

Golder Associates Inc.

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April 7, 2009

0938-7541

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

RECEIVED

APR 08 2009

Attention: Alvaro A. Linero, Program Administrator

BUREAU OF AIR REGULATION

**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 (O₂) (Titan), 42 ppmv @ 15-percent O₂ (Centaur).

CO

- BACT – Good combustion practices.
- BACT Emission Limit – 100 ppmv @ 15-percent O₂ (Titan), 250 ppmv @ 15-percent O₂ (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 (H₂S) have been reduced, because moisture and H₂S 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 H₂S removal equipment, siloxane removal equipment, piping, and other process components must be taken into consideration. LFG containing high levels of H₂S is corrosive to gas collection system piping and is especially corrosive to compressors or blowers. OLI is proposing a Low-Cat H₂S 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 H₂S 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., $27,500 \div 8,000 = 3.4$). 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 SO₂ 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 SCR's 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.

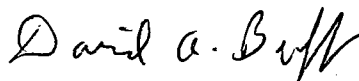
From an emission and compliance standpoint, open flares have comparable or lower NO_x emissions [approximately 0.07 pound per million British thermal units (lb/MMBtu)] than enclosed flares (0.06 to 0.08 lb/MMBtu). Open flares do have somewhat higher CO emissions (approximately 0.37 lb/MMBtu) compared 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, P.E., Q.E.P.
Principal Engineer

DB/SKM/tlc

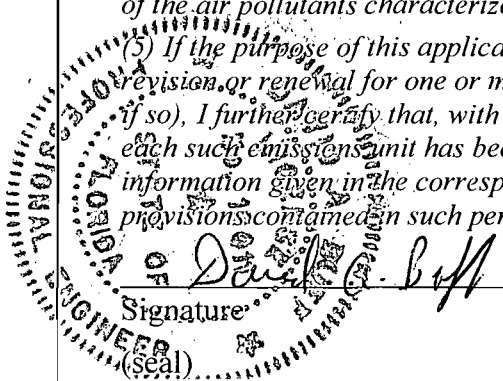
Enclosures

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>I, the undersigned, hereby certify, except as particularly noted herein*, that:</i> <i>(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</i> <i>(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.</i> <i>(3) If the purpose of this application is to obtain a Title V air operation permit (check here <input type="checkbox"/> , 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.</i> <i>(4) If the purpose of this application is to obtain an air construction permit (check here <input checked="" type="checkbox"/> , 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 <input type="checkbox"/> , 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.</i> <i>(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 <input type="checkbox"/> , 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.</i>  Signature: <u>David A. Buff</u> Date: <u>4/7/09</u>

* 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 (CRF):	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 NO_x 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 NO_x 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)		<u>1,050,500</u>
(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:		<u>1,638,780</u>
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:		<u>345,655</u>
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:		<u>427,842</u>
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)	<u>134,489</u>
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 NO_x CONTROL SCENARIOS, OKEECHOBEE LANDFILL FACILITY**

Cost Items	Comments/Reference	Value	NO _x 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
Total Annualized Cost (AC)(\$/yr):			2,378,735	1,990,980	5,489,780	14,045,155
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
Controlled NO _x Emissions (TPY):	90% Control		20.3	3.5	34.3	72.8
Reduction in NO _x Emissions (TPY):	Baseline - Controlled		182.7	31.5	308.7	655.2
Cost Effectiveness (AC/Total Reduction)	\$ per ton Removed				17,784	21,436

15 MW
 $52.5 \text{ (3.5 MW} \times 15)$
 67.5 MW total
 $4.6 \text{ MW} \times 15 = 69 \text{ MW}$

$\frac{1,165,516}{182.7}$	$\frac{2,378,735}{182.7}$	$\frac{1,990,980}{31.5}$	$\frac{5,489,780}{308.7}$
\Downarrow	\Downarrow	\Downarrow	\Downarrow
6,379	13,020	63,206	17,784

$343 \times 0.90 =$

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)		<u>346,800</u>
(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:		<u>454,308</u>
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:		<u>117,508</u>
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:		<u>253,410</u>
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)	<u>54,888</u>
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 <i>343</i>	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 <i>1910</i>	3,945.0
Controlled NOx Emissions (TPY) :	90% Control		20.3	3.5	34.3 <i>10%</i>	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

$$\frac{2,781,437}{955}$$

$$\Downarrow$$

$$2,912$$

$$\frac{2,361,355}{268}$$

$$\Downarrow$$

$$8,811$$

$$\frac{7,373,982}{2,028}$$

$$\Downarrow$$

$$3,637$$

ATTACHMENT A

VENDOR COST QUOTES

APPLICATION FOR PLAN APPROVAL

**Geological Reclamation
Operations and Waste Systems**

No. 009-00007

RENEWABLE ENERGY FACILITY



**Waste Management
Disposal Services of
Pennsylvania, Inc.**

September, 2008

Prepared by:

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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

		SCR Per Turbine	Source
Direct Capital Costs			
Equipment Capital	% of 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		CleanAir Systems, Inc. Estimate
	90% Reduction		EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
	3 Duct Pressure Drop		EPA Air Pollution Control Cost Manual, Sixth Edition dated January 2002
	3 SCR Pressure Drop		
	\$ 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 Catalyst	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 Catalyst	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



The Chemical Company

DATE: September 12, 2008 NO. PAGES 3

TO: GOLDER ASSOC via e-mail
ATTN: Dorothy Austin

BASF Catalysts LLC
ATTN: Nancy Ellison

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 Bumer
Gas Flow:	Horizontal
Fuel:	Natural Gas and Oil
Gas Flow Rate (At catalyst face):	Designed for Gas Velocities within $\pm 15\%$ of the mean velocity at the catalyst face
Temperature (At catalyst face):	Designed for Gas Temperatures within range $\pm 25^{\circ}\text{F}$ of noted temperatures
CO Concentration (At catalyst face):	Not Given
CO Reduction:	90%

Sincerely yours,

BASF Catalysts LLC

Frederick A. Booth
Senior Sales Engineer



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.

<u>BUDGET PRICE:</u> 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.



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 ₂ O	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 (CIST™) 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,” “stearyoxytrimethylsilane” “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 organosilicon 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 organosilicon 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 Nm³/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 citations), 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) midjet 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 $\mu\text{g}/\text{m}^3$ 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 ($\text{C}_2\text{H}_6\text{S}$), and dimethyl disulfide ($\text{C}_2\text{H}_6\text{S}_2$) 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 & Cl₂), Total fluoride (HF & F₂), ammonia (NH₃), 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/m³; Cl₂ < 0.62 mg/m³

Total Fluoride: HF < 0.015 mg/m³; F₂ 0.036 mg/m³

Moisture: 2.5%

Total Sulfur: H₂S 200 to 800 ppmv (other species are negligible)

Siloxanes: "Octamsil" (D4) 0.58 mg/m³ (50 ppbv); "Decamsil" (D5) 4.52 mg/m³ (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

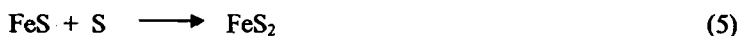
3.1 HYDROGEN SULFIDE REMOVAL SYSTEM

The hydrogen sulfide removal system consists of two vessels operating in parallel mode, each containing approximately 18 m³ of iron sponge. To establish the minimum recommended contact time of 60 seconds required for H₂S 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 H₂S 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 H₂S 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).



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).



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, FeSO₄. See Equation 6 below:



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 H₂S 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 Nm³H, the present average, 2800 Nm³H, the next planned increase, and 3800 Nm³H, 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 H₂S 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 H₂S AND SILOXANE REMOVAL

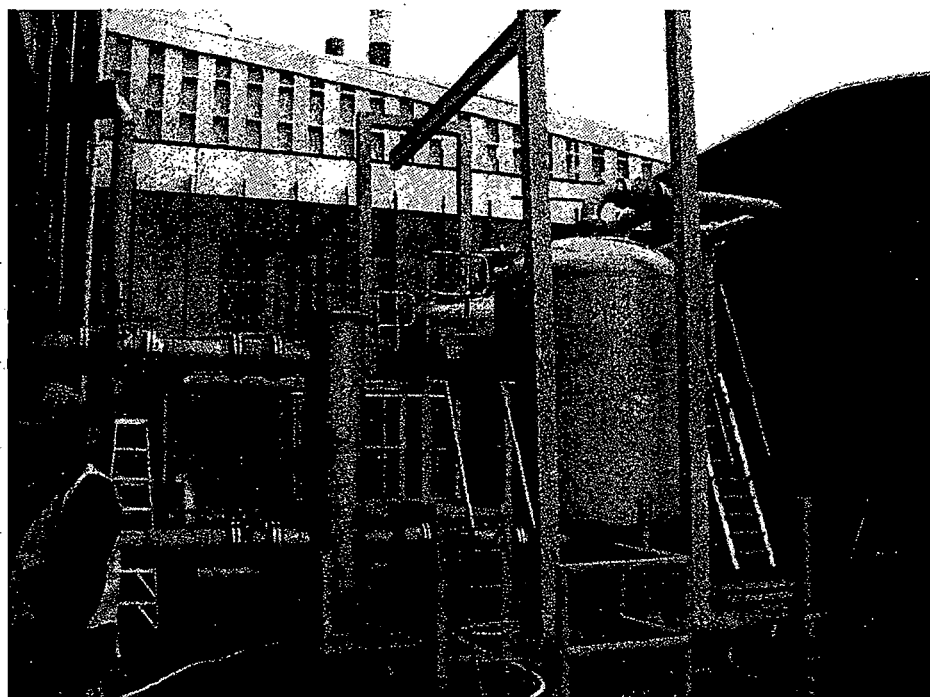
The savings in operation and maintenance costs on IC generator engines can be profound. Sometimes, the savings in just one maintenance item, like spark plugs, can be enough to economically justify installing a siloxane removal system. For IC generator engines, the typical payback period is usually between 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 Nm ³ H	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 H₂S 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 H₂S began to break through the SAG™ media. At this time the H₂S 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 H₂S was breaking through the SAG™ media above 200 ppmv. The impact of the H₂S 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	1,3,5-Trimethylbenzene
Freon 114	1,2,4-Trimethylbenzene
Chloromethane	1,3-Dichlorobenzene
Vinyl Chloride	1,4-Dichlorobenzene
Bromomethane	Chlorotoluene
Chloroethane	1,2-Dichlorobenzene
Freon 11	1,2,4-Trichlorobenzene
1,1,-Dichloroethene	Hexachlorobutadiene
Freon 113	Propylene
Methylene Chloride	1,3-Butadiene
1,1,-Dichloroethane	Acetone
Cis-1,2-Dichloroethane	Carbon Disulfide
Chloroform	2-Propanol
1,1,1-Trichloroethane	trans-1,2-Dichloroethene
Carbon Tetrachloride	Vinyl Acetate
Benzene	2-Butanone (Methyl Ethyl Ketone)
1,2-Dichloroethane	Hexane
Trichloroethene	Tetrahydrofuran
1,2-Dichloropropane	Cyclohexane
Cis-1,3-Dichloropropane	1,4-Dioxane
Toluene	Bromodichloromethane
trans-1,3-Dichloropropene	4-Methyl-2-Pentanone (MIBK)
1,1,2-Trichloroethane	2-Hexanone
Tetrachloroethene	Dibromochloromethane
Ethylene Dibromide	Bromoform
Chlorobenzene	4-Ethyltoluene
Ethylbenzene	Ethanol
m,p-Xylene	Methyl tert-Butyl Ether
o-xylene	Heptane
Styrene	Acrylonitrile
1,1,1,2-Tetrachloroethane	TPH or NMOC (Hexane/Heptane)

APPENDIX D

AFT METHOD SIL-1 SILOXANE SPECIES

Pentamethyldisiloxane (PMDS)

Hexamethyldisiloxane (MM)

Octamethyltrisiloxane (MDM)

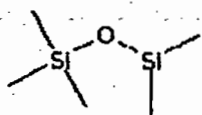
Octamethylcyclotetrasiloxane (D4)

Decamethylcyclopentasiloxane (D5)

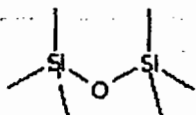
Dodecamethylcyclohexasiloxane (D6)

Molecular Structures: (at the end of each branch is a methyl group, CH₃)

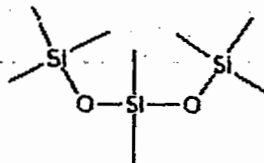
PMDS



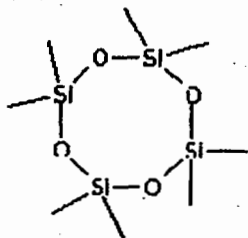
MM



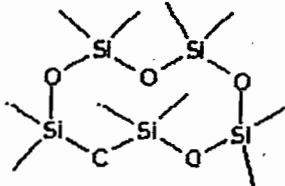
MDM



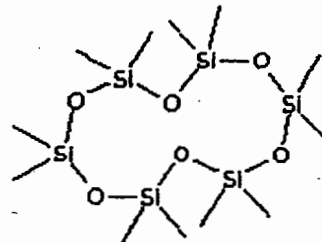
D4



D5

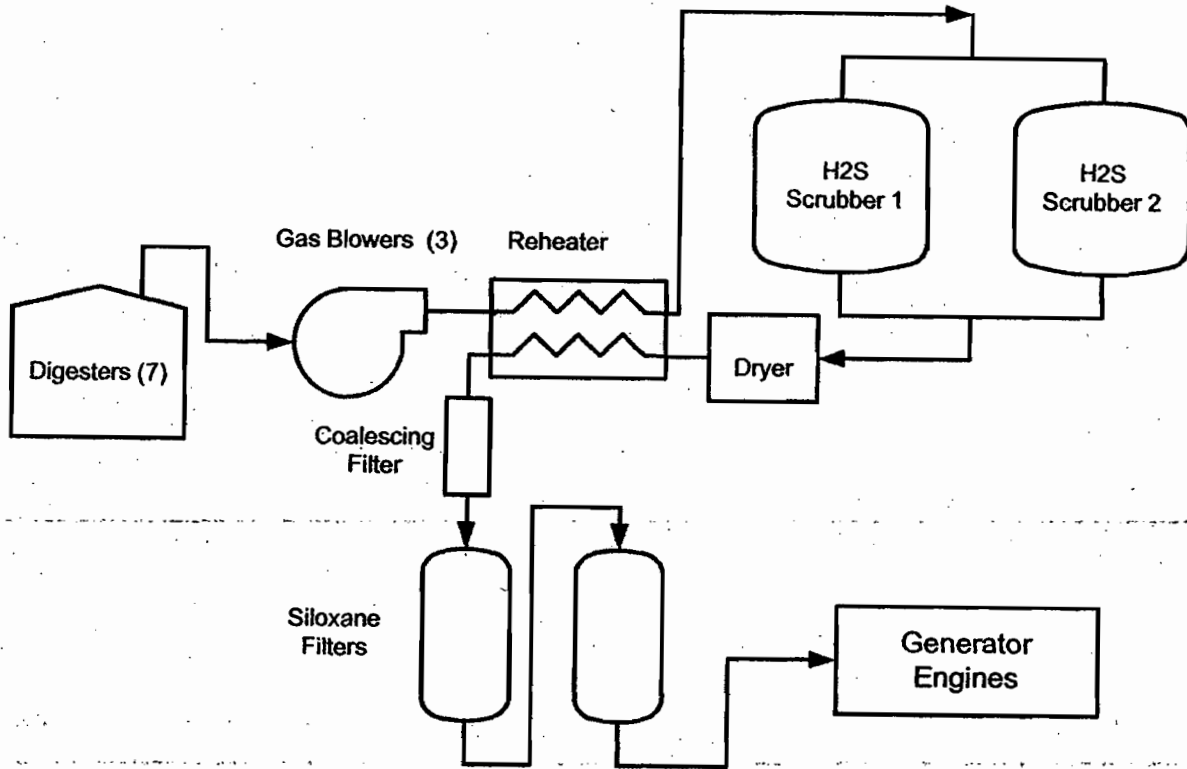


D6



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, Nm ³ H	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 ₂ S 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	Estimated SAG Media Life, Days	
		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



Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
Telephone: (850) 488-0114 FAX: (850) 922-6979

Colleen M. Castille
Secretary

September 1, 2006

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

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

Re: DEP File No. 0930104-014-AC and 0930104-015-AV
Berman Road Landfill Facility
Okeechobee Landfill, Inc.
Waste Management, Inc. of Florida

Dear Mr. Van Gessel:

On July 28, 2006 the Department received electronic notification of an air construction permit application for the construction of additional flares, other improvements planned at the Berman Road Landfill and to revise the facility's Title V Operation Permit. We received the fee of \$7,500 on August 4 that is required for an application for an Air Construction Permit pursuant to the Rules for the Prevention of Significant Deterioration of Air Quality (AC/PSD Permit).

The application was submitted with a transmittal letter prepared by Shaw Environmental & Infrastructure Inc. (Shaw). Shaw stated "the short time frame for the application's submittal precluded completion of detailed discussions with vendors and other necessary tasks necessary for a final BACT selection". Shaw also stated "since the BACT has not been chosen as yet, the ambient air impact analysis has not been completed".

A description as to what system of continuous emissions reduction is planned and a best available control technology (BACT) proposal are needed in accordance with Paragraph 62-212.400(4)(c), F.A.C. Also Source Impact Analysis, Air Quality Analysis, and Additional Impact Analyses are also needed as described in Paragraphs 62-212.400(5), (7), (8), and possibly (9), F.A.C. depending on effects upon Class I areas.

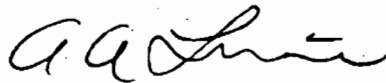
According to the information submitted, the emissions increases for the proposed projects will exceed the respective significant emissions rates for several pollutants. The key pollutant subject to PSD and that Shaw concentrated on is sulfur dioxide (SO₂). It appears that emissions increases of nitrogen oxides (NO_x), carbon monoxide (CO), and particulate matter (PM₁₀) also exceed their respective significant emissions rates. Therefore ambient analyses and a BACT proposal are required for the additional pollutants.

A great deal of very useful information was provided in the application. In the mentioned letter, Shaw requested a meeting "to discuss the application" and our engineer, Ms. Teresa Heron, advised them to let us know when they would like to meet with us. We understand Shaw is planning to meet with us this month. We can also discuss the information necessary to complete the application.

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."

We will forward any comments from EPA Region IV and the National Park Service as soon as they are received. If you have any questions regarding this matter, please contact Ms. Heron at 850/921-9529 or Debbie Nelson (meteorologist) at 850/921-9537.

Sincerely,



A.A. Linero, Program Administrator
South Permitting Section

AAAL/th

cc: Mike Stallard, Waste Management, Inc (via e-mail)
Joe Fasulo, Okeechobee Landfill, Inc (via e-mail)
Kristin Alzheimer, P.E., Shaw Environmental & Infrastructure, Inc (via e-mail)
Bruce K. Maillet, Shaw Environmental & Infrastructure, Inc (via e-mail)
Jim Little, U.S. EPA, Region 4 (via e-mail)
Darrel Graziani, Southeast District Office (via e-mail)
John Bunyak, National Park Service (via e-mail)



Shaw® Shaw Environmental & Infrastructure, Inc.

July 28, 2006

A World of
VIA EPSAP
(FDEP Permit Application Online Submittal Process)

Ms. Trina Vielhauer
Chief, Bureau of Air Regulation
Division of Air Resource Regulation
2600 Blair Stone Road MS# 5505
Tallahassee, FL 32399-2400

Subject: Title V PSD Permit Application No. 1270-1
Okeechobee Landfill, Inc. Facility ID No. 0930104-014-DC

Dear Ms. Vielhauer;

On behalf of Okeechobee Landfill Inc. (OLI) Shaw Environmental and Infrastructure, Inc. has attached, through the EPSAP, the application for a Title V PSD construction and operation permit for the proposed flares project at the Okeechobee Landfill. We have completed the application forms and have supplied the detail necessary for FDEP to begin their evaluation of the proposed project. As you are aware from our meeting on June 9, 2006, this application was submitted in accordance with the first amendment to the consent agreement between Okeechobee Landfill, Inc. (OLI) and FDEP. The proposed project is to control the landfill gas being produced from the landfill by flaring and to reduce odors by another temporary flare. The temporary flare is part of the amended consent decree.

In developing the flare project, OLI considered the expected landfill gas flow rate, which peaks at over 14,000-scfm in 2011 for the "Berman Road" section of Okeechobee landfill. Currently, based on daily measurements in June 2006, the average gas flow rate to the existing flares is approximately 5400 scfm. At our current permitted capacity of 6,000-scfm, there is only a small margin (little more than 10%) for any gas production increases. Additional wells that are scheduled to be connected to the gas system could easily consume the remaining 600-scfm. Additionally, while the facility is well below the projected estimate for 2011, this permit application with emission rates and increases, current H₂S inlet gas levels, proposed gas flaring equipment, PSD, and BACT components are being developed to proactively address the not to distant operational needs for 15,000-scfm of flaring capacity.

This permit application is unique compared to typical PSD applications and projects. Typically, the PSD applications cover a new facility or a facility modification while still in the planning stages. In the planning stages, a project can be cancelled or located elsewhere if air emission complexities prevent it from being economically feasible. Additionally, there is typically less time constraint because the typical projects do not have increased emissions unless the project is implemented. In the case of Okeechobee, the facility exists and is permitted by Florida DEP as a solid waste landfill, and the landfill gas generation will increase under the current planned permitted project. Socially and economically, the landfill is necessary for State and local residents. The facility has supported and is designated for natural disaster response efforts for accepting increased and specialized waste streams.

The permit application includes a BACT analysis that has been completed for the selection of the two most economically effective control technologies given the current information compiled and landfill gas parameters. The BACT analysis compiled various technologies: conventional, beneficial and

Ms. Trina Vielhauer
FDEP Division of Air Resource Regulation
Permit Application No. 1270-1, 0930104

innovative. The short timeframe allowed for the application's submittal precluded completion of detailed discussions with vendors and others necessary tasks necessary for a final BACT selection.

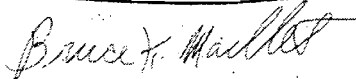
One of the options, OLI is considering is the beneficial use of the landfill gas in a coal-fired power plant located in Indiantown. This option, which is only in the feasibility phase, may allow the beneficial use of the landfill gas while reducing the emissions of sulfur dioxide and carbon monoxide that would have been produced by the landfill. Transmitting the landfill gas to the Indiantown facility via a pipeline to be used in their existing coal-fired boiler, which would be modified to receive the landfill gas, would support lower-cost electricity production and control emissions from landfill because the plant is already equipped with air pollution controls for sulfur dioxide. This project would be considered Renewable Energy. The amount of landfill gas available for use in the power plant could be the equivalent of up to 495,000,000 Btus per hour in 2011. This is the equivalent of 2.5 tons of coal per hour.

The eventual BACT selection will be dependent on a number of issues, including contracts, water requirements; waste and waste water disposal, and energy requirements. Once the BACT is selected and enough design details developed, OLI will be able to set an emission rate for SO₂. At that time, this emission rate will be used in the ambient air impact analysis and any interactive modeling required to support the project. Since the BACT has not been chosen as yet, the ambient air impact analysis has not been completed.

This application has been prepared to meet the requirements of the first amendment of the consent agreement. We feel this application demonstrates the intent of OLI to meet FDEP's requirements. We are available to answer any questions you may have on the project and this application.

We kindly request a meeting to discuss this application. If possible, please copy me on any correspondence with the Professional Engineer and Responsible Official so that I may timely support you and our project permitting team.

Sincerely
Shaw Environmental & Infrastructure, Inc.




Bruce K Maillet
Senior Consultant for Air

CC:

Mike Stallard, Okeechobee Landfill, Inc., Responsible Official
Kristin Alzheimer, P.E, Shaw Environmental & Infrastructure, Inc.

FYI -
Debbie



Electronic Permit Submittal and Processing System (EPSAP) Professional Engineer Signature Document

"This document is signed and sealed to secure the data in this permit application and any attached files that were submitted electronically as described in Florida Department of Business and Professional Regulation, Board of Professional Engineers, Procedures for Signing and Sealing Electronically Transmitted Plan, Specifications, Reports or other Documents, Rule 61G15-23.003., F.A.C."

EPSAP Application Number: 1270-1

Facility Identification Number: 0930104

Facility Owner/Company Name: OKEECHOBEE LANDFILL, INC.

RECEIVED

AUG 02 2006

DEPT OF ENV PROTECTION
WEST PALM BEACH

Purpose of Application:

Air construction permit and Title V permit revision, incorporating the proposed project.

Signature File Created: 7/28/2006 3:37:19 PM

File Description	Authentication Code
Submitted Application Data	A26E2D5AE1B80D585EB88003709789494E300AF6
Uploaded Facility Documents:	
Appendix F - Facility and EU Compliance Report and Plan.pdf	1D79D79957654E2D0F192893BB0577402A0C909D
Appendix J - Ambient Impact Analysis.pdf	81925C982D744B2FC8D0391AA5EB16472350C06C
Title Page Okeechobee Permit App 1270-1.pdf	EE925C4F03EECF8CAB30A0448BDF7F89906DA0D7
Appendix D - List of Insignificant Activities.pdf	7D36C062094083AED69E7D974AF8500BC6A6127B
Appendix B - Facility Process Flow Diagram.pdf	AFE545C224AFA5B341B73725C580F25340269A37
Appendix A - Facility Plot Plan.pdf	E0BF2BACB08B868DCF28BCA8D262FB9868CB5A53
Appendix L - Facility Permit History.pdf	F5FAA11DBB505DCB48C62D4D8C126CEF6BDA77EE
Appendix G - Requested Changes to Current V permit .pdf	81B3794DFC9874B88AEDAAE56969B5988C8CFDE8
Appendix E - Identification Applicable Requirements.pdf	B7F12E817A672BA9D6D38531A9DDB28706634280
Appendix H - Description Proposed Construct and Mod.pdf	45A1D1DCED4FA615DBAEADCEEBA2D4DFB093B665
Appendix C - Unconfined Particulate Matter.pdf	BF70C2BA944C51E928EB5C99BD0CDF5137B281AF
Appendix K - Support Calculations.pdf	2341A735B4E8C42DB0B89A2CD5D1D44738104F6B
FDEP App No. 1270-1 Cover Letter.pdf	BBDC26CC452CC1A353F3DE2FFB9B28507C9EF988
Appendix I - Rule Applicability Analysis rev1.pdf	28188BF322F242B0E1F46C05795535C257A5A478
Uploaded Emissions Unit Documents:	
Appendix R - O and M Plan.pdf	0696195F30A8C727948E0C7DA06122276DC4E65A
Appendix Q - Procedures for startup and shut down.pdf	B0BB145E687B58CABCAAC5DEE2353634CFFC9018
Appendix M1 - Process Flow Diagram.pdf	F53DF1242BAD6F0B9D734CE807B5527171961F92
Appendix M2 - Process Flow Diagram.pdf	25B8CD90A393E7D721E4AF5FDF423F5CA1E78895
Appendix T2 - EU Identification of Applicable Requirements.pdf	305B301B6FBE41C415CA055C411778CA3A33BD7E
Appendix T2 - EU Identification of Applicable Requirements.pdf	305B301B6FBE41C415CA055C411778CA3A33BD7E

DEP ROUTING AND TRANSMITTAL SLIP

TO: (NAME, OFFICE, LOCATION) 3. _____
1. Alvaro Linero 4. _____
2. _____ 5. _____

PLEASE PREPARE REPLY FOR:

- SECRETARY'S SIGNATURE
- DIV/DIST DIR SIGNATURE
- MY SIGNATURE
- YOUR SIGNATURE
- DUE DATE _____

ACTION/DISPOSITION

- DISCUSS WITH ME
- COMMENTS/ADVISE
- REVIEW AND RETURN
- SET UP MEETING
- FOR YOUR INFORMATION
- HANDLE APPROPRIATELY
- INITIAL AND FORWARD
- SHARE WITH STAFF
- FOR YOUR FILES

COMMENTS:

Air Resources
Mail Station
5500

RECEIVED

AUG 03 2006


BUREAU OF AIR REGULATION

FROM: Behram Fardoe DATE: 8/3/06 PHONE: 507-226-6625

Appendix N - Fuel Analysis.pdf	775124230336A4342A1963AD207DB348F423AA0C
Appendix Q - Procedures for startup and shut down.pdf	B0BB145E667B58CABCAAC5DEE2353634CFFC9018
Appendix S - Compliance Demonstration Reports.pdf	7D8D9EEF3C815F5EE60BCA762D0F96C745B64174
Appendix N - Fuel Analysis.pdf	775124230386A4342A1963AD207DB348F423AA0C
Appendix Q - Procedures for startup and shut down.pdf	B0BB145E687B58CABCAAC5DEE2353634CFFC9018
Appendix R - O and M Plan.pdf	0696195F30A8C727948E0C7DA06122276DC4E65A
Appendix N - Fuel Analysis.pdf	775124230386A4342A1963AD207DB348F423AA0C
Appendix V - Good Engineering Practice Stack Height Analysis.pdf	6FD2D146AF3F73BD035BA9FC9A6DE57BF9A21562
Appendix M2 - Process Flow Diagram.pdf	25B8CD90A393E7D721E4AF5FDF423F5CA1E78895
Appendix V - Good Engineering Practice Stack Height Analysis.pdf	6FD2D146AF3F73BD035BA9FC9A6DE57BF9A21562
Appendix V - Good Engineering Practice Stack Height Analysis.pdf	6FD2D146AF3F73BD035BA9FC9A6DE57BF9A21562
Appendix R - O and M Plan.pdf	0696195F30A8C727948E0C7DA06122276DC4E65A
Appendix V - Good Engineering Practice Stack Height Analysis.pdf	6FD2D146AF3F73BD035BA9FC9A6DE57BF9A21562
Appendix O - Detailed Description of Equipment.pdf	E0E7D364C9BDD6271FD3B082724D620C27CF6FB6
Appendix O - Detailed Description of Equipment.pdf	E0E7D364C9BDD6271FD3B082724D620C27CF6FB6
Appendix P - EU003 Stack Sampling.pdf	51AE0B33A29D4143A255FC93CDF7A96E01AA18E9
Appendix T1 - EU Identification of Applicable Requirements.pdf	F8975A2A65820A946599E217B11079C3C788617B
Appendix U - Control Technology Review and Analysis (PSD Report) rev1.pdf	A502162C417C9F218CF6047C5C13C320DD2290AC
Final Signature File	8522B0B3D3EF1D9043B0F41B4001398636C8DC54

Professional Engineer (PE): KRISTIN ALZHEIMER License No: 43456

(sign and affix PE seal below)


 PE Signature _____ Date 7/28/06



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NOV 28 2006

BUREAU OF AIR REGULATION

OKEECHOBEE LANDFILL, INC.
A WASTE MANAGEMENT COMPANY

10800 NE 128th Ave.
Okeechobee, FL 34972
(863) 357-0111
(863) 357-0772 Fax

November 27, 2006

Florida Department of Environmental Protection
Attn: Ms. Teresa Heron, Permit Engineer
2600 Blair Stone Road, MS-5505
Tallahassee, FL 32399-2400

Subject: Request for Permit Addendum Submission
Application No. 1270-1
Facility Identification Number 0930104 (Site Name: Okeechobee Landfill, Inc.)
Okeechobee, FL

Dear Ms. Heron:

Okeechobee Landfill Inc. respectfully requests an extension for the submittal of additional information requested by FDEP in a letter of August 30, 2006 and subsequent meetings and discussions between FDEP and Okeechobee Landfill. This request relates to the Air Construction Permit application that was submitted on July 28, 2006. Application No. 1270-1 was for processing of a PSD construction permit application. Our request for concurrent processing of a revised Title V operating permit application was previously withdrawn.

This extension request is being made to accommodate project changes recently taken under consideration which involve including the entire site footprint currently permitted for waste disposal and subsequent revised modeling based upon our BACT determination. The changes being considered also include the proposal to include landfill-gas fired electricity generating turbines utilizing the entire gas flow and relegating the flaring system to a secondary role. The additional information being provided to FDEP for the project will result in modification to many parts of the application; the addition of equipment information not included in the previous submittal (the turbines) and, will affect air quality impact assessments as a consequence of these significant changes.

We feel confident that the revised information can be provided to you in a timely manner to complete the existing application.

Sincerely,

Mike Stallard
Director, Landfill Operations

Cc: Al Linero, FDEP
Joe Fasulo, OLI Miguel Delgado, OLI
Michele Lersch, OLI David Thorley, OLI
Kris Alzheimer, P.E., Shaw
Bruce Maillet, Shaw
Kelly Fagan, Shaw

December 22, 2008

A.A. Linero, P.E.
Program Administrator
Air Permitting South Section
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, FL 32399-2400

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DEC 23 2008

BUREAU OF AIR REGULATION

**RE: Response to Comments, Florida Department of Environmental Protection Letter
Dated December 11, 2008 for Okeechobee Landfill
DEP file No. 0930104-014-AC, Application No. 1270-3**

Dear Mr. Linero:

On December 11, 2008, Waste Management, Inc. of Florida received a request for information from the Florida Department of Environmental Protection (FDEP) in response to the permit application (DEP File Number 0930104-014-AC). Attached is the response to your request for information provided by Shaw Environmental, Inc. (Shaw).

The requests made by FDEP are detailed below along with our response.

Comment 1. The application states (page 11, Section 5.2 of the PSD report) that the best available control technology (BACT) section has not been revised. The Department acknowledges that there is no need to review the BACT analyses referring to the LoCat desulfurization system. However, the BACT for the new proposed turbines needs to be addressed. Appendix B of the application lists for the primary operating scenario potential emissions of nitrogen oxides (NO_x) emissions in the order of 765.3 tons per year (TPY), sulfur dioxide (SO₂) 574.8 TPY, and carbon monoxide emissions in the order of 5,0542 TPY. The individual emission rates for NO_x are 72 parts per million, by volume (ppmv) for the Titan and 42 ppmv for the Centaur. CO is listed as 100 ppmv for the Titan and 250 ppmv for the Centaur.

The Department needs a description as to what system of continuous emissions reduction is planned and a best available control technology (BACT) proposal 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.

Response 1.

The proposed Titan 130 and Centaur 40 turbines operate under the same principles of combustion of LFG as the earlier proposed Mars turbines; the difference is in capacity. Therefore, the BACT analysis for the new proposed turbines, Titan 130 and Centaur 40 manufactured by Solar, remains the same as presented in Appendix D of the application 1270-2 submitted on February 27, 2007. In summary, "good combustion practices" will be the BACT for NO_x, CO, and PM for these turbines. The emission rates for the proposed turbines are different than the previously proposed Mars Turbines as mentioned in the above comment.

Attachment 1 includes the revised BACT determination and the revised BACT emission rates for the proposed turbines. Please note that the BACT determination reflects our review of the RBLC database.

Comment 2. Section 2.4 of the addendum to the application states that for the modeling purposes, more recent and averaged H₂S data were used. Please provide the time period of the data used in the modeling. Also, please explain how the new data was averaged.

Response 2. In the October 2008 Addendum, there was no change in the H₂S data from the February 2008 Air Quality Analysis report. The H₂S value considered for the BACT scenarios is 400 ppmv based on the estimated performance of the Lo-Cat system. The H₂S values for the interim scenarios are shown in the table below and were measured from July to November 2007. As shown in the table below, the H₂S concentration data was averaged for the enclosed flares and for the odor control (open) flare. These averages were used for the interim modeling scenarios.

2007 Month	H ₂ S Concentration (ppmv)	
	Enclosed Flares	Odor (Open Flare)
July	3600	3733
August	3133	3100
September	1017	4900
October	5467	7033
November	1733	6167
Average	2990	4986.6

Comment 3. Section 4.3.1 of the addendum to the application explains the receptor grid for the Ambient Air Quality Standard (AAQS) and Increment analyses. Please clarify or verify that a 50 km buffer was used for all analyses and that no further than 100 meter spacing of receptors were used where higher concentrations were found. Please also verify that a 50 km fence-line grid was used for the Significant Impact Analysis for PM₁₀.

Response 3. The Significant Impact Analysis receptor grid for all pollutants extended to approximately 30 km from the fence-line. Shaw believes that this receptor grid is sufficient for capturing the location of the maximum impacts from the project sources. All maximum concentrations were close to the fence-line and the maximum radius of impact (ROI) was 3.2 km from the sources (for 24-hr SO₂).

No further than 100 meter spacing of receptors were used where higher concentrations were found. Once the ROI was found for each pollutant, Shaw requested the off-property inventory for sources from FDEP that are located within the ROI plus 50 km (i.e. the 50 km buffer), which were then included in NAAQS and PSD increment compliance demonstration.

December 22, 2008

Comment 4. With regards to Appendix B on disk, please explain why there are different inventories for scenario 2B and scenario 2. Also, please explain the following with regards to the excel spreadsheets: what do the terms "Deleted – Duplicate Entry" and "Deleted – No Emission Information" mean, why is the Berman Road Landfill on the NO_x list for "Deleted – No Emission Information," why do the tables show blank cells in the column for whether the sources is within the Significant Impact Area, and why all of the sources inside the impact area are not shown whether or not they were modeled in the adjacent column.

Response 4. Shaw discussed this comment with Debbie Nelson on December 16, 2008. As previously discussed, there are two different inventories for scenario 2B and scenario 2 because the ROI is different for these scenarios.

Those sources in the off-property inventory provided by FDEP which had a blank for the emissions data were deleted and marked as "Deleted – No Emission Information." There were a few sources in the inventory that were duplicate entries, and were marked as "Deleted – Duplicate Entry." All Okeechobee Landfill, Inc. sources listed in the off-property inventory were deleted because these sources were already included in the model as on-site sources.

The tables show blank cells if the source is not within the criteria (ex. not within the area of impact). The final column in the spreadsheet is the final determination if the source should be included in the modeling. Appendix B was explained to and discussed with Debbie Nelson on December 16, 2008 with regards to these comments.

If there are further questions on the application, please contact the David Thorley at 713-328-7404.

Sincerely,



Kelly Fagan, P.E.
Project Manager

Seal



Kristin A. Alzheimer, P.E.

Attachment

Cc: John Van Gessel, Waste Management, Inc. of Florida: jvangessel@wm.com
Seth Nunes, Okeechobee Landfill, Inc. snunes1@wm.com
Jim Christiansen, Okeechobee Landfill, Inc.: jchristi@wm.com
David Thorley, Okeechobee Landfill, Inc.: dthorley@wm.com
Arijit Pakrasi, Shaw Environmental: arijit.pakrasi@shawgrp.com
Leah Blinn, Shaw Environmental: leah.blinn@shawgrp.com



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?

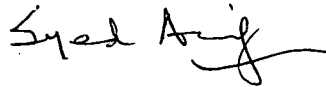
2. Submit Siloxane Contamination Information for the Okeechobee Landfill. List the concentration (ppmv or mg/m³) of the following contaminants in the landfill gas: Tetramethylsilane; Tetramethyldisiloxane; Pentamethyldisiloxane; Hexamethyldisiloxane; Octamethyltrisiloxane; Hexamethylcyclotrisiloxane; 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 NO_x emissions was not selected for this project instead of the Centaur 40 (3.5 MW) with a 42 ppm NO_x emissions and the Titan (15 MW) with a 72 ppm NO_x 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 NO_x emissions.
5. Submit a BACT analysis including \$/ton of NO_x 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 NO_x and CO Controls Cost Analysis for the Centaur and Titan turbines. In reviewing the information, we noticed that the vendor's quote for NO_x 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
David Unger, Waste Management, Inc. dunger@wm.com
David Buff, Golder Associates, Inc. dbuff@golder.com
Dee Morse, National Park Service, Denver CO: dee_morse@nps.gov
Lennon Anderson, DEP SED: lennon.anderson@dep.state.fl.us
Jack Long, DEP SED: jack.long@dep.state.fl.us
Heather Abrams, U.S. EPA Region 4: abrams.heather@epa.gov
Kathleen Forney, U.S. EPA Region 4: forney.kathleen@epa.gov

Livingston, Sylvia

From: Livingston, Sylvia
Sent: Wednesday, May 06, 2009 4:48 PM
To: 'jvangessel@wm.com'
Cc: 'dthorley@wm.com'; 'snunes1@wm.com'; 'jchristi@wm.com'; 'dunger@wm.com'; 'dbuff@golder.com'; 'dee_morse@nps.gov'; Anderson, Lennon; Long, Jack; 'abrams.heather@epamail.epa.gov'; 'forney.kathleen@epa.gov'; Gibson, Victoria; Walker, Elizabeth (AIR); Arif, Syed
Subject: RAI -0930104-014-AC/PSD-FL-382 (Berman Road & Clay Farms Landfills)
Attachments: RAI 0930104-014-AC.pdf

Dear Sir/Madam:

Please send a "reply" message verifying receipt of the attached document(s); this may be done by selecting "Reply" on the menu bar of your e-mail software, *noting that you can view the documents*, and then selecting "Send". We must receive verification of receipt and your reply will preclude subsequent e-mail transmissions to verify receipt of the document(s).

The document(s) may require immediate action within a specified time frame. Please open and review the document(s) as soon as possible.

The document is in Adobe Portable Document Format (pdf). Adobe Acrobat Reader can be downloaded for free at the following internet site: <<http://www.adobe.com/products/acrobat/readstep.html>> .

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Thank you,

Sylvia Livingston
Bureau of Air Regulation
Division of Air Resource Management (DARM)
850/921-9506
sylvia.livingston@dep.state.fl.us

Livingston, Sylvia

From: VanGessel, John [JVanGessel@wm.com]
Sent: Thursday, May 07, 2009 11:07 AM
To: Livingston, Sylvia
Cc: Thorley, David; Nunes, Seth; Christiansen, Jim; Unger, Dave (Renewable Energy); dbuff@golder.com; dee_morse@nps.gov; Anderson, Lennon; Long, Jack; abrams.heather@epamail.epa.gov; forney.kathleen@epa.gov; Gibson, Victoria; Walker, Elizabeth (AIR); Arif, Syed
Subject: RE: RAI -0930104-014-AC/PSD-FL-382 (Berman Road & Clay Farms Landfills)

I have received your letter dated May 6th and was able to review the same. Thanks.

John Van Gessel
Group General Counsel
Waste Management
Suite 700
1000 Parkwood Circle
Atlanta, GA 30339
(770) 805 3350
jvangessel@wm.com

Waste Management's renewable energy projects create enough energy to power over 1 million homes.

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-----Original Message-----

From: Livingston, Sylvia [<mailto:Sylvia.Livingston@dep.state.fl.us>]
Sent: Wednesday, May 06, 2009 4:48 PM
To: VanGessel, John
Cc: Thorley, David; Nunes, Seth; Christiansen, Jim; Unger, Dave (Renewable Energy); dbuff@golder.com; dee_morse@nps.gov; Anderson, Lennon; Long, Jack; abrams.heather@epamail.epa.gov; forney.kathleen@epa.gov; Gibson, Victoria; Walker, Elizabeth (AIR); Arif, Syed
Subject: RAI -0930104-014-AC/PSD-FL-382 (Berman Road & Clay Farms Landfills)

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Thank you,
Sylvia Livingston

Livingston, Sylvania

From: Abrams.Heather@epamail.epa.gov
Sent: Thursday, May 07, 2009 8:22 AM
To: Livingston, Sylvania
Subject: Re: RAI -0930104-014-AC/PSD-FL-382 (Berman Road & Clay Farms Landfills)
Attachments: RAI 0930104-014-AC.pdf

Got it
Thanks!
Heather Abrams
Air Permits Section
U.S. EPA - Region 4
61 Forsyth St. SW
Atlanta, Georgia 30303

Phone: 404-562-9185
Fax: 404-562-9019

"Livingston,
Sylvania"
<Sylvia.Livingston@dep.state.fl.us>

05/06/2009 04:47
PM

<jvangessel@wm.com>

To

cc

<dthorley@wm.com>,
<snunes1@wm.com>,
<jchristi@wm.com>,
<dunger@wm.com>,
<dbuff@golder.com>,
<dee_morse@nps.gov>, "Anderson,
Lennon"
<Lennon.Anderson@dep.state.fl.us>
, "Long, Jack"
<Jack.Long@dep.state.fl.us>,
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Kathleen Forney/R4/USEPA/US@EPA,
"Gibson, Victoria"
<Victoria.Gibson@dep.state.fl.us>
, "Walker, Elizabeth \ (AIR\)"
<Elizabeth.Walker@dep.state.fl.us>
>, "Arif, Syed"
<Syed.Arif@dep.state.fl.us>

Subject

RAI -0930104-014-AC/PSD-FL-382
(Berman Road & Clay Farms
Landfills)