural gas and ULSD combustion are based on 40 CFR Part 75 default $CO_2$ emission factors contained in Part 75, Appendix G, Section 2.3. These factors are 1040 scf of $CO_2$/MMBtu for natural gas and 1420 scf of $CO_2$/MMBtu for fuel oil (including distillate/ULSD). These values are converted to mass units (lb/MMBtu) as follows:

$(1040$ scf of $CO_2$/MMBtu$)(44$ lb $CO_2$/lb-mole$)/(385$ scf/lb-mole$) = 118.9$ lb $CO_2$/MMBtu (natural gas)

$(1420$ scf of $CO_2$/MMBtu$)(44$ lb $CO_2$/lb-mole$)/(385$ scf/lb-mole$) = 162.3$ lb $CO_2$/MMBtu (ULSD)

For methane ($CH_4$) and nitrous oxide ($N_2O$), USEPA emission factors were used. (http://www.epa.gov/climateleadership/documents/emission-factors.pdf) The natural gas factors are 1.0 gram of $CH_4$ per MMBtu and 0.1 gram of $N_2O$ per MMBtu. The distillate oil factors are 3.0 gram of $CH_4$ per MMBtu and 0.6 gram of $N_2O$ per MMBtu. The Global Warming Potential (GWP) factors used are 21 for $CH_4$ and 310 for $N_2O$. The results are 119.0 lb $CO_2e$ per MMBtu for natural gas and 162.85 lb $CO_2e$ per MMBtu for ULSD.

## (4) Rolling 12-Month GHG BACT Limit

Footprint is proposing a rolling 12-month GHG BACT limit of 895 lb $CO_2e$/MWhr (net to grid) for the CTG/HRSG/duct burner units. This takes into account the potential frequency of part

load/cycling operations, startups and shutdowns, and a degradation allowance over the life of the facility. Footprint proposes to demonstrate compliance with this rolling 12-month limit using the Part 75 continuous monitoring data (for fuel flow) and a $CO_2e$ emission factor of 119 lb/MMBtu heat input (HHV). This includes the Part 75 default $CO_2$ emission rate corresponding to 118.9 lb/MMBtu (based on 40 CFR Part 75, Appendix G), plus a 0.1 lb/MMBtu allowance for $CH_4$ and $N_2O$ (GWP included). It is our position that this is the most appropriate factor to use since GHG compliance reporting is based on the Part 75 reported values.

Our proposed GHG limit of 895 lbs $CO_2e$/net MWhr is equivalent to the rolling 12-month GHG limit approved for the Pioneer Valley Energy Center (PVEC). PVEC's limit of 895 lb $CO_2e$/net MWhr as contained in EPA's Final PSD Permit 052-042-MA15, as discussed in EPA's accompanying Fact Sheet, is based on a $CO_2$ emission factor of 116 lb/MMBtu. Adjusting the PVEC 895 lb $CO_2e$/net MWhr value by (119/116) actually yields 918 lb $CO_2e$/MWhr. So our proposal to meet 895 lb/MWhr based on 119 lb $CO_2e$/MMBtu is actually more stringent than the approved PVEC limit.

## (5) Sulfur Content for Natural Gas

Our proposed limit for natural gas sulfur content is 0.5 grains/100 scf of natural gas. This is based on EPA's definition of *pipeline natural gas,* as contained in 40 CFR 72.2. It is our understanding the MassDEP is planning to convert this to an emission rate value of 0.0014 lb $SO_2$/MMBtu, which is acceptable.

Brockton (in Plan Approval No. 4B08015) has been approved based on 0.2 grains/100 scf of natural gas. We note that this value of 0.2 grains/100 scf is what EPA allows as a default *pipeline natural gas* $SO_2$ emission factor for $SO_2$ allowance related reporting under 40 CFR Part 75 (corresponds to 0.0006 lb $SO_2$/MMBtu). For Part 75 purposes, 0.2 grains is considered appropriate for average annual $SO_2$ allowance reporting, but for purposes of a permitted emission limit we believe this value is too restrictive compared to what may actually be found for maximum sulfur content in natural gas. We believe the 0.5 grain/100 scf factors as defined by EPA is more appropriate. We note also PVEC actually has an approved BACT $SO_2$ emission rate of 0.0019 lb/MMBtu for natural gas.

## (6) Particulate Emission Rate

Our proposed particulate ($PM/PM_{10}/PM_{2.5}$) BACT emission rate for the CTG/HRSG/duct burner units is $\leq$ 0.009 lb/MMBtu, including both filterable and condensable emissions. As noted in Table 5-2 of the December 2012 MCPA, this proposed limit is more stringent than the MassDEP "top case" presumptive BACT precedent identified in the June 2011 BACT Guidance, that being Mystic Station Approval which was approved for 0.011 lb/MMBtu. The four Mystic Station MHI 501G units had tested PM emissions ranging from 0.005 – 0.010 lb/MMBtu.

PVEC (Final PSD Permit 052-042-MA15) has an approved $PM/PM_{10}/PM_{2.5}$ limit of 0.004 lb/MMBtu. PVEC is of course also based on the MHI 501G turbine, albeit with a newer generation combustion system. However, compliance with this new lower limit has not been demonstrated in practice for PVEC since this facility has not been constructed. However, given that essentially all of the tested particulate matter was condensable particulates for Mystic, it is not clear to us that a newer generation MHI 501G could reliably achieve 0.004 lb/MMBtu in

practice. We consider our proposed particulate emission rates to represent BACT, especially considering the rates most recently demonstrated in practice for Mystic Station.
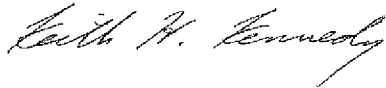
Our proposed $PM/PM_{10}/PM_{2.5}$ emission rates as a function of load are actually $\leq 0.0067$ lb/MMBtu at full load (includes duct firing and peak firing cases), $\leq 0.0071$ lb/MMBtu at 75% load, and $\leq 0.0088$ lb/MMBtu at 46 % load.

### (7) Corrected Spreadsheet from August 6 Letter

Attached is a corrected version of Attachment 4, Sheet 2 of 2 from our letter dated August 6. As we discussed, we had had made a copying error with this spreadsheet resulting in some incorrect value sin our August 6 submission.

If you have additional questions, please contact either me at (617) 803-7809 or George Lipka at (617) 443-7545.

Sincerely,

Keith H. Kennedy
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Attachments

# SURVEY OF ULTRA-TRACE METALS IN GAS TURBINE FUELS

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Gas turbines are multi-fuel capable power generation systems. Because of their robust design, they can operate on low heating value gases, liquid fuels, natural gases and refinery gases. In a recent industry study, the environmental impact related to gas turbine operation on fuel oil was determined based on the available emissions data for metal emissions from gas turbines. Data collected by EPA reported the noted detectable trace metal emissions during oil operation. However, many of the tests were over fifteen years old, and fuel from the storage tanks at the facility may have been even older. Attempts to determine an accurate environmental assessment were hindered by the quality of the emissions data, and the paucity of fuel sample analytical results for distillate fuels..

Considering the great improvements in the US refining infrastructure, we concluded that any metals in a distillate fuel oil sample would probably be at the ultra-trace level, and would very likely be at the detection limits of the most analytical methods. Further, the concentrations of any hazardous metals (such as lead or mercury) would be extremely low, and the modeled emissions from using such a fuel would yield no measurable health impact. To address this question, we reviewed the existing literature on the subject, and found that no coordinated effort had attempted to identify the concentrations of trace hazardous metals, certainly not using some of the latest measurement methods (in this case ICP-MS).

The next step was to collect samples, and screen them for the presence of eight hazardous metals. Fuel samples (distillate) were collected from around the United States, taken from existing storage facilities, with fuel tanks assigned to a gas turbine power generation unit. Samples were taken to be representative of each Petroleum Administrative Defense Districts (PADD). The survey results revealed no measurable concentrations of Arsenic, Mercury or Lead in any fuel sample taken. No detectable levels of Chromium VI were reported. All samples were screened using Mass-Spec, with detection levels below 1 ppb. These results indicate that the distillate feedstocks available to the power generation industry are essentially free of toxic metals, and pose no health risk to the public when used in a gas turbine. The results also suggest that the petroleum distillate transmission and distribution system does not introduce cross contamination to the fuel supply.

## Introduction

Non-combustible materials present in a fuel are typically released into the environment during the combustion process. With low-grade fuels, such as residual fuel oil or coal, metals, including toxic metals can be present in significant concentrations. Such is not the case for distillate fuels. Yet, there has been a widely held perspective that distillate fuels encumbered with potentially toxic metals.

The metals of most concern are those that exhibit a high degree of toxicity, or carcinogenicity, at very low concentrations. Mercury and lead are two key metals where there has been intense interest to reduce or eliminate their release into the environment. Removal of lead from gasoline, and switching to cleaner fuels has had a positive impact in reducing these emissions into the environment. In the twenty years since the removal of lead from gasoline was mandated there has been a steady decrease in lead emissions, and a steady increase in the quality of liquid fuels available for the power generation industry. As the results show here, the quality of distillate fuels is exceptional, and the metal contaminants found in liquid fuel oil are even lower than those mandated in drinking water.

## Experimental

Samples from across the US were collected at storage facilities supplying fuel to power generation installations. Thirteen samples were collected and analyzed using ion mass spectrometry to identify the presence of specific metal toxins in the fuels

The toxic metals selected for this study were based on the needs for conducting an environmental health risk analysis related to gas turbine operation. In the risk analysis, emissions from a gas or fuel oil fired gas turbine were determined based on the mass emission rates of each toxic component. Both organic and inorganic emissions were used in the health risk analysis. For liquid fuel (No. 2 fuel oil) operation, the analysis assumed that any metal in the exhaust was due to the presence of metals in the fuel oil. In the initial phase of the study, the dominant metal of concern (based on results of emission tests on gas turbines) was chromium, since emission measurements of chromium yielded the highest emission factors. Yet with chromium, the dominant risk is the Cr-VI oxidation state. However, the existing emissions test data did not attempt to quantify the oxidation state of any metals reportedly detected in the exhaust.

Routine industrial fuel tests, with metal detection levels in the ppm range, report measurable concentrations of arsenic and lead. However, the metals are almost routinely reported at the detection limits of the apparatus, which was not sufficient for our needs. In the risk analysis, the presence of either arsenic or lead at the ppm level would calculate unacceptable risk levels. To address the accuracy of the earlier fuel tests, and to estimate health risks related to emissions from burning liquid fuels, the set of metals selected for a detailed ultra-trace survey was selected. Those metals in selected are shown in the following table.

| | |
|---|---|
| 1. Arsenic | 5. Nickel |
| 2. Cadmium | 6. Manganese |
| 3. Chromium | 7. Selenium |
| 4. Lead | 8. Mercury |

Metal Analysis from Fuel Samples Selected from Across United States
Samples collected from Gas Turbine Installations around the United States

All concentrations are reported in units of ppb (by weight)

| State or Region | Sample ID | PADD | Arsenic | Cadmium | Total Chromium | Chrome VI | Lead | Manganese | Nickel | Selenium | Mercury |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 California | 30352 | V | 0 | 0 | 175 | 0 | 3.01 | 6.9 | 0 | 0 | 0 |
| 2 Colorado | 30374 | IV | 0 | 0 | 203 | 0 | 1.89 | 6.73 | 0 | 0 | 0 |
| 3 Florida | 30391 | III | 0 | 0 | 244.6 | 0 | 3.48 | 5.56 | 0 | 0 | 0 |
| 4 Wisconsin | 30353 | III | 0 | 0 | 226.8 | 0 | 2.07 | 6.03 | 4.93 | 0 | 0 |
| 5 Florida | 30354 | III | 0 | 0 | 238.2 | 0 | 5.29 | 5.76 | 12.33 | 0 | 0 |
| 6 Minnesota | 30355 | II | 0 | 0 | 272.1 | 0 | 7.2 | 6.35 | 184.77 | 0 | 0 |
| 7 California-South | 30405 | V | 0 | 0 | 175.8 | 0 | 18.79 | 10.07 | 15.05 | 0 | 0 |
| 8 NC | 30423 | III | 0 | 0 | 259.16 | 0 | 2.3 | 6.61 | 28.95 | 0 | 0 |
| 9 Arkansas | 30424 | IV | 0 | 0 | 202.49 | 0 | 46.18 | 10.95 | 28.2 | 0 | 0 |
| 10 Arkansas | 30447 | IV | 0 | 0 | 403 | | 61 | 0 | 0 | 0 | 0 |
| 11 Arizona | 30494 | IV | 0 | 0 | 306 | | 41 | 0 | 0 | 0 | 0 |
| 12 California-North | 30522 | V | 0 | 0 | 165 | 0 | 0 | 0 | 0 | 0 | 0 |
| 13 Maine | 30425 | I | 0 | 0 | 279.86 | 0 | 2.59 | 7.11 | 101.78 | 0 | 0 |
| Average | | | 0 | 0 | 242.4 | | 15.0 | 5.5 | 28.9 | 0 | 0 |
| SD | | | 0 | 0 | 65.05 | | 20.59 | 3.53 | 54.51 | 0 | 0 |
| Max | | | 0 | 0 | 403 | | 61 | 10.95 | 184.77 | 0 | 0 |
| Detection Limit, ppb | | | 0.9 | 0.1 | 0.07 | | 0.08 | 0.1 | 0.2 | 5 | 0.2 |

**Table 1. Summary Of Distillate Oil ICP Results.**

**Analytical Method.** Fuel characterization methods have been used extensively to quantify the presence of various components, including metals, in fuel oil. Historically, most of the test methods have cutoff their analysis at the 1 ppm (1,000 ppb) level, and usually this has been sufficient.

But to accurately determine the impact of burning liquid fuel, and the subsequent release of any metals into the environment, it has been necessary to push for a deeper and more thorough analysis using improved methods methods.

For this study, an Inductively Coupled Plasmas-Mass Spectrometer (Thermo-Elemental X7 ICP/MS) was used. It uses a high temperature plasma between 6000 K and 8000 K, connected to a high sensitivity mass spectrometer. The plasma is formed in an RF chamber, where the sample can be delivered as a solution, vapor, or even solid. The mass spectrometer is a quadrapole mass-spec designed to rapidly measure ions at each mass unit. Detection limits are species dependent, and range from parts-per-trillion (ppt) to parts-per-billion (ppb).

**No. 2 Fuel Oil Analysis Results.** The results of the survey show that No.2 Fuel Oil to be remarkably clean and of high quality. A detailed summary of the analytical results is shown in Table 1. the most prevalent compound in the fuel samples was chromium, although no Cr-VI was detected. The fuels were essentially free of arsenic, cadmium, selenium, and mercury. The concentration of arsenic permitted in drinking water is higher than the quantities reported in the fuel samples.

**Comparison with Other Fuel Samples.** As the name implies, residual fuel is the components of the petroleum feedstock that remain after distillation. Because of the nature of the distillation process (atmospheric or vacuum), most of the heavy metals would be expected to be found in the residual fuel oil. This appears to be the general rule that is easily demonstrated.

However, the mere presence of a metal, such as chromium, in the fuel, does not necessarily imply that it is in a toxic form in the turbine exhaust. For chromium, the oxidation state of concern is the +6. A 1998 survey of industrial boilers using heavy oil reported that the metal of critical concern was Nickel. In the case of Nickel, it is the presence of nickel-subsulfide ($Ni_2S_3$) that is the hazardous component. But it is not the nickel oxide of concern, NiO, but the

nickel subsulfide ($Ni_2S_3$). However, nickel sub-sulfide is in a reduced state, a condition that should be difficult to maintain in intense industrial burner.

With the recent regulatory focus on a wide range of industries, there has been intense focus to determine what compounds represent any real, or potential hazard. A recent survey of residual fuels used in large boilers indicated that nickel was present in ranges from 30-40 ppm, significantly higher than the levels of nickel observed in the current fuel study[1]. Stack test measurements revealed that there was no evidence of reduced nickel in the particulates, indicating that good combustion (and excess oxygen levels) are effective means of fully oxidizing all the compounds in the fuel. We would expect similar results from the nickel present in the No. 2 fuel oil samples noted in this study.

In a 1999 survey of crude oil samples, McGaw reported data on 18 metals trace metals in a wide range of crude oil samples[2]. A comparison of the average concentrations found in the McGaw reveals are markedly improved compared to the distillate samples from this study.

**Table 2. Comparison Of Crude Samples With Distillate Results**

| Metal | As | Cr | Pb | Ni | Hg | Cd |
|---|---|---|---|---|---|---|
| Concentration in crude oil samples (McGaw 1999 study), ppb | 60 | 270 | 32 | 19690 | 60 | 10 |
| Concentrations in distillate fuel oil (this study), ppb | 0 | 242 | 15 | 28 | 0 | 0 |

In a study on Iowa ground water quality, researchers used similar techniques as those selected here to identify any role between underground storage of fuels and possible aquifer contamination.[3] The Iowa ground water survey examined transportation fuels, which are even more tightly specified than the fuels used in gas turbines. The authors of that study also failed to identify the presence of any mercury in No. 2 diesel fuels taken from selected regional sources. The highest chromium reported in the study was only 31 ppb, although there was no attempt to identify the presence of any specific

oxidation states of the chromium. In essence, this earlier study from a relatively select group of sources further confirms the high quality, and lack of toxic metals, in the US distillate fuels base.

## Conclusions

Gas turbine liquid fuel samples were characterized for the presence of eight trace hazardous metals. The study revealed that many of the metals of concerned (including mercury and arsenic) are not present at any level above the detection limits of the ICP-MS used. Chromium is not present in the +6 oxidation state, the oxidation state of most concern. Nickel is present at even lower concentrations, but there is no evidence that nickel could form the toxic sulfide compound during a combustion process that occurs with excess oxygen available. The source of lead is probably due to cross contamination from the small quantities of leaded fuels that are still used today (aviation gasoline is still marketed as a low lead fuel).

## References

(1) *"Nickel Speciation of Flyash from Residual Oil-Fired Power Plants"*, Kevin Galbreath, University of North Dakota Energy & Environmental Research Center; presented at Air Quality IV, 22-24 Sep 2003, Arlington, Va.

(2) Magaw, RI, McMillen, SJ, Gala, WR., 1999. Risk evaluation of metals in crude oils: *Proc. 6th Int'l Petrol. Environmental Conf.* Nov. 16-18, Houston, TX, pp. 460-473.

(3) Rich Heathcote, Don Simmons, and Steven Hernholz, *Analysis of Motor-Vehicle Fuels for Metals by Inductively Coupled Plasma-Mass Spectrometry;* Hygenic Laboratory, Volume 39, No. 4, pp. 1-4, 2001, The University of Iowa.

GE Energy 107F Series 5 Rapid Response Combined Cycle Plant - Emission Data - Natural Gas

### GE Energy Performance Data - Site Conditions

| Operating Point | | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Case Description | | 50.4 DB firing | 100% DB firing | Unfired | Unfired | Unfired | 50% DB firing | 100% DB firing | Unfired | 50% DB firing | 100% DB firing | Unfired | Unfired |
| Ambient Temperature | °F | 90 | 90 | 90 | 90 | 105 | 105 | 105 | 105 | 105 | 105 | 105 | 105 |
| Ambient Pressure | psia | 14.7 | 14.7 | 14.7 | 14.7 | 14.7 | 14.7 | 14.7 | 14.7 | 14.7 | 14.7 | 14.7 | 14.7 |
| Ambient Relative Humidity | % | 60 | 60 | 60 | 60 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |

### GE Energy Performance Data - Plant Status

| HRSG Duct Burner (On/Off) | | Fired | Fired | Unfired | Unfired | Unfired | Fired | Fired | Unfired | Fired | Fired | Unfired | Unfired |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Evaporative Cooler state (On/Off) | | Off | Off | Off | Off | On | On | On | Off | Off | Off | Off | Off |
| Gas Turbine Load | % | PEAK | PEAK | 75% | 47% | BASE | PEAK | PEAK | BASE | PEAK | PEAK | 75% | 49% |
| Gas Turbines Operating | | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |

### GE Energy Performance Data - Fuel Data

| GT Heat Consumption | MMBtu/hr, HHV | 2017 | 2017 | 1590 | 1260 | 1990 | 2005 | 2005 | 1880 | 1928 | 1928 | 1520 | 1240 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Duct Burner Heat Consumption | MMBtu/hr, HHV | 183 | 377 | 0 | 0 | 0 | 183 | 377 | 0 | 183 | 377 | 0 | 0 |
| Total Heat Consumption (GT + DB) | MMBtu/hr, HHV | 2201 | 2394 | 1590 | 1260 | 1990 | 2188 | 2382 | 1880 | 2112 | 2305 | 1520 | 1240 |

### GE Energy Performance Data - HRSG Exit Exhaust Gas Emissions

| NOx | ppmvd @ 15% O2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CO | ppmvd @ 15% O2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| VOC | ppmvd @ 15% O2 | 1.7 | 1.7 | 1 | 1 | 1 | 1.7 | 1.7 | 1 | 1.7 | 1.7 | 1 | 1 |
| NH3 | ppmvd @ 15% O2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |

| NOx | lb/MMBtu | 0.0074 | 0.0074 | 0.0074 | 0.0074 | 0.0074 | 0.0074 | 0.0074 | 0.0074 | 0.0074 | 0.0074 | 0.0074 | 0.0074 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CO | lb/MMBtu | 0.0045 | 0.0045 | 0.0045 | 0.0045 | 0.0045 | 0.0045 | 0.0045 | 0.0045 | 0.0045 | 0.0045 | 0.0045 | 0.0045 |
| VOC | lb/MMBtu | 0.0022 | 0.0022 | 0.0013 | 0.0013 | 0.0013 | 0.0022 | 0.0022 | 0.0013 | 0.0022 | 0.0022 | 0.0013 | 0.0013 |
| NH3 | lb/MMBtu | 0.0027 | 0.0027 | 0.0027 | 0.0027 | 0.0027 | 0.0027 | 0.0027 | 0.0027 | 0.0027 | 0.0027 | 0.0027 | 0.0027 |
| Particulates - Filterable + Condensible, Including Sulfates | lb/MMBtu | 0.0063 | 0.0064 | 0.0071 | 0.0087 | 0.0059 | 0.0063 | 0.0065 | 0.0062 | 0.0065 | 0.0067 | 0.0074 | 0.0088 |

| NOx | lb/hr | 16.3 | 17.7 | 11.8 | 9.3 | 14.7 | 16.2 | 17.6 | 13.9 | 15.6 | 17.1 | 11.2 | 9.2 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CO | lb/hr | 9.9 | 10.8 | 7.2 | 5.7 | 9.0 | 9.8 | 10.7 | 8.5 | 9.5 | 10.4 | 6.8 | 5.6 |
| VOC | lb/hr | 4.8 | 5.3 | 2.1 | 1.6 | 2.6 | 4.8 | 5.2 | 2.4 | 4.6 | 5.1 | 2.0 | 1.6 |
| NH3 | lb/hr | 5.9 | 6.5 | 4.3 | 3.4 | 5.4 | 5.9 | 6.4 | 5.1 | 5.7 | 6.2 | 4.1 | 3.3 |
| Particulates - Filterable + Condensible, Including Sulfates | lb/hr | 13.8 | 15.4 | 11.3 | 10.9 | 11.8 | 13.8 | 15.4 | 11.7 | 13.7 | 15.4 | 11.2 | 10.9 |