Florida Department of
Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

January 23, 2009

Electronically Sent – Received Receipt Requested

jvangessel@wm.com
Mr. John Van Gessel
Vice President & Assistant Secretary
Waste Management, Inc. of Florida
2869 West Paces Ferry Road
Atlanta, Georgia 30339

Re: DEP File No. 0930104-014-AC
Berman Road and Clay Farms Landfills
Okeechobee Landfill, Inc.
Waste Management, Inc. of Florida

Dear Mr. Van Gessel:

On December 23, 2009 the Department received the response to our incompleteness letter dated December 11, 2008 regarding the air construction permit application for the construction of additional flares and turbines along with the Low Cat desulfurization system at the Berman Road and Clay Farms Landfills.

Pursuant to Rules 62-4.055, and 62-4.070 F.A.C., Permit Processing, the Department requests submittal of the additional information below prior to processing the application. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

- Revised Appendix B of the application lists, for the primary operating scenario, the potential emissions of nitrogen oxides (NO_X) and carbon monoxide (CO) for the Titan and the Centaur turbines along with different technologies to control these pollutants.

  The Department needs cost estimates to support the selection of best available control technology (BACT) for NO_X and CO, in accordance with Rule 62-210.200, Definitions, F.A.C and Rule 62-210.400(4)(c) Prevention of Significant Deterioration (PSD), F.A.C.

  Such cost estimates are typically provided in the form of cost to control a ton of pollutant using the top/down approach beginning with the most rigorous level of control. We understand that Waste Management plans to contact Solar in order to obtain a cost analysis for the technology using siloxane removal followed by NO_X control.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule
62-4.055(1): "The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department .... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."

If you have any questions regarding this matter, please contact Ms. Teresa Heron at 850/921-9529 or Ms. Debbie Nelson (meteorologist) at 850/921-9537.

Sincerely,

A.A. Linero, Program Administrator
Special Projects Section

AAL/th

cc: David Thorley, Waste Management, Inc. dthorley@wm.com
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Golder Associates Inc.

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Golder Associates

April 7, 2009

0938-7541

Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Attention: Alvaro A. Linero, Program Administrator

RE: DEP FILE NO. 0930104-014-AC
BERMAN ROAD AND CLAY FARMS LANDFILLS
OKEECHOBEE LANDFILL, INC.
WASTE MANAGEMENT, INC. OF FLORIDA

Dear Mr. Linero:

Okeechobee Landfill, Inc. (OLI) has received a request for additional information (RAI) from the Florida Department of Environmental Protection (FDEP) dated January 23, 2009, regarding the air construction permit application for the construction of additional flares and turbines along with the Low-Cat sulfur removal system at the Berman Road and Clay Farms Landfills. Specifically, FDEP has asked for cost estimates to support the best available control technology (BACT) analysis for the control of nitrogen oxides (NO_x) and carbon monoxide (CO) emissions for the Titan and Centaur combustion turbines (CTs) proposed for the project. The BACT analysis was originally submitted along with the construction permit application in February 2007, and both were subsequently revised in December 2008.

Golder Associates Inc. (Golder) was contracted to prepare the cost estimates to support the control technologies selected as BACT in the revised BACT analysis. The control technologies and emission rates proposed as BACT for the CTs in the revised December 2008 BACT analysis are presented below:

NO_x

- BACT – Good combustion practices.
- BACT Emission Limit – 72 parts per million by volume (ppmv) @ 15-percent oxygen (O_2) (Titan), 42 ppmv @ 15-percent O_2 (Centaur).

CO

- BACT – Good combustion practices.
- BACT Emission Limit – 100 ppmv @ 15-percent O_2 (Titan), 250 ppmv @ 15-percent O_2 (Centaur).

The BACT analysis identified various control technologies for NO_x and CO and arrived at the following conclusion for each:

NO_x Control Technologies

- Combustion Controls – Considered technically feasible.
- Staged Combustion (Dry Low-NO_x, Dry-Low Emissions, SoLoNO$_x$) – Not commercially available for small turbines like Solar Titan or Solar Centaur burning landfill gas (LFG).

- Catalytic Combustion (Xonon) – Has not been applied to a LFG-fired combustion turbine and not available for the Titan and Centaur CTs proposed for the project. The technology is still in the commercial demonstration stage.
- Diluent Injection – Water injection is not recommended for low-Btu gas-fired CTs because of potential flame instability, and is therefore rejected.
- Selective Non-Catalytic Reduction (SNCR) – None commercially available for LFG-fired CTs, so rejected.
- SCONO$_x$ – Technology requires gas temperature much lower than simple-cycle CT exhaust temperature, so not technically feasible.
- Selective Catalytic Reduction (SCR) – LFG contains siloxanes, silicone-carbon compounds that oxidize to silicon dioxide (SiO_2) when combusted. SiO_2 rapidly coats the catalyst, which consequently becomes deactivated and needs to be replaced in only hours or days. Therefore, the technology is not technically feasible.

CO Control Technologies

- Combustion Controls – Considered technically feasible.
- Oxidation Catalyst – No known installation on CTs firing LFG. Catalyst fouling due to siloxane in the gas stream. Considered not technically feasible.

Therefore, none of the alternative control technologies were considered feasible for the NO$_x$ and CO emissions from the LFG-fired CTs and good combustion practice was proposed as BACT for both. Please note that none of the technologies were rejected based on the economic impacts.

In response to FDEP's RAI, the following additional information is presented to support the BACT analysis.

NO$_x$ BACT

A combination of control technologies is sometimes technically feasible when a single control technology is not feasible. Among the alternative control technologies identified above, SCR is the top control technology for NO$_x$ emission reductions from natural gas-fired CTs. However, a SCR system is not technically feasible for the LFG-fired CTs because of siloxanes in the LFG stream, unless the siloxanes can be effectively removed from the stream. Siloxane removal systems are commercially available. Therefore, a combination control option – siloxane removal system followed by a SCR – was identified and evaluated as a control option for NO$_x$ emissions from the proposed LFG-fired CTs at the OLI Landfills. This option is evaluated below.

Siloxane Removal System Followed by SCR

A technical description of the SCR system was provided with the original and revised BACT reports submitted to FDEP. Deposits from siloxane combustion by-products can severely damage SCR catalysts. Fouling of the catalyst's surface by silicon-based deposits inhibits the reduction of NO$_x$, resulting in failure of the process to meet air emission compliance standards. SCR catalysts for simple cycle CTs are precious metal-based and are quite expensive to replace. Fouling of SCR catalysts can occur in as little as a day or two to several weeks or months, depending on the concentration of siloxanes in the gas stream and other factors.

EPA has evaluated siloxane removal systems related to add-on catalyst control systems for internal combustion engines in the recent proposed revisions to 40 CFR 63, Subpart ZZZZ, NESHAPS for Reciprocating Internal Combustion Engines (Federal Register, March 5, 2009, p. 9706). EPA states:

> *Currently, there are no viable beyond-the-floor options for engines that combust landfill or digester gas. Aftertreatment controls could theoretically be applied to engines burning waste gas; however, numerous studies have shown that a family of silicon-based compounds named siloxanes present in landfill gas can foul add-on catalyst controls. Such fouling can render the catalyst inoperable within short periods of time. Pre-treatment systems could be applied to clean the fuel prior to combustion theoretically allowing catalysts to be used, but has not shown to be a reliable technology at this time.*

Although the current status of siloxane removal systems is that these systems are unproven, and therefore, the SCR systems are not technically feasible for the OLI gas turbines, a cost analysis is presented for informational purposes. The BACT analysis for a Waste Management Disposal Services of Pennsylvania, Inc., application for a LFG-to-energy project utilizing Solar Centaur CTs, No. 009-00007 (the "WM Pennsylvania project") considered Applied Filter Technologies' SAG™ Process Siloxane Removal System. The same siloxane removal technology is evaluated here for the OLI facility. The SAG™ Process utilizes media similar to activated carbon (graphite carbon based) but with modified pore structures to perform better on removal of the individual siloxane species. The technology involves virtually no moving parts. The gas passes through the vessels, which remove the siloxanes in the presence of other organics while allowing the methane to pass through. The media for siloxane D5 (5 oxygen atoms) removal is called "DD"; for siloxane D4 (4 oxygen atoms) removal, "DM"; and for lower molecular weight siloxanes, "MD". By layering these media in the vessels in the order (from the gas inlet) of largest DD, DM, then MD, additional removal benefits may be realized over a homogeneous media bed.

Siloxane removal from the LFG is accomplished after moisture and hydrogen sulfide (H_2S) have been reduced, because moisture and H_2S may foul the SAG™ media. Therefore, the SAG™ process equipment would follow the Low-Cat sulfur removal equipment. The SAG™ media can be fouled by water vapor at relative humidity (RH) levels exceeding 45 percent. For this reason, gas conditioning equipment may be required to reduce the RH of the LFG to 45 percent or lower. Other considerations for the gas conditioning equipment design are the gas temperature and pressure.

In order to deliver the LFG at suitable pressure to the CTs, the pressure drop across the H_2S removal equipment, siloxane removal equipment, piping, and other process components must be taken into consideration. LFG containing high levels of H_2S is corrosive to gas collection system piping and is especially corrosive to compressors or blowers. OLI is proposing a Low-Cat H_2S removal system.

Based on an Applied Filter Technology paper, "Reducing Biogas Power Generation Costs by Removal of Siloxanes" (NZWMA, 2004), because of the range of siloxane and H_2S levels, the media life for the SAG™ siloxane removal system will range from 50 to 180 days. Once SAG™ media is spent, it is usually disposed of as a "non-hazardous" material in a landfill. This paper is attached for your reference.

Economic Impacts – The combination technology of siloxane removal system followed by SCR is considered to be technically feasible for the purpose of this evaluation. Cost analyses were performed using vendor cost estimates provided for a siloxane removal system and a SCR system in the WM Pennsylvania application. The following cost scenarios were evaluated:

- Annualized cost of the siloxane removal system;
- Annualized cost to control NO_x from the Solar Titan 130 CT using SCR;
- Annualized cost to control NO_x from the Solar Centaur 40 CT using SCR;

- Initial Phase – annualized cost to control NO_x based on the initial buildout of the OLI facility – one (1) Solar Titan and four (4) Solar Centaur CTs (1 siloxane removal system plus 5 SCR systems); and
- Ultimate Phase – annualized cost to control NO_x based on the ultimate buildout of the facility – one (1) Solar Titan and fifteen (15) Solar Centaur CTs (1 siloxane removal system plus 16 SCR systems).

The initial facility buildout of five CTs is expected to occur within about the first 5 years of operation. Therefore, a current BACT analysis is based on this cost scenario. However, this initial buildout includes a siloxane removal system large enough to accommodate the ultimate buildout, since this would be the most cost effective installation.

Additional CTs would be added in subsequent years, but may require up to 20 years for the ultimate buildout to be completed (depending on production of LFG). Since BACT may change over time, the BACT for these future turbines would generally be determined by FDEP some time closer to actual installation. However, for informational purposes, a cost analysis for the ultimate buildout was also developed.

The siloxane removal system cost is based on the system developed for the WM Pennsylvania project. The siloxane removal system for the WM Pennsylvania project has a design biogas flow of 8,000 standard cubic feet per minute (scfm). The design LFG flow for the OLI facility CTs (16 total) is 27,500 scfm. The cost for the OLI facility's siloxane removal system was determined by using the ratio of the gas flow rates of the two projects (i.e., 27,500 ÷ 8,000 = 3.4). Note that the cost of the siloxane removal system does not include any pretreatment device to reduce relative humidity, if necessary.

The graphite media of the siloxane removal system will also need to be replaced often. Air Filtration Technology estimates a maximum media life of 180 days. The cost calculation assumed media replacement twice a year.

The capital recovery cost was developed based on 20 years equipment life at 7 percent interest.

The capital and annual cost calculations for a siloxane removal system for the OLI CTs are presented in Table 1. The capital cost is estimated at $2.30 million, and the annual cost of the siloxane removal system is estimated at $1.2 million.

The capital and annual costs of SCR systems for NO_x control for the Titan 130 and Centaur 40 CTs are presented in Tables 2 and 3, respectively. The SCR system cost for the Centaur 40 is based on the exact same turbine proposed for the WM Pennsylvania facility. The SCR cost for the Titan 130 Centaur 40 was based on a 50 percent increase above the cost for the Centaur 40, since the Titan 130 produces three times more air flow than the Centaur 40.

According to Air Filtration Technology, a SAG™ siloxane removal system is capable of removing siloxane to undetectable levels. However, the small amount of siloxane left in the gas stream will still eventually foul the SCR catalyst, requiring more frequent catalyst replacement. A conservative assumption of SCR catalyst replacement once per year was used in the cost calculations. It is noted that some estimate that more frequent catalyst replacements may be required.

The capital recovery cost was developed based on 20 years equipment life at 7 percent interest. As shown in Tables 2 and 3, the capital costs for SCR were estimated to be $3.4 million for the Titan 130, and $2.3 million for the Centaur 40. The annual costs were estimated to be $1.17 million for the Titan 130 and $780,000 for the Centaur 40.

As described previously, in the first phase of the project, one Titan 130 and up to four Centaur 40 turbines would be installed. The cost summary of this scenario is presented in Table 4. As shown, the total annual cost is $5.5 million and the cost effectiveness is more than $17,000 per ton of NO_x removed. These costs are extremely high. As also summarized in Table 4, the total annual cost for controlling NO_x emissions for the ultimate buildout (16 CTs total) is $14 million per year, and the cost effectiveness is $21,400 per ton of NO_x removed.

Energy Impacts – The SCR technology would require additional auxiliary power to overcome the draft loss across the catalyst bed, to supply hot dilution air for mixing with the ammonia, and to pump ammonia into the vaporizer. The siloxane removal system would also require auxiliary power to account for the increased pressure drop across the media bed.

Environmental Impacts – SCR requires the storage and use of ammonia, which can cause environmental consequences if not handled and stored properly. Ammonia for the SCR can be in either liquid form or created from solid urea. If liquid ammonia is used, storage of this substance may trigger requirements as specified by the Occupational Safety and Health Administration and the Community Right-to-Know Act. Ammonia slip (i.e., unreacted ammonia emitted from the stack) is typically 5 parts per million (ppm) or less, but has the potential to increase with increasing ammonia feed rates. Additionally, during the life of the project, the SCR catalyst would require periodic regeneration or replacement. The used catalyst would be returned to the catalyst supplier for regeneration or would be disposed of in accordance with all applicable regulations.

The spent media of the siloxane removal system is usually disposed as a "non-hazardous" material in a landfill.

BACT Selection – The total capital investment for NO_x control for the initial phase of the OLI project (4 CTs) is approximately $15 million. The total annual cost is $5.5 million and the cost effectiveness is $17,800 per ton of NO_x removed. For the total project buildout (16 CTs), the capital cost for NO_x control is approximately $40 million, and the total annual cost is approximately $21,400 per ton of NO_x removed. It is noted that OLI is already committed to install the Low-CAT sulfur removal system in order to reduce potential SO_2 emissions, at a capital cost of approximately $15 million. This is already a very significant cost for air pollution control purposes.

Based on the extremely high capital and annual costs and cost effectiveness, controlling NO_x emissions using the SCR system, which also requires a siloxane removal system, is not an economically viable option. Indeed, if this cost were imposed, in addition to the high cost of the Low-CAT system already to be incurred, the proposed project would no longer be economically feasible. EPA has recently concluded that siloxane removal systems for landfill gas are not proven and are unreliable. There are no other NO_x control technologies that are technically feasible. Good combustion practice is therefore selected as BACT for NO_x emissions, which is inherent to the combustion process and does not create any energy or environmental impacts.

CO BACT

The oxidation catalyst system is the top CO control technology, which was previously rejected as not technically feasible because of siloxanes in the gas stream. Similar to the NO_x BACT analysis, Golder identified the combination control technologies of a siloxane removal system followed by an oxidation catalyst system and evaluated it as viable control option for CO emissions from the proposed LFG-fired CTs at the OLI Landfills.

Oxidation Catalyst

A technical description of the SCR system was provided with the original and revised BACT reports submitted to FDEP. This technology by itself is not considered to be applicable to units burning LFG because of siloxanes, which convert to SiO_2 in the combustion process. The SiO_2 quickly fouls downstream components including the catalysts. Thus, a siloxane removal system must first be installed for an oxidation catalyst system to be feasible. For the OLI Landfill CTs, an oxidation catalyst system could be added downstream of the siloxane removal system and the SCR system. However, such a system has never been applied on a LFG-fired CT.

Economic Impact – A cost analysis was prepared based on a recent cost quote from BASF Catalysts, LLC (see Attachment A). The cost quote is for an oxidation catalyst system to control CO from a natural gas-fired Titan 130 CT reducing CO from 25 ppmv (@15-percent O_2) to 2.5 ppmv (@15-percent O_2). The guaranteed CO emission rates of the LFG-fired OLI Landfill CTs are 100 and 250 ppmv for Titan 130 and Centaur 40, respectively. A 90-percent reduction would mean a 90 ppmv reduction for the Titan 130 and a 225 ppmv reduction for the Centaur 40. The vendor cost quote was adjusted accordingly for these desired ppmv reductions and also by the ratio of the air flow of the OLI Landfill turbines and the turbine considered in the vendor quote. Similar to the SCR catalyst, an oxidation catalyst life of 6 months was used in the cost analysis. The following cost scenarios were prepared:

- Annualized cost to control CO from the Solar Titan 130 CT using oxidation catalyst;
- Annualized cost to control CO from the Solar Centaur CTs using oxidation catalyst;
- Initial Phase – annualized cost to control CO based on the initial buildout of the OLI facility – one (1) Solar Titan and four (4) Solar Centaur CTs (1 siloxane removal system plus 5 oxidation catalyst systems); and
- Ultimate Phase – annualized cost to control CO based on the ultimate buildout of the facility – one (1) Solar Titan and fifteen (15) Solar Centaur CTs (1 siloxane removal system plus 16 oxidation catalyst systems).

The annualized cost calculations for oxidation catalyst systems on a Titan 130 CT and a Centaur 40 CT are presented in Tables 5 and 6. Cost effectiveness calculations are summarized in Table 7. The cost effectiveness scenarios for CO also include NO_x reduction because CO emissions control using oxidation catalyst is typically employed as an add-on to the SCRs controlling NO_x.

For the initial phase of the project, when one Titan 130 and up to four Centaur 40 CTs will be installed, an additional $3.3 million in capital costs is required due to the oxidation catalyst. As shown in Table 7, the annual cost increase is estimated at $1.9 million per year. The total cost effectiveness of NO_x and CO control is $3,600 per ton.

An additional $10 million capital cost is estimated to install oxidation catalyst systems for the ultimate buildout case of 16 turbines. The cost effectiveness for controlling both NO_x and CO from all turbines proposed for the project would be more than $4,000 per ton of pollutant. These costs just for CO control are extremely high.

Energy Impacts – Combustion controls are inherent to the combustion process and do not create any energy impacts. The oxidation catalyst technology would require a nominal amount of auxiliary power to overcome the draft loss across the catalyst.

Environmental Impacts – Combustion controls do not create negative environmental impacts since these systems are designed and operated to achieve the optimum balance between CO and NO_x emissions. The oxidation catalyst would require periodic regeneration or replacement. The used catalyst would usually be returned to the catalyst supplier for regeneration or would be disposed of in accordance with all applicable regulations.

BACT Selection – The total capital investment for NO_x and CO controls for the initial phase of the project is more than $18 million. The total annualized cost for the systems is $7 million per year. For the ultimate buildout of the project, the total capital investment for NO_x and CO controls is more than $50 million and more than $10 million for the CO oxidation catalyst systems alone. The total annualized cost for the systems is $20 million per year. These costs are extremely high by any standards, and would render the project economically infeasible. Therefore, good combustion practice is selected as BACT for CO.

Based on the above cost analyses, control of NO_x using SCR and control of CO using oxidation catalyst for the LFG-fired CTs at the OLI Landfill facility is not economically viable. Please note that there are no examples of these technologies applied to LFG-fired CTs. These technologies are technically feasible only if siloxanes are completely removed from the gas stream, as even a trace amount of siloxanes in the gas stream would foul the catalyst beds in a short time. EPA has acknowledged that siloxane removal systems are currently unreliable.

In addition, it is emphasized that NO_x emissions are much more of concern from an air quality perspective [i.e., ozone formation, acid rain, formation of particulates under 2.5 microns in size ($PM_{2.5}$), etc.]. Therefore, a higher cost effectiveness threshold exists for NO_x as compared to CO emissions.

Vendor cost quotes are presented in Attachment A. Please note that only the cost analysis tables for the WM Pennsylvania project are attached. The entire report (Application for Plan Approval No. 009-00007) is available upon request.

BACT FOR OPEN AND ENCLOSED FLARES

In response to FDEP's additional request, the following information regarding the open and enclosed flare systems used at landfills is presented. This information demonstrates that open flares are BACT for operation with the CTs compared to enclosed flares.

There are two main categories of flares – open and enclosed. Open flares burn LFG as open flames, though a windshield is normally fitted. Open flares are also known as candlestick or utility flares. Enclosed flares burn LFG in a vertical, cylindrical, or rectilinear enclosure. The enclosure is often insulated to reduce heat losses and allow operation at higher temperatures. Enclosed flares are also known as ground flares.

Open flares are typically considered better than enclosed flares for operation with the turbine facility. Open flares have a better "turn-down" ratio (10:1) than enclosed flares (6:1), which allows for better control of the extra gas generated by the landfill that cannot be combusted by the turbines due to input restrictions of the equipment itself. For example, a 3,000 scfm open flare can be operated at a minimum load of 300 scfm of LFG, whereas a 3,000 scfm enclosed flare would require a minimum of 500 scfm of LFG. Therefore, open flares provide better control of the extra gas the landfill is producing that exceeds the turbine capacity.

The startup and shutdown process is easier for open flares. Open flares can be shut down (in the case of a backup unit) for long periods of time and then generally can be fired up easily. Enclosed flares cannot be shut down for long periods as the insulation inside the flare will quickly deteriorate with water (high rainfall in Okeechobee County) and cause the flare to fail startup. Proper storage of an enclosed flare would involve the use of a rain cap that would require significant work to prep prior to startup should the flare be needed as a backup. Therefore, use of an enclosed flare as a backup unit under an automatic recovery mode is almost impossible. Personnel would need to be present to prepare the enclosed flare to light if the flare is required for a turbine shutdown.

Open flares have fewer parts to fail and require less time to repair than enclosed flares. Enclosed flares are a safety hazard as they require a confined space entry to maintain them; open flares do not. Enclosed flares also get very hot and many people have been severely burned by touching the stack, whereas open flares do not get hot at ground level and are safer for personnel to be around.

Since the open flares have fewer parts and do not require as much computer logic to operate, often open flares can be made available more quickly to combust LFG or manually be made to operate with site personnel after natural disasters, including hurricanes. In contrast, after a natural disaster, an enclosed flare may require certified vendor/manufacture personnel to be brought to the site to work computer-based controls (PLC) because the required telemetry or internet access may not be available due to loss of phone service. It is very difficult to obtain such service after a hurricane.

From an emission and compliance standpoint, open flares have comparable or lower NO_x emissions [approximately 0.07 pound per million British thermal units (lb/MMBtu)] than enclosed flares (0.06 to 0.08 lb/MMBtu). Open flares do have somewhat higher CO emissions (approximately 0.37 lb/MMBtu) compared to enclosed flares (0.20 lb/MMBtu), but NO_x emissions are much more of concern from an air quality perspective (i.e., ozone formation, acid rain, $PM_{2.5}$ formation, etc.).

Open flares make better backup devices than enclosed flares for short turbine outages because they can be in immediate compliance with the LFG combustion requirements, whereas enclosed flares take time to get to the compliant combustion temperature set by the performance test.

Thank you for consideration of this information. If you have any questions, please do not hesitate to call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

DB/SKM/tlc

Enclosures

cc: D. Thorley, WM
S. Nunes, OLI
M. Lersch, WM
J. Christiansen, WM

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APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff**
   Registration Number: **19011**

2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.****
   Street Address: **6026 NW 1st Place**
   City: **Gainesville** State: **FL** Zip Code: **32607-6018**

3. Professional Engineer Telephone Numbers...
   Telephone: **(352) 336-5600** ext. **545** Fax: **(352) 336-6603**

4. Professional Engineer E-mail Address: **DBuff@golder.com**

5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

David A. Buff 4/7/09
Signature Date

(seal)

* Attach any exception to certification statement.
**Board of Professional Engineers Certificate of Authorization #00001670.

TABLE 1
CAPITAL AND ANNUAL COSTS FOR SILOXANE REMOVAL SYSTEM

Cost Items	Cost Factors	Siloxane Removal System Cost ($)
DIRECT CAPITAL COSTS (DCC):		
(1) Siloxane Removal System	Vendor Quote [a]	962,500
Auxiliary Equipment (control panel, etc.)	5% of equipment cost, estimated	48,125
(2) Freight	5% of equipment cost, CCM Chapter 2	48,125
(3) Sales Tax	NA - Pollution Control Equipment	0
Subtotal: Total Equipment Cost (TEC)		1,058,750
(4) Direct Installation Costs		
(a) Foundation and Structural Support	8% of TEC, Cost Control Manual (CCM), Section 3, Table 2.8	84,700
(b) Handling & Erection	14% of TEC, CCM, Section 3, Table 2.8	148,225
(c) Electrical	16% of TEC, Solar Estimate	169,400
(d) Piping	16% of TEC, Solar Estimate	169,400
(e) Insulation	1% of TEC, CCM, Section 3, Table 2.8	10,588
Total DCC:		1,641,063
INDIRECT CAPITAL COSTS (ICC): [b]		
(1) Indirect Installation Costs		
(a) General Facilities	5% of TEC, CCM Section 4, Table 2.5	52,938
(b) Engineering and Home Office Fees	10% of TEC, CCM Section 4, Table 2.5	105,875
(c) Process Contingency	5% of TEC, CCM Section 4, Table 2.5	52,938
(2) Other Indirect Costs		
(a) Emissions Monitoring	Engineering Estimate	5,000
(b) Performance Testing	1% of TEC, CCM Section 3, Table 2.8	10,588
(c) Spare Parts	Engineering Estimate	5,000
(d) Contractor Fees	10% of TEC, CCM Section 3, Table 2.8	105,875
Total ICC:		338,213
PROJECT CONTINGENCY	15% of (DCC+ICC)	296,891
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	2,276,166
DIRECT OPERATING COSTS (DOC): [b]		
(1) Operating Labor		
Operator	1.0 hr/shift, $30/hr, 8760 hrs/yr	32,850
Supervisor	15% of operator cost	4,928
(2) Maintenance (labor and material)	1.5% of TCI, CCM Section 4, Equation 2.46	34,142
(3) Siloxane System Energy Requirement	6 in ΔP (estimated same as SCR), 308 MW/year, $60/MW	18,480
(3) Siloxane Removal Media Replacement	Vendor estimate, 35% of Equipment, Media Life 1/2 year	673,750
(4) Siloxane System Calibration	Solar Information - about $500K for 5 years	100,000
Total DOC:		864,150
INDIRECT OPERATING COSTS (IOC): [b]		
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	43,152
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	22,762
(3) Insurance	1% of total capital investment, CCM Chapter 2	22,762
(4) Administration	2% of total capital investment, CCM Chapter 2	45,523
Total IOC:	(1) + (2) + (3) + (4)	134,199
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	214,870
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	1,213,219

Notes:

[a] Cost estimates from similar systems considered for Waste Management Disposal Services of Pennsylvania, Inc's Renewable Energy Facility Application for Plan Approval, No. 009-00007, September 2008.

[b] Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

TABLE 2
CAPITAL AND ANNUAL COSTS FOR NOx CONTROL SYSTEM FOR SOLAR TITAN 130

Cost Items	Cost Factors	SCR System Solar T130 Cost ($)
DIRECT CAPITAL COSTS (DCC):		
(1) Basic SCR Equipment and Materials	Vendor Quote - SCR for Centaur 40 (a)	1,432,500
Auxiliary Equipment (pump skid, control panel, etc.)	5% of equipment cost, estimated	71,625
Ammonia Storage System	Assumed included	included
(2) Freight	5% of equipment cost	71,625
(3) Sales Tax	NA - Pollution Control Equipment	0
Subtotal: Total Equipment Cost (TEC)		1,575,750
(4) Direct Installation Costs(b)		
(a) Foundation and Structural Support	8% of TEC, Cost Control Manual (CCM), Section 3, Table 2.8	126,060
(b) Handling & Erection	14% of TEC, CCM, Section 3, Table 2.8	220,605
(c) Electrical	16% of TEC, Solar Estimate	252,120
(d) Piping	16% of TEC, Solar Estimate	252,120
(e) Insulation	1% of TEC, CCM, Section 3, Table 2.8	15,758
(f) Painting	1% of TEC, CCM, Section 3, Table 2.8	15,758
Total DCC:		2,458,170
INDIRECT CAPITAL COSTS (ICC): (b)		
(1) Indirect Installation Costs		
(a) General Facilities	5% of TEC, CCM Section 4, Table 2.5	78,788
(b) Engineering and Home Office Fees	10% of TEC, CCM Section 4, Table 2.5	157,575
(c) Process Contingency	5% of TEC, CCM Section 4, Table 2.5	78,788
(2) Other Indirect Costs		
(a) Emissions Monitoring	Engineering Estimate	10,000
(b) Performance Testing	1% of TEC, CCM Section 3, Table 2.8	15,758
(c) Spare Parts	Engineering Estimate	10,000
(d) Contractor Fees	10% of TEC, CCM Section 3, Table 2.8	157,575
Total ICC:		508,483
PROJECT CONTINGENCY	15% of (DCC+ICC)	444,998
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	3,411,650
DIRECT OPERATING COSTS (DOC): (b)		
(1) Operating Labor		
Operator	1.0 hr/shift, $30/hr, 8760 hrs/yr	32,850
Supervisor	15% of operator cost	4,928
(2) Maintenance (labor and material)	1.5% of TCI, CCM Section 4, Equation 2.46	51,175
(3) SCR Reagent Cost	$100/ton for 19% Aqueous, 355 TPY	35,540
(4) MW Loss Penalty	0.2% of Turbine Design Output of 15 MW, $0.06/kWh	15,768
(5) Auxiliary Power Requirement	4.8 kW blower + 18 kW pump for NH_3 inject skid; $0.06/kWh	11,984
(6) Catalyst Replacement Cost	Vendor estimate, 35% of Equipment, Catalyst Life 1 year	501,375
Total DOC:		653,619
INDIRECT OPERATING COSTS (IOC): (b)		
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	53,371
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	34,117
(3) Insurance	1% of total capital investment, CCM Chapter 2	34,117
(4) Administration	2% of total capital investment, CCM Chapter 2	68,233
Total IOC:	(1) + (2) + (3) + (4)	189,837
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	322,060
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	1,165,516

Notes:

(a) Cost estimates from the SCR system considered for Solar Centaur 40 turbine, Waste Management Disposal Services of Pennsylvania, Inc's Renewable Energy Facility, Application for Plan Approval, No. 009-00007, September 2008. SCR cost adjusted by an estimated 50% more since Titan 130 has 2.7 times more mass flow rate than the Centaur 40.

(b) Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

TABLE 3
CAPITAL AND ANNUAL COSTS FOR NOx CONTROL SYSTEMS, SOLAR CENTAUR 40

Cost Items	Cost Factors	SCR System Centaur 40 Cost ($)
DIRECT CAPITAL COSTS (DCC):		
(1) Basic SCR Equipment and Materials	Vendor Quote (a)	955,000
Auxiliary Equipment (pump skid, control panel, etc.)	5% of equipment cost, estimated	47,750
Ammonia Storage System	Assumed included	included
(2) Freight	5% of equipment cost	47,750
(3) Sales Tax	NA - Pollution Control Equipment	0
Subtotal: Total Equipment Cost (TEC)		1,050,500
(4) Direct Installation Costs		
(a) Foundation and Structural Support	8% of TEC, Cost Control Manual (CCM), Section 3, Table 2.8	84,040
(b) Handling & Erection	14% of TEC, CCM, Section 3, Table 2.8	147,070
(c) Electrical	16% of TEC, Solar Estimate	168,080
(d) Piping	16% of TEC, Solar Estimate	168,080
(e) Insulation	1% of TEC, CCM, Section 3, Table 2.8	10,505
(f) Painting	1% of TEC, CCM, Section 3, Table 2.8	10,505
Total DCC:		1,638,780
INDIRECT CAPITAL COSTS (ICC): (b)		
(1) Direct Installation Costs(b)		
(a) General Facilities	5% of TEC, CCM Section 4, Table 2.5	52,525
(b) Engineering and Home Office Fees	10% of TEC, CCM Section 4, Table 2.5	105,050
(c) Process Contingency	5% of TEC, CCM Section 4, Table 2.5	52,525
(2) Other Indirect Costs		
(a) Emissions Monitoring	Engineering Estimate	10,000
(b) Performance Testing	1% of TEC, CCM Section 3, Table 2.8	10,505
(c) Spare Parts	Engineering Estimate	10,000
(d) Contractor Fees	10% of TEC, CCM Section 3, Table 2.8	105,050
Total ICC:		345,655
PROJECT CONTINGENCY	15% of (DCC+ICC)	297,665
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	2,282,100
DIRECT OPERATING COSTS (DOC): (b)		
(1) Operating Labor		
Operator	1.0 hr/shift, $30/hr, 8760 hrs/yr	32,850
Supervisor	15% of operator cost	4,928
(2) Maintenance (labor and material)	1.5% of TCI, CCM Section 4, Equation 2.46	34,232
(3) SCR Reagent Cost	$100/ton for 19% Aqueous, 61 TPY	6,130
(4) MW Loss Penalty	0.2% of Turbine Design Output of 3.3 MW, $0.06/kWh	3,469
(6) Auxiliary Power Requirement	4.8 kW blower + 18 kW pump for NH_3 inject skid; $0.06/kWh	11,984
(8) Catalyst Replacement Cost	Vendor estimate, 35% of Equipment, Catalyst Life 1 year	334,250
Total DOC:		427,842
INDIRECT OPERATING COSTS (IOC): (b)		
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	43,205
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	22,821
(3) Insurance	1% of total capital investment, CCM Chapter 2	22,821
(4) Administration	2% of total capital investment, CCM Chapter 2	45,642
Total IOC:	(1) + (2) + (3) + (4)	134,489
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	215,430
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	777,761

Notes:

(a) Cost estimates from SCR system considered for Solar Centaur 40 turbine, Waste Management Disposal Services of Pennsylvania, Inc's Renewable Energy Facility, Application for Plan Approval, No. 009-00007, September 2008.

(b) Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

TABLE 4
COST EFFECTIVENESS CALCULATION FOR NOx CONTROL SCENARIOS, OKEECHOBEE LANDFILL FACILITY

			NOx Control Scenarios			
Cost Items	**Comments/Reference**	**Value**	**1 Titan 130**	**1 Centaur 40**	**1 Titan 130 + 4 Centaur 40**	**1 Titan 130 + 15 Centaur 40**
Annualized Cost for Siloxane System ($/yr)	Table 1	1,213,219	1,213,219	1,213,219	1,213,219	1,213,219
Annualized Cost of SCR System for Titan 130 ($/yr)	Table 2	1,165,516	1,165,516	--	1,165,516	1,165,516
Annualized Cost of SCR System for Centaur 40 ($/yr)	Table 3	777,761	--	777,761	3,111,045	11,666,420
Total Annualized Cost (AC)($/yr):			2,378,735	1,990,980	5,489,780	14,045,155
Titan 130 Baseline NOx Emissions (TPY) :	72 ppm, Emission Guarantee	203.0	203.0	--	203.0	203.0
Centaur 40 Baseline NOx Emissions (TPY) :	42 ppm, Emission Guarantee	35.0	--	35.0	140.0	525.0
Controlled NOx Emissions (TPY) :	90% Control		20.3	3.5	34.3	72.8
Reduction in NOx Emissions (TPY):	Baseline - Controlled		182.7	31.5	308.7	655.2
Cost Effectiveness (AC/Total Reduction)	$ per ton Removed				17,784	21,436

TABLE 5
CAPITAL AND ANNUAL COSTS FOR CO OXIDATION CATALYST SYSTEM FOR SOLAR TITAN 130

Cost Items	Cost Factors	CO Catalyst System Solar T130 Cost ($)
DIRECT CAPITAL COSTS (DCC):		
(1) CO Catalyst System (Frame+CO Modules)	Vendor Quote [(a)]	308,000
Auxiliary Equipment (ducts, catalyst housing)	5% of equipment cost, estimated	15,400
Instrumentation and Controls	10% of equipment cost, CCM Chapter 2	30,800
(2) Freight	5% of equipment cost, CCM Chapter 2	15,400
(3) Sales Tax	NA - Pollution Control Equipment	0
Subtotal: Total Equipment Cost (TEC)		369,600
(3) Direct Installation Costs[(b)]		
(a) Foundation and Structural Support	8% of TEC, Cost Control Manual (CCM), Section 3, Table 2.8	29,568
(b) Handling & Erection	14% of TEC, CCM, Section 3, Table 2.8	51,744
(c) Electrical	4% of TEC, CCM, Section 3, Table 2.8	14,784
(d) Piping and Wiring	2% of TEC, CCM, Section 3, Table 2.8	7,392
(e) Insulation	1% of TEC, CCM, Section 3, Table 2.8	3,696
(f) Painting	1% of TEC, CCM, Section 3, Table 2.8	3,696
(g) Sample Ports	Estimated 1% of TEC	3,696
Total DCC:		484,176
INDIRECT CAPITAL COSTS (ICC):[(b)]		
(1) Indirect Installation Costs		
(a) General Facilities	5% of TEC, CCM Section 4, Table 2.5	18,480
(b) Engineering and Home Office Fees	10% of TEC, CCM Section 4, Table 2.5	36,960
(c) Process Contingency	5% of TEC, CCM Section 4, Table 2.5	18,480
(2) Other Indirect Costs		
(a) Emissions Monitoring	Engineering Estimate	10,000
(b) Performance Testing	1% of TEC, CCM Section 3, Table 2.8	3,696
(c) Contractor Fees	10% of TEC, CCM Section 3, Table 2.8	36,960
Total ICC:		124,576
PROJECT CONTINGENCY	15% of (DCC+ICC)	91,313
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+Project Contingency	700,065
DIRECT OPERATING COSTS (DOC):[(b)]		
(1) Operating Labor		
Operator	1.0 hr/shift, $30/hr, 8760 hrs/yr	32,850
Supervisor	15% of operator cost	4,928
(2) Maintenance (labor and material)	1.5% of TCI, CCM Section 4, Equation 2.46	10,501
(3) MW Loss Penalty	Estimated 0.2% of Design Output of 15 MW, $0.06/kWh	15,768
(4) Catalyst Replacement Cost	Vendor estimate, 35% of Equipment, Catalyst Life 1/2 year	215,600
Total DOC:		279,646
INDIRECT OPERATING COSTS (IOC):[(b)]		
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	28,967
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	7,001
(3) Insurance	1% of total capital investment, CCM Chapter 2	7,001
(4) Administration	2% of total capital investment, CCM Chapter 2	14,001
Total IOC:	(1) + (2) + (3) + (4)	56,970
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	66,086
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	402,702

Notes:

[(a)] Cost estimates from BASF Catalysts, LLC for a CO catalyst system for a Solar Titan 130 turbine. System cost adjusted for CO ppm reduction and for 90% control and mass flow rate of the turbine considered for the Okeechobee Landfill project.

[(b)] Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

TABLE 6
CAPITAL AND ANNUAL COSTS FOR CO OXIDATION CATALYST SYSTEM FOR SOLAR CENTAUR 40

Cost Items	**Cost Factors**	**CO Catalyst System Solar Centaur 40 Cost ($)**
DIRECT CAPITAL COSTS (DCC):		
(1) CO Catalyst System (Frame+CO Modules)	Vendor Quote [a]	289,000
Auxiliary Equipment (ducts, catalyst housing)	5% of equipment cost, estimated	14,450
Instrumentation and Controls	10% of equipment cost, CCM Chapter 2	28,900
(2) Freight	5% of equipment cost, CCM Chapter 2	14,450
(3) Sales Tax	NA - Pollution Control Equipment	0
Subtotal: Total Equipment Cost (TEC)		346,800
(3) Direct Installation Costs[b]		
(a) Foundation and Structural Support	8% of TEC, Cost Control Manual (CCM), Section 3, Table 2.8	27,744
(b) Handling & Erection	14% of TEC, CCM, Section 3, Table 2.8	48,552
(c) Electrical	4% of TEC, CCM, Section 3, Table 2.8	13,872
(d) Piping and Wiring	2% of TEC, CCM, Section 3, Table 2.8	6,936
(e) Insulation	1% of TEC, CCM, Section 3, Table 2.8	3,468
(f) Painting	1% of TEC, CCM, Section 3, Table 2.8	3,468
(g) Sample Ports	Estimated 1% of TEC	3,468
Total DCC:		454,308
INDIRECT CAPITAL COSTS (ICC):[b]		
(1) Indirect Installation Costs		
(a) General Facilities	5% of TEC, CCM Section 4, Table 2.5	17,340
(b) Engineering and Home Office Fees	10% of TEC, CCM Section 4, Table 2.5	34,680
(c) Process Contingency	5% of TEC, CCM Section 4, Table 2.5	17,340
(2) Other Indirect Costs		
(a) Emissions Monitoring	Engineering Estimate	10,000
(b) Performance Testing	1% of TEC, CCM Section 3, Table 2.8	3,468
(c) Contractor Fees	10% of TEC, CCM Section 3, Table 2.8	34,680
Total ICC:		117,508
PROJECT CONTINGENCY	15% of (DCC+ICC)	85,772
TOTAL CAPITAL INVESTMENT (TCI):	DCC + ICC+Project Contingency	657,588
DIRECT OPERATING COSTS (DOC):[b]		
(1) Operating Labor		
Operator	1.0 hr/shift, $30/hr, 8760 hrs/yr	32,850
Supervisor	15% of operator cost	4,928
(2) Maintenance (labor and material)	1.5% of TCI, CCM Section 4, Equation 2.46	9,864
(3) MW Loss Penalty	Estimated 0.2% of Design Output of 3.3 MW, $0.06/kWh	3,469
(4) Catalyst Replacement Cost	Vendor estimate, 35% of Equipment, Catalyst Life 1/2 year	202,300
Total DOC:		253,410
INDIRECT OPERATING COSTS (IOC):[b]		
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	28,585
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	6,576
(3) Insurance	1% of total capital investment, CCM Chapter 2	6,576
(4) Administration	2% of total capital investment, CCM Chapter 2	13,152
Total IOC:	(1) + (2) + (3) + (4)	54,888
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	62,076
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	370,375

Notes:

[a] Cost estimates from BASF Catalysts, LLC for a CO catalyst system for a Solar Titan 130 turbine. System cost adjusted for CO ppm reduction and for 90% control and mass flow rate of the turbine considered for the Okeechobee Landfill project.

[b] Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

TABLE 7
COST EFFECTIVENESS CALCULATION FOR NOx AND CO CONTROL SCENARIOS, OKEECHOBEE LANDFILL FACILITY

Cost Items	Comments/Reference	Value	NOx + CO Control Scenarios 1 Titan 130	 1 Centaur 40	 1 Titan 130 + 4 Centaur 40	 1 Titan 130 + 15 Centaur 40
Annualized Cost for Siloxane System ($/yr)	Table 1	1,213,219	1,213,219	1,213,219	1,213,219	1,213,219
Annualized Cost of SCR System for Titan 130 ($/yr)	Table 2	1,165,516	1,165,516	--	1,165,516	1,165,516
Annualized Cost of SCR System for Centaur 40 ($/yr)	Table 3	777,761	--	777,761	3,111,045	11,666,420
Annualized Cost of CO Catalyst for Titan 130 ($/yr)	Table 4	402,702	402,702	--	402,702	402,702
Annualized Cost of CO Catalyst for Centaur 40 ($/yr)	Table 5	370,375	--	370,375	1,481,500	5,555,624
Total Annualized Cost (AC)($/yr):			2,781,437	2,361,355	7,373,982	20,003,481
Titan 130 Baseline NOx Emissions (TPY) :	72 ppm, Emission Guarantee	203.0	203.0	--	203.0	203.0
Centaur 40 Baseline NOx Emissions (TPY) :	42 ppm, Emission Guarantee	35.0	--	35.0	140.0	525.0
Titan 130 Baseline CO Emissions (TPY) :	100 ppm, Emission Guarantee	858.0	858.0	--	858.0	858.0
Centaur 40 Baseline CO Emissions (TPY) :	250 ppm, Emission Guarantee	263.0	--	263.0	1,052.0	3,945.0
Controlled NOx Emissions (TPY) :	90% Control		20.3	3.5	34.3	72.8
Controlled CO Emissions (TPY) :	90% Control		85.8	26.3	191.0	480.3
Reduction in NOx Emissions (TPY):	Baseline - Controlled		182.7	31.5	308.7	655.2
Reduction in CO Emissions (TPY):	Baseline - Controlled		772.2	236.7	1,719.0	4,322.7
Total Reduction in Emissions (TPY):			955	268	2,028	4,978
Cost Effectiveness (AC/Total Reduction)	$ per ton Removed				3,637	4,018

ATTACHMENT A

VENDOR COST QUOTES

APPLICATION FOR PLAN APPROVAL

Geological Reclamation Operations and Waste Systems

No. 009-00007

RENEWABLE ENERGY FACILITY

WASTE MANAGEMENT

Waste Management
Disposal Services of
Pennsylvania, Inc.

September, 2008

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TABLE OF CONTENTS

1 INTRODUCTION

Waste Management Disposal Services of Pennsylvania, Inc. (WMDSPI) is requesting, through submittal of the plan approval application presented herein, authorization to construct and operate a renewable energy facility (G.R.O.W.S. Renewable Energy), consisting of five (5) simple cycle gas turbines manufactured by Solar Turbines, Inc. Each turbine will produce approximately 3300 kW of electrical power.

The renewable energy facility will be fueled by gas collected from Geological Reclamation Operations and Waste Systems (G.R.O.W.S.), an existing municipal solid waste disposal facility that is owned and operated by WMDSPI. More specifically, gas collected from the landfill area known as G.R.O.W.S. North will initially be the source of fuel for the G.R.O.W.S. Renewable Energy facility.

As currently configured, landfill gas collected from G.R.O.W.S. North would be treated on-site then directed via pipeline to Exelon for combustion in a nearby Exelon generating station. While WMDSPI would maintain the pipeline and the option for directing landfill gas to Exelon under certain circumstances, WMDSPI has determined that on-site use of treated landfill gas in the G.R.O.W.S. Renewable Energy facility is the most effective alternative for disposition of landfill gas at the site.

The proposed G.R.O.W.S. Renewable Energy project is a manifestation of a commitment by WMDSPI and other Waste Management affiliated companies (collectively, "WM"), to pursue a nationwide sustainability initiative that focuses on the creation of landfill gas-to-energy facilities as a key component of sustainability. The G.R.O.W.S. Renewable Energy project has been identified as part of the company's decision to expand its roster of landfill gas-to-energy facilities. Under this initiative, WM is committed to create an additional sixty renewable energy facilities over the next five years, and together with its existing facilities, will generate more than 700 megawatts of clean renewable energy. As the country's largest group of landfill owners and operators, WM is in a unique position to expand its waste-based generation capacity in this manner and to manage the use of landfill gas as a significant source of alternative energy.

In addition, the company's initiative to develop landfill gas-to-energy projects reflects a key component of the US EPA's Landfill Methane Outreach Program. The Commonwealth of Pennsylvania is an LMOP State Partner, and has approved several similar landfill gas to energy projects. The timely approval of this project will allow G.R.O.W.S. North to continue to manage its landfill gas in an environmentally sound manner, while providing the community with an alternative energy source. Through such projects, as well as through its Alternative Energy Portfolio standards, Pennsylvania has acknowledged that the use of renewable energy sources such as biomass is crucial to developing a diverse energy supply and increasing electricity system reliability.

The G.R.O.W.S. Renewable Energy facility will serve as WMDSPI's primary means of handling landfill gas generated in the G.R.O.W.S. North landfill. Operation of the facility will allow WMDSPI to provide energy to the local power grid. WMDSPI will maintain its pipeline connection to Exelon, including a connection from G.R.O.W.S. North landfill in the event that the Renewable Energy facility becomes unavailable. WMDSPI may consider the use of the existing backup flares for the G.R.O.W.S. landfill to combust, as a backup, the landfill gas generated at the G.R.O.W.S. North landfill, up to the permitted capacity of each flare. Accordingly, WMDSPI does not propose any modification of existing permit conditions governing the landfill, the landfill gas treatment system or the existing backup flares, except to the extent necessary to establish the Renewable Energy facility as the primary destination for landfill gas collected in the G.R.O.W.S. North landfill area.

If permitted capacity, as requested in this application, is available at the G.R.O.W.S. Renewable Energy facility in the future, and other conditions warrant, it is possible the landfill gas generated at the G.R.O.W.S. landfill will be routed to this plant. However, the plant considered under this application has been designed to initially combust landfill gas collected from the G.R.O.W.S. North landfill.

APPENDIX C

COST ANALYSIS FOR NOX CONTROLS

BACT Analysis

Methodology based on Section 4.2 (NOx Post Combustion), Chapter 2 (Selective Catalytic Reduction)
EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002

Capital Cost

	% of Capital	SCR Per Turbine	Source
Direct Capital Costs			
Equipment Capital		$ 955,000.00	CleanAir Systems, Inc. Estimate
Installation Labor and Materials	50%	$ 477,500.00	CleanAir Systems, Inc. Estimate
(A) Total Direct Costs		$ 1,432,500.00	
Indirect Costs			
General Facilities	5%	$ 71,625.00	EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
Engineering and Home Office Fees	10%	$ 143,250.00	EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
Process Contingency	5%	$ 71,625.00	EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
(B) Total Indirect Costs		$ 286,500.00	
(C) Project Contingency	15%	$ 257,850.00	EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
Total Cost = A + B+ C		$ 1,976,850.00	

Annual Operating Costs

Direct Costs -				
Maintenance	1.50%		$ 29,652.75	EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
Reagent Consumption	2	gallons/hr		CleanAir Systems, Inc. Estimate
	$ 2.50	/gallon Ammonia		Commodities Market Price
			$ 43,800.00	
Utilities	48.6	MMBtu/hr (HHV)		Manufacturer's Rated Capacity
	0.16	lbs/MMBtu Nox Uncontrolled		
	90%	Reduction		CleanAir Systems, Inc. Estimate
	3	Duct Pressure Drop		EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
	3	SCR Pressure Drop		EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
	$ 0.10	/kW-hr		
			16.1 kW	EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
			$ 14,089.62	
Replacement Catalyst Costs as % of Capital	35%		$ 334,250.00	CleanAir Systems, Inc. Estimate
Operating Life of Catayst	8760	hours		CleanAir Systems, Inc. Estimate
	1	years		
Annualized Catalyst Replacement Costs			$ 334,250.00 /year	
Total Direct Annual Costs			$ 421,792.37	
Indirect Costs -				
Capital Recovery Factor	7%	Annual Interest Rate		EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
	10	years		
	0.1424			EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
Indirect Annual Cost			$ 281,458.97	
Total Annual Cost			$ 703,251.34	
			7.95 lbs/hr	NOx emissions Rate
			34.821 tpy	
			31.3389 tons reduced based on rated efficiency of unit by CleanAir Systems, Inc.	
			$ 22,440.20 /tons Nox reduced	

BACT Analysis

Methodology based on Section 4.2 (NOx Post Combustion), Chapter 2 (Selective Catalytic Reduction)
EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002

Capital Cost

			Siloxane Removal Per Turbine		Source
Direct Capital Costs	% of Capital				
Equipment Capital		$	280,000.00		Applied Filter Technologies Estimate
Installation Labor and Materials	50%	$	140,000.00		Applied Filter Technologies Estimate
(A) Total Direct Costs		$	420,000.00		
Indirect Costs					
General Facilities	5%	$	21,000.00		EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
Engineering and Home Office Fees	10%	$	42,000.00		EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
Process Contingency	5%	$	21,000.00		EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
(B) Total Indirect Costs		$	84,000.00		
(C) Project Contingency	15%	$	75,600.00		EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
Total Cost = A + B+ C		$	**579,600.00**		

Annual Operating Costs

Direct Costs -					
Maintenance	1.50%	$	8,694.00		EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
Replacement Media Costs as % of Capital	35%	$	202,860.00		Applied Filter Technologies Estimate
Operating Life of Catayst	20000	hours			
	2.283105023	years			
Annualized Media Replacement Costs		$	88,852.68	/year	
Utilities		$	17,500.00		
Total Direct Annual Costs		$	115,046.68		
Indirect Costs -					
Capital Recovery Factor	7%	Annual Interest Rate			EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
	10	years			
	0.1424				EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
Indirect Annual Cost		$	82,522.00		
Total Annual Cost		$	**197,568.68**		
			7.95	lbs/hr	
			34.821	tpy	
			90%	Reduction	
			31.3389	tons reduced	
		$	**6,304.26**	**/tons Nox reduced**	

TOTAL COST OF CONTROL = $ 28,744.47 /ton Nox reduced

CO CATALYST COST QUOTE

BASF
The Chemical Company

DATE:	**September 12, 2008**	**NO. PAGES**	**3**
TO:	**GOLDER ASSOC** **ATTN: Dorothy Austin** **BASF Catalysts LLC** **ATTN: Nancy Ellison**	**via e-mail**	
FROM:	**Fred Booth**	**Ph 410-569-0297 // FAX 410-569-1841**	

RE: **Rand Whitney Project**
CO Catalyst - BASF Catalysts LLC Budgetary Proposal EPB00757

We provide BASF Catalysts LLC Budgetary Proposal EPB00757 for One (1) BASF Catalysts LLC **Camet®** CO Catalyst system per requirements of your e-mail request on September 12, 2008. We offer CO oxidation catalyst design and pricing based on:

- Three (3) year Performance guarantee;
- BASF Catalysts LLC Scope: CO catalyst modules and catalyst internal frame and gas seals, and interface engineering.
- By others: Duct / catalyst housing (including any transitions), internal insulation, grooved internal liner sheets, frame supports and pedestals, catalyst loading door, personnel manway and sample ports.

CO SYSTEM DESIGN BASIS:	Data per e-mail of 9/11/08
Dimensions:	HRSG Inside Liner – 19 ft W x 8.5 ft H
Gas Flow from:	Combustion Turbine + Duct Burner
Gas Flow:	Horizontal
Fuel:	Natural Gas and Oil
Gas Flow Rate (At catalyst face):	Designed for Gas Velocities within ±15% of the mean velocity at the catalyst face
Temperature (At catalyst face):	Designed for Gas Temperatures within range ±25°F of noted temperatures
CO Concentration (At catalyst face):	Not Given
CO Reduction:	90%

Sincerely yours,

BASF Catalysts LLC

Frederick A Booth

Frederick A. Booth
Senior Sales Engineer

Corporate
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BASF
The Chemical Company

Golder Assoc.
Rand Whitney Project
CO Oxidation Catalyst - BASF Catalysts LLC Budgetary Proposal EPB00757
September 12, 2008

BASF Catalysts LLC CORPORATION
CAMET® CATALYTIC OXIDATION SYSTEM

DELIVERABLES: Equipment and services consisting of:

1. CO Catalyst modules: The CO Catalyst is manufactured with a special stainless steel foil substrate which is corrugated and coated with an alumina washcoat. The washcoat is impregnated with platinum group metals. The catalyzed foil is folded and encased in welded steel frames, approximately 2 ft. square, to form individual modules. Two (2) of the total modules are provided with four (4) replaceable catalyst test buttons in each module (eight total buttons provided).
2. Catalyst internal support frame and internal gas seals: The internal support frame and internal seals are fabricated from standard structural **Carbon Steel** members and shapes. Mechanical expansion seals around the perimeter of the frame and inside the liner sheet prevent bypass around the catalyst. Design accommodates movement of the frame due to thermal expansion while maintaining a continuous seal. The internal frame system interfaces with two types of customer provided connections; ductplate mounted slide plates and liner sheet grooves, both designed by BASF Catalysts LLC.
3. Drawings showing installation details, loadings, and support requirements;

The equipment is supplied by BASF Catalysts LLC and installed by others in accordance with the BASF Catalysts LLC design and installation instructions. CO Catalyst modules should be installed after initial turbine firing.

BUDGET PRICE: Per Unit **Delivery: FOB, plant gate, job site.**

CO System - Frame + CO Modules Cost, $$	**$110,000**
CO System - Frame + CO Modules Est. Weight, lb	**8,000**

WARRANTY AND GUARANTEE:

Mechanical Warranty:	Twelve (12) months from date of start up or eighteen (18) months from date of delivery, whichever is earlier.
Performance Guarantee:	Thirty-Six (36) months of operation from date of start up provided start up is no later than ninety (90) days from date of delivery. Catalyst warranty is prorated over the guaranteed life.
Expected Life:	Five (5) to Seven (7) Years

DOCUMENT / MATERIAL DELIVERY SCHEDULE

Drawings for Approval	Three weeks after notice to proceed
Material Delivery	fob, plant gate, Jobsite
Frame and Seals	12 – 14 weeks after release for fabrication
Catalyst Modules	14 – 16 weeks after release for fabrication

SPENT CATALYST

BASF Catalysts LLC agrees to support buyer's efforts in the disposal of spent catalyst and potential metal reclaim from spent catalyst. The catalyst proposed contains platinum group metals, and unless contaminated in operation by others, is **not a hazardous material**. Buyer may receive credit for recovered platinum metals based upon the quantity of platinum group metals recovered and the world price of platinum group metals then in effect, net of recovery cost and disposal costs.

BASF
The Chemical Company

Golder Assoc.
Rand Whitney Project
CO Oxidation Catalyst - BASF Catalysts LLC Budgetary Proposal EPB00757
September 12, 2008

Table A - Performance Data

	CASE	1
	DUCT BURNER - FIRED / UNFIRED	FIRED
	GIVEN GAS FLOW AFTER BURNER, lb/hr	572,000
	ASSUMED GAS ANALYSIS - AFTER BURNER, % VOL. - N_2	75.10
	O_2	13.00
	CO_2	3.00
	H_2O	8.00
	Ar	0.90
	CALC. GAS MOL. WT.	28.32
	GIVEN CO AFTER BURNER, lb/hr	N / A
	CALC. CO AFTER BURNER, ppmvd @ 15% O_2	N / A
	ASSUMED GAS TEMP. @ CO CATALYST, °F (+/-25)	500
DESIGN REQUIREMENTS	CO OUT, ppmvd @ 15% O_2	90% CO Reduction
	GUARANTEED PERFORMANCE DATA	
	CO CONVERSION, % - Min.	90.0%
	CO OUT, lb/hr - Max.	N / A
	CO OUT, ppmvd @ 15% O_2	N / A
	CO PRESSURE DROP, "WG - Max.	2.5
	EXPECTED PERFORMANCE DATA	
	SO_2 -> SO_3 CONVERSION, % - Max.	2%

ATTACHMENT B

REFERENCE MATERIAL

REDUCING BIOGAS POWER GENERATION COSTS BY REMOVAL OF SILOXANES

P. M. Tower and J. V. Wetzel, Applied Filter Technology, Inc., Snohomish, Washington, USA

ABSTRACT

The cost of utilizing digester biogas (DBG) to fire boilers or to power electricity generator engines or microturbine-driven generators is adversely affected by biogas volatile contaminants (VCs). Among the VC contaminants found in DBG are volatile inorganic contaminants (VICs) like ammonia and hydrogen sulfide, and volatile organic contaminants (VOCs) that range from those containing one (1) carbon atom to as many as thirty (30) carbon atoms. These VOCs are made up of primarily carbon, hydrogen, and oxygen but can also contain sulfur (like methyl mercaptan), halogens such as bromine, chlorine and fluorine (like methylene chloride and chlorodifluoromethane), and organosilicons (such as trimethylsilanol and siloxanes).

While sulfur and halogen-containing VCs are harmful because they produce noxious emissions, corrosive acids upon combustion (and can foul some emission catalysts), the damage caused by organosilicons like siloxanes is far worse. Some of the problems encountered with all three types of VCs in biogas are discussed with their commensurate impact on operating costs at the Mangere Wastewater Treatment Plant (WWTP) in New Zealand. The focus of this paper is primarily on the removal of the organosilicons (mainly the siloxanes) and secondarily on the removal of hydrogen sulfide (H_2S).

KEYWORDS

Biogas, Power Generation, Cost Reduction, Siloxane Removal, Hydrogen Sulfide Removal, Mangere

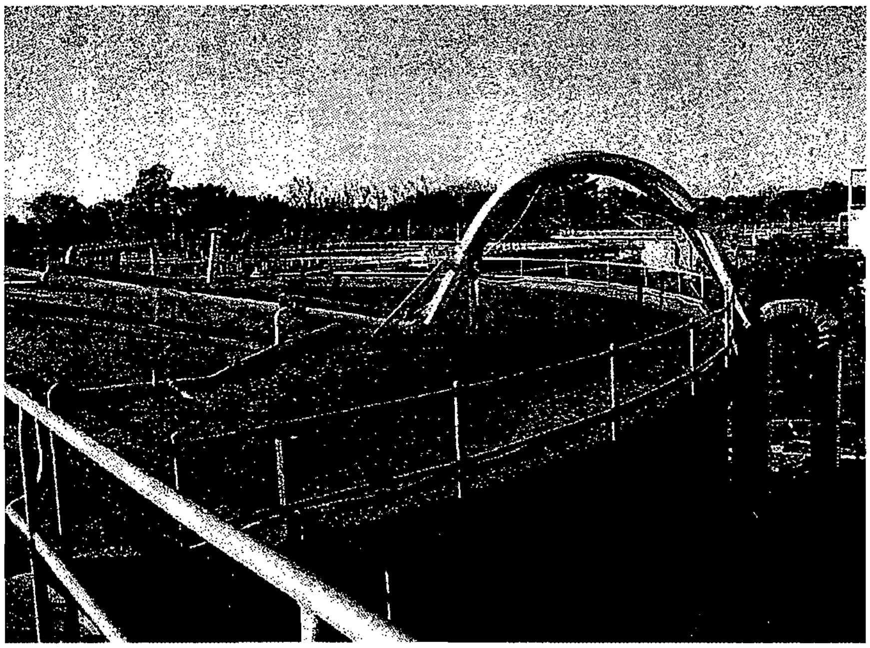
1 INTRODUCTION

Prior to Applied Filter Technology's (AFT's) involvement, recent upgrades to the Mangere Wastewater Treatment Plant had been undertaken that included both infrastructure and processes. Infrastructure-related upgrades over the previous several years include adding digesters (now numbering 7 -- with more planned) and piping for conveyance of waste activated sludge and biogas. Process-related changes include the addition of Treated Waste Activated Sludge (TWAS) to the digesters instead of Primary Activated Sludge. Other changes include replacing the older digester gas mixing system with a jet mixing system. In addition, a complete upgrade was made of the cogeneration system starting at the compressor room and including the LP dryer, new blowers, pipelines, and new biogas generator engines. Picture 1 below shows the gas collection piping for Digester No. 6.

Soon after startup, premature engine wear was discovered in the new biogas fuelled generator engines. Hydrogen sulfide (H_2S) and siloxanes in the biogas had been previously identified as possible causes of generator engine damage. Deposits taken from the engine cylinders were analyzed and determined to contain calcium (46%), sulfur (36%), and silicon (16%). In October of 2002, Watercare Services, Ltd. commissioned Meritec Ltd. (now known as Maunsell Ltd.) to identify, evaluate, and select the preferred methods for treating the biogas to meet generator engine specifications. The overall aim of this project was to provide the Mangere WTP with the most economical means of reducing the H_2S and Siloxane content of the biogas to meet generator engine specifications and to compare the additional costs of this treatment to the potential benefits in cost reduction for operating these engines.

In December, 2002, Meritec Ltd. contacted AFT to determine the feasibility, capital cost, and operating and maintenance (O&M) costs for a siloxane removal system based on the SAG™ Process. SAG™ is an acronym for "segmented activity gradient" which refers to the process for sequential removal of contaminants like siloxanes from biogases. In addition, AFT was consulted on the H_2S removal system. A Catalytic Iron Sponge (CIS™) was proposed because it was determined to be the most cost effective for H_2S removal. Meritec provided analytical information on the Digester Biogas, from which AFT developed the design of the siloxane removal system.

Photograph 1: Digester No. 6 Gas Collection Piping



Removal of the H_2S is necessary not only from a power generation equipment protection standpoint, but also to protect the media in the SAG™ System that removes the siloxanes. Under certain circumstances, the H_2S will deposit elemental sulfur in the pores of the SAG™ media, reducing its ability to remove siloxanes and shortening its replacement interval. Since it had been determined that the H_2S removal system would not be operational at the time the SAG™ System had to be started up, this was an important detail that had to be addressed in the equipment design.

ABOUT SILOXANES

Siloxanes are organosilicon molecules that also contain mostly carbon, hydrogen, and oxygen, but can also contain nitrogen and halogens. Their primary use for the consumer market is in toiletries and cosmetics of all types, including deodorants, hair sprays and gels, lipsticks and glosses, lotions, shaving products and others. A little research in the home will turn up products with "dimethicone," "dimethiconol," dimethicone polyol," "dimethicone copolyol," "dimethicone/vinyl dimethicone crosspolymer," "phenyl methicone," "phenyl trimethicone," "cyclomethicone," "cyclopentasiloxane," "cyclohexasiloxane," "stearoxytrimethylsilane" "caprylyl trimethicone SV," and "disodium dimethicone copolyol sulfosuccinate" in the ingredient list. These are products in a broad group of hundreds of chemicals known as silicones, which are all forms of organosilicons or siloxanes. To further emphasize the problem, use of siloxanes is increasing worldwide as new uses for these materials are discovered and commercialized. Commensurate siloxane increases in biogas are expected.

Siloxanes and organosilicons are a problem in biogas because they form silicon dioxide, SiO_2, upon combustion. SiO_2 is a white powdery substance that accumulates on the heated surfaces in combustion equipment, especially in the cylinders of IC generator engines. An IC generator engine burning 220 Nm^3/H (400 SCFM) biogas containing just 1 ppmv of siloxane D5, for example, will generate approximately 59 kg (130 lb.) of SiO_2 per year if operated continuously. Not all of this SiO_2 will remain in the engine; however, what does remain can cause considerable damage and add greatly to the cost of operating the generation equipment. The presence of sodium, aluminum, magnesium, iron, and other elements leads to silicate formation (Tower, 2002, 2003, 2004). Silicates are glass-like materials that are extremely abrasive to generator engine internals. Photograph 2 below shows the SiO_2 and silicate deposits on a piston taken from one of the generator engines. Additional information on the common siloxanes found in biogas appears in Appendix D.

Photograph 2: SiO_2 and silicate Deposits on piston crown and rings

2 BIOGAS TREATMENT SYSTEM DESIGN CONSIDERATIONS

2.1 OVERVIEW

The combination of gases, water vapor, and VCs (VICs and VOCs) comprise what is called the biogas matrix. Simply defined, the biogas matrix is made up of molecules of gases, water vapor, and contaminants. In this gas matrix are the "permanent gases" which are predominantly methane, carbon dioxide, nitrogen, oxygen, and trace amounts of 2-carbon atom to 5-carbon atom alkanes and alkenes. VCs usually comprise a tiny fraction of the biogas matrix. Even so, they can produce a lot of damage. For this reason, it is critically important to determine the complete biogas molecular matrix in order to properly design gas conditioning and contaminant removal equipment.

Since it is necessary to reduce the moisture level in the biogas, the volume percent or mole percent of the permanent gases and water vapor must be measured. This information is critical to the design of the gas conditioning equipment preceding the siloxane removal system. Once the permanent gases and moisture level of the biogas have been determined, the enthalpy of the gas can be calculated and used in the design basis. For the power generation equipment, a moisture level not greater than 80% relative humidity (RH) is required (generator engine manufacturer specification). However, the SAG™ media can be fouled by water vapor at RH levels exceeding 45%. Thus, this requirement overrides that of the power generation equipment. For this reason, the gas conditioning equipment design is based on reducing the RH of the biogas to 45% or lower.

Other considerations for the gas conditioning equipment design are the gas temperature and pressure. In order to deliver the gas at suitable pressure to the generator engines, resistance in the H_2S removal equipment, siloxane removal equipment, piping, and other process components must be taken into consideration. For low pressure systems, the biogas is usually compressed by blowers to about 60 kPag (about 9 psig) or a little less. The heat of compression is rejected by aftercoolers built into the gas conditioning skid.

Digester biogas containing high levels of H_2S are corrosive to gas collection system piping and are especially corrosive to compressors or blowers. Because the digester biogas at the Mangere WTP contains a fairly high level of H_2S, location of the H_2S removal equipment is ahead of the blowers. After the gas is dried and compressed, the temperature is controlled to about 40 degrees C. (104 degrees F.) maximum. Since the SAG™ System media operates best at temperatures of 25 degrees C. (77 degrees F.) or lower, the siloxane removal system design has to accommodate this higher temperature and still perform adequately. Temperature losses in the gas pipeline further reduce the conditioned and treated biogas temperature to around 22 degrees C. (about 72 degrees F.) at the engines. A process flow diagram of the biogas treatment system is in Appendix E.

2.2 BIOGAS SAMPLING AND TESTING

There are four basic types of biogas composition data required for the design of a siloxane removal system. These are: 1) the permanent gas volume per cent; 2) the complete VOC profile, including the individual species and their concentrations; 3) the inorganic and organic sulfur contaminants and their concentrations; and 4) the individual siloxanes and their concentrations. Although not required for the design of the siloxane removal or hydrogen sulfide removal equipment, testing for total chlorine, total fluorine, and ammonia are also performed by Watercare Services due to the potential contribution to the engines' O&M costs and NO_x exhaust emissions.

While there are several tests available to determine the biogas composition in each of these 4 areas, the preferred methods are those which provide the most data. Since most biogas treatment system designs are based on just one or two analyses, it is critical to gather as much information as possible. Most wastewater treatment facilities utilizing anaerobic digestion do not have extensive biogas data over a long period of time, so VIC and VOC averages, composition changes, ranges from low to high values, and trends cannot be taken into consideration for treatment equipment design. From the perspective of good plant management practices (GPMP), a complete biogas analysis should be performed not less often than once per year. A robust design for biogas treatment equipment can and should be based on data that are not less than one year old and an additional set of data that is not less than 3 months old.

2.2.1 SAMPLING TECHNIQUES FOR VOLATILE CONTAMINANTS (VCs) AND PERMANENT GASES

Sampling of the biogas for "permanent gases," VICs, and VOCs can be done by several methods. The most common of these are: absorption tubes employing an adsorbent like charcoal or specialized resins; 1 liter and 6 liter metal canisters; and gas impermeable bags, such as those constructed of Tedlar®. Sampling for VOCs by absorption tubes is accomplished by drawing a specified volume of the gas through a charcoal tube. The charcoal in the tube absorbs or adsorbs the VOCs. Analysis of the absorbed or adsorbed VOCs is accomplished by stripping the absorbent media in the tube with a solvent like carbon disulfide or hexane. The solvent containing the stripped VOCs is analyzed by gas chromatography or gas chromatography coupled with mass spectrometry to determine and quantify the VOCs. By knowing the gas volume drawn through the charcoal tube and the concentration found in the solvent, the concentration of each VOC in the biogas can be calculated. Our experience with the charcoal tube sampling method reveals that it has several drawbacks. The first of these is poor reproducibility of results. Second, not all of the VOC species in the biogas are absorbed onto the charcoal, as they are displaced during the sampling period by more strongly adsorbed VOC species and water. For this reason, the identified and quantified desorbed species may not be representative of the actual biogas matrix. Third, even though there are three distinct charcoal tube analysis methods for the range of VOCs found in biogas (Pendergrass, 2003, 3 citings), the combination of their results covers just a fraction of what is possible with, for example, the Modified EPA 18 Method. . Fourth, when the charcoal tubes are stripped, the adsorbed species may not fully desorb, skewing the accuracy of the test results. There is also variability between tubes used for analyzing VOCs ("Determination of Tetrahydrofuran...," ca. 1998, "Determination of Pyridine...," ca. 1998). These phenomena are believed by AFT to be the reason for lack of reproducibility of test results with charcoal tubes, and, as such, they are considered to be best used as a semi-qualitative and semi-quantitative method. Charcoal tubes cannot be used to sample for the permanent gases.

Gas sampling canisters (such as Summa or Silco) offer several advantages over the other methods for VC analysis. First, a larger volume of gas can be taken at the time of sampling. Second, they are reusable. Third, they have a longer "hold" time between sampling and analysis than either of the other methods. The larger volume of gas (1 or 6 liters) permits a representative sample of the gas to be taken, with extra gas available for re-checks of spurious results. These canisters are easy to use and require no pumps to collect a sample from low-pressure gas sources as they arrive evacuated and under a vacuum. While these canisters are re-usable, they must be very carefully cleaned before re-use. One drawback is the greater cost to use these and also the higher shipping fees due to their weight.

Analysis of the biogas from a canister is accomplished through direct injection into a gas chromatograph or gas chromatograph coupled with a mass spectrometer.

Our preferred method of gas sampling is the 1-liter Tedlar bag. One or two 1-liter Tedlar bags provides enough sample to complete the permanent gases, sulfur species, and VOC analyses. These are light, easy to use, and are disposable. One drawback is the relatively short hold time before analysis of the sulfurous species. On rare occasions, Tedlar bags can leak, thus, the practice of using two bags in order to have a backup is employed. Unlike the evacuated metal canisters, a pump must be used if the gas source pressure is too low.

The permanent gases analysis can be accomplished only through the capture of a physical biogas sample, such as is obtained by the canister or Tedlar bag method.

2.2.2 SAMPLING TECHNIQUES FOR SILOXANES

While the same methods of sampling for the permanent gases, sulfur species, and VOCs may be used for siloxanes, the most reliable and most widely accepted sampling method is by chilled methanol impingement. This sampling method was developed by Dow Corning ("Organosilicon Compounds in Biogas...," 1999) and improved and expanded by Air Toxics (Saeed, et al., 2002). The procedure involves passing the biogas stream through two each (connected in series) midget impingers equipped with 20 ml capacity glass vials, each containing nominally 15 ml of high purity methanol ("Siloxanes in Air..." December 2001). The siloxanes present in the biogas dissolve in the methanol, and are later analyzed by direct injection into a GC/MS. Biogas flow is controlled to nominally 112 ml per minute via a needle valve and rotameter, which are part of the sampling train. After 180 minutes, the sampling is stopped, the vials are removed from the impingers, capped, and kept chilled at 4 degrees C. (40 degrees F.) until analyzed (Tower, 2002).

2.2.3 TEST METHODS FOR VCs AND PERMANENT GASES

TESTING FOR SULFUR-BEARING VCs

After a representative and adequate size of the biogas has been obtained by either a Tedlar bag or metal canister, the analytical tests are performed as soon as practical to avoid any biogas matrix deterioration. The first test that is run is for the sulfur species. In the United States, we use the ASTM D5504 method, which detects 20 different sulfurous compounds; including hydrogen sulfide (see Appendix A). This test is accomplished by direct injection of the biogas into a gas chromatograph equipped with an SCD (sulfur chemiluminescence detector). Results from this test are reported in either ug/m^3 or ppbv. The detection limit of this method for most sulfur species is in the low ppbv range, with some species able to be detected at lower than 1 ppbv. One drawback of the ASTM D5504 method is loss of the lower concentration organic sulfur species detection limit if any dilutions of the gas are necessary to bring very high H_2S levels into the instrument calibration range. Watercare's Laboratory Services Air Quality Group analyzes specifically for H_2S, methyl mercaptan (CH_3SH), dimethyl sulfide (C_2H_6S), and dimethyl disulfide ($C_2H_6S_2$) by gas chromatography.

TESTING FOR PERMANENT GASES

From the same Tedlar bag, the permanent gases, or expanded ASTM D1945 (see Appendix B) test is conducted. The permanent gases test is run by direct injection into a gas chromatograph and includes methane, carbon dioxide, nitrogen, and oxygen. The ASTM D1945 test includes hydrogen and gases containing 2 through 5 carbon atoms, as well as the heating value of the gas (BTU per cubic foot) and its total specific gravity.

TESTING FOR VOCs

With the ASTM D5504 and ASTM D1945, the EPA TO-14A test is also run. This test results in the detection and concentration, usually to the ppbv range, of 62 VOCs (see Appendix C). Since the inception of testing at the Mangere Plant, AFT has developed an expanded VOC test that detects (down to 100 ppbv) and quantifies over 250 different organic contaminants (P. Tower, 2003). This test, based on the modified EPA Method 18, includes the method TO-14A and semi-volatiles ("Method 8270C...," 1996). The necessity for a more expanded test is due to the presence of organic contaminants called "biogenics," like d-limonene, alpha pinene, and d-carene, which not included in other test methods.

TESTING FOR SILOXANES

The best method of analyzing the methanol from the impingers for siloxanes is by gas chromatography coupled with mass spectrometry (GC/MS). With this technique, not only is the total mass of siloxanes determined, but also the individual species and their masses. By knowing the volume of gas passed through the sampling train and the mass of siloxanes measured, their concentrations can be calculated. Unfortunately, the test method does not yet have the same level of detection as the ASTM D5504 or the EPA TO-14A. The lowest molecular weight siloxane routinely encountered, Hexamethyldisiloxane, or "MM" has a reportable detection limit 45 ppbv. The highest molecular weight siloxane, Dodecamethylcyclohexasiloxane, or "D6" has a reportable detection limit of 16 ppbv (Saeed, et al., 2002).

THE MANGERE TESTING PROTOCOL

Testing was begun in April of 2003 by the Laboratory Services Air Quality Group, a division of Watercare Services Ltd. The scope of their testing included the permanent gases, total chlorine (HCl & Cl_2), Total fluoride (HF & F_2), ammonia (NH_3), total sulfur, siloxanes, and moisture content. For the total chlorine, total fluoride, ammonia, and moisture content, Laboratory Services employed USEPA Method 26—Determination of Hydrogen Halides and Halogen Emissions from Stationary Sources, and USEPA CTM027—Determination of Ammonia Emissions from Stationary Sources. Discussion of these methods is beyond the scope of AFT's involvement in this project.

2.3 BIOGAS SAMPLING TEST RESULTS AND DATA INTERPRETATION

Results from the Laboratory Services Air Quality Group are listed below:

Permanent Gases: Methane 60 to 61%; Carbon Dioxide 37%, Nitrogen 1.7 to 2.6%, Oxygen 0.3 to 0.4%

Total Chlorine: HCl < 0.32 mg/m^3; Cl_2 < 0.62 mg/m^3

Total Fluoride: HF < 0.015 mg/m^3; F_2 0.036 mg/m^3

Moisture: 2.5%

Total Sulfur: H_2S 200 to 800 ppmv (other species are negligible)

Siloxanes: "Octamsil" (D4) 0.58 mg/m^3 (50 ppbv); "Decamsil" (D5) 4.52 mg/m^3 (313 ppbv)

VOCs (results in ug/m3):

Tetrachloroethene	667
1,3,5-Trimethyl Benzene	2845
1,2,4-Trimethyl Benzene	6222
O+M+P Xylenes	4622
Ethylbenzene	1822
n-Propylbenzene	267
Isopropylbenzene	444
Toluene	5734
sec-Butylbenzene	267
p-Isopropyltoluene	400
Heptane	1600
Hexane	1111
Trichloroethene	711
Benzene	622
cis-1,2 Dichloroethene	1333

It is these data, together with the biogas flow range, temperature and pressure that form the basis for the siloxane removal system design.

3 THE MANGERE WTP BIOGAS TREATMENT SYSTEM DESIGN

3.1 HYDROGEN SULFIDE REMOVAL SYSTEM

The hydrogen sulfide removal system consists of two vessels operating in parallel mode, each containing approximately 18 m^3 of iron sponge. To establish the minimum recommended contact time of 60 seconds required for H_2S removal, the linear velocity of the gas passing through the vessels is recommended to be in the 0.55 to 5.5 m/second (1 to 10 ft. per minute) range. Although it is not required to meet the engine manufacturer's specifications for the biogas, a properly operated iron sponge system can reduce the hydrogen sulfide level by 95% or more. The specification for the engines is 300 ppmv H_2S or less. The siloxane removal system, however, requires the hydrogen sulfide to be below 50 ppmv and preferably below 20 ppmv.

There are two separate modes of operating an iron sponge system—anaerobically and aerobically. An aerobically operated iron sponge system will have about three times the capacity for H_2S as an anaerobically operated system. Aerobic operation is accomplished by adjusting the oxygen content of the incoming biogas to approximately 1% by volume to promote catalytic function. This is usually done by introducing 5% by volume air into the biogas stream ahead of the iron sponge system. In addition, the pH of the iron sponge bed is kept at 8 or above, and preferably above 9 by the introduction of sodium carbonate solution, usually between 3% and 10% strength. The byproduct of catalytic or aerobic iron operation under alkaline conditions is the production of elemental sulfur (see equations 1, 2 and 3 below).

$$F_e2O_3 \cdot H_2O + 3H_2S \longrightarrow Fe_2S_3 + 4H_2O \qquad (1)$$

$$2Fe_2S3 + 3O_2 + 2H_2O \longrightarrow 2Fe_2O_3 \cdot H_2O + 6S \qquad (2)$$

$$4FeS + 3O_2 + 2H_2O \longrightarrow 2Fe_2O_3 \cdot H_2O + 4S \qquad (3)$$

The byproduct of anaerobic iron sponge operation under acidic conditions is the production of iron disulfide, or FeS2. FeS2 consumes the iron that would be available for catalytic operation and slowly "kills" the media (see equations 4 and 5 below).

$$Fe_2O_3 \cdot H2O + 3H_2S \longrightarrow 2FeS + 4H_2O \qquad (4)$$

$$FeS + S \longrightarrow FeS_2 \qquad (5)$$

In addition to having a lower capacity for H2S, anaerobically operated iron sponge can become pyrophoric and must be allowed to stabilize (oxidize) in air before it can be disposed. Usually, anaerobically spent iron sponge is removed from the vessels and spread onto the ground in a layer about 7 to 10 centimeters deep and allowed to pick up oxygen for several days. The formation of ferrous sulfide, FeS is undesirable in an iron sponge operation because at a temperature of 38 degrees C. FeS begins oxidizing to ferrous sulfate, $FeSO_4$. See Equation 6 below:

$$FeS + 2O_2 \longrightarrow FeSO_4 \qquad (6)$$

The upper temperature limit for operating a catalytic iron sponge system is 48 degrees C. (120 degrees F.). Above this temperature, equation 6 will proceed and severely shorten the life of the iron sponge media. It is also important to note that the reaction described in Equation (2) above is exothermic. The iron sponge media will increase in temperature 6.3 degrees C. (11.4 degrees F.) for every 1,000 ppmv of H_2S in the biogas. After use, the spent iron sponge may be disposed as a "non-hazardous" material. Because it contains high levels of sulfur, it is sometimes used as a soil amendment for fruit and vegetable crops.

For the present and future planned biogas flows, media life calculations were performed for both anaerobic and aerobic operations. The design flows are 1700 Nm^3H, the present average, 2800 Nm^3H, the next planned increase, and 3800 Nm^3H, an expected high flow after the installation of new wastewater treatment equipment. The details of the calculation are contained in Appendix F.

3.2 SILOXANE REMOVAL SYSTEM

Siloxane removal from the biogas is accomplished after the moisture and hydrogen sulfide have been reduced. Because there are several types of siloxanes, AFT proposed the use of its SAG™ Process for the best performance. The SAG™ Process utilizes media similar to activated carbon (graphite carbon based) but with modified pore structures to perform better on removal of the individual siloxane species. The media for siloxane D5 removal is called "DD;" for siloxane D4 removal, "DM," and for lower molecular weight siloxanes, "MD." By layering these media in the vessels in the order (from the gas inlet) of largest DD, DM, then MD, additional removal benefits of up to 50% may be realized over a homogeneous media bed. The SAG™ Process is patent pending. First, it should be noted that although only siloxanes D4 and D5 were detected during the biogas analyses, SAG™ Media for lower molecular weight siloxanes was also included to provide extra insurance against fouling. It is likely that other organosilicon species may be present in biogas or will be present in the biogas as global siloxane usage increases. AFT is working on a test method that will expand the range of siloxanes and organosilicons able to be detected and quantified.

When designing a siloxane removal system, the target life of the media is 60 days or greater. Because of the various flows and planned H_2S levels shortly after startup, the media life for the SAG™ siloxane removal system varies from a low of 50 days to a high of 180 days. The best equipment size to handle this flow range, given the required performance and media required, is two vessels, each containing approximately 13.3 m3 of media, or a total of just over 6,352 kg. Once SAG™ media is spent, it is usually disposed as a "non-hazardous" material in a landfill. Refer to Appendix F to view the various flows and estimated media lives for the siloxane removal system. Please note that the originally designed siloxane removal equipment is not large enough to handle the planned 3800 Nm3H flow, and additional equipment will have to be installed. For this reason, this flow was not detailed on the calculation grid for the siloxane removal system in Appendix F.

4 THE ECONOMIC BENEFIT OF H_2S AND SILOXANE REMOVAL

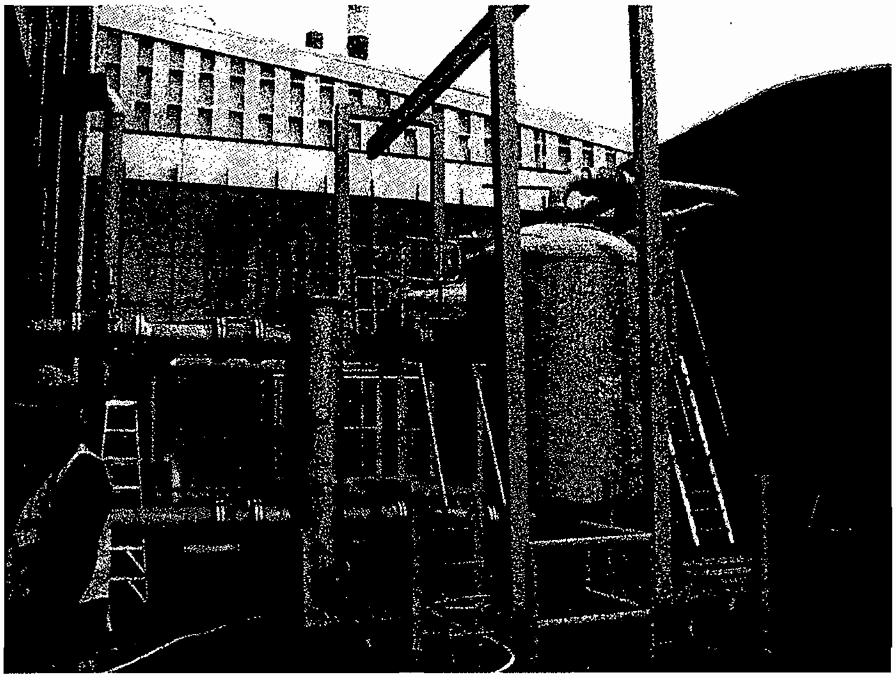
The savings in operation and maintenance costs on IC generator engines can be profound. Sometimes, the savings in just one maintenance item, like spark plugs, can be enough to economically justify installing a siloxane removal system. For IC generator engines, the typical payback period is usually between 6 months and 18 months. Below are some of the estimated cost savings that made this project economically feasible:

Figure 1: Anticipated Operating and Maintenance Cost Savings

Area of Cost Savings	Annual Cost at 1700 Nm3H	Net Present Value (NPV)
Natural Gas Burned	$142,510	$1,384,000
Engine Cylinder Damage	$400,000	$3,884,000
Spark Plugs	$155,000	$1,505,000
Oil	$54,000	$524,000

NPV of projects is based on 6% discount factor and 15 year project life. NPV factor is 9.712.

Photograph 3: Siloxane Removal Equipment during installation



The siloxane removal system was started up in late September of 2003, without the hydrogen sulfide removal equipment being operational. As was suspected, the SAG™ media began to remove the H_2S to below 100 ppmv. The impact of this phenomenon on siloxane removal was not readily quantifiable as samples are taken and analyzed every 2 weeks. Accordingly, after approximately two weeks of operation, the H_2S began to break through the SAG™ media. At this time the H_2S removal equipment (which is positioned ahead of the siloxane removal equipment) was ready to be brought on-line. Rough calculations indicated that the SAG™ media had picked up approximately 5% by weight of elemental sulfur by the time the H_2S was breaking through the SAG™ media above 200 ppmv. The impact of the H_2S on the SAG™ media was close to what was predicted and did appear to shorten the SAG™ media life.

5 SUMMARY

The purpose of this paper is to introduce the reader to the process whereby a robust biogas treatment system is designed and constructed for the removal of hydrogen sulfide and siloxanes. We studied the gas conditioning equipment which compresses, chills and removes water from the biogas before it enters the catalytic iron sponge process and is reheated to control its ability to condense water before it enters the siloxane removal equipment. The entire treatment train from the gas source at the digesters to the intake at the IC generators engines must be viewed as a process. All of the individual parts of this process must function in harmony for the desired biogas treatment to occur, including the up-front activity of obtaining a representative biogas analysis. Thoroughly analyzing the biogas and interpreting the results correctly must occur before any design work can begin. Periodic raw biogas analyses are also essential as well as the treated biogas analyses to determine changes in the gas composition and contaminant levels. This is "must have" information for troubleshooting.

At the Mangere WTP, the estimated savings afforded by the biogas treatment system are substantial. It is unfortunate that at this writing there are not more operational or cost comparison data. The biogas treatment system operation at the Mangere WTP should be reviewed after one full year of operation to determine how closely the actual savings compare to the estimated savings.

ACKNOWLEDGEMENTS

Photographs 1 and 2, and Figure 1 are courtesy of Maunsell, Ltd.

The authors wish to thank Mr. Warwick Cutfield, and Mr. Trevor Collins of Maunsell, Ltd. for their input and dedication to details on the overall biogas treatment process, and Dr. You-Sing Yong of Watercare Services Ltd. for providing analytical results on the biogas. AFT's involvement in this project would not have happened nor would it have achieved its level of success without the untiring efforts and brilliance afforded by the gracious personnel of Maunsell Ltd. and WaterCare Services Ltd.

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APPENDIX A

ASTM METHOD D5504 SULFUR SPECIES

Hydrogen Sulfide

Carbonyl Sulfide

Methyl Mercaptan

Ethyl Mercaptan

Dimethyl Sulfide

Carbon Disulfide

Isopropyl Mercaptan

tert-Butyl Mercaptan

n-Propyl Mercaptan

Ethyl Methyl Sulfide

Thiophene

Isobutyl Mercaptan

Diethyl Sulfide

Butyl Mercaptan

Dimethyl Disulfide

3-Methylthiophene

Tetrahydrothiophene

2-Ethylthiophene

2,5-Dimethylthiophene

Diethyl Disulfide

APPENDIX B

ASTM METHOD D1945 GAS CONSTITUENTS

BY % VOLUME

Oxygen/Argon

Nitrogen

Carbon Monoxide

Methane

Carbon Dioxide

Hydrogen

Ethane

Ethene

Propane

Isobutane

n-Butane

Neopentane

Isopentane

n-Pentane

n-Hexane

n-Heptane

C6+

OTHER

Heat of Combustion (BTU/Cu.F.)

Total Specific Gravity

APPENDIX C

EPA METHOD TO-14A VOC SPECIES

Freon 12
Freon 114
Chloromethane
Vinyl Chloride
Bromomethane
Chloroethane
Freon 11
1,1,-Dichloroethene
Freon 113
Methylene Chloride
1,1,-Dichloroethane
Cis-1,2-Dichloroethane
Chloroform
1,1,1-Trichloroethane
Carbon Tetrachloride
Benzene
1,2-Dichloroethane
Trichloroethene
1,2-Dichloropropane
Cis-1,3-Dichloropropane
Toluene
trans-1,3-Dichloropropene
1,1,2-Trichloroethane
Tetrachloroethene
Ethylene Dibromide
Chlorobenzene
Ethylbenzene
m,p-Xylene
o-xylene
Styrene
1,1,2,2-Tetrachloroethane
1,3,5-Trimethylbenzene
1,2,4-Trimethylbenzene
1,3-Dichlorobenzene
1,4-Dichlorobenzene
Chlorotoluene
1,2-Dichlorobenzene
1,2,4-Trichlorobenzene
Hexachlorobutadiene
Propylene
1,3-Butadiene
Acetone
Carbon Disulfide
2-Propanol
trans-1,2-Dichloroethene
Vinyl Acetate
2-Butanone (Methyl Ethyl Ketone)
Hexane
Tetrahydrofuran
Cyclohexane
1,4-Dioxane
Bromodichloromethane
4-Methyl-2-Pentanone (MIBK)
2-Hexanone
Dibromochloromethane
Bromoform
4-Ethyltoluene
Ethanol
Methyl tert-Butyl Ether
Heptane
Acrylonitrile
TPH or NMOC (Hexane/Heptane)

APPENDIX D

AFT METHOD SIL-1 SILOXANE SPECIES

Pentamethyldisiloxane (PMDS)

Hexamethyldisiloxane (MM)

Octamethyltrisiloxane (MDM)

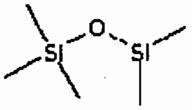
Octamethylcyclotetrasiloxane (D4)

Decamethylcyclopentasiloxane (D5)

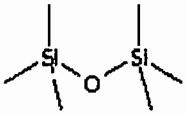
Dodecamethylcyclohexasiloxane (D6)

Molecular Structures: (at the end of each branch is a methyl group, CH_3)

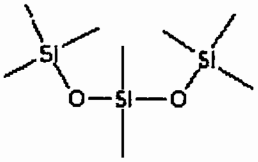
PMDS



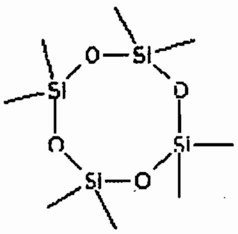
MM



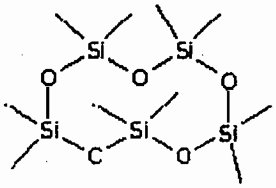
MDM



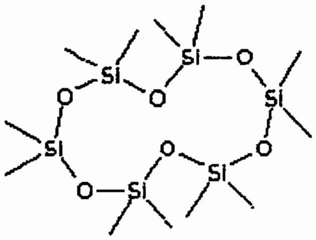
D4



D5

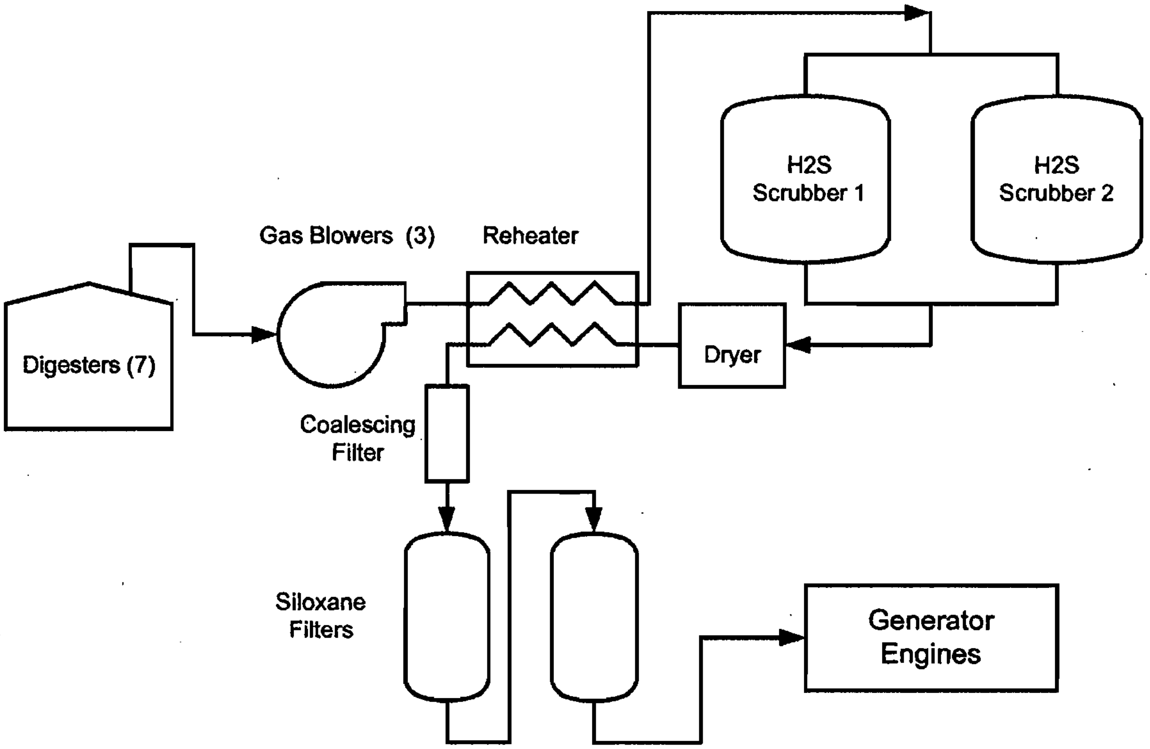


D6



APPENDIX E

MANGERE BIOGAS TREATMENT SYSTEM PROCESS FLOW DIAGRAM



APPENDIX F

MANGERE BIOGAS TREATMENT SYSTEM DESIGN CALCULATIONS

HYDROGEN SULFIDE REMOVAL SYSTEM (PARALLEL FLOW)

Hydrogen Sulfide Removal System Performance Estimates (Calculations performed at 781 ppmv)								Estimated CIS Media Life, Days		Contact Time, Seconds
Flow, Nm3H	Vessel Flow Scheme	Vessel Diameter, m	Media Depth m, nominal	CIS Media m^3, nominal	Velocity m/second	Resistance kPa, initial	kg CIS media	Anaerobic	Aerobic	
1700	Full, 1 on, 1 off	3.0	2.55	36	0.043	1.4	30,100	45	91	59
2800	2 on, 1/2 each	3.0	2.55	36	0.036	1.2	30,100	55	110	71
3800	2 on, 1/2 each	3.0	2.55	36	0.039	1.6	30,100	40	81	66

CIS = Catalytic Iron Sponge

SILOXANE REMOVAL SYSTEM (SERIES FLOW)

Siloxane Removal System Performance Estimates (Calculations performed at concentrations shown)										Estimated SAG Media Life, Days	
Flow, Nm^{3}H	ppmv H_2S in biogas	Siloxanes in biogas, mg/m^3		Vessel Diameter, m	Media Depth, m,	SAG Media m^3, nominal	Velocity m/second	Resistance kPa, initial	kg SAG media		
		D4	D5							Siloxane D5	Siloxane D4
1700	800	4.52	0.58	2.13 (7 ft.)	1.86 (6 ft.)	13.3	0.085	1.5	6,352	> 90	90
1700	200	4.52	0.58	2.13 (7 ft.)	1.86 (6 ft.)	13.3	0.085	1.5	6,352	>180	180
2800	800	4.52	0.58	2.13 (7 ft.)	1.86 (6 ft.)	13.3	0.14	3.0	6,352	> 60	60
2800	200	4.52	0.58	2.13 (7 ft.)	1.86 (6 ft.)	13.3	0.14	3.0	6,352	> 140	140
2800	800	13.0	1.0	2.13 (7 ft.)	1.86 (6 ft.)	13.3	0.14	3.0	6,352	> 50	50

Florida Department of
Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

May 6, 2009

Electronically Sent – Received Receipt Requested

jvangessel@wm.com
Mr. John Van Gessel
Vice President & Assistant Secretary
Waste Management (WM), Inc. of Florida
2869 West Paces Ferry Road
Atlanta, Georgia 30339

Re: DEP File No. 0930104-014-AC and PSD-FL-382
Berman Road and Clay Farms Landfills
Okeechobee Landfill, Inc.
Waste Management, Inc. of Florida

Dear Mr. Van Gessel:

On April 8, 2009 the Department received the response to our request for additional information (RAI) letter dated January 23, 2009 regarding the air construction permit application for the construction of additional flares and turbines along with the Low Cat desulfurization system at the Berman Road and Clay Farms Landfills.

Pursuant to Rules 62-4.055, and 62-4.070 F.A.C., Permit Processing, the Department requests submittal of the additional information below prior to processing the application. Should your response to any of the below items require new calculations, please submit the new calculations, assumptions, reference material and appropriate revised pages of the application form.

1. On page 3 of your response you stated that "*siloxane removal systems.... are unproven, and therefore, the SCR systems are not technically feasible for the OLI gas turbines*". Since then, we have contacted the South Carolina Department of Health and Environmental Control where they have permitted a landfill, Lee County Landfill, which installed a siloxane gas removal treatment system. The gas-to-energy facility at this landfill, the Santee Cooper Electric Generation Facility, is currently in operation. It appears the applicant proposed the siloxane gas removal treatment system of the landfill gas for overall protection of their equipment and not necessarily for NOx reduction for their Solar Taurus 60 turbine and their 4 Jenbacher Engine engines. These units are not equipped with SCR. Also, the Enoree Landfill [listed in the EPA landfill methane outreach program (LMOP)], installed gas treatment to reduce siloxane content from parts per million to parts per billion based on initial laboratory testing according to the EPA

website, it is expected that this gas cleaning technology could increase the life expectancy of the engines. Why is siloxane not of concern for WM at the Okeechobee landfill? What experience does WM have with this contaminant at the Pompano landfill and the gas-to-energy facility at this location?

2. Submit Siloxane Contamination Information for the Okeechobee Landfill. List the concentration (ppmv or mg/m^3) of the following contaminants in the landfill gas: Tetramethylsilane; Tetramethyldisiloxane; Pentamethyldisiloxane; Hexamethlydisiloxane; Octamethyltrisiloxane; Hexamethylcyclotrisiloxane; Octamethylcyclotetrasiloxane; Decamethylcyclopentasiloxane and Dodecamethylcyclohexasiloxane.
3. Table 7 of the information submitted, lists the annualized cost for siloxane removal as $1,213,219 for all turbines. This value was also used for each individual turbine. Please adjust this value to reflect the cost for siloxane removal for each turbine alone.
4. Explain the rationale why the Mercury 50 (4.6 MW) with a 25 ppm NOx emissions was not selected for this project instead of the Centaur 40 (3.5 MW) with a 42 ppm NOx emissions and the Titan (15 MW) with a 72 ppm NOx emissions. It is our understanding that the Ultra Lean Premix (ULP) combustion system on the Mercury 50 has been modified to support landfill gas combustion thus reducing NOx emissions.
5. Submit a BACT analysis including $/ton of NOx removed using the Solar Mercury 50 turbine without SCR installation and with/without siloxane removal system.
6. Appendix C and Attachment A of your response gave information about the NOx and CO Controls Cost Analysis for the Centaur and Titan turbines. In reviewing the information, we noticed that the vendor's quote for NOx is missing and that the CO vendor's quote information lists fuel as natural gas and oil instead of landfill gas. Please submit updated quotes for this project specifically.
7. In all the cost effectiveness calculations that were submitted with your response the project contingency was based on 15% of the Direct Capital Cost (DCC) plus the Indirect Capital Cost (ICC). Please explain the rationale for using a high percentage of 15% when the EPA Cost Manual uses 3% contingency figure. Additionally, explain the reasons for using contingency based on DCC+ICC and not on Purchased Equipment Cost (PEC) as indicated in the manual.
8. On April 22, 2009, the Department received an e-mail from Mr. Dave Thorley of your organization stating that the landfill will require 4 additional 3,000 standard cubic feet per minute (scfm) open flares along with 1 existing flare. The new flares will be required in conjunction with 1 Titan and 6 Centaur turbines in the first 7 years of operation after the permit issuance. The original application stated that 1 additional flare with 1 existing flare will be sufficient for the landfill. Please explain the need for additional flares if turbines are also being installed at the facility.

Rule 62-4.050(3), F.A.C. requires that all applications for a Department permit must be certified by a professional engineer registered in the State of Florida. This requirement also applies to responses to Department requests for additional information of an engineering nature. Please note that per Rule 62-4.055(1): "The applicant shall have ninety days after the Department mails a timely request for additional information to submit that information to the Department .... Failure of an applicant to provide the timely requested information by the applicable date shall result in denial of the application."

If you have any questions regarding this matter, please contact Ms. Teresa Heron at 850/921-9529 or Ms. Debbie Nelson (meteorologist) at 850/921-9537.

Sincerely,

Syed Arif, P.E. Acting Program Administrator
Special Projects Section

SA/th

cc: David Thorley, Waste Management, Inc. dthorley@wm.com
Seth Nunes, Waste Management, Inc. snunes1@wm.com
Jim Christiansen, Waste Management, Inc. jchristi@wm.com
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Golder Associates

June 4, 2009

0938-7541

RECEIVED
JUN 09 2009
BUREAU OF AIR REGULATION

Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, FL 32399-2400

Attention: Mr. Syed Arif, P.E., Acting Program Administrator

RE: REQUEST FOR ADDITIONAL INFORMATION
DEP FILE NO. 0930104-014-AC AND PSD-FL-382
BERMAN ROAD AND CLAY FARMS LANDFILLS
OKEECHOBEE LANDFILL, INC.
WASTE MANAGEMENT (WM), INC. OF FLORIDA

Dear Mr. Arif:

Okeechobee Landfill, Inc. (OLI), a subsidiary of Waste Management, Inc. (WM) of Florida has received a request for additional information (RAI) from the Florida Department of Environmental Protection (FDEP) dated May 6, 2009, regarding the construction permit application for the construction of additional flares and turbines along with the LO-CAT II desulfurization system at the Okeechobee Landfill. Each of FDEP's requests is answered below, in the same order as they appear in the RAI letter.

Comment 1. **On page 3 of your response you stated that "*siloxane removal systems... are unproven, and therefore, the SCR systems are not technically feasible for the OLI gas turbines*". Since then, we have contacted the South Carolina Department of Health and Environmental Control where they have permitted a landfill, Lee County Landfill, which installed a siloxane gas removal treatment system. The gas-to-energy facility at this landfill, the Santee Cooper Electric Generation Facility, is currently in operation. It appears the applicant proposed the siloxane gas removal treatment system of the landfill gas for overall protection of their equipment and not necessarily for NOx reduction for their Solar Taurus 60 turbine and their 4 Jenbacher Engine engines. These units are not equipped with SCR. Also, the Enoree Landfill [listed in the EPA landfill methane outreach program (LMOP)], installed gas treatment to reduce siloxane content from parts per million to parts per billion based on initial laboratory testing according to the EPA website, it is expected that this gas cleaning technology could increase the life expectancy of the engines. Why is siloxane not of concern for WM at the Okeechobee landfill? What experience does WM have with this contaminant at the Pompano landfill and the gas-to-energy facility at this location?**

Response: Under current operation, siloxane is not a matter of concern to WM at the Okeechobee Landfill, or at its other landfills. Siloxane poses no problem to the operation of the three landfill gas (LFG)-fired turbines at the Central Sanitary Landfill & Recycling Center in Pompano Beach, Florida (Pompano Landfill). Small deposits of siloxane (in the form of silica and silicate) on the turbine blades at the Pompano Landfill have been noticed, but these are removed during the engine overhauls and cause no operational problem. There are no known installations of siloxane removal systems on LFG streams prior to combustion in a turbine. Siloxane removal systems do not remove all siloxane; therefore, the siloxane that passes through the removal system will still be deposited on turbine blades and inside post-combustion control devices. These deposits will foul the selective catalytic reduction (SCR) catalysts. Please note that WM is proposing a desulfurization gas treatment (LO-CAT II) system at the Okeechobee Landfill.

Comment 2. **Submit Siloxane Contamination Information for the Okeechobee Landfill. List the concentration (ppmv or mg/m^3) of the following contaminants in the landfill gas: Tetramethylsilane; Tetramethyldisiloxane; Pentamethyldisiloxane; Hexamethyldisiloxane; Octamethyltrisiloxane; Hexamethylcyclotrisiloxane; Octamethylcyclotetrasiloxane; Decamethylcyclopentasiloxane and Dodecamethylcyclohexasiloxane.**

Response: A gas analysis for siloxanes was conducted on the Okeechobee Landfill LFG in May 2008; the results are presented in Attachment A. As shown, only octamethyltrisiloxane was detected in the gas stream, at a concentration of 1,700 parts per billion, volumetric (ppbv).

Comment 3. **Table 7 of the information submitted, lists the annualized cost for siloxane removal as $1,213,219 for all turbines. This value was also used for each individual turbine. Please adjust this value to reflect the cost for siloxane removal for each turbine alone.**

Response: The annualized cost of $1,213,219 is for one siloxane removal system to treat the design LFG flow of 27,500 standard cubic feet per minute (scfm) for all 16 turbines. The same cost was used for each individual turbine with the conservative assumption that only one siloxane removal system will be installed to treat the total LFG flow instead of installing individual siloxane removal systems for individual turbines. The capital and annual costs for 16 siloxane removal systems will be many times higher than one siloxane removal system to serve all 16 turbines.

However, to satisfy the Department's request, a revised Table 7 is presented in Attachment B, which shows the annualized cost for individual siloxane removal systems. The annualized cost calculation tables are also attached. Please note that the equipment cost is based on the WM Pennsylvania project, where a siloxane removal system was considered for treating a gas flow of 8,000 scfm. The equipment cost of the Pennsylvania system was linearly scaled down to estimate the equipment cost to treat 1,500-scfm gas flow for the Centaur 40 turbine and 5,000-scfm gas flow for the Titan 130 turbine. This approach may result in costs that are lower than actual, as the cost of the siloxane removal system may not be linearly scalable. For example, based on Solar's information, the capital costs for the 1,500-, 3,000-, and 4,500-scfm siloxane removal systems are $335,000, $485,000, and $680,000, respectively.

As shown in the revised Table 7, the cost effectiveness ($/ton) for the first phase of the project, which includes one Titan and four Centaur turbines, remains about the same. However, the cost effectiveness for all 16 turbines has increased from $4,018 to $4,259 per ton.

Comment 4. **Explain the rationale why the Mercury 50 (4.6 MW) with a 25 ppm NOx emissions was not selected for this project instead of the Centaur 40 (3.5 MW) with a 42 ppm NOx emissions and the Titan (15 MW) with a 72 ppm NOx emissions. It is our understanding that the Ultra Lean Premix (ULP) combustion system on the Mercury 50 has been modified to support landfill gas combustion thus reducing NOx emissions.**

Response: The Mercury 50 was not selected because it is not proven on LFG yet. WM operates the largest fleet of LFG-fired turbines in the country, all of which are Solar Turbines. WM has a long history with Solar Turbines and has been following the Mercury 50 product through its development. The Mercury 50 has not operated on LFG as of yet. Solar tested the unit with diluted pipeline natural gas in the factory. There have been Mercury 50's sold for LFG applications; however, none are currently in operation. Once starting operations, it will take a considerable amount of time to evaluate the turbine's performance and operating costs. Multiple turbine applications have failed using LFG as fuel; the Solar Saturn was one of them. WM wants to install a turbine that is proven to operate on LFG.

Comment 5. **Submit a BACT analysis including $/ton of NOx removed using the Solar Mercury 50 turbine without SCR installation and with/without siloxane removal system.**

Response: See response to Comment 4. The Solar Mercury 50 turbine was made commercially available in 2004; however, there are no known installations of a Mercury 50 turbine operating on LFG anywhere in the U.S. Since there are none operating, actual operating and maintenance cost data are unavailable. As a result, a cost analysis to estimate $/ton of nitrogen oxide ($NO_x$) removal using the Mercury 50 turbine is not practical.

Comment 6. **Appendix C and Attachment A of your response gave information about the NOx and CO Controls Cost Analysis for the Centaur and Titan turbines. In reviewing the information, we noticed that the vendor's quote for NOx is missing and that the CO vendor's quote information lists fuel as natural gas and oil instead of landfill gas. Please submit updated quotes for this project specifically.**

Response: The original vendor quote for the SCR NO_x control system used in the WM Pennsylvania project is not available. The Pennsylvania Department of Environmental Protection was contacted; they stated that they do not have the original vendor quote. However, the SCR cost basis of $955,000 used in the WM Pennsylvania project (for Solar Centaur 40 turbine) can be supported by the following references:

1. The U.S. Environmental Protection Agency's (EPA's) Alternative Control Techniques Document used a SCR capital cost of $622,000 in 1990 dollars (Table 6-10, Alternative Control Techniques Document – NO_x Emissions from Stationary Gas Turbines, EPA-453/R-93-007) for a Solar Centaur T4500 turbine, which is similar to the Centaur 40. Using the consumer price index (CPI-U) (consumer price index for all urban consumers, published by the Bureau of Labor Statistics available at inflationdata.com), this price is equivalent to more than $1 million in 2009 dollars. SCR cost for Centaur 40 turbine used in the Okeechobee BACT analysis is $955,000.
2. Based on internet research, in the PSD permit application dated February 2002 for PG&E Gas Transmission's Compressor Station 4 in Sandpoint, Idaho (see Attachment C for reference), an equipment cost of $1.3 million has been used for the SCR system on a Solar Titan gas turbine. This cost is equivalent to $1.55 million in 2009 dollars (assuming the equipment cost of $1.3 million is in 2002 dollars). The SCR cost for the Solar Titan turbine used in the Okeechobee Landfill BACT analysis is $1.4 million, which is a scaled-up cost based on the $955,000 used in the WM Pennsylvania project. The above references support the estimated cost of SCR for Okeechobee.

The carbon monoxide (CO) oxidation catalyst control system cost from BASF Catalysts LLC was obtained in September 2008 for a Solar Titan 130 turbine, which is fired with natural gas and oil. Please note that a CO oxidation catalyst system has never been used on a turbine fired with LFG and the cost for such a system is not readily available. The oxidation catalyst system is a post-combustion control technology and its effectiveness (and therefore, cost) depends primarily on the exhaust gas characteristics. It should also be noted that apart from siloxane compounds, the characteristics of the turbine exhaust gas from LFG combustion are similar to those of natural gas firing. The effect of siloxane compounds in the exhaust gas has been considered in the cost analysis in the form of more frequent catalyst replacements. The basic equipment cost should be the same as that for the system for a natural gas-fired turbine.

In support of the oxidation catalyst system costs used in the Okeechobee Landfill BACT analysis, an EPA memo on Oxidation Catalyst Costs for New Stationary Combustion Turbines, dated December 30, 1999, is included as Attachment D. Based on Table 1 of the memo (page 6, Engelhard costs), the oxidation catalyst system (catalyst + frame) cost for the Centaur 40 turbine is $155,000 (exhaust flow of OLI Centaur 40 turbine is 41.8 pounds per second) in mid-1998 dollars, which is about $205,000 in 2009 dollars. Also based on the linear relationship between catalyst cost and exhaust flow rates provided in page 6 of the memo, the oxidation catalyst system for the Titan 130 turbine is $274,000 in mid-1998 dollars, which is $361,000 in 2009 dollars. Note that the oxidation catalyst system costs used in the Okeechobee Landfill BACT analysis for the Centaur 40 and Titan 130 turbines are $289,000 and $308,000, respectively.

Comment 7. In all the cost effectiveness calculations that were submitted with your response the project contingency was based on 15% of the Direct Capital Cost (DCC) plus the Indirect Capital Cost (ICC). Please explain the rationale for using a high percentage of 15% when the EPA Cost Manual uses 3% contingency figure. Additionally, explain the reasons for using contingency based on DCC+ICC and not on Purchased Equipment Cost (PEC) as indicated in the manual.

Response: The project contingency figure of 15 percent is based on Table 2.5, Chapter 2, Section 4 (NO_x Control) of the EPA Cost Control Manual. As explained in Section 2.3.1 of Chapter 2, Section 1, project contingencies are designed to cover unforeseen costs that may arise from possible redesign and modification of equipment, escalation increases in cost of equipment, increases in field labor costs, delays encountered in start-ups, etc. As shown in Table 2.5, the project contingency is applied on the sum of DCC and ICC.

Comment 8. On April 22, 2009, the Department received an e-mail from Mr. Dave Thorley of your organization stating that the landfill will require 4 additional 3,000 standard cubic feet per minute (scfm) open flares along with 1 existing flare. The new flares will be required in conjunction with 1 Titan and 6 Centaur turbines in the first 7 years of operation after the permit issuance. The original application stated that 1 additional flare with 1 existing flare will be sufficient for the landfill. Please explain the need for additional flares if turbines are also being installed at the facility.

Response: WM revised and re-submitted the air construction permit application in October 2008 to include the additional flares. WM wants to install the additional flares to maintain 100-percent backup capability in the event all of the turbines are shut down, to ensure continued compliance with New Source Performance Standards (NSPS) Subpart WWW and other regulatory requirements. All turbines may be shut down if the electric grid is shut down due to natural calamities such as hurricanes, etc. Total design LFG flow of the Okeechobee Landfill is 32,400 scfm and all 11 flares will be needed to destruct the total flow. Please note that the email from Mr. David Thorley was in response to a verbal request by FDEP from an April 2009 conference call. The conference call was requested by FDEP to discuss the project, when a specific request was made by FDEP for the installation plans for the next 7 years.

Thank you for consideration of this information. If you have any questions, please do not hesitate to call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David a. Buff

David Buff, P.E., Q.E.P.
Principal Engineer

Salahuddin Mohammad
Senior Project Engineer

SKM/DB/tlc

Enclosures

cc: D. Thorley, WM
S. Nunes, OLI

R060409_541.docx

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff, P.E.**
Registration Number: **19011**

2. Professional Engineer Mailing Address...
Organization/Firm: **Golder Associates Inc.****
Street Address: **6026 NW 1st Place**
City: **Gainesville** State: **FL** Zip Code: **32607**

3. Professional Engineer Telephone Numbers...
Telephone: **(352) 336-5600** ext. **21145** Fax: **(352) 336-6603**

4. Professional Engineer E-mail Address: **DBuff@golder.com**

5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Signature Date 6/4/09

(seal)

* Attach any exception to certification statement.
**Board of Professional Engineers Certificate of Authorization #00001670.

ATTACHMENT A

RESULTS OF OKEECHOBEE LANDFILL SILOXANE ANALYSIS

MAY 2008

CHAIN OF CUSTODY RECORD

Pg 1 of 1

AIR TECHNOLOGY Laboratories, Inc.
18501 E. Gale Avenue, Suite 130
City of Industry, CA 91748
626-964-4032 • Fax: 626-964-5832

Project Name: Okeechobee Siloxanes
Project #: 012-0100
P.O. #: 0001-2008

FOR LABORATORY USE ONLY

Method of Transport
- Walk-in ☐
- Courier ☐
- UPS ☐
- FedEx ☒
- ATL ☐

Sample Condition Upon Receipt
- 1. CHILLED Y☐ N☒
- 2. HEADSPACE (VOA) Y☐ N☒
- 3. CONTAINER INTACT Y☒ N☐
- 4. SEALED Y☐ N☒
- 5. # OF SPLS MATCH COC Y☐ N☐
- 6. PRESERVED Y☐ N☒

Company:
Contact: Kris Carlson
Address: 400 West Windsor Street
City Monroe State NC Zip Code 28112
TEL: (704) 506 7312
FAX: ( )

Sampled/Relinquished by: (Signature and Printed Name) Jeff McNabb Jeff McNabb	Date: 5/2/08	Time: 1614	Received by: (Signature and Printed Name)	Date:	Time:
Relinquished by: (Signature and Printed Name) FEDEX	Date: 5/6/08	Time: 1115	Received by: (Signature and Printed Name) Joann DelaOsa Joann DelaOsa	Date: 5/6/08	Time: 1115
Relinquished by: (Signature and Printed Name)	Date:	Time:	Received by: (Signature and Printed Name)	Date:	Time:

I hereby authorize ATL to perform the work indicated below:
Jeff McNabb 5/2/08
Project Mgr/Submitter (Print Name) Date
Jeff McNabb
Signature

Send Report To:
Attn: Kris Carlson
Co: Carlson Environmental
Address 400 W Windsor St
City Monroe State NC Zip 28112

Bill To:
Attn: Kris Carlson
Co: Carlson Environmental
Address 400 W. Windsor St
City Monroe State NC Zip 28112

Special Instructions/Comments: Canister #3621 did not have any negative pressure when delivered. sample LFG#2

Unless otherwise requested, all samples will be disposed 14 days after reporting or at Lab's discretion.

Sample Archive/Disposal:
- ☐ Laboratory Standard
- ☐ Other
- ☐ Return To:

* $10.00 FEE PER HAZARDOUS SAMPLE DISPOSAL.

DELIVERABLES
- EDD ☐
- LEVEL III ☐
- LEVEL IV ☐

LAB USE ONLY Lab No.	Sample Description Sample I.D. *	Date	Time	T03 Gas / BTEX / MTBE	T03 Hexane	T03 Carbon Chain	TO14A VOCs	TO15 VOCs Std or Low Level	15/16 Sulfur Comp Std/Low Level	15/16 H₂S Std or Low Level	Fixed Gas D1946 or 3C	25C/3C TNMOC	25.1 TGNMHC	D1945 Natural Gas	RSK 175 Dissolved Gas	Siloxanes			AIR • VAPOR	INDOOR AIR	LANDFILL GAS	WATER	SOLID • SOIL	OIL • SOLVENT • LIQUID	OTHER	TAT	Container(s) #	Container(s) Type	PRESERVATION	REMARKS
—	~~LFG #2~~ VOID	5/2	1345													~~X~~	VOID				X						1	C	N	3621
A0505005-01	LFG #1	5/2	1330													X					X						1	C	N	1344
	*Do not analyze per K. Carlson	5/6/08	1335																											

• TAT starts 8 a.m. following day if samples received after 5 p.m.

TAT: A= Overnight ≤ 24 hr B= Emergency Next workday C= Critical 2 Workdays D= Urgent 3 Workdays E= Routine 7 Workdays

Container Types: B=Tedlar Bag C=Canister V=VOA O= Other

Preservatives: H=Hcl N=None

DISTRIBUTION: White with report, Yellow to folder, Pink to submitter.

LCS/LCSD Recovery and RPD Summary Report

QC Batch #: 080517MS2A1

Matrix: Air

EPA Method TO-14/TO-15

Lab No:	Method Blank		LCS		LCSD						
Date Analyzed:	05/17/08		05/17/08		05/17/08						
Data File ID:	17MAY009.D		17MAY006.D		17MAY007.D						
Analyst Initials:	VM		VM		VM						
Dilution Factor:	0.2		1.0		1.0			Limits			
ANALYTE	Result ppbv	Spike Amount	Result ppbv	% Rec	Result ppbv	% Rec	RPD	Low %Rec	High %Rec	Max. RPD	Pass/ Fail
1,1-Dichloroethene	0.0	10.0	9.8	98	10.1	101	2.6	70	130	30	Pass
Methylene Chloride	0.0	10.0	9.7	97	10.1	101	3.5	70	130	30	Pass
Trichloroethene	0.0	10.0	9.9	99	9.8	98	0.4	70	130	30	Pass
Toluene	0.0	10.0	9.3	93	9.4	94	0.6	70	130	30	Pass
1,1,2,2-Tetrachloroethane	0.0	10.0	7.9	79	8.0	80	2.1	70	130	30	Pass

RPD = Relative Percent Difference

Reviewed/Approved By:

Mark Johnson
Operations Manager

Date: 5-19-08

The cover letter is an integral part of this analytical report

Client: Carlson Environmental
Attn: Kris Carlson

Client's Project: Okeechobee Siloxanes
Date Received: 05/06/08
Matrix: Air
Units: ppbv

EPA Method TO15 (Siloxanes)

Lab No:	**A8050605-01**				
Client Sample I.D.:	**LFG#1**				
Date Sampled:	**05/02/08**				
Date Analyzed:	**05/17/08**				
QC Batch No:	**080517MS2A1**				
Analyst Initials:	**VM**				
Dilution Factor:	**87**				

ANALYTE	PQL	Result	RL								
Hexamethyldisiloxane	10	ND	870								
Hexamethylcyclotrisiloxane	10	ND	870								
Octamethyltrisiloxane	10	ND	870								
Octamethylcyclotetrasiloxane	10	1,700	870								
Decamethyltetrasiloxane	10	ND	870								
Decamethylcyclopentasiloxane	50	ND	4,400								
Dodecamethylpentasiloxane	200	ND	17,000								

PQL = Practical Quantitation Limit
ND= Not Detected (below RL)
RL = PQL X Dilution Factor

Reviewed/Approved By: ______________________ **Date** 5-19-08

Mark Johnson
Operations Manager

The cover letter is an integral part of this analytical report

ATTACHMENT B

REVISED COST EFFECTIVENESS CALCULATIONS FOR NO_X AND CO CONTROL SCENARIOS

TABLE 1a
CAPITAL AND ANNUAL COSTS FOR SILOXANE REMOVAL SYSTEM FOR THE TITAN 130 TURBINE

Cost Items	Cost Factors	Siloxane Removal System Cost ($)
DIRECT CAPITAL COSTS (DCC):		
(1) Siloxane Removal System	Vendor Quote [a]	175,000
Auxiliary Equipment (control panel, etc.)	5% of equipment cost, estimated	8,750
(2) Freight	5% of equipment cost, CCM Chapter 2	8,750
(3) Sales Tax	NA - Pollution Control Equipment	0
Subtotal: Total Equipment Cost (TEC)		192,500
(4) Direct Installation Costs		
(a) Foundation and Structural Support	8% of TEC, Cost Control Manual (CCM), Section 3, Table 2.8	15,400
(b) Handling & Erection	14% of TEC, CCM, Section 3, Table 2.8	26,950
(c) Electrical	16% of TEC, Solar Estimate	30,800
(d) Piping	16% of TEC, Solar Estimate	30,800
(e) Insulation	1% of TEC, CCM, Section 3, Table 2.8	1,925
Total DCC:		298,375
INDIRECT CAPITAL COSTS (ICC): [b]		
(1) Indirect Installation Costs		
(a) General Facilities	5% of TEC, CCM Section 4, Table 2.5	9,625
(b) Engineering and Home Office Fees	10% of TEC, CCM Section 4, Table 2.5	19,250
(c) Process Contingency	5% of TEC, CCM Section 4, Table 2.5	9,625
(2) Other Indirect Costs		
(a) Emissions Monitoring	Engineering Estimate	5,000
(b) Performance Testing	1% of TEC, CCM Section 3, Table 2.8	1,925
(c) Spare Parts	Engineering Estimate	5,000
(d) Contractor Fees	10% of TEC, CCM Section 3, Table 2.8	19,250
Total ICC:		69,675
PROJECT CONTINGENCY	15% of (DCC+ICC)	55,208
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	423,258
DIRECT OPERATING COSTS (DOC): [b]		
(1) Operating Labor		
Operator	1/2 hr/shift, $30/hr, 8760 hrs/yr	16,425
Supervisor	15% of operator cost	2,464
(2) Maintenance (labor and material)	1.5% of TCI, CCM Section 4, Equation 2.46	6,349
(3) Siloxane System Energy Requirement	6 in ΔP (estimated same as SCR), 48 MW/year, $60/MW	2,880
(3) Siloxane Removal Media Replacement	Vendor estimate, 35% of Equipment, Media Life 1/2 year	122,500
(4) Siloxane System Calibration	Solar Information - about $500K for 5 years	100,000
Total DOC:		250,618
INDIRECT OPERATING COSTS (IOC): [b]		
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	15,143
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	4,233
(3) Insurance	1% of total capital investment, CCM Chapter 2	4,233
(4) Administration	2% of total capital investment, CCM Chapter 2	8,465
Total IOC:	(1) + (2) + (3) + (4)	32,073
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	39,956
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	322,646

Notes:

[a] Cost estimates from similar systems considered for Waste Management Disposal Services of Pennsylvania, Inc's Renewable Energy Facility Application for Plan Approval, No. 009-00007, September 2008. WM Pennsylvania cost = $280,000 (for 8,000 scfm). Scaled cost for Titan 130 (5,000 scfm) = $280,000 x 5,000/8,000 = $175,000.

[b] Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

TABLE 1b
CAPITAL AND ANNUAL COSTS FOR SILOXANE REMOVAL SYSTEM FOR THE CENTAUR 40 TURBINE

Cost Items	Cost Factors	Siloxane Removal System Cost ($)
DIRECT CAPITAL COSTS (DCC):		
(1) Siloxane Removal System	Vendor Quote [a]	52,500
Auxiliary Equipment (control panel, etc.)	5% of equipment cost, estimated	2,625
(2) Freight	5% of equipment cost, CCM Chapter 2	2,625
(3) Sales Tax	NA - Pollution Control Equipment	0
Subtotal: Total Equipment Cost (TEC)		57,750
(4) Direct Installation Costs		
(a) Foundation and Structural Support	8% of TEC, Cost Control Manual (CCM), Section 3, Table 2.8	4,620
(b) Handling & Erection	14% of TEC, CCM, Section 3, Table 2.8	8,085
(c) Electrical	16% of TEC, Solar Estimate	9,240
(d) Piping	16% of TEC, Solar Estimate	9,240
(e) Insulation	1% of TEC, CCM, Section 3, Table 2.8	578
Total DCC:		89,513
INDIRECT CAPITAL COSTS (ICC): [b]		
(1) Indirect Installation Costs		
(a) General Facilities	5% of TEC, CCM Section 4, Table 2.5	2,888
(b) Engineering and Home Office Fees	10% of TEC, CCM Section 4, Table 2.5	5,775
(c) Process Contingency	5% of TEC, CCM Section 4, Table 2.5	2,888
(2) Other Indirect Costs		
(a) Emissions Monitoring	Engineering Estimate	5,000
(b) Performance Testing	1% of TEC, CCM Section 3, Table 2.8	578
(c) Spare Parts	Engineering Estimate	5,000
(d) Contractor Fees	10% of TEC, CCM Section 3, Table 2.8	5,775
Total ICC:		27,903
PROJECT CONTINGENCY	15% of (DCC+ICC)	17,612
TOTAL CAPITAL INVESTMENT (Total Plant Cost) (TCI):	DCC + ICC+Project Contingency	135,027
DIRECT OPERATING COSTS (DOC): [b]		
(1) Operating Labor		
Operator	1/2 hr/shift, $30/hr, 8760 hrs/yr	16,425
Supervisor	15% of operator cost	2,464
(2) Maintenance (labor and material)	1.5% of TCI, CCM Section 4, Equation 2.46	2,025
(3) Siloxane System Energy Requirement	6 in ΔP (estimated same as SCR), 14 MW/year, $60/MW	840
(3) Siloxane Removal Media Replacement	Vendor estimate, 35% of Equipment, Media Life 1/2 year	36,750
(4) Siloxane System Calibration	Solar Information - about $250K for 5 years	50,000
Total DOC:		108,504
INDIRECT OPERATING COSTS (IOC): [b]		
(1) Overhead	60% of oper. labor & maintenance, CCM Chapter 2	12,548
(2) Property Taxes	1% of total capital investment, CCM Chapter 2	1,350
(3) Insurance	1% of total capital investment, CCM Chapter 2	1,350
(4) Administration	2% of total capital investment, CCM Chapter 2	2,701
Total IOC:	(1) + (2) + (3) + (4)	17,950
CAPITAL RECOVERY COSTS (CRC):	CRF of 0.0944 times TCI (20 yrs @ 7%)	12,747
ANNUALIZED COSTS (AC):	DOC + IOC + CRF	139,200

Notes:

[a] Cost estimates from similar systems considered for Waste Management Disposal Services of Pennsylvania, Inc's Renewable Energy Facility Application for Plan Approval, No. 009-00007, September 2008. WM Pennsylvania cost = $280,000 (for 8,000 scfm). Scaled cost for Centaur 40 (1,500 scfm) = $280,000 x 1,500/8,000 = $52,500.

[b] Factors and cost estimates reflect OAQPS Cost Manual, 6th Edition, January 2002.

TABLE 7 (Revision 6/4/09)
COST EFFECTIVENESS CALCULATION FOR NOx AND CO CONTROL SCENARIOS, OKEECHOBEE LANDFILL FACILITY

Cost Items	Comments/Reference	Value	NOx + CO Control Scenarios 1 Titan 130	 1 Centaur 40	 1 Titan 130 + 4 Centaur 40	 1 Titan 130 + 15 Centaur 40
Annualized Cost for Siloxane System Titan 130 ($/yr)	Table 1a	322,646	322,646	--	322,646	322,646
Annualized Cost for Siloxane System Centaur 40 ($/yr)	Table 1b	139,200	--	139,200	556,801	2,088,005
Annualized Cost of SCR System for Titan 130 ($/yr)	Table 2	1,165,516	1,165,516	--	1,165,516	1,165,516
Annualized Cost of SCR System for Centaur 40 ($/yr)	Table 3	777,761	--	777,761	3,111,044	11,666,415
Annualized Cost of CO Catalyst for Titan 130 ($/yr)	Table 4	402,702	402,702	--	402,702	402,702
Annualized Cost of CO Catalyst for Centaur 40 ($/yr)	Table 5	370,375	--	370,375	1,481,500	5,555,625
Total Annualized Cost (AC)($/yr):			1,890,864	1,287,336	7,040,209	21,200,909
Titan 130 Baseline NOx Emissions (TPY) :	72 ppm, Emission Guarantee	203.0	203.0	--	203.0	203.0
Centaur 40 Baseline NOx Emissions (TPY) :	42 ppm, Emission Guarantee	35.0	--	35.0	140.0	525.0
Titan 130 Baseline CO Emissions (TPY) :	100 ppm, Emission Guarantee	858.0	858.0	--	858.0	858.0
Centaur 40 Baseline CO Emissions (TPY) :	250 ppm, Emission Guarantee	263.0	--	263.0	1,052.0	3,945.0
Controlled NOx Emissions (TPY) :	90% Control		20.3	3.5	34.3	72.8
Controlled CO Emissions (TPY) :	90% Control		85.8	26.3	191.0	480.3
Reduction in NOx Emissions (TPY):	Baseline - Controlled		182.7	31.5	308.7	655.2
Reduction in CO Emissions (TPY):	Baseline - Controlled		772.2	236.7	1,719.0	4,322.7
Total Reduction in Emissions (TPY):			955	268	2,028	4,978
Cost Effectiveness (AC/Total Reduction)	$ per ton Removed		1,980	4,800	3,472	4,259

ATTACHMENT C

PSD PERMIT APPLICATION FOR PG&E GAS TRANSMISSION COMPRESSOR STATION 4

PG&E National
Energy Group
Gas Transmission
Northwest

PSD PERMIT APPLICATION
PG&E GAS TRANSMISSION NORTHWEST
COMPRESSOR STATION 4 - UNIT A
SANDPOINT, IDAHO

REVISED IMPACTS MODELING FOR NO_X

FEBRUARY 2002

PREPARED FOR
PG&E GAS TRANSMISSION, NORTHWEST CORPORATION
1400 S.W. FIFTH AVENUE, SUITE 900
PORTLAND, OR 97201

BY
MEYER GROUP
2031 DORIS AVENUE
WALNUT CREEK, CA 94596

APPENDIX C

BACT ANALYSIS

Technological Considerations of SCR Controls in Pipeline Applications

At this time, the only natural gas compression facility which has been required to install SCR as BACT is the Southern California Gas Company (SoCalGas) compressor station at Wheeler Ridge in the southern San Joaquin Valley. The facility, which called for three 5,650 horsepower Solar Centaur Type H gas turbines, was permitted in 1991 by the San Joaquin Valley Unified APCD limiting NO_x to 5 ppmv at steady state conditions and 8 ppmv at non-steady state conditions. The turbines were placed in service in October 1993, utilizing Norton high temperature SCR systems. An initial source test satisfied the permit condition at steady state. As a result, the SJV APCD concluded that the technology was "achieved in practice" and posted the BACT determination on the California Air Pollution Control Officers Association (CAPCOA) BACT Clearinghouse database. (SJV APCD, 6/25/96)

The first variance petition for relief from the permitted NO_x limit was submitted in December 1993 while the manufacturer attempted to resolve SCR system failure problems. Seven additional petitions for variances were filed during the ensuing three years. In September 1996, SoCalGas filed an Application for Authority to Construct Emission Control Modifications requesting approval to remove the SCR systems and retrofit Solar's SoLoNOx™ lean pre-mix NO_x control system.

Following its analysis, in February 1997 the San Joaquin Valley Unified APCD issued its Notice of Preliminary Decision for the Proposed Issuance of an Authority to Construct. In January 1997, this determination was posted on the CARB BACT database with a statement that the high temperature SCR system was deemed not technologically feasible. It was also posted on the USEPA RACT-BACT-LAER Clearinghouse database (as LAER) with a similar statement. None-the-less, the USEPA Region 9 intervened, over-ruling the APCD.

USEPA Region 9 required that SoCalGas replace the SCR system with one by a different vendor. The replacement system was supplied by Engelhard. The permit limits for NO_x were increased to 8 ppmv at steady state conditions and 12 ppmv at non-steady state conditions, while ammonia slip continues to be limited to 20 ppmv. This system operated successfully for about six months, at which time it began experiencing catalyst failure. With the catalyst deteriorating, it is necessary to increase the ammonia injection rate, with an increase in ammonia slip. While to date, the units have been in compliance with permit limits, they are now close to the limit for ammonia slip. It is expected that catalyst replacement will be necessary after about 18 to 24 months of operation, significantly less than the guaranteed three years. Due to the current high demand for the high temperature catalyst systems, it may not be possible to get all three systems replaced in time to avoid permit violations.

A spokesman for SoCalGas stated that while progress is being made, he believes that one or two more design cycles may be needed before they can be successful for pipeline applications. To achieve the original limit of 5 ppmv for NO_x, he believes catalyst replacement would be required about twice a year.

HIGH TEMPERATURE SCR COST EFFECTIVENESS
REDUCE NOx 79% ON SOLAR TITAN GAS TURBINE

Component	Basis	Cost	Source
Capital Costs :			
Purchased Equipment Cost (PE):			
SCR System (design + media + exhaust duct work)		$1,092,068	Note 1
NH3 leak detections sys & sensors		$51,000	Note 1
Exhaust air dilution blowers (i.e., gas coolers to < 900 deg F)		$11,500	Note 1
Catalyst insulation (i.e., system protection for > 900 deg F exhaust temp)		$26,000	Note 1
CEM		$131,400	USEPA-CEMS
Freight @	5.0%	$61,173	OAQPA
Taxes on Materials @	5.0%	$68,657	Idaho
Total PE Cost		$1,441,798	
Installation Cost:			
Direct Cost @ 30% PE		$432,540	OAQPA, USDOE
Indirect Cost @ 31% PE		$446,958	OAQPA, USDOE
Taxes on Labor @	0.0%	$0	Idaho
Total Installation Cost:		$879,497	
Total Capital Cost		$2,321,296	
Annual Operating Costs:			
CEM Maintenance		$39,800	USEPA-CEMS
O&M Labor incl. Overheads and Supv. @ 3 hr./day,	$45.79 /hour	$50,140	USDOE, Note 2
Maintenance Materials @ 50% of O&M Labor		$25,070	USDOE
Annual Fuel Use	949967 MMBtu		MFR
Fuel Penalty (0.5% performance loss) @	$4.00 /MMBtu	$18,999	USDOE, Note 2
Injection Skid 7.5 KW Blower & 5 KW Pump @	$0.06 /KWH	$6,570	USDOE, Note 2
Ammonia (NH3 = NOx * 17/46 + 10 ppmv avg. slip)	8.0 lb/hr		USDOE, Note 2
	@ $550 /ton	$19,222	
Catalyst Replacement (3 year life)		$40,714	USDOE, Note 3
Catalyst Disposal, % of Catalyst Replacement Cost	3.75%	$1,221	USDOE
Administrative Costs @ 2% of Total Capital Cost	2.0%	$46,426	OAQPA, USDOE
Taxes, % of Total Capital Cost	0.9%	$20,195	Idaho
Insurance, % of Total Capital Cost	1.0%	$23,213	OAQPA, USDOE
Total Annual Operating Cost		$291,371	
Total Annualized Cost:			
Annualized Capital Cost - 15 year life @ 10%, CRF=	0.1315	$305,189	OAQPA, USDOE
Total Annual Operating Cost		$291,371	
Total Annualized Cost		$596,561	

NOx Emissions, Maximum Potential as Guaranteed:			Note 4
Uncontrolled NOx Emissions, tons/year		84.73	Appendix A
Controlled NOx Emissions, tons/year, @	79% Effectiv	17.79	Note 5
NOx Emission Reduction, tons/year		66.94	
Total Annualized Cost		$596,561	Note 4
SCR Cost Effectiveness, $/ton		$8,912	Note 4
NOx Emissions, Expected Average Over Range:			Note 6
Uncontrolled NOx Emissions, tons/year		66.79	Appendix A
Controlled NOx Emissions, tons/year, @	79% Effectiv	14.03	Note 5
NOx Emission Reduction, tons/year		52.76	
Total Annualized Cost		$592,491	Note 6
SCR Cost Effectiveness, $/ton		$11,229	Note 6
NOx Emissions, Expected Average Over Range, @ 90% Hours Operated:			Notes 6 & 7
Uncontrolled NOx Emissions, tons/year		60.11	Appendix A
Controlled NOx Emissions, tons/year, @	79% Effectiv	12.62	Note 5
NOx Emission Reduction, tons/year		47.49	
Total Annualized Cost		$580,491	Notes 6 & 7
SCR Cost Effectiveness, $/ton		$12,224	Notes 6 & 7

References:

California Air Resources Board, Determination of Reasonably Available Control Technology and Best Available Retrofit Control Technology for the Control of Oxides of Nitrogen from Stationary Gas Turbines, May 18, 1992 (CARB)

Gas Turbine World 2000-2001 Catalog (GTW)

Manufacturer's data for the proposed installation (MFR)

Southern California Gas Company, personal communication with Jack Brunton, March 29, 2001 (SoCalGas)

U.S. Department of Energy, Cost Analysis of NOx Control Alternatives for Stationary Gas Turbines' November 5, 1999 (USDOE)

U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Cost Control Manual, Fifth Edition (OAQPS)

U.S. Environmental Protection Agency's Continuous Emission Monitoring System Cost Model Version 3.0 (USEPA-CEMS)

Notes:

General Note:
The overall structure of the cost estimate is based upon the cost analysis in USDOE.
The assumptions in USDOE were used unless better data were available.

1. USDOE cost data for high temperature SCR (Table A-6) incorporate cost quotes from Engelhard. However, actual costs tend to be significantly higher as the quoted systems are not complete. PG&E National Energy Group has "as constructed" data for the application of 3 high-temperature SCR

systems on simple-cycle gas turbines of 16.5MWe, nominal output for a guaranteed NOx outlet concentration of 9ppm. Based on that experience, actual cost data were employed after adjustment for turbine output. These higher costs are consistent with those reported in CARB.

2. Cost basis assumptions from USDOE, labor rates inclusive of overheads and energy costs from PG&E GTN

3. Catalyst life of 3 years is based upon manufacturer's guarantee and the experience of SoCalGas where actual life has been significantly less than 3 years. PG&E National Energy Group has secured vendor guarantees for SCR systems applied to electric generation ranging from 2200 hours of use and/or 37 months after the initial start-up date (even if not operated). Actual guarantees for dormant catalyst life are consistent with the 3 year life assumption for catalyst application on the pipeline system. Therefore, a 3-year replacement life represents the "best-case" cost scenario, where media life of 2200 hours of use (fired hours) would represent the "worst-case" cost scenario.
   Actual life-cycle cost has yet to be obtained in practice.
   Catalyst replacement cost is based on the formula and cost provided to PG&E NEG by Engelhard, 15 cu ft catalyst/MW @ $500/cu ft.

4. Maximum potential to emit, based upon highest emission rate as guaranteed by manufacturer in the normal lean pre-mix operating range and between 0 deg. And 100 deg. F.
   Manufacturer's guarantee is 25 ppmv NOx between 94% and 100% gas generator speed (NGG) and 42 ppmv NOx between 90% and 94% NGG. (90% NGG is equivalent to approximately 35% to 50% available horsepower while 94% NGG is equivalent to approximately 60% to 75% available horsepower depending on ambient temperature. Worst case for NOx as guaranteed is at 42 ppmv and 94% NGG.
   See emissions calculations in Appendix A.

5. Both USDOE and CARB assume uncontrolled emissions of 42 ppmv and a 79% removal efficiency to arrive at 9 ppmv as the controlled emission rate. A 79% removal efficiency has therefore been assumed.

6. Under normal operation, the unit will range between 100% and 90% NGG and the NOx emission concentration from 25 ppmv to 42 ppmv. Expected NOx emissions are the average of the manufacturer's guaranteed emissions over the 90% to 94% NGG range @ 42 ppmv and the 94% to 100% NGG range @ 25 ppmv. See emissions calculations in Appendix A.
   Operating cost affected by emissions rate (ammonia use) has been reduced proportionately.

7. The above calculations assume that the unit is operating 100% of the time.
   During year 2000, operating records indicate that system wide, the average unit operated 72% of the time.
   For purposes of this analysis, it is assumed that the unit will operate on average 90% of the time.
   Emissions and all variable operating expenses have been reduced in proportion to operating hours.

Catalyst Replacement Cost:

Rating, MW	13.5
Cu. Ft. catalyst/MW	15
Catalyst cost/cu. Ft.	$500
Total cost of replacement catalyst	$101,250
Life, years	3
Capital Recovery Factor (CRF) @ 10% Interest	0.4021
Amortized Cost of replacement catalyst	$40,714
Disposal cost/cu. Ft.	$15
Total cost of catalyst disposal	$3,038
Amortized Cost of catalyst disposal	$1,221

ATTACHMENT D

1999 EPA MEMO ON OXIDATION CATALYST COSTS FOR NEW STATIONARY COMBUSTION TURBINES

December 30, 1999

MEMORANDUM

FROM: Sims Roy
Emission Standards Division
Combustion Group

TO: Docket A-95-51

SUBJECT: Oxidation Catalyst Costs for New Stationary Combustion Turbines

The purpose of this memorandum is to summarize information on the cost of oxidation catalyst control for new stationary combustion turbines. Catalyst vendors provided information to EPA on the costs of acquiring, installing, and operating oxidation catalysts for HAP reduction for various turbines; these costs were applied to seven model turbines ranging in size from 1.13 megawatts (MW) to 170 MW. The total capital and annual costs were then estimated using methodologies from the OAQPS Control Cost Manual. A detailed description of the cost methodologies is given in Attachment A.

The total capital and annual costs for each model turbine are presented in the table below. The annual costs were estimated for both the guaranteed life of the catalyst (3 years) and the "typical" life of the catalyst (6 years).

Model Turbine	**Total Capital Cost ($)**[a]	**Total Annual Cost ($)**	
		3-Year Costs	**6-Year Costs**
GE PG 7121EA, 85.4 MW	3,272,268	1,157,833	956,998
GE PG 7231FA, 170 MW	4,753,816	1,673,902	1,382,131
GE PG 6561B, 39.6 MW	1,736,369	631,334	524,762
GE LM25000, 27 MW	1,103,989	415,818	348,060
Solar Centaur 40, 3.5 MW	677,525	268,560	226,974
Solar Mars T12000, 9 MW	485,196	202,673	172,898

Model Turbine	**Total Capital Cost ($)**[a]	**Total Annual Cost ($)**	
		3-Year Costs	**6-Year Costs**
Solar Saturn T1500, 1.13 MW	364,154	161,431	139,086

[a] Costs reflect mid-1998 figures.

Attachment A

MEMORANDUM

DATE: May 14, 1999

SUBJECT: Stationary Combustion Turbines Control Options Cost Information Summary

The purpose of this memorandum is to summarize the cost information that has been received for control options to date. This information will be used with model turbines developed for the Stationary Combustion Turbines source category as part of estimating the national impacts of viable regulatory options.

Background

In support of MACT determinations for new and existing combustion turbines, a set of model turbines has been developed that can be used to evaluate the national impact of control options being considered. The following approach will be used to determine national impacts:

1) Develop model turbines
2) Estimate control costs for each control option for each model turbine
3) Estimate emission reduction for each control option for each model turbine
4) Relate model turbines to turbines in the EPA Inventory Database for Stationary Combustion Turbines
5) Extrapolate from the inventory database population to the national population
6) Determine regulatory options
7) Estimate economic impacts for each regulatory option

Cost information has been received that will be used to estimate the control costs for each option being considered on a model turbine basis. This memorandum reflects the cost information that has been received to date. Any additional cost data received from vendors will be incorporated, as necessary, at a later time.

Cost Information

The methodology in the OAQPS Control Cost Manual will be used to determine the annual cost of control technologies. The OAQPS methodology provides generic cost categories and default assumptions to estimate the installed costs of control devices. Direct cost inputs are required for certain key elements, such as the capital costs of the control device. Other costs, such as installation, are then estimated based on percentages of the direct cost inputs.

In the OAQPS methodology, five cost categories are used to describe the annual cost of a control device. These are as follows:

1) Purchased Equipment Costs (PEC), which include the capital cost of the control device and auxiliary equipment, instrumentation, sales tax, and freight;
2) Direct Costs for Installation (DCI), which are the construction-related costs associated with installing the catalyst;
3) Indirect Costs for Installation (ICI), which include expenses related to engineering and start-up;
4) Direct Annual Costs (DAC), which include annual increases in operating and maintenance costs due to the addition of the control device; and
5) Indirect Annual Costs (IAC), which are the annualized cost of the control device system and the costs due to tax, overhead, insurance, and administrative burdens.

The cost that will be used in model turbine analyses is the total annual cost, which is the sum of the Direct Annual Costs (DAC) and the Indirect Annual Costs (IAC). The following information reflects the capital and operating costs that have thus far been obtained from vendors on the control technologies under consideration. Cost estimates are in 1998 dollars unless otherwise indicated.

Catalytic Systems

- **CO Oxidation Catalyst Systems**

Several vendors were contacted for capital and operating-related costs for CO oxidation catalysts. The following general information was requested:

1) What is the cost range of the catalyst material?
2) Would this number change in considering three flow ranges, i.e., small, medium, and large, starting with a minimum flow of 100 Mlbs/hour and ending with ~3000 Mlbs/hour?
3) What operating temperature ranges with respect to high CO removal/oxidation are recommended?
4) What happens during start-up and low load operation? What would be the result of a prolonged operation with gas turbine exhaust temperatures of ~500°F?
5) What are recommended space requirements and would flow straightening equipment be necessary?
6) What is the cost of reactor housing, required steel support, foundation needs and ductwork?

Cost information for CO oxidation catalysts was received from Engelhard, a catalyst vendor, and Nooter/Eriksen, a heat recovery steam generator (HRSG) vendor. Generalized estimates were also received for costs associated with increased pressure drops and retrofit applications. The information received is summarized below.

Engelhard

Engelhard CO catalysts are manufactured with a special stainless steel foil substrate which is corrugated and coated with an alumina washcoat. The washcoat is impregnated with platinum group metals. The catalyzed foil is folded and encased in welded steel frames, approximately 2 ft. square, to form individual modules. The individual modules are installed within the support frame. The modules typically weigh approximately 50 lb. each. The number of modules required increases with gas flow. Substrate depth and corrugation patterns can vary depending on project requirements. Typically, performance is warranted for 2 to 3 years with an expected life of 5 to 7 years. Typical guarantees are based on a ±15% gas velocity profile distribution. The catalyst is not a hazardous material and in most cases can be recycled to reclaim the precious metals. Engelhard can also provide catalysts on a ceramic substrate.

Engelhard provided costs for a simple cycle turbine installation (catalyst at turbine discharge temperature) for six turbine exhaust flows ranging from 28.4 lb/sec to 984.0 lb/sec. These costs were based on an oxidation catalyst that would achieve 90% CO conversion efficiency and 1" pressure drop across the catalyst panels (not total system pressure drop). The costs provided include the cost of an internal support frame and catalyst modules only. These costs are shown in Table 1.

Table 1. CO Oxidation Catalyst Costs Provided by Engelhard

Turbine Exhaust Flow (lb/sec)	Turbine Exhaust Temperature (F)	Required Inside Liner Cross Section (sq. ft.)	Estimated Cost Catalyst + Frame[a]
28.4	1050	67	$140,000
41.0	819	90	$155,000
318.0	990	716	$600,000
658.0	998	1522	$1,100,000
812.0	975	1881	$1,450,000
984.0	1116	2388	$1,550,000

[a] Costs reflect mid-1998 figures.

Regression analysis on the cost data in Table 1 suggest there is a nearly linear relationship between catalyst cost and exhaust flow rate ($r^2 = 0.993$, when Catalyst cost = 1541.8*(lb/sec) +

102370). Therefore, in estimating catalyst costs for the model turbines, the capital cost of a CO catalyst and frame for a given exhaust flow rate can be calculated using this relationship.

Information was also provided by Engelhard in response to the questions posed concerning operating issues associated with operating CO oxidation catalysts. A graph showing that lower performance/conversion accompanies lower temperatures was supplied. Typically, the catalysts Engelhard provides for gas turbine installations are supplied to a Heat Recovery Steam Generator (HRSG) supplier. The CO catalyst is generally installed within a HRSG. Supplemental firing usually is performed to increase steam production and thus gas temperatures at the catalyst and conversion requirements can be impacted by supplemental firing. Engelhard typically meets given HRSG cross section and maximum specified pressure drop allowed.

Engelhard indicated that reasonable retrofit estimates could not be provided due to many site-specific requirements. Their scope includes an internal support frame and catalyst modules which are installed inside the HRSG housing and as such, issues including flow straightening, housing, foundations, etc., are handled by other vendors.

Nooter/Eriksen

Nooter/Eriksen has become virtually sole sourced to Engelhard's Camet catalyst for their oxidation catalysts and provided an estimate of $650,000 for a 60% CO oxidation catalyst (no support frame or casing) in a GE Frame 7F installation (3,500,000 lb/hr with a catalyst temperature of approximately 900°F). They indicated that the price variation is approximately linear with mass flow and would approximately double to achieve 90% conversion. They were unable to comment on HAP destruction. The CO catalyst is occasionally required to also oxidize volatile organic compounds (VOCs), in which cases the catalyst is generally effective with unsaturated VOCs only and the catalyst must be located in a higher temperature window.

For high CO oxidation (90%), a temperature range of approximately 700°F to 760°F is preferred. If VOC oxidation is also required, the temperature window generally increases to 950°F to 1,100°F. It was indicated that prolonged operation at 500°F will not generally harm an oxidation catalyst unless the combustion turbine is operating with a high soot concentration in the exhaust, although there is little oxidation activity at 500°F.

Concerning retrofit issues, it was indicated that new ductwork to redirect flow outside of the original flow path would probably have the effect of obsoleting the greater portion of the HRSG. Most catalyst system guarantees are based on even flow distribution (typically ±15% RMS of the mean) entering the catalyst. If flow distribution devices were not originally included with the HRSG, this could increase the overall HRSG pressure loss by 0.5" to 1.0" W.C.

Generalized Pressure Drop Costs

Installation of a catalyst system will increase the pressure drop experienced by the turbine exhaust flow. The additional pressure drop results in a decrease in turbine power output. If the turbine is not operating at full load, additional fuel can be burned to make up for the lost power (fuel penalty). The fuel penalty is assessed as the cost of increased fuel, which is calculated by assuming a percentage heat rate increase per inch of pressure drop due to the increased exhaust backpressure on the turbine that results from installing an oxidation catalyst. An equation for the fuel penalty was provided by the Gas Research Institute, which is based on an anticipated heat rate increase of 0.105% per inch pressure drop, \$2/MMBtu for natural gas, and a 9,000 Btu/hp-hr baseline.

If the unit is operating at full load, the loss in power cannot be regained by burning additional fuel and will result in a loss in electricity sales. The costs associated with the power loss depend on site-specific factors, such as value of lost product or capital and annual costs for equipment required to make up for the power loss. Information on the loss in annual sales at different selling prices for electrical power was provided to EPA by Dow Chemical Company. For a GE Frame 7 turbine, the annual cost (lost sales) per inch of water pressure drop may be estimated using the following relationship: Annual Cost (\$/inch) = 1,160*Power Value (\$/Mwh) + 100.

Generalized Retrofit Costs

Estimates for retrofit costs were provided to EPA by Dow Chemical Company. Site-specific factors can have a major impact on the cost of retrofitting a catalyst control system to an existing turbine installation. In general, the heat recovery unit (if one exists) must be altered, ductwork and piling supports must be added, and piping, electrical conduits, and wiring must be lengthened. Some turbine installations have enough space between the turbine exhaust and the heat recovery unit to add the catalyst system. In cases where space is very limited, the heat recovery unit might have to be removed and replaced with a new vertical style unit. Estimates were provided for retrofit costs for adding a catalyst system to an ABB Type 11 turbine (gas flow rate = 580 lb/sec). The retrofit costs totaled about \$800,000, which included \$100,000 for ductwork. The cost of down time must also be estimated. It is difficult to extrapolate from the costs provided for this unit since the complexity and cost associated with retrofit installations varies so much by site.

- **Other Catalytic Systems**

Cost information in the form of comparisons to SCR systems for NOX control were received for SCONOx and XONON. More detailed cost information is needed from each vendor before an accurate assessment can be made concerning the cost of using these systems in conjunction with the model turbines. The information provided on these two systems is summarized below.

SCONOx™

Cost information for SCONOx was submitted by Goal Line Environmental Technologies LLC. The information consisted of a cost comparison model between SCONOx and SCR (selective catalytic reduction). The comparison is difficult to use for HAPs since it was based on NOX control and therefore takes into account cost issues concerning ammonia use in the SCR system. The lifetime cost (10 years) for the reduction of NOX from 20 ppm to 2.5 ppm for a typical 270 MW plant was estimated as $12,970,970 for the SCONOx system and $17,882,560 for an SCR system. This analysis would need to be significantly adapted to be used constructively in model turbine cost analyses.

XONON

A cost comparison of the XONON system was provided by Catalytica Combustion Systems. The comparison consisted of estimates for DLN (dry low NOX), DLN + SCR (selective catalytic reduction), and XONON for controlling NOX from two different turbine models. As with the SCONOx information, the use of ammonia is a cost consideration that needs to be excluded when considering the cost of the XONON system.

Lean pre-mix (LPM) Combustors

Cost information for lean pre-mix combustors was taken from the "Alternative Control Techniques Document -- NOX Emissions from Stationary Gas Turbines" (ACT). The incremental capital costs for LPM units relative to diffusion flame units are provided for eight turbines in the ACT. A regression formula was developed where the incremental capital cost is a function of turbine rating (MW). This relationship is as follows:

$$\text{Incremental capital cost (1990\$)} = 21454.3 * \text{MW} + 408431; \; r^2 = 0.981$$

It is not expected that the maintenance requirements for an LPM unit will be different than for a standard design; therefore, the incremental capital cost is the only cost to be considered in calculating annual costs. According to the ACT, retrofit costs are 40 to 60 percent greater than new installation costs.

Golder Associates Inc.

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Gainesville, FL 32607
Telephone (352) 336-5600
Fax (352) 336-6603

Golder Associates

July 28, 2009

0938-7541

Florida Department of Environmental Protection
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

RECEIVED
JUL 29 2009
BUREAU OF AIR REGULATION

Attention: Alvaro A. Linero, Program Administrator

RE: DEP FILE NO. 0930104-014-AC
BERMAN ROAD AND CLAY FARMS LANDFILLS
OKEECHOBEE LANDFILL, INC.
WASTE MANAGEMENT, INC. OF FLORIDA

Dear Mr. Linero:

Okeechobee Landfill, Inc. (OLI) and Golder Associates Inc. (Golder) met with you on June 22, 2009, to discuss additional information requirements for the air construction permit application for additional flares and turbines along with the Lo-Cat sulfur removal system at the Berman Road and Clay Farms Landfills (Okeechobee Landfill). OLI also received e-mails from you on July 2, 2009, requesting additional information to complete the best available control technology (BACT) analysis for the combustion turbines (CTs) being proposed by OLI. Specifically, you have requested additional information for the Solar Mercury 50 turbine and referenced the landfill gas to energy (LFGTE) project at the University of New Hampshire where a Mercury 50 turbine is being installed. You have also referenced the Ridgewood Power facilities LFGTE project in Rhode Island where selective catalytic reduction (SCR) is proposed to control nitrogen oxide (NO_x) emissions from a landfill gas (LFG)-fired CT. Golder has collected additional information on these projects and summarizes the following findings for your consideration. We also provide supplemental information and reiterate previous information submitted to the Florida Department of Environmental Protection (FDEP) on behalf of OLI.

University of New Hampshire Landfill Gas Project, NH

The New Hampshire Department of Environmental Services granted both a prevention of significant deterioration (PSD) and nonattainment new source review (NSR) permit to the University of New Hampshire (UNH) to construct and operate a LFGTE facility, which includes a LFG-fired Solar Mercury 50 CT. NO_x emissions from the turbine are subject to lowest achievable emission rate (LAER) and limited to 5 parts per million volume (ppmv) corrected to 15-percent oxygen (@15% O_2).

The UNH LFGTE facility will use 7,000 standard cubic feet per minute (scfm) of LFG generated at the Turnkey Landfill located 12.5 miles away. The raw LFG from the landfill, which has a heating value of approximately 500 British thermal units per standard cubic foot (Btu/scf), will be extensively treated prior to being burned in the CT at the facility. The dirty, low-energy gas will first be treated at a processing plant to remove moisture, sulfur compounds, siloxanes, volatile organic compounds (VOCs), O_2, and carbon dioxide (CO_2). This processing plant contains treatment that is much more extensive than a siloxane removal system in our current BACT review. Treated gas leaving the processing plant will be dry with heating value of 810 to 950 Btu/scf, which is nearly natural gas quality.

Note that Solar typically guarantees NO_x emissions for 5 parts per million (ppm) @15% O_2 for natural gas-fired Mercury 50 turbines and 25 ppm @15% O_2 for LFG-fired Mercury 50 turbines.

Based on information available on the Internet, the UNH LFGTE processing plant cost is $18 million. The Mercury 50 turbine at the UNH is limited to NO_x of 5 ppm @15% O_2, but the project does not consider any post-combustion NO_x control system like SCR. The primary reason UNH and the turbine manufacturer believe this limit is achievable is because of the expensive pre-combustion gas processing to convert the LFG to natural gas quality. However, the UNH LFGTE facility is not operational yet and no operational data are available.

Ridgewood Power Facility LFGTE Project, Johnson, RI

The Rhode Island Department of Environmental Management (RIDEM) Office of Air Resources issued a preliminary determination in March 2009, and has now issued a final permit, to construct and operate five Solar Taurus 60 LFG-fired CTs at the existing Ridgewood Power facility owned by Rhode Island Central Genco, LLC. This project is also subject to nonattainment NSR permitting and the NO_x emissions from the CTs are subject to LAER. NO_x emissions from each turbine are controlled by SCR and are limited to 25 ppm @15% O_2.

According to RIDEM Office of Air Resources, 25 ppm @15% O_2 is the most stringent emission limitation required by any preconstruction permit for a LFG-fired engine project, which is also the BACT guideline of the South Coast Air Quality Management District and the Bay Area Air Quality Management District in California for NO_x emissions from a LFG-fired turbine. Table 1 of the preliminary determination (see Attachment A) issued by the Office of Air Resources presents the NO_x limitations of recently permitted LFG-fired turbines. As shown, the NO_x emissions limit for the most recently permitted Solar Centaur is 42 ppm @15% O_2, the same limit proposed by OLI for the proposed Solar Centaur CTs.

An important conclusion presented in the preliminary determination is that the Solar Mercury 50 turbine is unsuitable for the project. This is the only commercially available LFG-fired turbine for which a 25 ppm @15% O_2 warranty is available from the manufacturer. However, no details are available regarding the reasons the Mercury 50 was considered unsuitable. Rhode Island Central Genco has chosen the Solar Taurus turbines and proposed to meet the 25 ppm NO_x LAER emission limit by using SCR and treating the LFG to remove siloxanes and sulfur prior to burning in the CTs.

The Office of Air Resources has also stated in the preliminary determination that they are unaware of any successful installation of SCR in a LFG application.

Since the project has not been constructed yet, no operational data are available. Further, according to Solar, no equipment for this project has yet been ordered.

Review of Information

The following conclusions are drawn based on research on the above projects and other related documents:

- Currently there are no operational data available for a LFG-fired Mercury 50 turbine.
- The NO_x emissions guarantee for a LFG-fired Mercury 50 turbine is 25 ppm @15% O_2. A lower NO_x limit has been permitted only for a Mercury 50 using pipeline quality gas (treated landfill gas).

- LAER for NO_x from a LFG-fired turbine is 25 ppm based on vendor guarantee on a Mercury 50. Since this project is not yet operational, it is not known whether it can be achieved in practice.
- The lowest permitted NO_x emission rate for a LFG-fired turbine other than a Mercury 50 is 32 ppm @15% O_2.
- The most recent permitted NO_x emission rate for a Solar Centaur LFG-fired turbine is 42 ppm @15% O_2.
- SCR has been proposed on a LFG-fired Solar Taurus turbine only to achieve the LAER limit of 25 ppm. It is not known whether this limit can be achieved in practice.

The request for additional information (RAI) response sent to the FDEP regarding the Okeechobee landfill project included cost analysis for adding SCR to control NO_x emissions from the proposed Solar Centaur and Solar Titan turbines. This cost analysis (see Table 7 of the April 7, 2009 RAI response) assumed an overly conservative SCR NO_x control efficiency of 90 percent, which means the Centaur 40 turbine NO_x emissions were assumed to be reduced to 4.2 ppm from 42 ppm and the Titan 130 turbine NO_x emissions were assumed to be reduced to 7.2 ppm from 72 ppm. No LFG-fired turbines have been permitted with lower than 25 ppm NO_x emissions limit, even those with SCR.

Note that if the SCR cost analysis for the OLI turbines were based on a controlled NO_x limit of 25 ppm, the cost effectiveness numbers in dollars per ton ($/ton) of NO_x reduction would be significantly higher. To demonstrate this, a revised Table 7 is attached, which is a revised version of the original Table 7 submitted with the April 7, 2009 RAI response.

In the April 7 RAI response, Golder presented a detailed cost analysis for a siloxane removal system for the design LFG flow of the landfill, SCR for NO_x control from each turbine, and an oxidation catalyst system for CO control from each turbine. These costs were summarized in Table 7 to calculate the cost effectiveness numbers for different scenarios such as one Titan turbine, one Centaur turbine, one Titan and four Centaurs for the first phase of the project, and one Titan and fifteen Centaurs for the full project buildout. The cost effectiveness numbers presented in the April 7th version of Table 7 were for both NO_x and CO emissions reduction by an overly conservative 90 percent and for an annualized (spread over 20 years at 7 percent interest) cost of $7.3 million per year for the first phase and $20 million per year for the full project. The annualized costs calculated were $1.2 million for a siloxane removal system, $1.17 million for the SCR system for a Titan turbine, and $780,000 for the SCR system for a Centaur turbine. The initial capital investment was $15 million for one siloxane removal system and five SCRs just in the first phase of the project.

In the June 4, 2009 RAI response, Golder explained why the SCR basic equipment costs considered for the Titan and Centaur turbines are reasonable. In support of the siloxane removal system cost, Golder has collected information from Green Energy Solutions (GES) (www.gesbyparker.com), which is attached with this letter (Attachment B). According to GES, the cost of siloxane removal is 0.2 to 0.6 cents per kilowatt-hour (kWh), which is $1.13 million to $3.39 million for the proposed 64.5-megawatt (MW) Okeechobee Landfill project. Golder used a basic equipment cost of $0.96 million and a total capital investment of $2.27 million for the siloxane removal system considered for the Okeechobee Landfill. Therefore, the siloxane removal system costs presented in the June 4 response are confirmed.

As shown in the attached revised Table 7, the cost effectiveness to control NO_x emissions using SCR is $29,000 per ton of NO_x in the first phase of the project, which is based on controlling the NO_x emissions to the manufacturer's guaranteed level of 25 ppm @15% O_2. These costs are excessive and would render this 64-MW renewable energy project economically unviable.

Based on the findings of the information search, Golder requests the following to be considered:

- The Solar Mercury 50 turbine is untested at this time and is not suitable for the Okeechobee Landfill project. OLI does not want to use a new brand of turbines for which no operational data are available. The Mercury 50 has been used as LAER, but was based on pipeline-quality gas. Also, siloxane removal systems are required for the Mercury 50, but OLI is not sure if they will work. The Mercury 50 has a recuperator system, whereas the Titan and Centaurs do not. Waste Management (WM), the parent company of OLI, previously tried to operate the Saturn turbines with recuperator systems and they did not work, and OLI is not willing to use those types of turbines again until they are proven. Since OLI is proposing a phased PSD project, BACT will have to be re-evaluated for NO_x for later phases (every 7 years as necessary); the Mercury 50 will be evaluated as part of the NO_x BACT at that time, which may have a proven track record at that time that may result in a different BACT determination.
- SCR is not suitable for LFG-fired turbines. No data are available on a successful installation of SCR on a LFG-fired turbine. NO_x emissions from the Okeechobee Landfill project are subject to BACT, not LAER, and OLI should not be forced to use a control technology that is both untested and cost prohibitive.
- WM operates numerous LFGTE facilities nationwide and siloxane poses no problem to turbine operation for turbines that do not have recuperators. Siloxane is a major concern for application of SCR, but not for the turbines without recuperators.
- The Virginia Department of Environmental Quality has recently issued a draft permit to King George Landfill, Inc. to construct and operate a landfill gas electric generation facility in King George, VA, which will consist of four Solar Centaur turbines with NO_x emissions limited to 96 ppm @15% O_2. NO_x emissions limits proposed for the Okeechobee Landfill turbines are 72 ppm for the Titan and 42 ppm for each of the fifteen Centaurs.
- The only turbine at a LFGTE application with a permitted NO_x limit lower than 25 ppm is the Mercury 50 turbine at UNH. However, this turbine will be burning a near natural gas quality gas after a very expensive pretreatment of the LFG. The gas treatment plant at UNH costs $18 million and processes 7,000 scfm of gas. The design flow of Okeechobee Landfill is 32,400 scfm.
- FDEP has approved major power plant applications with NO_x control cost effectiveness figures much higher than $2,500 per ton of NO_x removed. However, these costs are for much larger power plants (i.e., 300 MW to thousands of MW), and thus are much more able to absorb the cost of expensive control equipment. These costs can also be passed on to the electric rate-payer. OLI is a private enterprise proposing small renewable energy projects (20 to 65 MW), and therefore the cost impacts are proportionately higher.
- For OLI, the Lo-Cat sulfur removal system cost and operational costs have greatly increased since the permit application was originally submitted. The Lo-Cat cost is now in the neighborhood of $14 million and operational costs are more than $900,000 just for the chemicals and electricity. Additionally, the Lo-Cat system may require a water treatment plant, which was not included in the original BACT analysis. Having to install a SCR system with

an associated siloxane removal system at OLI will render the project economically infeasible. This would stop a project that is a renewable energy source, which would affect Florida's ability to meet its renewable energy goals.

I hope that the above information will be helpful to you in making the BACT determination for the proposed LFG-fired turbines at the Okeechobee Landfill. If you have any questions, please do not hesitate to call me at (352) 336-5600.

Sincerely,

GOLDER ASSOCIATES INC.

David A. Buff

David A. Buff, P.E., Q.E.P.
Principal Engineer

DB/SKM/tz

Enclosures

cc: D. Thorley, WM
M. Lersch, WM
J. Christiansen, WM

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TABLE 7 (Revised July 23, 2009)
COST EFFECTIVENESS CALCULATION FOR NO_x CONTROL SCENARIOS, OKEECHOBEE LANDFILL FACILITY

			NO_x Control Scenarios			
Cost Items	**Comments/Reference**	**Value**	**1 Titan 130**	**1 Centaur 40**	**1 Titan 130 + 4 Centaur 40**	**1 Titan 130 + 15 Centaur 40**
Annualized Cost for Siloxane System ($/yr)	Table 1	1,213,219	1,213,219	1,213,219	1,213,219	1,213,219
Annualized Cost of SCR System for Titan 130 ($/yr)	Table 2	1,165,516	1,165,516	--	1,165,516	1,165,516
Annualized Cost of SCR System for Centaur 40 ($/yr)	Table 3	777,761	--	777,761	3,111,045	11,666,420
Total Annualized Cost (AC)($/yr):			2,378,735	1,990,980	5,489,780	14,045,155
<u>Uncontrolled NO_x Emissions (TPY):</u>						
Titan 130 Baseline NO_x Emissions (TPY):	72 ppm, Emission Guarantee	203.0	203.0	--	203.0	203.0
Centaur 40 Baseline NO_x Emissions (TPY):	42 ppm, Emission Guarantee	35.0	--	35.0	140.0	525.0
<u>Controlled NO_x Emissions (TPY):</u>						
Titan 130 Controlled NO_x Emissions (TPY):	Assumed 25 ppm BACT Limit		70.5	--	70.5	70.5
Centaur 40 Controlled NO_x Emissions (TPY):	Assumed 25 ppm BACT Limit		--	20.8	83.3	312.5
Total Reduction in NO_x Emissions (TPY):	Baseline - Controlled		132.5	14.2	189.2	345.0
Cost Effectiveness (AC/Total Reduction)	$ per ton Removed				29,019	40,709

Professional Engineer Certification

1. Professional Engineer Name: **David A. Buff**
Registration Number: **19011**

2. Professional Engineer Mailing Address...
Organization/Firm: **Golder Associates Inc.****
Street Address: **6026 NW 1st Place**
City: **Gainesville** State: **FL** Zip Code: **32607-6018**

3. Professional Engineer Telephone Numbers...
Telephone: **(352) 336-5600** ext. **21145** Fax: **(352) 336-6603**

4. Professional Engineer E-mail Address: **dbuff@golder.com**

5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐ *, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.*

(4) If the purpose of this application is to obtain an air construction permit (check here ☒ *, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here* ☐ *, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.*

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐ *, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.*

David a. Buff
Signature

7/28/09
Date

(Seal)

---

* Attach any exception to certification statement.

**Board of Professional Engineers Certificate of Authorization #00001670.

ATTACHMENT A

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR RESOURCES

PRELIMINARY DETERMINATION FOR A MAJOR MODIFICATION OF THE RIDGEWOOD POWER FACILITY

MARCH 2009

NAME OF SOURCE: Rhode Island Central Genco, LLC

LOCATION: 65 Shun Pike
Johnston, Rhode Island

CONTACT: Kevin Hubanks
Ridgewood Power Management
160B Guthrie Lane, Suite 3
Brentwood, California 94513
(201) 447-9000

APPLICATION PREPARED BY: GZA GeoEnvironmental, Inc.
380 Harvey Road
Manchester, NH 03103
(603) 623-3600

OWNER OF SOURCE: Rhode Island Central Genco, LLC

I. Description of the Proposed Project

Rhode Island Central Genco, LLC (RICG) proposes to install five, landfill gas-fired combustion turbines and three flares at its existing facility in Johnston, RI.

The proposed project will include five Solar Taurus 60 landfill gas-fired combustion turbines. Each combustion turbine has a nominal electrical output of 6 MWe. The hot flue gases from each combustion turbine pass through a heat recovery steam generator (HRSG) to generate steam. The steam produced by the five HRSGs will be used to power a single steam turbine. The design rating for the steam turbine is approximately 11 MW of electrical power. The total landfill gas consumption for the five combustion turbines is approximately 12,200 scfm.

Additionally, the proposed project will include a John Zink Ultra Low Emissions (ULE) flare. This flare will be used to treat the purge gas from regenerating the adsorbent in the landfill gas treatment system that is part of this project. The flare will use up to 630 scfm of landfill gas for a purge gas stream of up to 6900 scfm. The flare is expected to operate continuously..

The proposed project will also include two John Zink enclosed flares. These flares are to serve as backup flares to provide additional landfill gas control capacity in the event any of the power generating equipment (engines and/or turbines) is out-of-service. Each flare is capable of treating 3000 scfm of landfill gas.

The existing facility consists of nine Waukesha, two Deutz and four Caterpillar landfill gas fired engine-generator sets. The Waukesha and Deutz engine-generator sets will be permanently removed. Each Caterpillar engine-generator set consists of a 2229 HP engine and a 1600 kWe generator. Each Caterpillar engine consumes approximately 500 scfm of landfill gas when operating at maximum capacity.

Each combustion turbine will be equipped with Selective Catalytic Reduction (SCR) to limit emissions of nitrogen oxides to 25 ppmv corrected to 15% O_2. The entire facility, including the existing engines, will have a nominal electrical output of approximately 51 MW and is capable of combusting approximately 15,000 scfm of landfill gas.

The facility is located within the property of the Central Landfill, 65 Shun Pike. The Central Landfill, owned and operated by the Rhode Island Resource Recovery Corporation, is an integrated solid waste management facility located on a site comprising approximately 1100 acres. The primary solid waste management activity at the site is the operation of a municipal solid waste landfill.

A large quantity of landfill gas is generated at the Central Landfill from the anaerobic decomposition of the municipal solid waste. The landfill gas is collected in a number of vertical extraction wells and horizontal collection trenches and then piped to the Ridgewood facility. Flares control any excess landfill gas that is not used by Ridgewood.

The landfill gas is treated prior to combustion. The landfill gas treatment system will remove siloxanes and other contaminants that would interfere with the SCR system. The gas treatment system filters, dewaters and compresses the landfill gas. This gas treatment system meets the requirements of 40 CFR 60, Subpart WWW (40 CFR 60.752(b)(2)(iii)(C)). It will also remove sulfur compounds, down to a concentration of 100 ppmv, as hydrogen sulfide.

Additional sources of air pollution emissions will include a four cell wet cooling tower for the steam turbine condenser and an auxiliary cooling tower for the gas treatment and compression system.

Potential Emissions from the Existing Facility

POLLUTANT	LB/HR/ENGINE			TONS/YR
	WAUKESHA	CATERPILLAR	DEUTZ	
Nitrogen oxides	5.29[1]	2.46	2.30	148.1
Carbon monoxide	10.58	13.51	9.56	691.2
PM-10/Particulates	1.02	0.49	0.38	47.7
VOC/Nonmethane hydrocarbons	2.65	0.76	0.62	111.7
Sulfur dioxide[2]	17.26	15.53	12.57	1062.59
Hydrogen sulfide[2]	0.52	0.19	0.15	25.14
Hydrogen chloride	4.18 E-02	3.74 E-02	3.02 E-02	2.38

[1] Nitrogen oxides emissions are limited to 14,166 lbs per month
[2] Assumes 3000 ppm H_2S in landfill gas

The existing facility is classified as a major stationary source under the requirements for major stationary sources in nonattainment areas (Section 9.4 of Air Pollution Control Regulation No. 9) because potential emissions of nitrogen oxides and volatile organic compounds exceed 50 tons per year. The existing facility is also classified as a major stationary source under the requirements for major stationary sources in attainment or unclassifiable areas, also known as the PSD requirements (Section 9.5 of Air Pollution Control Regulation No. 9) because potential emissions of carbon monoxide exceed 100 tons per year and potential emissions of sulfur dioxide exceed 250 tons per year.

The proposed project is considered a major modification because the existing facility is a major stationary source and the emissions increase from the proposed modification of nitrogen oxides (162.1 tpy), carbon monoxide (705.7 tpy) and VOC (41.6) exceed the significant thresholds for those pollutants (25 tpy for nitrogen oxides, 100 tpy for carbon monoxide and 25 tpy for VOC).

Potential Emissions from the Proposed Combustion Turbines

POLLUTANT	LB/HR/TURBINE	TONS/YR
Nitrogen oxides	7.95	159.1
Carbon monoxide	34.86	697.4
PM-10/Particulates	1.90	39.3
VOC/Nonmethane hydrocarbons	1.99	39.9
Sulfur dioxide	2.70	54.1
Ammonia	2.35	47.1
Hydrogen sulfide	0.03	0.6
Hydrogen chloride	0.197	3.9

Potential Emissions from the Proposed Flares

POLLUTANT	LB/HR/FLARE		TONS/YR[1]
	REGEN FLARE	BACKUP FLARE	
Nitrogen oxides	0.52	5.94	3.00
Carbon monoxide	1.25	19.80	8.37
PM-10/Particulates	1.08	1.66	4.73
VOC/Nonmethane hydrocarbons	0.31	0.82	1.65
Sulfur dioxide	0.64	3.04	2.80
Ammonia	-	-	-
Hydrogen sulfide	0.007	0.032	0.03
Hydrogen chloride	0.046	0.22	0.20

[1] Potential emissions from the flares are based on the regen flare emissions, except for nitrogen oxides, carbon monoxide and VOC, where potential emissions are based on the backup flares being used in place of the regen flare for 2000 hours per year.

Potential Emissions from the Existing Remaining Engines

POLLUTANT	LB/HR/ENGINE	TONS/YR
	CATERPILLAR	
Nitrogen oxides	2.46	43.1
Carbon monoxide	13.51	236.7
PM-10/Particulates	0.49	8.58
VOC/Nonmethane hydrocarbons	0.76	13.32
Sulfur dioxide	0.51	8.94
Ammonia	-	-
Hydrogen sulfide	0.0055	0.1
Hydrogen chloride	0.0375	0.66

Facility-Wide Potential Emissions from the Modified Facility

POLLUTANT	TONS/YR
Nitrogen oxides	205.2
Carbon monoxide	942.5
PM-10/Particulates	52.6
VOC/Nonmethane hydrocarbons	54.9
Sulfur dioxide	65.8
Ammonia	47.1
Hydrogen sulfide	0.73
Hydrogen chloride	4.8

II. Requirements for Major Stationary Sources in Nonattainment Areas

The nonattainment area provisions of APC Regulation No. 9 are applicable to the pollutants nitrogen oxides (NO_x) and volatile organic compounds (VOC). The following is a discussion of the various provisions of Section 9.4 of APC Regulation No. 9 and how the applicant has demonstrated compliance with those provisions.

A. Lowest Achievable Emission Rate (LAER) (Subsection 9.4.2(a))

Subsection 9.4.2 (a)(2) requires that a major modification must meet an emission limitation that is considered the lowest achievable emission rate (LAER). The lowest achievable emission rate will be based on technological factors and can be in the form of a numerical emission standard or a design, operational or equipment standard. It is the responsibility of the applicant to present and defend the technology chosen to represent LAER.

LAER is the most stringent emission limitation derived from either of the following:

(1) the most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or

(2) the most stringent emission limitation achieved in practice by such class or category of source.

By definition LAER can not be less stringent than any applicable new source performance standard (NSPS).

- *Combustion Turbines*

1. Nitrogen Oxides

In California, BACT is defined as the most stringent limitation or control technique:

1) which has been achieved in practice,
2) is contained in any State Implementation Plan (SIP) approved by the United States Environmental Protection Agency, or
3) any other emission control technique, determined by the Air Pollution Control Officer to be technologically feasible and cost effective.

This definition of BACT is very similar to the definition of LAER contained in APC Regulation No. 9.

The BACT Guidelines of the South Coast Air Quality Management District and the Bay Area Air Quality Management District in California for nitrogen oxides emissions from a landfill gas fired turbine are 25 ppmv, dry corrected to 15% O_2. Additionally, the California Air Resources Board has issued a guidance document for permitting electrical generation technologies. The document, entitled "Guidance for the Permitting of Electrical Generation Technologies", includes recommendations for Best Available Control Technology (BACT) for engines and turbines using waste gas.

The Air Resources Board has recommended a NO_x emission level of 25 ppmvd corrected to 15% O_2 as representing BACT for gas turbines using waste gas.

The Office of Air Resources believes that a nitrogen oxides emission limit of 25 ppmvd corrected to 15% O_2 is the most stringent emission limitation required by any rule or regulation.

As part of the review of this permit application, the Office of Air Resources reviewed several recently issued permits by state and local air pollution control agencies for landfill gas-fired engine projects. Table 1 summarizes our findings.

Table 1
NO_x Emission Limitations for Recently Permitted Projects

FACILITY	TURBINE	DATE	STATE	NO_X
Chiquita Canyon Landfill	Solar Mercury 50		CA	25 ppm@15%O_2
Gas Recovery Systems, Inc.	Solar Taurus 60	3/2007	MI	32 ppm@15% O_2
Bethlehem Renewable Energy	Solar Taurus 60	12/2006	PA	32 ppm@15% O_2
Resource Technology Corporation	Solar Taurus 60	9/2002	IL	32 ppm@15% O_2
DQE Services-Monmouth Energy	Solar Taurus	6/2001	NJ	32 ppm@15% O_2
MCUA Landfill Gas Project	Solar Taurus 60	3/1999	NJ	32 ppm@15% O_2
Green Knight/Plainfield	Solar Centaur	8/2001	PA	35 ppm@15% O_2
Gas Recovery Systems, Inc.	Solar Centaur T-4500	12/2006	MI	42 ppm@15% O_2
Resource Technology Corporation	Solar Taurus 60	9/2001	IL	65 ppm@15% O_2
Riverview Energy Systems	Solar Centaur T-4701	2/2005	MI	71 ppm@15% O_2
Riverview Energy Systems	Solar Centaur T-4701	5/2002	MI	71 ppm@15% O_2
Resource Technology Corporation	Solar Titan 130	12/01	IL	75 ppm@15% O_2
Resource Technology Corporation	Solar Taurus 60	3/2001	IL	150 ppm@15% O_2
Waste Management of Illinois	Solar Centaur	1995/1999	IL	

The Office of Air Resources believes that a nitrogen oxides emission limit of 25 ppmvd corrected to 15% O_2 is the most stringent emission limitation required by any preconstruction permit.

The applicant maintains that the only commercially available turbine for which the manufacturer will warranty a nitrogen oxides emission limitation of 25 ppmvd corrected to 15% O_2 when firing landfill gas is the Solar Mercury 50. The applicant has determined that the Mercury 50 turbine is unsuitable for this project. The Department, based on its review, has found no evidence that an emission limitation lower than 25 ppmvd corrected to 15% O_2 has been achieved in practice on a consistent basis.

Therefore the Office of Air Resources believes that LAER for the proposed gas turbines is a NO_x emission limitation of 25 ppmvd corrected to 15% O_2.

The applicant proposes to meet this emission limitation by using selective catalytic reduction (SCR) to reduce the concentration of NOx in the exhaust gases from the turbines to a concentration of 25 ppmvd corrected to 15% O_2. Selective catalytic reduction (SCR) is a post combustion or flue gas treatment technique. The process involves the injection of ammonia into the flue gases upstream of a catalyst bed. The ammonia, mixed with the combustion products, passes over a catalyst bed and the nitrogen oxides (NO_x) in the flue gas are reduced to nitrogen (N_2) and water vapor (H_2O).

The Department is not aware of any successful installations of SCR in a landfill gas application. Landfill gas contains siloxanes, a commercially produced, man-made compound found in consumer products. Combustion of landfill gas containing siloxanes produces silica which can blind catalyst surfaces. To make it possible for the SCR installation to be successful, the applicant proposes to install a landfill gas treatment system to remove landfill gas contaminants such as siloxanes and sulfur.

LAER for nitrogen oxides is therefore represented by combustor design and good combustion practices with post combustion treatment (SCR). The emission limit chosen to represent LAER for NO_x is:

25 ppmvd corrected to 15% O_2

2. Volatile Organic Compounds

The most stringent control technology identified for reducing VOC emissions was catalytic oxidation. As stated previously, landfill gas contains impurities that, when combusted, have been shown to poison catalyst based post combustion treatment technologies such as SCR and an oxidation catalyst. It is the Office of Air Resources' position that there is no technically feasible, post combustion treatment technology for reducing volatile organic compound emissions, from landfill gas-fired turbines. We are not aware of any successful installation of post combustion treatment technologies to landfill gas-fired turbines. Therefore, the technically feasible control techniques for VOC emissions from landfill gas fired turbines are combustor design and good combustion practices to minimize NMHC emissions.

The Department believes that the only rule or regulation that limits VOC emissions from landfill gas-fired turbines is the New Source Performance Standard for Municipal Solid Waste Landfills (40 CFR 60, Subpart WWW). If the turbine is used as a "control system" for collected landfill gas, VOC emissions must be either reduced by 98 weight percent or the outlet VOC concentration must be less than 20 parts per million by volume, dry basis as hexane corrected to 3 percent oxygen.

As part of the review of this permit application, the Office of Air Resources reviewed several recently issued permits by state and local air pollution control agencies for landfill gas-fired engine projects. Table 2 summarizes our findings:

Table 2
VOC Emission Limitations for Recently Permitted Projects

FACILITY	TURBINE	DATE	STATE	VOC
Green Knight/Plainfield	Solar Centaur	8/2001	PA	10 ppmvd@15%O_2 (as methane)
DQE Services-Monmouth Energy	Solar Taurus	6/2001	NJ	10 ppmvd@15%O_2 (as methane)
MCUA Landfill Gas Project	Solar Taurus 60	3/1999	NJ	5 ppmvd@15%O_2 (as hexane)
Bethlehem Renewable Energy	Solar Taurus 60	12/2006	PA	20 ppmvd@3%O_2 (as hexane)
Riverview Energy Systems	Solar Centaur T-4701	2/2005	MI	20 ppmvd@3%O_2 (as hexane)
Riverview Energy Systems	Solar Centaur T-4701	5/2002	MI	20 ppmvd@3%O_2 (as hexane)
Resource Technology Corporation	Solar Titan 130	12/2001	IL	20 ppmvd@3%O_2 (as hexane)
Resource Technology Corporation	Solar Taurus 60	3/2001	IL	20 ppmvd@3%O_2 (as hexane)
Gas Recovery Systems, Inc.	Solar Taurus 60	3/2007	MI	0.08 lbs/hr
Resource Technology Corporation	Solar Taurus 60	9/2002	IL	1.71 lbs/hr
Resource Technology Corporation	Solar Taurus 60	9/2001	IL	1.64 lb/hr
Gas Recovery Systems, Inc.	Solar Centaur T-4500	12/2006	MI	2.5 tpy
Waste Management of Illinois	Solar Centaur	1995/1999	IL	1.9 lb/hr

A VOC emission rate of 5 ppmvd corrected to 15% O_2 (as hexane) is roughly equivalent to 27 ppmvd corrected to 15% O_2 (as methane). A VOC emission rate of 20 ppmvd corrected to 3% O_2 (as hexane) is roughly equivalent to 35 ppmvd corrected to 15% O_2 (as methane). Therefore the most stringent VOC emission rate required in any preconstruction permit is 10 ppmvd corrected to 15% O_2 (as methane).

Based on vendor guarantees the applicant has proposed that the emission limitation that represents LAER for VOC is 10 ppmvd corrected to 15% O_2 (as methane) measured at full load operation. This is consistent with the lowest reported values for recently permitted projects.

LAER for volatile organic compounds is therefore represented by combustor design and good combustion practices to minimize VOC emissions. The emission limit chosen to represent LAER for VOC is:

10 ppmvd corrected to 15% O_2 (as methane)

- *Flares*

The regen flare is to be an Ultra Low Emission (ULE) flare. ULE flares have the lowest NO_x emissions and the highest VOC destruction efficiency compared to the alternative flare types. Therefore it is the Department's position that LAER for nitrogen oxides and volatile organic compounds from flaring is represented by the use of ultra low emission flares. The emission limits chosen to represent LAER are:

Nitrogen oxides:	*0.025 lb/MMBTU*
Volatile Organic Compounds:	*99% destruction efficiency*

The backup flares will only be used in the event that an engine, turbine or the regen flare is not operating. The applicant has proposed to use enclosed flares instead of ULE flares because the flares are to be used as backup devices and are not expected to be used on a regular basis. Enclosed flares have a slightly lower VOC destruction efficiency and higher emissions of NO_x and CO than ULE flares.

The capital cost of an ULE flare can be twice that of a comparably sized enclosed flare. ULE flares also tend to be less reliable than enclosed flares.

Although enclosed flares have higher emissions of NO_x, CO and VOC than ULE flares, the emissions will be lower than that of the engines or turbines that they would backup. The enclosed flare, if needed as a backup for the regen flare, will have higher emissions of these pollutants. Based on reliability estimates for a ULE flare, the applicant estimates that the ULE flare would be out of service for no more than 2000 hours/year.

Considering the difference in capital costs, reliability issues and the fact that the flares will be used as backup devices, it is the Department's position that enclosed flares are an acceptable choice for the backup flares. The emission limits chosen to represent LAER for an enclosed flare are:

Nitrogen oxides:	*0.06 lb/MMBTU*
Volatile Organic Compounds:	*98% destruction efficiency*

B. Compliance Status of Existing Major Stationary Sources (Subsection 9.4.2(b))

Subsection 9.4.2 (b) requires that the applicant certify that all existing major stationary sources owned or operated by the applicant located within the state are in compliance with all applicable state and federal air pollution rules and regulations under the Clean Air Act and federally enforceable compliance schedules.

The applicant, Rhode Island Central Genco, LLC, has provided a certification that all of the facilities owned or operated by Rhode Island Central Genco, LLC or operated under common control with Rhode Island Central Genco, LLC are in compliance with all applicable state and federal air pollution rules and regulations under the Clean Air Act and federally enforceable compliance schedules. The Shun Pike facility is the only facility owned or operated by Ridgewood in Rhode Island.

C. Emission Offsets (Subsection 9.4.2(c))

Subsection 9.4.2 (c) requires the applicant to provide evidence that the total tonnage of emissions of the nonattainment air pollutant allowed from the proposed new source shall be offset by a greater reduction in the actual emissions of such air pollutant from the same or other sources.

Rhode Island Central Genco, LLC has entered into a purchase agreement for 117 tons of NO_x offsets and 36 tons of VOC offsets to satisfy this requirement. The NO_x offsets were generated by the voluntary installation of an SCR system at the Medical Area Total Energy Plant (MATEP) in Boston, MA and the shutdown of equipment associated with the Lawrence RDF and the Ogden Martin Systems of Haverhill plants located in Lawrence, MA. The VOC offsets were generated by the shutdown of the Quebecor Printing Providence, Inc. facility in Providence, RI in 1998.

Subsection 9.4.2 (d) lists 6 criteria that emission offsets must satisfy. The emission offsets must:

> *(1) be approved by the Director, and be part of a federally enforceable permit, or part of an operating permit issued pursuant to 40 CFR Part 71 or under regulations approved pursuant to 40 CFR Part 70, or made part of the federally approved State Implementation Plan.*

The Massachusett Department of Environmental Protection (MADEP) issued BWP AQ 21 Final Approval to the Medical Area Total Energy Plant (MATEP) facility. This permit limits allowable NO_x emissions from the facility. The voluntary installation of air pollution controls (selective catalytic reduction) is federally enforceable through this permit.

The Massachusetts Department of Environmental Protection (MADEP) emission trading and banking rule (310 CMR 7.00: Appendix B) is part of the Massachusetts State Implementation Plan (SIP). Emission Reduction Credit Approvals issued pursuant to this rule are federally enforceable. MADEP issued Approval Numbers MBR-99-ERC-007 for the MATEP project, MBR-98-ERC-003 for the Lawrence RDF plant shutdown and MBR-99-ERC-009 for the Ogden Martin Systems of Haverhill Plant shut down. Therefore all of these emission reduction credits are federally enforceable.

The Rhode Island Department of Environmental Management, Office of Air Resources approved the creation and banking of 708.5 tons of VOC from the shutdown of the Quebecor Printing Providence Inc. facility pursuant to the Banking of Emissions section of Air Pollution Control Regulation No. 9. Air Pollution Control Regulation No. 9 is part of the Rhode Island State Implementation Plan.

(2) be federally enforceable prior to the issuance of the Major Source Permit

BWP AQ 21 and MBR-99-ERC-007 for the MATEP project were issued on January 6, 2000. MBR-98-ERC-003 for the Lawrence RDF Plant was issued on September 30, 1999. MBR-99-ERC-009 for the Ogden Martin Systems of Haverhill facility was issued on March 7, 2000.

The creation and banking of 708.5 tons of VOC from the shutdown of the Quebecor Printing Providence Inc. facility was approved on November 8, 2001.

(3) actually occur at the source of the offsets prior to the start-up of the new source

The installation of selective catalytic reduction at the MATEP facility has already occurred.

The shutdowns of the Lawrence RDF Plant, the Ogden Martin Systems of Haverhill facility and the Quebecor Printing Providence Inc. facility have already occurred.

(4) be at an offset ratio of at least 1.2 to 1

The net emissions increase of nitrogen oxides from the proposed modification to the Ridgewood facility is 96.64 tons per year. Rhode Island Central Genco, LLC must purchase 116 tons of offsets. Their planned purchase is 117 tons. This will be a requirement in any permit issued pursuant to this preliminary determination. The offset ratio is 117/96.64 = 1.2.

The net emissions increase of volatile organic compounds from the proposed modification to the Ridgewood facility is 29.76 tons per year. Rhode Island Central Genco, LLC must purchase 36 tons of offsets. This will be a requirement in any permit issued pursuant to this preliminary determination. The offset ratio is 36/29.76 = 1.2.

(5) be obtained from a source in the same nonattainment area or in another nonattainment area provide that:

a) *The other nonattainment area has an equal or higher nonattainment area classification than the area in which the source is to be located; and*

b) *Emissions from such other area contribute to a violation of the national ambient air quality standard in the nonattainment area in which the source is to be located.*

The MATEP facility, Lawrence RDF Plant and Ogden Martin Systems of Haverhill facility are located in an area designated serious nonattainment with respect to the one-hour standard for ozone and moderate nonattainment with respect to the eight-hour standard for ozone. These are the same classifications as the entire state of Rhode Island.

In Chapter V of EPA's proposed rule to "Reduce Interstate Transport of Fine Particulate Matter and Ozone" (69 FR 4565, dated January 30, 2004), EPA provides a Table V-3, titled "Upwind States That Contain Emission Sources That Contribute Significantly (Before Considering Cost) to Projected 8-hour Nonattainment in Downwind States" that summarizes the projected downwind counties to which sources in upwind states contribute significantly. This table indicates that sources in Connecticut, Massachusetts, New Jersey, New York, Ohio, Pennsylvania and Virginia contribute to Rhode Island's ozone violation.

The Quebecor Printing Providence Inc. facility was located in Rhode Island.

(6) when considered in conjunction with the proposed emissions increase, have a net air quality benefit in the area.

Since the offset ratio is greater than 1:1 there will be a net reduction in NO_x and VOC emissions.

Therefore all of the requirements of section 9.4.2(c) & 9.4.2(d) pertaining to emission offsets are satisfied.

D. Alternatives Analysis (Subsection 9.4.2(e))

Subsection 9.4.2 (e) requires the applicant to prepare an analysis of alternative sites, sizes, production processes, and environmental control techniques that demonstrate the benefits of the proposed source significantly outweigh the environmental and social cost imposed as a result of its location, construction or modification.

The applicant has satisfied this requirement with the analysis contained in Section 5.0 of the application.

The New Source Performance Standards for Municipal Solid Waste Landfills (40 CFR 60, Subpart WWW) requires that the landfill gas be collected and routed to:

1. An open flare; or,

2. An enclosed combustion device or a control system that reduces VOC emissions by 98%; or,

3. A treatment system that processes the collected gas for subsequent sale or use.

The proposed facility is sighted at the Central Landfill to satisfy this requirement; therefore there is no consideration of alternative sites.

The applicant evaluated two alternative technologies; (1) the use of dedicated pollution control equipment such as a flare; and (2) the use of a reciprocating engine instead of the combustion turbine. This evaluation concluded that the chosen technology (combustion turbine) is superior to each of the identified alternatives in terms of cost and environmental impact.

The project has been sized for five turbines based on the current landfill gas projections for Phase V and the proposed Phase VI. The alternate size analysis concluded that the modular design of the project would allow for future expansion should the markets for renewable power and the availability of gas make a larger plant economically feasible.

E. NO_x Air Quality Impact (Subsection 9.4.2(f))

Subsection 9.4.2 (f) requires that the applicant demonstrate compliance with the conditions in subsections 9.5.2(b)-(d) and 9.5.3(a)-(c) for the pollutant nitrogen oxides. See section III.B-D of this document for a complete discussion of these requirements.

F. Air Toxics Regulation (Subsection 9.4.2(g))

Subsection 9.4.2(g) requires the applicant to demonstrate that the emissions from the proposed facility will not cause an increase in the ground level ambient concentration at or beyond the property line in excess of that allowed by Air Pollution Control Regulation No. 22 ("Air Toxics") and any Calculated Acceptable Ambient Levels. See section III.E of this document for a complete discussion of these requirements.

G. Health Risks from Proposed Air Pollution Sources (Subsection 9.4.2(h))

Subsection 9.4.2 (h) requires the applicant to conduct any studies required by the Guidelines for Assessing Health Risks from Proposed Air Pollution Sources and meet the criteria therein.

The proposed source does not meet the applicability criteria in this document and therefore is not required to perform this type of study.

H. Applicable Air Pollution Control Regulations (Subsection 9.4.2(i))

Subsection 9.4.2 (i) requires the applicant to demonstrate that the facility will be in compliance with all applicable state and federal air pollution control regulations at the time the source commences operation. See section III.G of this document for a complete discussion of these requirements.

III. Requirements for Major Stationary Sources in Attainment or Unclassifiable Areas

The following is a discussion of the various provisions of Section 9.5 of APC Regulation No. 9 and how the applicant has demonstrated compliance with those provisions.

A. Best Available Control Technology (BACT) (Subsection 9.5.2(a))

Subsection 9.5.2 (a) of APC Regulation No. 9 requires that a stationary source shall apply BACT for each pollutant it would have the potential to emit. Best available control technology is defined as "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each air pollutant which would be emitted from any proposed stationary source or modification which the Director, on a case-by-case basis, taking into account energy, environmental and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable state or federal air pollution control rule or regulation. If the Director determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of air emissions standards infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to satisfy the requirement of best available control technology. Such standard shall to the degree possible set forth the emission reduction achievable by implementation of such design, equipment, work practice or operation and shall provide for compliance by means which achieve equivalent results."

The Office of Air Resources requires the use of the "top down" approach in a BACT analysis. The first step in the "top down" approach is to determine, for the source category being evaluated, the most stringent level of control available. If it can be shown that this level of control is technically or economically infeasible, then the next most stringent level of control is determined and similarly evaluated. Such an evaluation would continue until the level of control under consideration could not be ruled out by any technical, environmental or economic considerations.

The purpose of the BACT analysis is to determine the lowest emission limits that can be met by the source, in light of energy, economic and environmental impacts. The following is an evaluation of the applicant's BACT analysis.

- *Combustion Turbines*

1. Carbon Monoxide (CO)

The most stringent control technology identified for reducing CO emissions was catalytic oxidation. As stated previously, landfill gas contains impurities that, when combusted, have been shown to poison catalyst based post combustion treatment technologies such as SCR and an oxidation catalyst. It is the Office of Air Resources' position that there is no technically feasible, post combustion treatment technology for reducing carbon monoxide emissions, from landfill gas-fired turbines. We are not aware of any successful installation of post combustion treatment technologies to landfill gas-fired turbines. Therefore, the technically feasible control techniques for CO emissions from landfill gas fired turbines are combustor design and good combustion practices to minimize CO emissions.

The BACT Guidelines of the South Coast Air Quality Management District and the Bay Area Air Quality Management District in California for carbon monoxide emissions from a landfill gas fired turbine are 130 ppmv, dry corrected to 15% O_2 and 200 ppmv, dry corrected to 15% O_2 respectively. The Pennsylvania DEP's General Permit for landfill gas fired turbines includes a CO emission limitation of 100 ppmv, dry corrected to 15% O_2.

As part of the review of this permit application, the Office of Air Resources reviewed several recently issued permits by state and local air pollution control agencies for landfill gas-fired turbine projects. Table 3 summarizes our findings:

Table 3
CO Emission Limitations for Recently Permitted Projects

FACILITY	TURBINE	DATE	STATE	CO
Green Knight/Plainfield	Solar Centaur	8/2001	PA	28 ppm@15% O_2
Waste Management of Illinois	Solar Centaur	1995/1999	IL	50 ppm@15% O_2
DQE Services-Monmouth Energy	Solar Taurus	6/2001	NJ	72 ppm@15% O_2
MCUA Landfill Gas Project	Solar Taurus 60	3/1999	NJ	72 ppm@15% O_2
Bethlehem Renewable Energy	Solar Taurus 60	12/2006	PA	100 ppm@15% O_2
Chiquita Canyon Landfill	Solar Mercury 50		CA	
Gas Recovery Systems, Inc.	Solar Taurus 60	3/2007	MI	13.2 lbs/hr
Resource Technology Corporation	Solar Taurus 60	9/2002	IL	15.00 lbs/hr
Gas Recovery Systems, Inc.	Solar Centaur T-4500	12/2006	MI	89 tpy
Resource Technology Corporation	Solar Taurus 60	9/2001	IL	34.86 lbs/hr
Riverview Energy Systems	Solar Centaur T-4701	2/2005	MI	15.78 lbs/hr
Riverview Energy Systems	Solar Centaur T-4701	5/2002	MI	15.78 lbs/hr
Resource Technology Corporation	Solar Titan 130	12/01	IL	10.36 lbs/hr
Resource Technology Corporation	Solar Taurus 60	3/2001	IL	9.53 lbs/hr

The most stringent CO emission rate required in any preconstruction permit is 28 ppmvd corrected to 15% O_2. In 2006, the Pennsylvania Department of Environmental Protection reviewed more than 60 stack test results for carbon monoxide emissions from landfill gas-fired turbines. The measured emissions ranged from 15 to 82 ppmvd corrected to 15% O_2. They concluded that since CO emissions from landfill gas fired turbines can vary significantly due to both combustor design and the varying composition of landfill gas, a buffer should be added to the achievable CO emission levels for turbines. They concluded that a CO emission rate of 100 ppmvd corrected to 15% O_2 represents Best Available Technology (BAT). The term "best available technology" is defined in the DEP rules as *"...equipment, devices, methods or techniques as determined by the Department which will prevent, reduce or control emissions of air contaminants to the maximum degree possible and which are available or may be made available...".*

Based on vendor guarantees the applicant has proposed that the emission limitation that represents BACT for CO is 100 ppmvd corrected to 15% O_2 measured at full load operation.

The Office of Air Resources has concluded that BACT for carbon monoxide is represented by combustor design and good combustion practices to minimize CO emissions. The emission limit chosen to represent BACT for CO is:

100 ppmvd corrected to 15% O_2

2. Sulfur dioxide (SO_2)

Landfill gas can contain a variety of sulfur compounds. The only means of controlling SO_2 emissions from a landfill gas fired turbine is to limit the sulfur content of the landfill gas. Post combustion control techniques have not been applied to landfill gas-fired turbines. The landfill gas will be treated prior to combustion to remove hydrogen sulfide down to 100 ppmv.

The NSPS for stationary combustion turbines (40 CFR 60, Subpart KKKK) requires that turbines must not burn any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. The treated landfill gas will have potential sulfur emissions less than 0.034 lb SO_2/MMBTU.

The Office of Air Resources has concluded that BACT for sulfur dioxide is landfill gas pretreatment to remove hydrogen sulfide down to 100 ppmv. The emission limit chosen to represent BACT is:

0.034 lb/MMBTU

3. Particulate Matter less than 10 microns (PM-10)

The Office of Air Resources is not aware of any landfill gas-fired turbine installations where flue gas controls are used to reduce particulate emissions. Additionally, the Office of Air Resources believes that the concentration of particulate matter in the flue gases from a turbine, during combustion of landfill gas is not sufficient to warrant consideration of flue gas controls as a BACT option. Particulate loading is calculated to be on the order of 0.07 grains/acf. The effectiveness of flue gas controls at this loading would be minimal. Therefore, flue gas controls are not considered a practical option.

The use of SCR will increase particulate emissions slightly. SCR catalysts can increase the conversion rate of sulfur dioxide in the exhaust gases to sulfur trioxide. Sulfur trioxide reacts with ammonia in the exhaust gases to form ammonium salts, a particulate. The applicant estimates that the use of SCR will increase particulate emissions by 0.0028 lb/MMBTU.

The turbine vendor has provided an emission warranty of 0.021 lb/MMBTU for the turbines without the SCR. Particulate emissions with the SCR system would increase to 0.0238 lb/MMBTU.

The Office of Air Resources has concluded that BACT for particulate emissions is good combustion practices to minimize particulate emissions. The emission limits chosen to represent BACT for PM-10 emissions is:

0.0238 lb/MMBTU

4. Ammonia (NH_3)

The SCR process involves the injection of ammonia into the flue gases. Due to a number of factors, it is impractical to inject ammonia at the theoretical quantity needed to remove all the NO_x and therefore an excess of ammonia over the theoretical quantity is necessary to achieve high conversion efficiencies. As a result, some unreacted ammonia passes through the system and is discharged to the atmosphere. This unreacted ammonia emission is commonly referred to as "ammonia slip."

Ammonia slip could, theoretically, be reduced through the use of flue gas controls such as a specially designed ammonia decomposition catalyst. However, the Office of Air Resources is not aware of any commercial applications of this technology, or any other flue gas control technique, for combustion turbines. Therefore, we do not consider flue gas controls an available BACT option.

The Department is not aware of any successful installations of SCR in a landfill gas application. Therefore there is no operating experience upon which to determine an achievable emission limitation. The applicant has proposed to limit ammonia slip to 20 ppmvd corrected to 15% O_2.

Therefore the Office of Air Resources concluded that BACT for ammonia slip is represented by an SCR system design and good operating practices to minimize emissions. The emission limit chosen to represent BACT for ammonia emissions is:

20 ppmvd, corrected to 15 percent O_2

- *Flares*

1. Carbon Monoxide

The regen flare is to be an Ultra Low Emission (ULE) flare. The applicant identified one enclosed flare used to treat landfill gas that had a lower emission limitation (0.01 lb/MMBTU) than the manufacturer's warranty (0.06 lb/MMBTU) for the ULE flare. The flare is located at the Lopez Canyon Sanitary Landfill in Los Angeles, CA. The entry for this facility in the South Coast Air Quality Management District's BACT determinations states that the CO limit may not be achievable in all cases. Therefore this emission limit is not considered to have been demonstrated as achievable in practice. The Office of Air Resources concluded that the emission limit chosen to represent BACT for carbon monoxide emissions is the manufacturer's warranty:

0.06 lb/MMBTU

The backup flares will only be used in the event that an engine, turbine or the regen flare is not operating. The applicant has proposed to use enclosed flares instead of ULE flares because the flares are to be used as backup devices and are not expected to be used on a regular basis. The applicant identified four enclosed flares used to treat landfill gas that had a lower emission limitation than the manufacturer's warranty (0.2 lb/MMBTU) for the enclosed flare.

The enclosed flares at the Edgeboro Disposal site in New Jersey and at the Fresh Kills landfill in New York both have lower carbon monoxide emission limits but have higher nitrogen oxide emission limits. In an enclosed flare carbon monoxide emissions can be reduced by increasing the flare operating temperature. However, in doing so, nitrogen oxides emissions will increase. Nitrogen oxides are an ozone precursor and Rhode Island is nonattainment for the ozone standard. Therefore the Office of Air Resources would prefer to have a source maximize the reductions in nitrogen oxides at the expense of increased emissions of carbon monoxide. For these reasons we don't consider either the Edgeboro Disposal site or Fresh Kills Landfill as representative.

The flares operated by the Los Angeles Bureau of Sanitation have only been tested at low loads and the South Coast Air Quality Management District BACT entry states that the CO limits may not be achievable under all operating conditions. Therefore we do not consider this emission limit as having been achieved in practice.

The flare at the Northwest Regional Landfill is located in the desert and flare performance in the desert is different than flare performance in the eastern United States. According to the manufacturer (Perennial Energy), the flare at Northwest Regional Landfill would not be able to achieve the same emission level (0.13 lb/MMBTU) at the Ridgewood site. Therefore we do not consider the Northwest Landfill as representative.

The Office of Air Resources concluded that the emission limit chosen to represent BACT for carbon monoxide emissions is the manufacturer's warranty:

0.20 lb/MMBTU

2. Sulfur dioxide (SO_2)

Landfill gas can contain a variety of sulfur compounds. The only means of controlling SO_2 emissions from a landfill flare is to limit the sulfur content of the landfill gas. The landfill gas will be treated prior to combustion to remove hydrogen sulfide down to 100 ppmv.

The Office of Air Resources has concluded that BACT for sulfur dioxide is landfill gas pretreatment to remove hydrogen sulfide down to 100 ppmv.

B. Air Quality Impact Analysis (Subsection 9.5.2(b))

Subsection 9.5.2(b)(1) requires the applicant to demonstrate, by means of air quality modeling, that allowable emissions from the proposed source would not cause or contribute to:

a. air pollution in violation of any national ambient air quality standard; or,

b. any increase in ambient concentrations exceeding the remaining available increment for the specified air contaminant.

The Office of Air Resources' review of the applicant's air quality impact analysis consists of three parts:

1. A review of the modeling methodology used to predict the ambient impacts of the facility;

2. A review of the emission rates used as input to the air quality models to predict the ambient impacts of the facility; and

3. A comparison of the predicted impacts for criteria pollutants to the applicable significant impact levels and a comparison of the predicted impacts for non-criteria pollutants to Acceptable Ambient Levels.

Therefore, the following is a summary of the Office of Air Resources findings with respect to each of these reviews.

1. Modeling Methodology

   a. Discussion of Emission Sources

   The applicant identified 18 emission sources located at either the Ridgewood Power facility, the Central Landfill or the Rhode Island State Energy Center that have the potential to cause a significant impact on surrounding air quality. The sources consist of 1-6000 cfm ultra low emissions flare, 1-400 scfm flare, 2-2000 scfm flares, 1-630 cfm regen flare, 2-6000 cfm enclosed flares, 2-Deutz landfill gas-fired engines, 4-Caterpillar landfill gas-fired engines, a steam boiler located at the Administration Building of the Central Landfill, 2-turbines located at Rhode Island State Energy Center, 3-engines serving grinders, the 5-proposed combustion turbines and the two cooling towers associated with the landfill gas power plant. The 2-1300 scfm flares were not included in the modeling because they will be removed from service at the same time that the existing Waukesha engines are removed from service..

   The flares, steam boiler, engines and turbines were modeled as point sources. Flares were modeled using the default parameters generated by the SCREEN3 model.

   b. Model Selection

   The applicant used EPA's AERMOD model to predict air impacts from the proposed facility at simple, intermediate and complex terrain.

c. Meteorology

The meteorological data used by the applicant to predict air impacts for criteria pollutants is consistent with EPA recommended procedures. The data covered a five-year period from 1986 to 1990. Surface data was collected at T. F. Green Airport and upper air data was collected at Chatham, Mass. These stations are the closest and most representative national weather service stations to the site of the proposed facility.

The meteorological data used by the applicant to predict air impacts for listed toxic air contaminants is consistent with RIDEM recommendations. The data covered five-years of data, 1972, 1976, 1980, 1984 and 1988. Surface data was collected at T. F. Green Airport and upper air data was collected at Chatham, Mass. These stations are the closest and most representative national weather service stations to the site of the proposed facility.

d. Receptor Locations

The applicant placed receptors at 10-meter intervals along the property boundary of the Central Landfill. A main polar grid of receptors was placed at distances of 25 meters out to 1000 meters, 100 meters out to 5000 meters and 500 meters out to 6000 meters. A supplemental polar grid centered on the Caterpillar engines, with receptors at distances of 25 meters out to 1000 meters was also included. A third polar grid centered on the regen flare and backup flares, with receptor rings at 25-meter intervals out to 500 meters was included to address impacts form the flares. All radials were placed at 10 degree intervals. The construction of the receptor network and the selection of distances are consistent with procedures specified in EPA's Guideline on Air Quality Models (40 CFR Part 51, Appendix W).

e. Model Options

The options chosen by the applicant are consistent with those recommended for regulatory use in EPA's Guideline for Air Quality Models (40 CFR Part 51, Appendix W).

f. Good Engineering Practice (GEP) Stack Height and Building Downwash Parameters

A GEP stack height analysis was conducted for all emission sources modeled as point sources. The stack heights of the steam boiler, the 2-RISEC turbines, the Recovermat engine/grinder and the 2-cooling towers were less than the calculated GEP stack height. Therefore building downwash effects were considered in the modeling for these sources. The applicant's GEP analysis and determination of direction specific building dimensions is consistent with EPA's Guideline for Determination of Good Engineering Practice Stack Height (EPA 450/4-80-023R) and the Building Profile Input Program User's Guide (EPA 454/R-93-038).

g. Cavity Impacts

Refined air quality modeling was conducted using the AERMOD model, which accounts for building cavity impacts.

h. Class I Areas

The nearest Class I area is the Lye Brook Wilderness Area in southern Vermont located approximately 190 km northwest of the facility. The applicant evaluated the impact on this Class I area using EPA's VISCREEN model. The model predicts that visibility will not be impacted by the proposed project.

i. Background Concentrations

Background air quality data, to represent sources that were not included in the modeling, were based on the highest, second high for short-term concentrations (1-hr, 3-hr, 8-hr or 24-hr) and on the highest annual concentrations measured at any site in Rhode Island for the period 2004-2006.

The modeling methodology used in the permit application is acceptable for predicting impacts of the facility on the surrounding air quality.

2. Emission Rates

a. Criteria Pollutants

The sources of the emission factors for the emission points at Central landfill used to calculate the emission rates for the pollutants NO_x, CO and PM-10 were either permit limitations, test data, EPA's AP-42 "Compilation of Air Pollutant Emission Factors" or vendor supplied information/performance guarantees.

The emission rates for SO_2 for all emission points combusting landfill gas from the gas treatment system were based on a maximum sulfur content of the landfill gas of 100 ppm. This is the performance level of the proposed gas treatment system. Remote flares 1, 2 and 3 will combust landfill gas that is not treated. The assumed sulfur content of the landfill gas combusted in these flares is 3000 ppmv, 600 ppmv and 2000 ppmv for Remote flares 1, 2 and 3 respectively. The emission rate for SO_2 for the steam boiler was calculated using an AP-42 emission factor.

Emission rates for the RISEC power plant were obtained from the facility's preconstruction permit.

b. Air Toxics

Emission rates for all listed toxic air contaminants were calculated based on maximum concentrations observed in samples of the landfill gas collected and analyzed during the first three quarters of 2007.

The Office of Air Resources finds the applicant's emission estimates to be acceptable for use in predicting air quality impacts.

3. Impact Analysis

The criteria pollutants evaluated in the modeling analysis are nitrogen oxides, sulfur dioxide, particulate matter, and carbon monoxide. The maximum predicted impacts due to the proposed modification combined with the other emissions sources at the Central Landfill, Ridgewood Power and RISEC facility when added to background concentrations are below the applicable NAAQS. The maximum predicted impacts of criteria pollutants due to the facility and the other emission sources are summarized in Table 4 and compared to the NAAQS.

The maximum predicted impacts due to the proposed modification combined with the other new or modified emissions sources at the Central Landfill, Ridgewood Power and RISEC facility are below the applicable PSD increments. The maximum predicted impacts of criteria pollutants due to the facility and the other emission sources are summarized in Table 5 and compared to the PSD increments.

The proposed project is a major modification for the pollutant nitrogen oxides. Subsection 9.5.3(a) of Air Pollution Control Regulation No. 9 limits increment consumption for major modifications to 25% of the remaining annual increment. Table 6 is a summary of the maximum predicted impacts of nitrogen oxides for the proposed facility in comparison to the allowable remaining PSD increment.

The applicant has satisfactorily demonstrated that the proposed facility will not cause or contribute to air pollution in violation of the NAAQS for these pollutants or in excess of the allowable PSD increments for criteria pollutants.

Subsection 9.5.2(b)(2) requires the applicant to prepare an analysis of the ambient air quality in the area that the source would affect for each pollutant for which it would result in a significant net emissions increase. Nitrogen oxides, carbon monoxide and particulate matter less than 10 microns in diameter (PM-10) are the only pollutants for which there would be a significant net emissions increase. The maximum predicted air quality impacts of nitrogen dioxide, carbon monoxide and PM-10, due to the proposed modification alone, are below the threshold levels in subsection 9.5.2(b)(2)d. As a result, no preconstruction ambient monitoring program is deemed to be necessary for these pollutants.

The maximum predicted impacts of these three pollutants due to the modification alone are summarized in Table 7 and compared to the threshold levels.

TABLE 4
Summary of Maximum Predicted Impacts of
Criteria Pollutants and Comparison to NAAQS (μg/m^3)

Pollutant	Averaging Time	Maximum Predicted Impact (μg/m^3)	Background Concentration (μg/m^3)	Total Concentration (μg/m^3)	NAAQS (μg/m^3)
SO_2	3-hour	48	126	174	1300
	24-hour	26	63	89	365
	Annual	4.7	18	23	80
CO	1-hour	635	11,106	11,741	40,000
	8-hour	534	2862	3,396	10,000
NO_2	Annual	11.2	33	44	100
PM-10	24-hour	19	54	73	150
	Annual	2.7	24	27	50

TABLE 5

Summary of Maximum Predicted Impacts of Criteria Pollutants and Comparison to PSD Increments (μg/m^3)

Pollutant	Averaging Time	Maximum Predicted Impact All Sources (μg/m^3)	Full PSD Increment (μg/m^3)
SO_2	3-hour	48	512
	24-hour	26	91
	Annual	4.7	20
NO_2	Annual	11.2	25
PM-10	24-hour	19	30
	Annual	2.7	17

TABLE 6

Maximum Predicted Impacts of Nitrogen Oxides and Comparison to Allowable Remaining PSD Increments (μg/m^3)

Pollutant	Averaging Time	Maximum Predicted Impact All Existing Sources (μg/m^3)	Full PSD Increment (μg/m^3)	Maximum Predicted Impact from Modification (μg/m^3)	Allowable Remaining PSD Increment (μg/m^3)
NO_2	Annual	11.0	25	3.0	3.5

TABLE 7

Summary of Maximum Predicted Impacts of Proposed Modification and Comparison to Ambient Air Monitoring Threshold Levels (μg/m^3)

Pollutant	Averaging Time	Maximum Predicted Impact (μg/m^3)	Threshold Level (μg/m^3)
CO	8-hour	176	575
NO_2	Annual	3.0	14
PM-10	24-hour	9.9	10

C. *Additional Impacts Analysis (Subsection 9.5.2(c))*

Subsection 9.5.2(c) requires the applicant to provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the modification and general commercial, residential, industrial and other growth associated with modification. Additionally, this subsection requires the applicant to provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the modification.

1. Visibility Analysis

The applicant conducted a Level 1 visibility impairment analysis using the VISCREEN program, as specified in the "Workbook for Plume Visual Impact Screening and Analysis" (EPA-450/4-88-015). The results of the VISCREEN program satisfactorily demonstrate that this modification should not cause visibility impairment at the Lye Brook Wilderness Area in Vermont, the nearest Class I area to this facility.

2. Soils and Vegetation Analysis

The applicant has presented an assessment of the impacts on soils and vegetation as a result of emissions from the proposed modification. This assessment compared predicted project impacts with screening levels presented in the 1980 EPA document "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals" (EPA 450/2-81-078).

This analysis concluded that emissions from the proposed modification will not cause or contribute to air pollution that would adversely impact soils and vegetation in the area.

3. Growth Analysis

The applicant's analysis concluded that there is not expected to be any significant, direct, industrial, commercial or residential growth associated with this modification that would adversely affect air quality in the vicinity of the project. It is not anticipated that any industrial, commercial, or residential growth will occur to support the 50 or so people whom will constitute the peak construction work force.

D. *Welfare Impacts (Subsection 9.5.2(d))*

Subsection 9.5.2(d) requires the applicant to apply the applicable procedures of the Guidelines for Assessing the Welfare Impacts of Proposed Air Pollution Sources and meet the criteria therein.

The Office of Air Resources "Guidelines for Assessing the Welfare Impacts of Proposed Air Pollution Sources" specifies the procedures to be followed for evaluating a facility's impact on plants, animals and soil. Applicants must apply the procedures and comply with the screening concentrations in A Screening Procedure for the Impacts of Air Pollution on Plants, Soils and Animals (EPA 450/2-81-078, December 12, 1980). The applicant has correctly applied the procedure in this assessment and met the criteria therein.

E. Air Toxics Regulation and CAALs (Subsection 9.4.2(g))

Subsection 9.4.2(g) requires the applicant to demonstrate that the emissions from the facility will not cause an increase in the ground level ambient concentration at or beyond the property line in excess of that allowed by Air Pollution Control Regulation No. 22 ("Air Toxics") and any Calculated Acceptable Ambient Levels.

The applicant evaluated 38 compounds that are possible constituents in landfill gas and are listed toxic air contaminants in Air Pollution Control Regulation No. 22. Fourteen of the thirty-eight compounds that are listed toxic air contaminants in Air Pollution Control Regulation No. 22 were not detected in the landfill gas sampled and analyzed at Central Landfill.

Potential emissions of the remaining twenty-four compounds were calculated and compared to the minimum quantities in Table III of Air Pollution Control Regulation No. 22 (see Table 8). Potential emissions of seventeen of the twenty-four compounds are less than the Table III minimum quantities and therefore no further analysis is necessary for these compounds.

The maximum predicted impacts of the seven remaining compounds, due to the proposed modification combined with the other emissions sources at Ridgewood Power, are below the applicable AALs. The maximum predicted impacts of the seven listed toxic air contaminants due to the RPPP facility are summarized in Table 9 and compared to the applicable AALs.

Additionally, unreacted ammonia will be discharged from the SCR system used to reduce emissions of nitrogen oxides. Potential emissions of the ammonia were calculated and compared to the minimum quantities in Table III of Air Pollution Control Regulation No. 22 (see Table 8). The maximum predicted impacts of ammonia due to the RICG facility are summarized in Table 9 and compared to the applicable AALs.

TABLE 8

Potential emissions of listed toxic air contaminants compared to Table III minimum quantities

Listed toxic air contaminant	CAS Number	Potential emissions (lbs/year)	Table III Minimum Quantity (lbs/year)
Acetone	67641	520.2	20,000
Ammonia	**7664417**	**94,200**	**300**
Benzene	**71432**	**44.8**	**10**
Carbon Disulfide	75150	123.6	2000
Chlorodifluoromethane	75456	126.8	36,500
Cyclohexane	110827	85.4	20,000
1,4 Dichlorobenzene	**106467**	**14.8**	**10**
cis-1,2-Dichloroethene	156592	25.6	1000
Ethyl benzene	100414	339	9000
Ethylidene dichloride (1,1 Dichloroethane)	75343	10	70
Hexane	110543	144	20,000
Hydrogen Chloride	**7647010**	**11,165**	**700**
Hydrogen Sulfide	**7783064**	**1632**	**10**
Isopropanol (2-Propanol)	67630	176.4	1000
Mercury (total)		**45.4**	**0.3**
Methyl Ethyl Ketone	78933	332.6	4000
Methyl Isobutyl Ketone	108101	37	9000
Methylene Chloride	75092	24.6	200
Styrene	100425	33	3000
Tetrachloroethylene	**127184**	**69**	**20**
Toluene	108883	1432.6	3000
Trichloroethylene	79016	30.8	50
Trichlorofluoromethane	75694	102.6	3000
Vinyl Chloride	**75014**	**20.4**	**20**
Xylene	1330207	903.8	1000

TABLE 9

Summary of Maximum Predicted Impacts of Listed Toxic Air Contaminants and Comparison to Acceptable Ambient Levels (μg/m³)

Pollutant	Averaging Time	Maximum Predicted Source Impact (μg/m³)	Acceptable Ambient Level (μg/m³)
1,4 Dichlorobenzene	1-hour	0.006	12,000
	24-hour	0.003	800
	Annual	0.0003	0.09
Benzene	1-hour	0.019	30
	24-hour	0.008	20
	Annual	0.001	0.1
Hydrogen sulfide	1-hour	0.661	40
	24-hour	0.267	30
	Annual	0.032	10
Tetrachloroethylene	1-hour	0.029	1000
	Annual	0.001	0.2
Mercury	1-hour	0.0215	2
	24-hour	0.0088	0.3
	Annual	0.001	0.009
Hydrogen Chloride	1-hour	4.536	2000
	Annual	0.214	9
Ammonia	1-hour	15.324	1000
	24-hour	9.468	100
	Annual	1.253	70
Vinyl Chloride	1-hour	0.009	1000
	24-hour	0.004	100
	Annual	0.0004	0.2

F. Health Risks from Proposed Air Pollution Sources (Subsection 9.5.2(f))

Subsection 9.5.2 (f) requires the applicant to conduct any studies required by the Guidelines for Assessing Health Risks from Proposed Air Pollution Sources and meet the criteria therein.

The proposed source does not meet the applicability criteria in this document and therefore is not required to perform this type of study.

G. Applicable Air Pollution Control Regulations (Subsection 9.5.2(g))

Subsection 9.5.2 (g) requires the applicant to demonstrate that the facility will be in compliance with all applicable state and federal air pollution control regulations at the time the source commences operation. The following is a discussion of the applicable state and federal air pollution control rules and regulations and how compliance with each rule or regulation is addressed:

1. State Air Pollution Control Rules and Regulations

a. APC Regulation No. 1 "Visible Emissions"

This regulation limits visible emissions to less than 20% except for a period or periods aggregating more than three minutes in any one hour. The Office of Air Resources will limit opacity to less than 10% except for a period or periods aggregating more than three minutes in any one hour. The landfill gas fired turbines are not expected to create visible emissions and therefore, compliance with this regulation should be assured.

b. APC Regulation No. 7 "Emission of Air Contaminants Detrimental to Person or Property"

The applicant has demonstrated in the air quality impact analysis that this facility will not cause or contribute to air pollution in violation of any National Ambient Air Quality Standard.

Additionally, the applicant has demonstrated that emissions from the facility will not adversely impact soils, vegetation, wildlife or human health.

Therefore, based on the foregoing, compliance with this regulation is expected.

c. APC Regulation No. 8 "Sulfur Content of Fuels"

This regulation would limit the sulfur content of the fuel used at this facility to less than 0.55 lbs/million BTU heat release potential.

The sulfur content of the landfill gas used at this facility, after treatment, is on the order of 0.017 lbs/MMBTU. Therefore compliance with the provisions of this regulation would be expected.

d. APC Regulation No. 14 "Recordkeeping and Reporting"

This regulation would require the applicant to maintain certain records and submit this information to the Office of Air Resources as requested. Any recordkeeping or reporting requirements will be made a part of any permit issued pursuant to this application. See Section E. of the draft permit.

e. APC Regulation No. 17 "Odors"

This regulation states that a source cannot emit an objectionable odor beyond its property line. The landfill gas-fired turbines would not be expected to generate odors that would be objectionable beyond the property line. However, unreacted ammonia is emitted from the SCR system used to control nitrogen oxides emissions.

The ability to detect an odor varies from person to person. There can be huge differences in the odor sensitivity of different individuals. At a given concentration, one person may smell and recognize the odor, while another person may barely notice it. Odor thresholds reported in the literature can vary by orders of magnitude. In the field, a staff member of the Department determines if an odor is objectionable by personal observation, taking into account its nature, concentration, location, duration and source.

The following are the reported odor thresholds for ammonia from a number of different sources:

CHRIS:	Chemical Hazards Response Information System (CHRIS) Manual, U.S. Coast Guard – **46.8 ppm**
AAR:	Emergency Action Guides, Bureau of Explosives, American Association of Railroads 1996 – **0.037-20 ppm**
AIHA:	Odor Thresholds for Chemicals with Established Occupational Standards, American Industrial Hygiene Association, 1989 – **0.043-53 ppm**
TOXNET:	Hazardous Substances Data Bank, Toxicology Data Network, United States National Library of Medicine – **0.37-56 ppm**
3M:	2004 Respirator Selection Guide – **5.75 ppm**

The maximum predicted 1-hour average impact of ammonia from the air quality modeling was 15.324 $\mu g/m^3$ (0.021 ppm). This impact is less than the lowest reported odor threshold. Therefore compliance with this regulation is expected.

f. APC Regulation No. 22 “Air Toxics”

The air quality modeling conducted by the applicant has demonstrated that the emissions from the facility will not cause an increase in the ground level ambient concentration at or beyond the property line in excess of that allowed by Air Pollution Control Regulation No. 22 ("Air Toxics"). Therefore compliance with this regulation can be expected.

2. Federal Air Pollution Control Rules and Regulations

40 CFR 60, Subpart WWW, “Standards of Performance for Municipal Solid Waste Landfills”

The applicant must comply with the requirements of 40 CFR 60.752(b)(2)(iii)(C). This requires that the landfill gas be treated prior to use in the turbines. The landfill gas treatment system to be used at this facility will filter, de-water and compress the landfill gas prior to use in the turbines and meets the requirements for a "treatment system" in 40 CFR 60.752(b)(2)(iii)(C).

The regen flare and backup flares must comply with the requirements of 40 CFR 60.752(b)(2)(ii)(B). This requires that the flares either reduce nonmethane organic compounds (NMOC) by 98 weight percent or reduce the outlet NMOC concentration to less than 20 parts per million by volume, dry basis as hexane at 3 percent oxygen. All three flares are capable of meeting this requirement.

The standard also contains requirements for monitoring of operations, compliance testing, recordkeeping and reporting. Those requirements applicable to this facility will be made a part of the draft permit issued pursuant to this application to ensure compliance with these provisions.

Therefore compliance with the NSPS can be expected.

40 CFR 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines”

This NSPS is applicable to the combustion turbines for the proposed project. The standard contains the following emission limitations for nitrogen oxides and sulfur dioxide:

Nitrogen oxides:	74 ppmv, dry basis corrected to 15% O_2 or 3.6 lb/MW-hr
Sulfur dioxide:	0.9 lb/MW-hr or combust fuel with potential SO_2 emissions less than 0.06 lb/MMBTU or less.

The emission limitations determined to represent LAER or BACT in this application are well below these requirements under all operating conditions. Therefore, compliance with these limitations will be assured.

The standard also contains requirements for monitoring of operations and compliance testing. Those requirements applicable to this facility will be made a part of the draft permit issued pursuant to this application to ensure compliance with these provisions.

In conclusion, the facility should be fully capable of complying with the provisions of 40 CFR 60 Subpart KKKK.

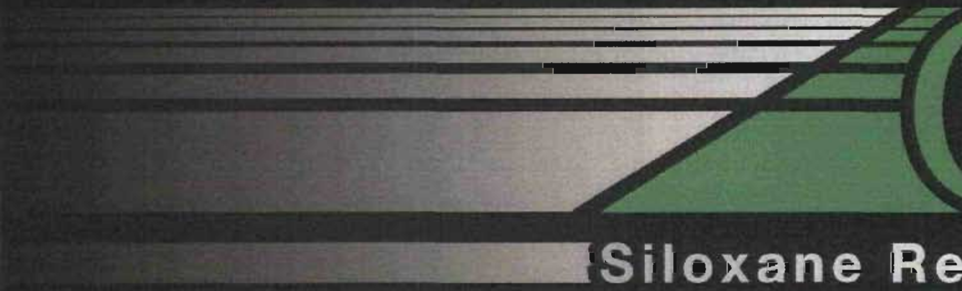
V. Conclusion

Based on the information supplied by the applicant and the Office of Air Resources' review of the proposed project, the Office of Air Resources believes that the applicant has satisfied all of the applicable provisions of APC Regulation No. 9, Section 9.4 relative to the requirements for issuance of a Major Source Permit for a major modification in a nonattainment area and Section 9.5 relative to the requirements for issuance of a Major Source Permit for a major modification in an attainment area. As such, the Office of Air Resources is proposing approval of the application for a major modification of the Ridgewood Power facility subject to the permit conditions and emission limitations contained in the draft permit.

RICG-pd.doc

ATTACHMENT B

Parker



GES

Siloxane Removal System

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A five step comprehensive package guaranteed to remove siloxane from your landfill or digester gas for a minimum of five years

Your risk free siloxane removal solution includes:

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❷ **A GES Siloxane Removal System** – individually designed to meet your specific needs

❸ **Factory Start Up & Commissioning** – to ensure your satisfaction from the very first day

❹ **Validation, Calibration & Media Replacement** – included at a fixed cost for 5 years

❺ **Guaranteed Performance & Quality** – a 5 year money back performance guarantee

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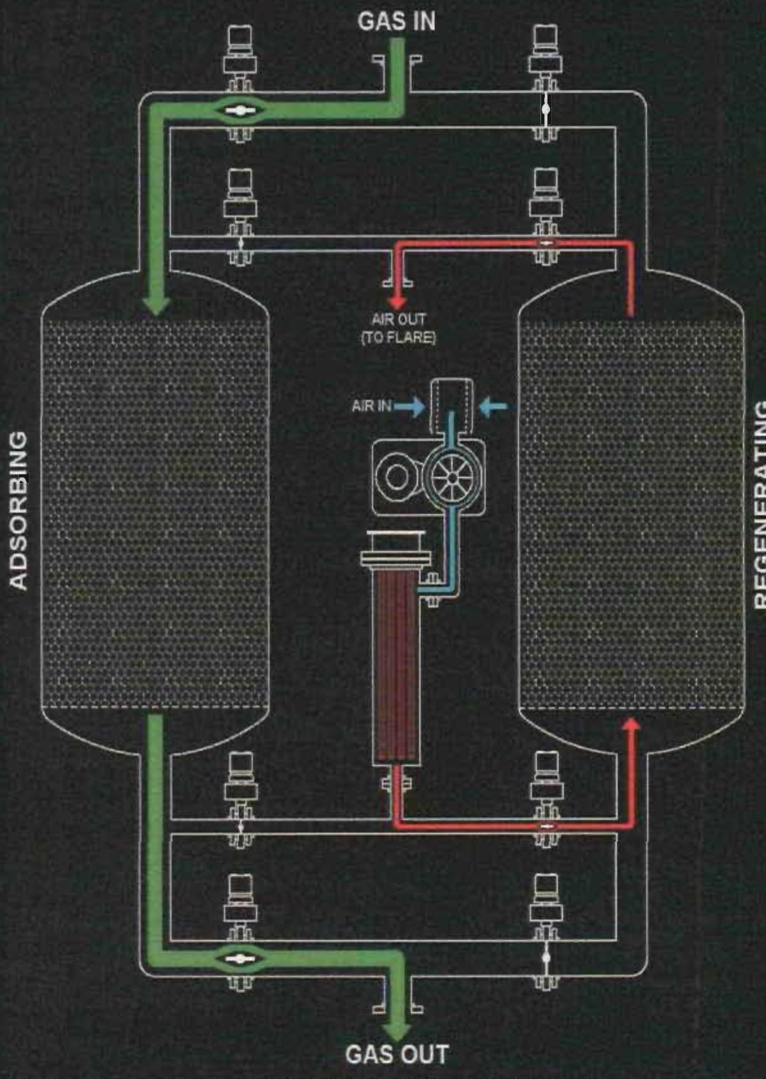
The GES Siloxane Removal System is the only regenerative system that is proven to continuously meet or exceeds the original equipment manufacturer's specifications for fuel gas siloxane content. While one tower adsorbs siloxane using a specialized blended media the other regenerates, exhausting the collected siloxane to a flare or thermal oxidizer. The cycle is fully adjustable allowing it to handle a wide range of gas qualities or to adjust to changing gas conditions.

Each system is individually designed to meet the specific needs of your application as determined by a detailed on site audit, and is commissioned by a factory professional to ensure your complete satisfaction.

Each system also comes with a minimum **5 year performance guarantee** that is validated by monthly gas samples taken by factory trained service professionals. Sample analysis, calibration, consumable parts, and media replacement is included for the duration of the guarantee.



*Simplified for marketing purposes. Not an accurate representation

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Guaranteed siloxane removal - for an investment of only 0.2 to 0.6 cents* per kWh

* Typical cost intended for reference only. Actual cost depends upon the type of combustion equipment used, and the specific parameters of your application.

Common applications

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Digester Gas

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1-800-345-8462
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www.GESbyParker.com

From: Thorley, David [DThorley@wm.com]
Sent: Monday, November 16, 2009 5:07 PM
To: Linero, Alvaro
Cc: Christiansen, Jim; Bishop, Tony; Tindell, Bryan; Sal Mohammad (E-mail)
Subject: Okeechobee
Attachments: Bio-DesulfuriationJan091.pdf; ETV Statement Report - THIOPAQ Gas Purification Technology1.pdf; NATCO presentation 9-10-2009.pdf

November 16, 2009

FDEP File No.:0930104-014-AC

Dear Mr. Linero:

As discussed on Friday and again today, the Okeechobee Landfill, Inc (OLI), would like the FDEP to consider an additional H2S removal technology for desulphurization of the gas at the landfill. This new technology is provided by NATCO and is called Thiopaq. Okeechobee Landfill is still reviewing the technology to see if it could possibly work in the Florida environment while reasonably reducing H2S concentrations in the landfill gas. Additionally, the information that OLI has received regarding this technology is attached.

Furthermore, as you know, the H2S concentrations in the landfill gas at OLI have been reducing over the last couple of years and the gas flow rates at the site have also declined. Per our phone conversation, I have agreed to further evaluate the expected gas generation for the site for the next 7 years and over the course of the life of the site. OLI will re-evaluate what equipment (flares and turbines) that it anticipates installing over the next 7 years while assuming the final turbine and flare build out in the application will remain the same.

With this additional information in regards to the referenced permit application, the applicant - OLI, hereby waives the upcoming deadline of November 20, 2009, for the Department to have the permit issued or denied by the State of Florida Department of Environmental Protection granted under Sections 120.6091) and 403.0876, F.S. This waiver shall expire on February 1, 2010.

Sincerely,

David Thorley

David Thorley, P.E.
Director of Air Programs - South
1001 Fannin, Suite 4000
Houston, TX 77002
office: 713-328-7404
fax: 713-328-7411
cell: 713-201-3752

Walker, Elizabeth (AIR)

From:	Linero, Alvaro
Sent:	Wednesday, July 29, 2009 9:46 AM
To:	Walker, Elizabeth (AIR)
Subject:	FW: Okeechobee Landfill

From: Linero, Alvaro
Sent: Thursday, July 02, 2009 3:57 PM
To: 'SNunes1@wm.com'; 'Thorley, David'; 'Buff, Dave'; 'Sal_Mohammad@golder.com'
Cc: Heron, Teresa
Subject: RE: Okeechobee Landfill

Seth and Dave(s):

Further to the email I sent earlier today, you should probably have included something about the University of New Hampshire/Waste Management project and the limit they have of 5 ppm using the Mercury 50.

More recently Rhode Island issued a determination for the Rhode Island Resource Recovery Corp/Central Genco based on Solar Taurus 60 that requires SCR.

Thanks again.

Al Linero.

From: Linero, Alvaro
Sent: Thursday, July 02, 2009 1:02 PM
To: 'SNunes1@wm.com'; 'Thorley, David'; 'Buff, Dave'; Sal_Mohammad@golder.com
Cc: Heron, Teresa
Subject: Okeechobee Landfill

Hi Seth and Dave(s):

We enjoyed meeting with you June 22nd.

We understand that you may be sending additional information for our consideration in making our BACT determination for the combustion turbines to be used at the Okeechobee Landfill. The information for consideration would be recent BACT determinations conducted for landfill gas combustion turbine projects in California and elsewhere.

We would need to receive such information soon in order to consider it while we write up the evaluation over the next month or so.

As we mentioned, we are familiar with the Solar Mercury CT at 4.3 MW versus the Solar Centaur at 3.5 MW.

The Mercury was developed with DOE assistance under the Advanced Turbine System (ATS) project to produce a low NOx CT that would avoid SCR. It is our understanding that the University of New Hampshire in conjunction with WM have a project that is very close to startup using this unit.

Feel free to provide comments on this since at first glance it appears that it would be a good fit for the Okeechobee project.

Thanks.

Al Linero.

Heron, Teresa

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Thanks.

Al Linero.

Walker, Elizabeth (AIR)

From:	Heron, Teresa
Sent:	Thursday, October 15, 2009 2:09 PM
To:	Walker, Elizabeth (AIR)
Subject:	FW: Okeechobee Landfill LFGTE & Flares Project - 0930104-014-AC
Attachments:	SKMBT_C55009101513160.pdf

FYI and files

From: Mohammad, Sal [mailto:Sal_Mohammad@golder.com]
Sent: Thursday, October 15, 2009 1:30 PM
To: Heron, Teresa
Cc: Buff, Dave
Subject: Okeechobee Landfill LFGTE & Flares Project - 0930104-014-AC

Teresa –
Please find attached waiver for the 90-day permit processing time for the Okeechobee Landfill LFGTE and new flares project. We have extended the deadline up to November 20, 2009. The waiver has also been faxed to the Office of General Council.

Thanks,
Sal

Sal Mohammad | Senior Project Engineer | **Golder Associates Inc.**
6241 NW 23rd Street, Suite 500, Gainesville, Florida, USA 32653
T: +1 (352) 336-5600 | F: +1 (352) 336-6603 | E: Sal_Mohammad@golder.com | **www.golder.com**

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

WAIVER OF 90 DAY TIME LIMIT FOR ISSUANCE OF PERMIT UNDER SECTIONS 120.60(1) and 403.0876, FLORIDA STATUTES

Applicant: **Okeechobee Landfill, Inc. – Okeechobee Landfill Landfill-Gas-to Energy (LFGTE) Plant and Flares Project**

FDEP File No.: 0930104-014-AC

The undersigned has read Sections 120.60(1) and 403.0876, Florida Statutes (F.S.), and fully understands the applicant's rights under those sections.

With regard to the above referenced permit application, the applicant hereby, with full knowledge and understanding of its rights under Sections 120.60(1) and 403.0876, F.S., waives the right under those statutes to have the application for a permit issued or denied by the State of Florida Department of Environmental Protection within the ninety day time period prescribed in those sections. Said waiver is made freely and voluntarily by the applicant, is in its self-interest, and is made without any pressure or coercion by anyone employed by the State of Florida Department of Environmental Protection.

This waiver shall expire on November 20, 2009.

The undersigned is authorized to make this waiver on behalf of the applicant.

David a. Buff 10/15/09
Signature/Date

David A. Buff, Principal Engineer
Name/Title (please print)