EVALUATING ALTERNATIVES FOR BIOGAS CLEAN-UP AND USE

FINAL REPORT 08-23
DECEMBER 2007

NEW YORK STATE
ENERGY RESEARCH AND
DEVELOPMENT AUTHORITY

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Evaluating Alternatives for Biogas Clean-up and Use

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Prepared for the

New York State Energy Research and Development Authority

Albany, NY
www.nyserda.org

Kathleen M. O'Connor, P.E.
Project Manager

Prepared by:

Malcom Pirnie, Inc.

NYSERDA Report 08-23 | NYSERDA | December 2007

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1.0 INTRODUCTION

1.1 PROJECT BACKGROUND

The Gloversville-Johnstown Joint Wastewater Treatment Facility (WWTF) located in Johnstown, New York operates under the New York State Pollution Discharge Elimination System (SPDES) Permit Number NY-0026042. The plant was designed for an average flow of 13 million gallons per day (mgd). Currently, peak flows treated at the WWTF can approach 30 mgd, with an average daily flow rate of 6 mgd. The plant treats domestic wastewater, landfill leachate, and industrial wastewater from leather tanning and finishing, textile corporations, and other major industries. The plant also accepts whey from a local dairy manufacturer and may begin accepting whey from a new dairy manufacturer in the near future.

Anaerobic digestion is employed by the WWTF as one element of its overall solids processing operations. Anaerobic digestion involves the decomposition of organic matter and inorganic matter in the absence of oxygen and results in a stabilized sludge and a reduction in the overall quantity of sludge that must be dewatered and managed. Digester gas containing approximately 65 percent methane is produced as a byproduct that can be recovered for beneficial reuse to meet electrical or thermal loads.

Digester gas that is produced at the WWTF is recycled by two gas compressors through the digester mixing system. Recovered gas is used to fire two on-site generator sets that produce electricity, which is used to offset commercially purchased power. Digester gas that is not burned in the generator sets is stored in an on-site gas holder and used during periods of low gas production. A flare is available to burn off excess gas that exceeds the storage capacity. Waste heat from the generator sets is used to maintain the temperature within the primary digester. When waste heat production is insufficient, natural gas is used as fuel for on-site boilers that are used to heat the primary digester.

Over the past few years, many operational and physical improvements have been made to the digester and cogeneration facility, which have resulted in increased biogas production and use, and subsequent increased on-site electrical power generation.

1.1.1 Purpose of Report

The objective of this study, which is being performed under the New York State Energy Research and Development Authority (NYSERDA) Program Opportunity Notice 946, Advanced Clean-up & Emission Control Technologies for Biogas-fueled DG Systems, is to investigate alternatives for biogas clean-up in order to reduce wear and tear of the existing cogeneration engines, enable the use of alternative technologies for on-site electrical generation, or facilitate sale of the biogas to existing and proposed adjacent industries as an alternative to fossil fuel.

While increased biogas production has resulted in increased on-site electrical generation at the WWTF, it also has resulted in operation of the cogeneration engines in a manner different from what was originally envisioned, which resulted in significant wear and tear on the engines. The increased maintenance and repairs required to keep the engines operational are driving up the unit costs of on-site electrical generation and are possibly affecting the payback of the improvements that have been made to date. Under current operations, the WWTF flares a portion of the biogas produced because of capacity limitations of the existing engines. The amount of biogas that is wasted to flare will increase significantly once additional whey begins to be received, unless electrical generation capacity is expanded or gas recovery and use operations are modified.

1.1.2 Scope of Work

The scope of work for this study includes the following tasks to improve biogas quality and use:

- Review existing operations and proposed future modifications.
- Evaluate the potential impacts of proposed modifications on biogas production.
- Assess biogas quality at the plant.
- Assess potential impacts of gas impurities on existing cogeneration equipment.
- Identify alternative technologies for clean-up of the biogas.
- Evaluate the feasibility of alternative end uses of the biogas if a clean-up device is installed, including an evaluation of potential regulatory implications.

1.2 FACILITY DESCRIPTION

The WWTF includes the following unit operations:

- Parshall Flume
- Primary Settling Tanks
- Aeration Tanks
- Final Settling Tanks
- Rotary Drum Thickener
- Gravity Thickeners
- Anaerobic Digesters
- Belt Filter Presses

1.2.1 WWTF Flow

Approximately 5 to 6 mgd of wastewater (during dry weather) flow into the plant through the screens and grit removal channels before entering the three primary settling tanks. The primary effluent combines with return activated sludge (RAS) from the aeration tanks and the equalized wet weather flow from the equalization basins and is directed to the aeration tanks. Effluent from the aeration system enters the four final settling tanks and the final effluent is discharged into the Cayadutta Creek.

1.2.2 Sludge Handling and Recycle Flows

The sludge from the primary settling tanks is pumped to the gravity thickeners at an average rate of 180,000 gpd. Waste activated sludge (WAS) from the final settling tanks is directed to the rotary drum thickener before being pumped to the primary anaerobic digester at a rate of 11,000 gpd. In the anaerobic digester, the thickened WAS is combined with thickened primary sludge and with whey, which is pumped at a rate of 7,500 gpd from the whey holding tank. The combined sludge is anaerobically digested in a two-stage digestion process and then dewatered using a belt filter press before being transported off-site to the local landfill. The supernatant and filtrate from the gravity thickeners, anaerobic digesters, and belt filter presses are recycled back to the head of the primary settling tanks for treatment.

1.2.3 Whey Treatment

Approximately 10,000 gallons of whey from a local dairy manufacturer are delivered to the plant by truck each weekday. To provide the WWTF with greater operating control and flexibility, a new 100,000 gallon whey holding tank was recently constructed. Whey is discharged to the holding tank and pumped from the tank into the primary anaerobic digester at a constant rate.

1.2.4 Biogas Production

The digester gas production in the first months after the operational improvements averaged over 130,000 cubic feet per day (cfd). Due to capacity constraints associated with the cogeneration engines, approximately 10 percent of the biogas could not be used in the engines and was flared.

Digester gas quality can be indicated by its methane content. Higher methane percentages correspond to higher heating values and are generally indicative of better operating conditions. Typically, digester gas contains 55 to 70 percent methane with carbon dioxide representing the majority of the remaining volume. Hydrogen sulfide, nitrogen, particulates, and water vapor also are present in minor percentages. Hydrogen sulfide and other impurities such as siloxane and struvite contribute to the wear and tear of the cogeneration engines. During the study period, the average amount of carbon dioxide in the digester gas sampled at the WWTF was 24 percent, which indicates a methane content of approximately 75 percent. The existing gas clean-up system consists of a sediment trap and Winslow sock filters.

1.2.5 Description of Existing Cogeneration

The biogas produced at the anaerobic digesters is used by two 150 kW Caterpillar cogeneration engines to produce electricity. Approximately 1,756,500 kWh are generated every year. The units are designed to run on natural gas, are 15 years old, and are no longer in production. Maintenance is performed regularly on the engines, including the complete rebuild of the engines approximately once every four years. The maintenance cost on the cogeneration equipment for 2005 was approximately $60,000. Engine rebuilding costs are approximately $45,000 per engine. The calculated maintenance cost per kWh generated is $0.047/kWh.

2.0 ANAEROBIC DIGESTION AND COGENERATION SYSTEM

2.1 CURRENT OPERATIONS

The existing anaerobic digestion facility was constructed at the WWTF in the early 1990s with the addition of the digester building, energy recovery building, and sludge day tank. A significant upgrade, which included draining and cleaning both digesters, replacing the mixing systems, modifying the floating secondary digester cover to operate as a fixed cover, and adding a gasholder membrane, was completed in 2005.

The WWTF is designed to treat 13 mgd of sewage using an activated sludge process with the capability for separate-stage nitrification. The WWTF treats sanitary wastewater from the cities of Gloversville and Johnstown, commercial and institutional users, landfill leachate, and 30 permitted industrial users. The industrial users account for approximately 20 percent of the influent flow and are mainly leather tanning and finishing and textile corporations. These industries predominantly operate during the first months of the year, resulting in seasonal variations of the plant influent and characteristics.

Primary sludge is pumped to the cyclone degritters and grit classifiers and then to the gravity thickener. Thickened sludge is pumped to the primary anaerobic digester; ferrous chloride is added on line to control the hydrogen sulfide concentration in the digester gas by precipitating iron sulfides within the primary digester and for odor control. Secondary sludge is pumped to the gravity thickener and mixed with the primary sludge every two hours. When not being pumped to the gravity thickener, secondary sludge is pumped to a rotary drum thickener and then pumped to the primary digester; in either path, the primary and secondary sludge are always mixed before feeding the primary digester.

Whey is stored in a holding tank and pumped into the primary anaerobic digester at a fixed rate for treatment in the anaerobic digesters.

Primary and secondary sludge and whey are digested in the primary digester. Almost all of the stabilization and gas production occurs in this tank. Digestion is improved by mixing the sludge with gas collected from the primary and secondary digesters. Mixing also is achieved by recirculating the sludge into the primary digester; the sludge recirculation pump also has the function to mix warm sludge from the digester with the influent sludge to avoid temperature shocks. Heating is achieved by recirculating the sludge from the primary digester to a spiral heat exchanger and back to the digester using the heat exchanger feed pumps. Hot water can be supplied to the heat exchanger by the cogeneration system or by dual fueled boilers at a rate of 510 gallons per minute (gpm).

The secondary digester is neither heated nor mixed under current operations, but it is equipped with gas mixers. The new gas mixing equipment for the primary and secondary digesters was installed in 2004. The primary functions of the second-stage digester are to: provide quiescent conditions for solids-liquid separation; provide short-term storage for digested sludge to improve flexibility of sludge dewatering operations; provide storage for digester gas; and serve as standby primary digester in case of process upset. Digested sludge is transferred by gravity from the secondary digester to the digested sludge holding tank (day tank). When dewatering operations are being performed, digested sludge is transferred from the day tank to belt filter presses for mechanical dewatering. Sludge cake is disposed of at a landfill.

Gas collected from the digesters is stored in the gasholder membrane and used as fuel by the gas engine generators (cogeneration systems) and the hot water boilers. The generator sets produce electricity that is used on-site and waste heat. The waste heat is recovered from the generator cooling and exhaust systems and is used to heat the cogeneration building and the primary digester. When digester gas production is insufficient to provide the required energy requirements for the generators, the system automatically switches to natural gas. The system must be manually switched back to digester gas. In addition, maintenance personnel occasionally run the generator on natural gas in an effort to help clean the internal combustion engine and extend the life of the generator sets. Two hot water boilers are used to increase the temperature of the cogeneration building hot water system in the event that the quantity of waste heat that is recovered from the cogeneration system is insufficient to heat the digester and the building. Gas that exceeds the storage capacity of the gasholder membrane is burned in the flare.

2.2 EXISTING EQUIPMENT

The digester building includes a two-stage anaerobic sludge digestion system, which consists of one 90-foot-diameter primary digester equipped with a floating cover; one 90-foot-diameter secondary digester equipped with a fixed cover; a membrane gasholder; and appurtenant equipment for digester heating, mixing, and gas collection. Both digesters are equipped with gas mixing systems. However, under normal operation, only the primary digester is mixed. Each tank is equipped with a pressure relief system to maintain the pressure within the tanks at the desired operating pressure.

The primary digester operates with a sidewater depth of approximately 32 feet, which results in an approximate volume of 1.5 million gallons. An unvalved overflow is provided for the gravity transfer of digested sludge to the secondary digester. The height of the unvalved overflow is adjustable over a 2-foot range. The primary digester is equipped with a floating steel, truss-type, duodeck cover manufactured by the Ralph B. Carter Company. The cover is designed to float upon the liquid contents of the tank, and it is ballasted to provide an operating gas pressure of 9 to 10 inches water column with 50 percent submergence of the ceiling plates. The liquid level in the primary digester is variable over a 1.5-foot range. The digester is equipped with a gas recirculation system for mixing the contents of the digester. The system includes a "piston bubble" turbomixer digester gas mixing system.

The second-stage digester operates with a maximum sidewater depth of 28 feet. A sludge draw-off from the digester bottom is provided. Digester supernatant is displaced to an unvalved overflow box with the height adjustable over a 2-foot range. The secondary digester is equipped with a steel, duodeck, gasholder cover manufactured by the Ralph B. Carter Company. The cover was designed to float directly on the liquid contents of the digester and provide for gas storage. Frequent problems with the floating cover caused the cover to tilt and leak gas, and a project was undertaken to affix the cover in place to eliminate the risks and operating challenges associated with the floating cover and provide 47,000 cubic feet of additional gas holding storage.

Safety equipment for the gas system includes: two Varec Model 233 sediment and drip trap assemblies, manually operated drip traps, two 4-inch and two 6-inch Varec 450

Series thermal valve and flame trap assemblies, and one 6-inch Varec Model 386 back pressure regulator.

Two NAFCO Model 46080-F16B in-line gas filters are provided for removal of particulates from digester gas. One is located in the gas mixing compressor suction line, while the other is located in the gas utilization line. The filters have 8-inch inlet and outlet connections and are equipped with a stainless steel "demister mesh" for removal of water particles and a polypropylene fabric filter element for removal of particulates down to 5 microns. The entire unit is designed for a pressure drop of less than 0.05 inches of water column across a clean filter at a gas flow of 12,000 standard cubic feet per hour (scfh).

2.3 DIGESTER PERFORMANCE

Selected operating data are included in Table 2-1. Data are monthly averages of weekly WWTF monitoring during the period of December 2005 through May 2006 and are indicative of the operation of the solids handling system after the upgrade and modification of the anaerobic digesters were completed.

The variables used to estimate the digester performance are the solids retention time, digester load, and percent volatile solids reduction. The retention time required for the first-stage unit is normally between 10 and 20 days; the digester currently operates in the upper range. The typical organic loading rate for a standard rate digester is between 0.03 and 0.1 pounds (lb) total volatile solids per cubic foot of digester volume per day. The digester's organic loading is maintained around 0.1 lbVSS/cf-day, which indicates that the digester operates in the higher portion of the range. The volatile solids reduction varied from 42 to 54 percent with an average of 47 percent. Normal volatile solids reduction in anaerobic digestion ranges from 35 to 60 percent (EPA Procedure Design Manual). Primary sludge generally digests more completely than waste activated (secondary) sludge and gives a higher volatile solids reduction. Whey is readily digested and contributes to high volatile solids reduction.

Table 2-1: Selected WWTF Operating Data

Parameter	Unit	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	AVERAGE
Influent Sludge:								
Gravity Thickener Flow	MGD	0.029953	0.045996	0.03197	0.04133	0.04969	0.075622	**0.0457601**
Gravity Thickener Solids	%	6.2	4.4	5.9	4.9	4.0	3.5	**4.8**
Gravity Thickener Volatile Solids	%	75	73	64	66	73	72	**70**
Rotary Drum Thickener Flow	MGD	0.0079	0.0084	0.0116	0.0191	0.0126	0.0080	**0.0113**
Rotary Drum Thickener Solids	%	7.7	7.8	6.5	5.7	5.7	5.0	**6.4**
Rotary Drum Thickener Volatile Solids	%	85	85	85	85	84	84	**85**
Whey flow rate to digester	gal/day	9,857	8,057	7,857	8,572	5,007	5,630	**7,497**
Whey Solids	%	9.2	8.8	9.3	7.5	7.1	5.5	**7.9**
Whey Volatile Solids	%	90	90	90	88	90	87	**89**
Organic Loading to Digester	lbsVSS/day	22,540	21,928	20,768	23,973	19,570	20,175	**21,492**
Organic Loading Rate	lbsVSS/cf-day	0.11	0.11	0.10	0.12	0.10	0.10	**0.11**
Solids Retention Time	days	32	25	30	22	23	17	**25**
Influent Sludge Volatile Solids	%	81	79	75	75	78	74	**77**
Effluent Sludge Volatile Solids	%	66	66	63	63	62	61	**64**
VSS Reduction	%	54%	48%	42%	43%	54%	45%	**47%**
Gas Production								
Gas Flowrate to Boiler (avg)	cu ft/d	298	14	3,062	0	3,390	7,830	**2,432**
Gas Flowrate to Boiler (min)		0	0	102	0	0	0	**0**
Gas Flowrate to Boiler (max)		1,190	63	8,407	0	10,028	27,180	**27,180**
Gas Flowrate to Cogen	cu ft/d	111,783	125,255	112,879	141,749	119,340	122,024	**122,171**
Gas Flowrate to Burner	cu ft/d	16,141	9,490	18,188	8,841	1,663	9,564	**10,648**
Gas Total (avg)	cu ft/d	128,221	134,760	134,129	150,590	124,393	139,418	**135,252**
Gas Total (min)		125,314	119,662	126,387	140,330	90,677	114,800	**90,677**
Gas Total (max)		134,611	149,683	148,403	160,849	153,882	158,266	**160,849**
Gas Specific Production	cu ft/lbsVSS	10.9	13.5	15.9	15.8	12.3	15.5	**14.0**

2.4 GAS PRODUCTION

The reported gas production value is the sum of the measured gas going to the boiler, to the cogeneration system, and to the flare. Specific biogas production, relative to the volatile solids load, has been calculated and ranges between 11 and 16 scf/lbVSS, with an average of 14 scf/lbVSS. Typical values vary from 12 to 18 cf/lbVSS (Metcalf & Eddy).

2.5 OVERVIEW OF BIOGAS QUALITY

Untreated anaerobic digester gas, a direct byproduct of sludge digestion, provides a medium grade fuel with a heating value ranging from 550-680 British Thermal Units per cubic feet (BTU/cf) of gas. The use of digester gas at WWTFs to power on-site combustion sources has become an established alternative to conventional fuels such as natural gas. However, trace compounds contained in the digester gas, such as volatile methylsiloxanes (VMSs), sulfides and other organic substances have been identified as causing deleterious effects to combustion devices and their add-on air pollution control equipment. The problems associated with burning digester gas in internal combustion engines include:

- Newer engines are less tolerant of the contaminants found in digester gas, which potentially leads to increased maintenance and rapid deterioration of the units.

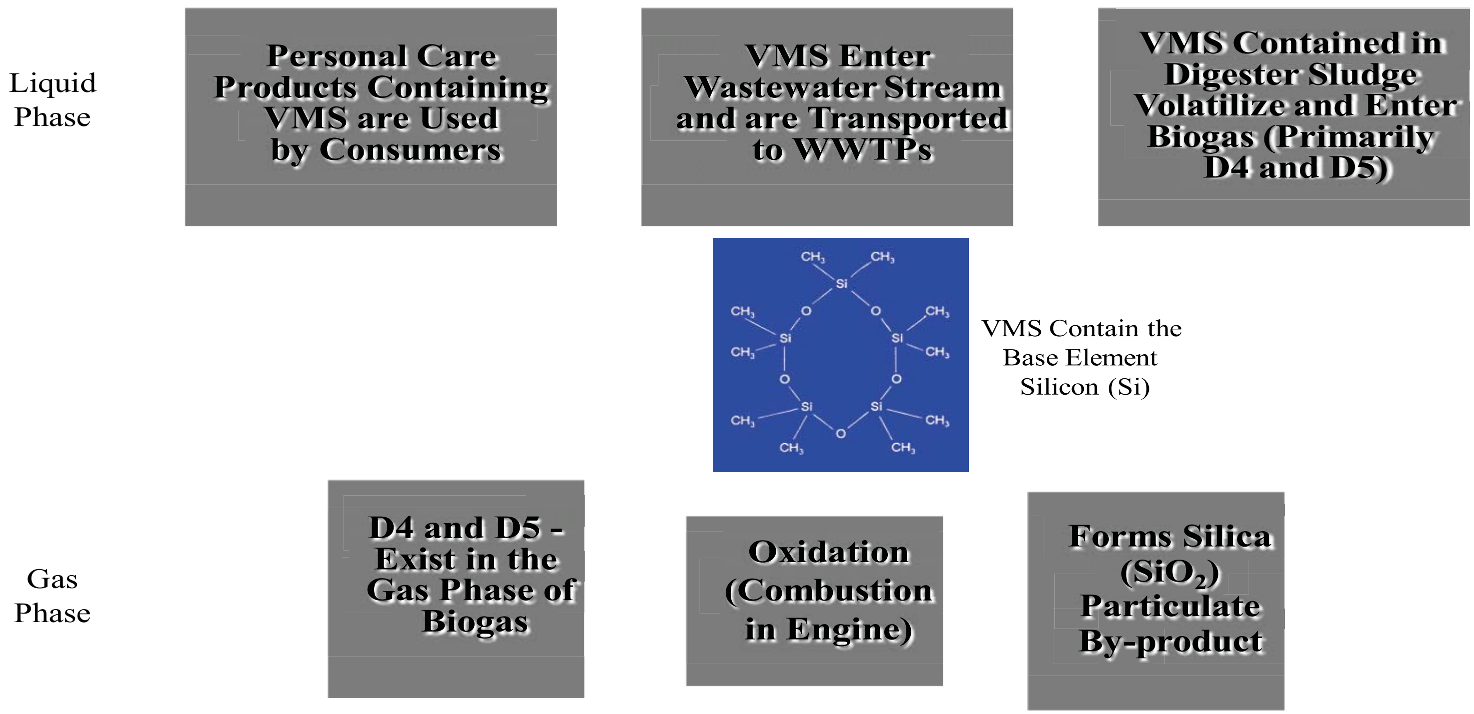
- Air pollution control devices, such as catalytic oxidizers, are fouled from the contaminants in the digester gas. The catalyst media are shown to be masked by the particulates.

VMSs are one class of compounds that have been identified as a significant contributor to these deleterious effects. When VMSs (containing silicon) are combusted in the engines they form silica, a particulate matter material. The relationships associated with these compounds are presented on Figure 2-1, and definitions are given below:

- Silicon – Silicon (Si) is the base element that forms both siloxane and silica.

- Siloxane – Siloxane exists in the gas phase and is formed when silicon becomes methylated. The methylated silicon compounds are termed methylsiloxanes. [Methlysiloxanes are commonly found in cosmetic products, such as deodorants, and find their way into collection systems that end up at treatment plants. The compounds are found in many areas within the treatment system, including the digester sludge. The VMSs in the sludge volatize and become part of the digester

Figure 2-1
Fate of Siloxanes in WWTPs



VMS- Volatile Methyl Siloxane
D4-Octamethylcyclotetrasiloxane
D5- Decamethylcyclopentasiloxane

- gas that is produced during the anaerobic digester process. VMSs are siloxanes with relatively low molecular weight (<600) and high vapor pressure. Two types of VMSs were consistently found in the digester gas at levels above the detection limit. The compounds are:
  - Octamethylcyclotetrasiloxane (D4)
  - Decamethylcyclopentasiloxane (D5)

- Silica – Silica (SiO_2) is a particulate that is formed when VMSs are combusted in the engines. Silica ash has glass-like properties and has the potential to foul engines and catalysts used for emissions control. The fouling reduces the efficiency of the catalyst, which causes the need for frequent replacement. To prevent the formation of silica in the engines, the siloxanes must be removed from the biogas prior to combustion.

There are also many WWTFs around the country that have not reported significant problems caused by VMSs in the digester gas with their engine operations. Many WWTFs have dealt with the problems through engine maintenance. Engine problems include issues resulting from silica buildup in the pistons, valves, and cylinders. However, these facilities operate engines without air pollution control devices and have older units. The VMS problems are arising from the replacement of older units with newer units (lower mechanical tolerances in the engine intervals to handle particulate buildup) and the need to meet stricter emission limits by installing air pollution control devices. As a result, WWTFs frequently incur higher expenses for upgrading to newer engines and reducing their emissions by adding post combustion control devices.

2.5.1 Sampling and Data Evaluation

Malcolm Pirnie developed a sampling program to better understand the quality of the digester gas at the plant and provide a site-specific database by which gas cleaning technologies may be evaluated. The testing was conducted to quantify the VMSs and other contaminants in the digester gas that may impact the performance of the engines, catalysts, and gas cleaning technologies. The analytical target compound list included VMSs, volatile organic compounds (VOCs), and reduced sulfur compounds, as well as a gas analysis (methane, carbon dioxide, oxygen and nitrogen content). A total of two sampling events were conducted on the following dates:

- May 11, 2006
- June 8, 2006

Sampling was conducted on the raw digester gas as it exits the digesters as well as the filtered gas just prior to the engines.

Additional monitoring was performed on the raw digester gas to assess the variation of carbon dioxide and hydrogen sulfide content in the gas. Monitoring was conducted every other day from June 16, 2006 through July 17, 2006. During three sampling events (July 7, July 11, and July 13, 2006), additional samples were collected from the filtered gas.

2.5.1.1 VMS Sampling

Malcolm Pirnie used a VMS sampling method developed by DOW Chemical Corporation, which is a variation of USEPA Method TO-5, Compendium of Methods for the Determination of Toxic Organic Compounds in Air, EPA–600/4-89-017. Analysis was conducted by Air Toxics Ltd. following their Air Toxics Method @71. As shown on Figure 2-2, the sampling train consisted of two 24-milliliter (ml) midget impingers in series (connected by Tygon tubing). Each impinger was filled with 6 ml of methanol. The digester gas sample passed through the two impingers and an airflow calibrator, which measured the digester flow through the sampling train. The VMSs in the digester gas were absorbed into the methanol, which was later analyzed by a laboratory. During sampling, the impingers were partially submerged in a cooler filled with ice to maintain sample integrity. The digester gas exiting the sampling train was vented to the ambient air near the gas feed line.

Upon completion of each sampling event the impingers were sent to the analytical laboratory (Air Toxics, Ltd.) via next day delivery. The laboratory analyzed the methanol samples using gas chromatograph/flame ionization detector for the siloxanes target compound list: Octamethylcyclotetrasiloxane (D4), Decamethylcyclopentasiloxane (D5), Dodecamethylcyclohexasiloxane, Hexamethyldisiloxane and Octamethyltrisiloxane. The raw gas sample collected on May 11, 2006 did not arrive at the laboratory in proper condition to be analyzed; therefore, results are not available for that sample.

Two siloxane compounds, D4 and D5, were found above the detection limits in all of the samples analyzed. The results of compounds detected in the siloxane analysis are given in Table 2-2.

Figure 2-2
Siloxane Sampling Train

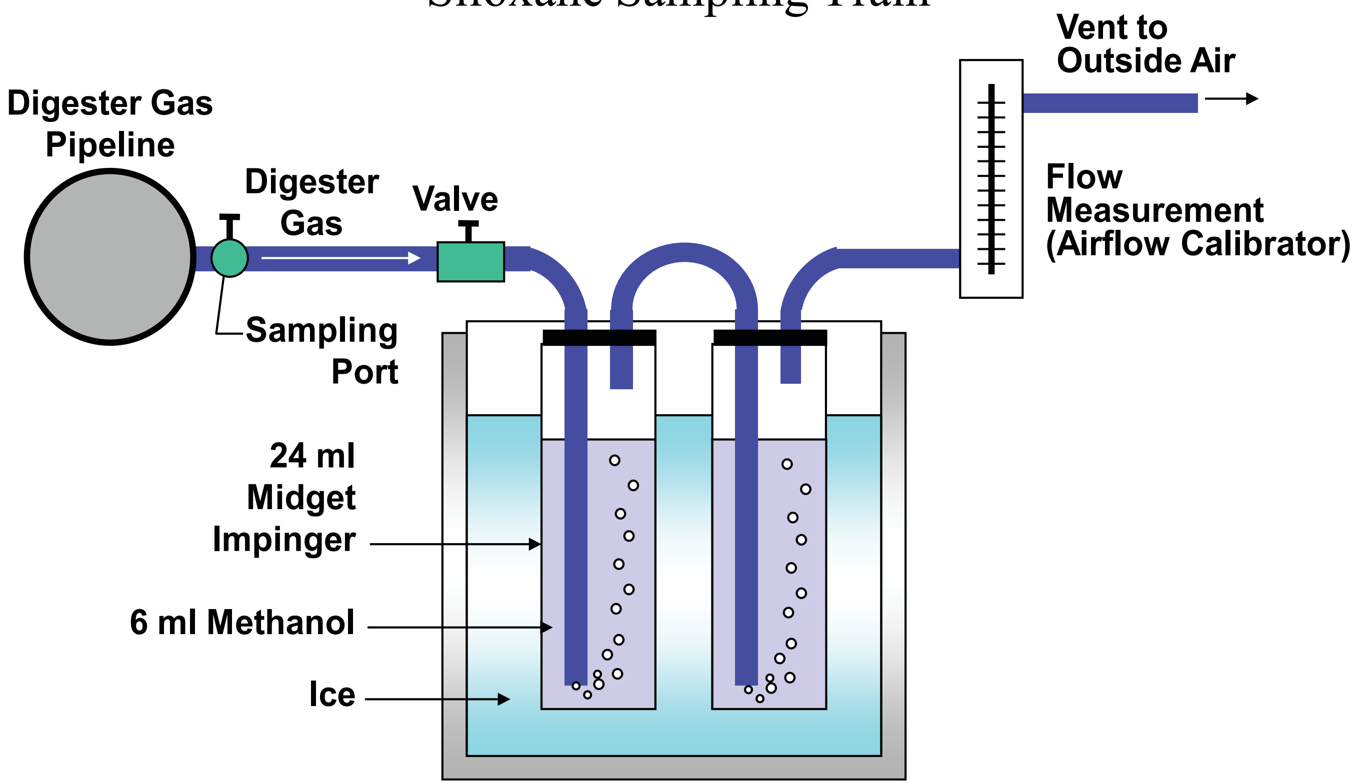


Table 2-2: VMS Sampling Results

Compound	Concentration (ppb*)					
	Raw Gas			Filtered Gas		
	5/11/2006	6/8/2006	Average	5/11/2006	6/8/2006	Average
Octamethylcyclotetrasiloxane (D4)	NA	162	**NA**	146	166	**156**
Decamethylcyclopentasiloxane (D5)	NA	422	**NA**	308	422	**365**
Dodecamethylcyclohexasiloxane	NA	(72)	**NA**	(70)	(69)	**70**
Hexamethyldisiloxane	NA	(96)	**NA**	(96)	(93)	**95**
Octamethyltrisiloxane	NA	(66)	**NA**	(66)	(64)	**65**
Total	NA	818	**NA**	687	813	**750**

*ppb = parts per billion.

Notes - Non-Detect compounds are indicated by the values in parentheses, which reflect 1/2 of the detection limit.

NA = the sample could not be analyzed

Many WWTFs have total siloxane concentrations that are greater than 1 parts per million (ppm). Although the total concentrations at the WWTF were less than 1 ppm, the total of 750 ppb (0.75 ppm) is still enough to cause increased engine wear. Therefore, although not required, treatment would be likely to reduce engine maintenance requirements.

2.5.1.2 VOC Sampling

VOC samples were collected in tedlar bags and were analyzed by Air Toxics Ltd. following USEPA Method TO-15. Of the 62 target compounds on the TO-15 list, only 22 were measured at concentrations greater than the method detection limit. A summary of the compounds detected in the VOC analysis are presented in Table 2-3.

Table 2-3: VOC Sampling Results

Compound	Concentration (ppb)					
	Raw Gas			Filtered Gas		
	5/11/2006	6/8/2006	Average	5/11/2006	6/8/2006	Average
Vinyl Chloride	7	(11)	**9**	(2)	(10)	**6**
Methylene Chloride	13	40	**27**	(2)	30	**16**
Hexane	63	26	**45**	63	34	**49**
2-Butanone (Methyl Ethyl Ketone)	7	(11)	**9**	14	(10)	**12**
cis-1,2-Dichloroethene	44	350	**197**	47	580	**314**
Cyclohexane	9	(11)	**10**	(2)	(10)	**6**
2,2,4-Trimethylpentane	120	(11)	**66**	120	(10)	**65**
Benzene	12	(11)	**12**	13	(10)	**12**
Heptane	70	31	**51**	76	38	**57**
Trichloroethene	26	(11)	**19**	29	48	**39**
4-Methyl-2-Pentanone	6	(11)	**9**	12	(10)	**11**
Toluene	1200	4600	**2900**	1400	2800	**2100**
Tetrachloroethene	20	(11)	**16**	21	(10)	**16**
Ethyl Benzene	36	58	**47**	47	57	**52**
m,p-Xylene	140	190	**165**	160	170	**165**
o-Xylene	48	67	**58**	48	53	**51**
Cumene	19	30	**25**	19	22	**21**
Propylbenzene	38	61	**50**	26	39	**33**
4-Ethyltoluene	110	200	**155**	79	130	**105**
1,3,5-Trimethylbenzene	70	180	**125**	48	130	**89**
1,2,4-Trimethylbenzene	140	340	**240**	69	240	**155**
1,4-Dichlorobenzene	4	(11)	**8**	(2)	(10)	**6**

Note - Non-Detect compounds are indicated by the values in parentheses, which reflect 1/2 of the detection limit.

Total VOC concentrations averaged around 3 to 4 ppm, which is common for municipal treatment plant digester gas. Concentrations at these levels typically do not require treatment.

2.5.1.3 Reduced Sulfur Sampling

Reduced sulfur samples, which include hydrogen sulfide (H_2S), were collected in tedlar bags and were analyzed by Air Toxics Ltd. following ASTM D-5504. Of the 20 target compounds on the D-5504 list, only two were measured at concentrations greater than the method detection limit. A summary of the compounds detected in the reduced sulfur analysis is presented in Table 2-4.

Table 2-4: Reduced Sulfur Sampling Results

Compound	Concentration (ppb)					
	Raw Gas			Filtered Gas		
	5/11/2006	6/8/2006	Average	5/11/2006	6/8/2006	Average
Hydrogen Sulfide	140,000	220,000	**180,000**	86,000	140,000	**113,000**
n-Butyl Mercaptan	1,400	(300)	**850**	(600)	(335)	**468**

Note - Non-Detect compounds are indicated by the values in parentheses, which reflect 1/2 of the detection limit.

The raw gas H_2S maximum value of 220 ppm is relatively low compared to other anaerobic digesters that are in operation. This is likely due to the addition of ferrous chloride to the anaerobic digester sludge. Concentrations at these levels typically do not require treatment.

2.5.1.4 Gas Analysis Sampling

Gas analysis samples were collected in tedlar bags and were analyzed by Air Toxics Ltd. following Modified ASTM D-1945. The analysis measures the percentage of methane, carbon dioxide, oxygen, and nitrogen in the digester gas sample. The relative gas contents of the digester gas are well within the range of typical digester gas. A summary of the results of the gas analysis is presented in Table 2-5.

Table 2-5: Gas Analysis Sampling Results

Compound	Concentration (%)					
	Raw Gas			Filtered Gas		
	5/11/2006	6/8/2006	Average	5/11/2006	6/8/2006	Average
Oxygen	0.13	0.18	**0.16**	0.25	0.24	**0.25**
Nitrogen	0.35	0.33	**0.34**	0.8	0.54	**0.67**
Methane	62	59	**61**	61	62	**62**
Carbon Dioxide	39	41	**40**	38	38	**38**

The laboratory reports for all gas analyses are included in Appendix A.

2.5.1.5 Gas Quality Monitoring

Over a period of six weeks, a total of 16 separate gas monitoring events were conducted by WWTF personnel. Monitoring was conducted using colorimetric detector (Draeger) tubes, which are glass vials filled with a chemical reagent that changes color in response to the presence of specific gas parameters. The length of the color change indicates the measured concentration. While not a precise measurement, colorimetric monitoring provides a cost-effective method of regularly assessing variations in gas quality. Concentrations of carbon dioxide, as a percent, and concentrations of hydrogen sulfide, in parts per million, were measured in the samples. In addition to the actual measurements, at the time of gas sampling, digester operating parameters such as the flow of sludge and whey to the digester, temperature, and gas production were monitored. A summary of results is presented in Table 2-6. Samples of raw biogas and biogas that had gone through the existing rudimentary biogas pretreatment system were collected.

During the sampling period, the raw gas CO_2 concentration ranged between 30 and 44 percent; concentrations in the filtered gas were slightly lower, with an average reduction of 15 percent attributable to the existing gas filters. Figure 2-3 shows the whey flow to the digester and the raw gas CO_2 concentration during the sampling period. There is a slight correlation between the increase of whey flow and an increase of CO_2 concentration in the digester gas, corresponding to lower methane concentrations. However, the methane content of the digester gas throughout the sampling period was between 60 and 70 percent, which is within the range of typical digester gas.

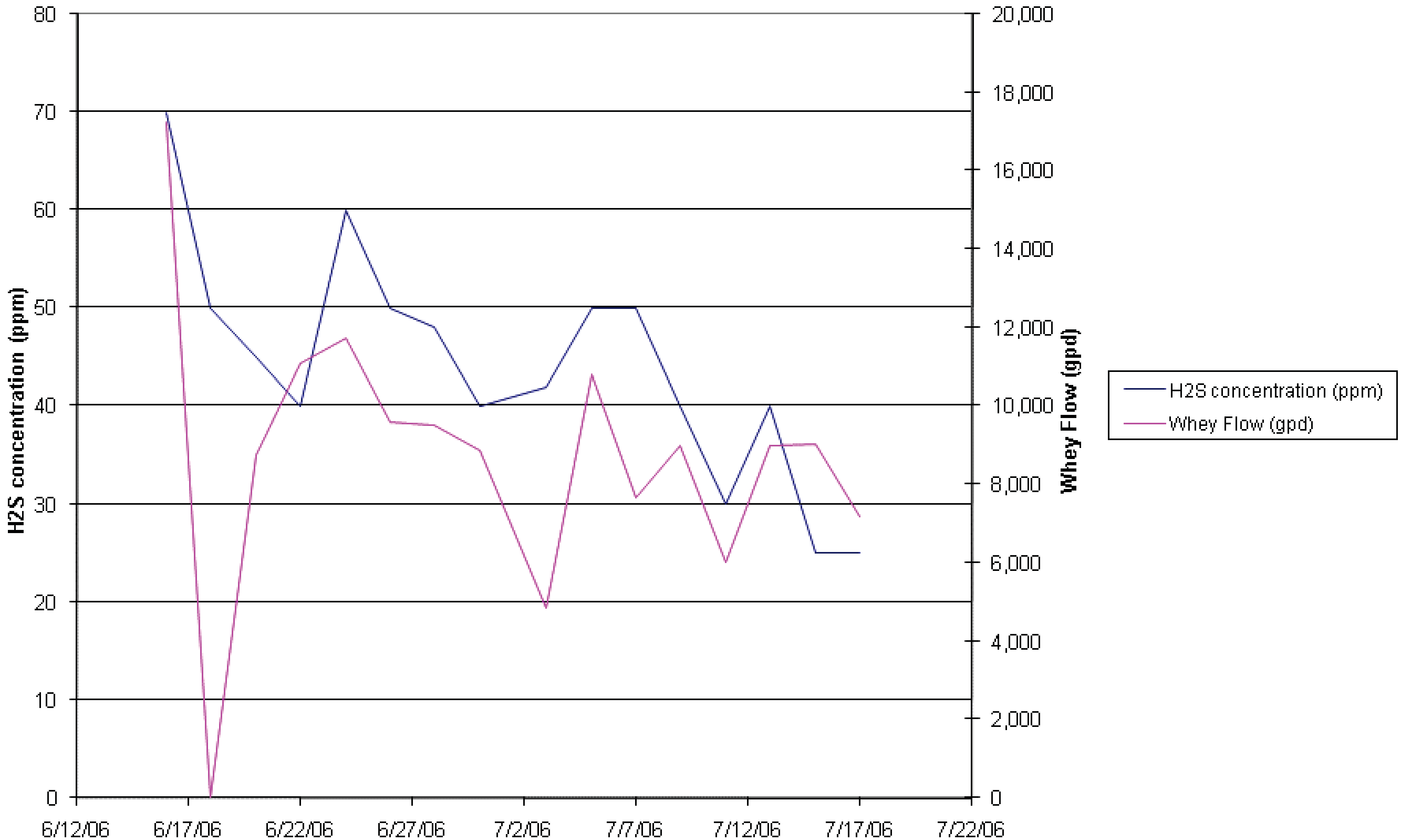
The raw gas concentration of H_2S during the sampling period ranged between 25 and 70 ppm. Concentrations in the filtered gas were significantly lower, with an average reduction of 80 percent attributable to the existing gas filters. Figure 2-4 shows the relationship between whey flow to the digester and the raw gas H_2S concentration during the sampling period. It can be seen that higher whey feed rates correspond to higher H_2S concentrations. The H_2S values in the raw gas were lower than the ones measured with the reduced sulfur sampling, which would be expected given the fact that H_2S is only one component of the total reduced sulfur measurements. As stated before, H_2S concentrations measured during all sampling events were relatively low.

Table 2-6: Gas Monitoring Results

Parameter	Unit	6/16/06	6/18/06	6/20/06	6/22/06	6/24/06	6/26/06	6/28/06	6/30/06	7/3/06	7/5/06	7/7/06	7/9/06	7/11/06	7/13/06	7/15/06	7/17/06
Raw Digester Gas CO_2	%	37	30	40	40	35	32	35	30	38	42	44	40	38	42	40	38
Raw Digester Gas H_2S	mg/l	70	50	45	40	60	50	48	40	42	50	50	40	30	40	25	25
Filtered Digester Gas CO_2	%											37		30	38		
Filtered Digester Gas H_2S	mg/l											5		10	5		
Gravity Thickener Flow	gpd	63,090	63,090	63,110	63,110	63,110	43,090	43,090	43,090	45,990	45,990	45,990	45,990	28,290	28,290	28,290	28,290
Rotary Drum Thickener Flow	gpd	2,500	2,500	4,000	4,000	4,000	3,200	3,200	3,200	0	0	0	0	0	0	0	0
Whey Flow	gpd	17,260	40	8,790	11,110	11,740	9,620	9,530	8,900	4,880	10,820	7,700	9,000	6,030	9,020	9,040	7,200
Total Flow to Digester	gpd	82,850	65,630	75,900	78,220	78,850	55,910	55,820	55,190	50,870	56,810	53,690	54,990	34,320	37,310	37,330	35,490
Digester Temperature	°F	97.5	98	96	97.5	97	97	95	96	99.5	97.5	97	97.5	98	97.5	96.5	96
Gas Flowrate Boiler	CFD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Flowrate Cogen	CFD	131,150	134,920	128,690	130,890	129,920	125,210	110,770	129,100	118,300	125,460	122,180	118,670	118,850	121,770	122,970	113,830
Gas Flowrate Burner	CFD	37,920	3,790	11,610	13,110	38,170	8,760	11,780	0	1	7,260	80	0	0	60	0	0
Total Gas Production		169,070	138,710	140,300	144,000	168,090	133,970	122,550	129,100	118,301	132,720	122,260	118,670	118,850	121,830	122,970	113,830

Figure 2-3: Whey Flow vs. CO2 concentration

Figure 2-4: Whey Flow vs. H2S concentration



2.6 COGENERATION SYSTEM PERFORMANCE

The existing cogeneration system is used to produce electricity for the site and heat for the cogeneration building and primary digester. The cogeneration equipment consists of two Caterpillar G342NA reciprocating engine driven induction generators. The engines have dual-fuel carburetors and can run both on anaerobic digester gas and natural gas. Each unit uses 50 scfm of anaerobic digester gas for a combined maximum daily capacity of 144,000 cf/d.

Based on the manufacturer's literature, the generators are capable of producing 150 kilowatts (kW), assuming 100 percent load at 1,200 revolutions per minute (rpm).

Following the anaerobic digesters improvements and increased gas production, both generators have been running full time. Typical monthly power generation values are shown in Table 2-7.

The table shows that, out of a maximum theoretical monthly power generation of 216,000 kilowatt hours per year (kWh/year), on average 154,240 kWh/year of electricity is generated. Based on the WWTF's current average unit cost for electricity of $0.15, the facility has an average avoided electricity cost of $277,632 per year. The total annual operation and maintenance cost is estimated to be $77,533, which results in a net revenue for the cogeneration system of approximately $200,000 per year.

Both engines have a heat recovery system on the engine cooling system and exhaust. Throughout much of the year, waste heat recovery is sufficient to heat the primary digester. However, as shown in Table 2-7, during cold weather months, natural gas has to be purchased to meet the full thermal load of the digester while maintaining operation of the cogeneration system.

Table 2-7-: Power Generated

Parameter	Unit	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	AVERAGE
Electric kWh NiMo	kWh	242,400	247,200	194,400	240,000	216,000	215,616	**225,936**
Electric kWh cogeneration	kWh	146,880	160,320	129,840	172,320	147,120	168,960	**154,240**
Digester gas production	cu ft/mo	4,068,832	4,206,754	3,671,792	4,477,645	3,808,414	4,493,556	**4,121,166**
Natural gas plant therms	therms/mo	12,398	10,843	11,045	9,536	1,844	967	**7,772**
Natural gas digester therms	therms/mo	473	206	64	17	31	2	**132**

3.0 PROPOSED DIGESTER FACILITY OPERATIONS

3.1 FUTURE OPERATIONS

A new dairy manufacturer is under construction in the vicinity of the WWTF. The new dairy manufacturer will discharge whey during a 5-day week directly to the WWTF through a dedicated acid whey forcemain. Whey will be stored in the whey holding tank and pumped daily to the anaerobic digesters at a constant rate. The future operation of the digesters is based on an estimated whey flow of 66,100 gpd (47,000 gpd over 7 days) at full production. The dairy manufacturer's startup is planned for 2007.

Operating parameters and biogas production rates for current operations and with the dairy manufacturer's contribution are shown in Table 3-1. Future conditions were estimated based on the following assumptions:

- Flows and loadings to the digesters from the plant's secondary treatment (gravity thickener and rotary drum thickener) will not vary;
- The performance of the digesters, measured as percent VSS reduction and unit gas specific production, remains unchanged; and
- The new dairy industry's whey has a solids concentration of 5 percent (based on actual samples).

3.2 DIGESTER PERFORMANCE

Based on Malcolm Pirnie's process calculations, the additional flow and loading introduced by the dairy whey will overload the existing anaerobic digesters as currently operated. Currently, the secondary digester is not heated or mixed, and is utilized as a holding tank for solids/liquid separation of the digested sludge. Under the proposed conditions, additional primary digestion volume is required.

One alternative is utilizing the existing secondary digester as a primary digester. The secondary digester is equipped with a mixing system, identical to the primary digester, and both tanks can be fed simultaneously. To compensate for the loss of holding capacity currently provided by the secondary digester, a sludge holding tank would need to be

Table 3-1: Digesters operation parameters and gas production

Parameter	Unit	Current Average	Dairy @ Full Production
Influent Sludge:			
Gravity Thickener Flow	MGD	**0.045760**	**0.045760**
Gravity Thickener Solids	%	**4.8**	**4.8**
Gravity Thickener Volatile Solids	%	**70**	**70**
Rotary Drum Thickener Flow	MGD	**0.0113**	**0.0113**
Rotary Drum Thickener Solids	%	**6.4**	**6.4**
Rotary Drum Thickener Volatile Solids	%	**85**	**85**
Whey flow rate to digester	gal/day	**7,497**	**47,241**
Whey Solids	%	**7.9**	**5.0**
Whey Volatile Solids	%	**89**	**89**
Organic Loading to Digester	lbsVSS/day	**21,492**	**35,614**
Organic Loading Rate	lbsVSS/cf-day	**0.11**	**0.18**
Solids Retention Time	days	**25**	**14**
Influent Sludge Volatile Solids	%	**77**	**81**
Effluent Sludge Volatile Solids	%	**64**	**69**
VSS Reduction	%	**47%**	**47%**
Gas Production			
Gas Specific Production	cu ft/lbsVSS	**14.0**	**14.0**
Gas Total	cu ft/d	**135,252**	**236,144**
Current Gas Utilization Rate (cogen)	cu ft/d	**122,171**	**122,171**
Surplus Gas	cu ft/d	**13,080**	**113,972**

constructed. Another alternative is installing a pretreatment primary digester, or another anaerobic technology, upstream of the existing primary digester, dedicated to whey digestion. Under this scenario, the existing digesters would continue to operate in their current configuration. For the purpose of this study, it was assumed that both digesters operate as primary digesters with sludge heating and mixing and that a sludge holding tank is constructed. However, a detailed assessment of the two alternatives should be completed prior to implementation, particularly if other significant changes to the characteristics of the incoming wastewater or the quantity of waste treated in the anaerobic digester system are expected.

3.3 GAS PRODUCTION

Table 3-1 shows that the future gas production from the anaerobic digestion system, after the new dairy manufacturer begins operations, will increase to 236,000 cfd at the current gas production rate of 14 cu ft/lb VSS destroyed. The gas production was estimated based on the results of a sample analysis of the whey that is currently discharged by the same dairy manufacturer at a different location, but using the same manufacturing processes and operations. This is an approximate 75 percent increase from the current gas production. Based on the current biogas utilization rate at the cogeneration units, on an annual average basis there will be a surplus of biogas of approximately 114,000 cu ft/day.

3.4 GAS QUALITY

No information is available on the quality of the gas that will be produced in the future. For the purpose of this report, it was assumed that the gas quality will be comparable to the existing gas. Based on the results of the gas monitoring performed during the sampling events completed as part of this study, a slight correlation exists between increased whey discharge and increased concentrations of CO_2 and H_2S. However, the type of whey currently being received by the WWTF is different from the whey that will be discharged by the new dairy manufacturer. It is reasonable to assume that with the increased volume of whey being treated through the digesters the gas quality will decrease slightly.

Based on the sampling conducted as part of this study, no supplemental biogas treatment is required at this time if the WWTF simply continues to operate its current internal combustion engines and boiler. However, implementation of biogas treatment with the current engines is likely to reduce engine maintenance requirements and implementation of biogas clean-up is recommended should any modification or expansion of the cogeneration system be implemented. Alternative electrical generating technologies and new internal combustion engines tend to have tighter operating tolerances and are more likely to be adversely affected by impurities in the biogas. For the purpose of the economic evaluations completed as part of this study, biogas treatment was included for all energy production/recovery alternatives that were considered.

4.0 BIOGAS CLEAN-UP TECHNOLOGIES

A list of potential technologies was developed based on current installations as well as ongoing research in this area. It must be noted that, to a certain extent, some of these are emerging technologies that are still in the process of being proven in full-scale operations. Although these methods are theoretically sound, the ability to treat the WWTF's digester gas is not guaranteed for all three technologies. The technologies are:

- Activated Carbon
- Refrigeration/Condensation
- Pressure Swing Adsorption/Temperature Swing Adsorption (PSA/TSA)

A rating system was developed to assess each technology. The ratings compare the technologies to one another and identify those that may be best suited for this application. Although no supplemental biogas treatment is required to operate the current internal combustion engines and boiler, as explained in Section 3, biogas clean-up is recommended for modifications or expansion of the cogeneration system and for reduced engine maintenance. The selection criteria were based on the biogas quality required for new cogeneration systems. Each technology was rated based on the following factors:

- History of Operation: track record of the technology for gas cleaning.
- Performance: capability of the technology to achieve necessary removals.
- Implementability: ease of applying the technology in this situation.
- Installed Capital Cost: approximate installed cost of the technology.
- Maintenance: intensity of maintenance effort.

Each factor is given a rating of Good, Fair, or Poor.

4.1 ACTIVATED CARBON TECHNOLOGY

The mechanism for contaminant removal from a gas stream by activated carbon is adsorption, during which gas phase compounds are captured at an active site on the surface of the carbon. Activated carbon has a high surface-to-volume ratio; thus, a large surface area is available for adsorption in a relatively small volume. Carbon adsorption units are highly effective at removing many organic compounds. Adsorption of organic compounds is relatively non-selective; it is not strongly affected by solubility or chemical class of the compounds.

At most sites using carbon adsorption as a control technology, there are at least two units available for operation. The operating unit is occasionally monitored for breakthrough. As compounds pass through the system, the active sites on the carbon become filled. Eventually, the number of active sites becomes insufficient to effectively remove the contaminants and breakthrough occurs. When breakthrough occurs on the first vessel, flow is diverted to the second adsorber. Once impending breakthrough is detected, replacement or regeneration of the carbon in the first vessel is implemented.

Upon impending breakthrough, the media is removed from the vessel and either disposed of or taken off-site for thermal regeneration. When the carbon is heated to a sufficient temperature, the contaminants re-enter the air phase, thereby freeing the active sorption sites. Testing has been conducted, which indicates that both graphite and coconut-shell based carbon are effective at removing VMSs from gas streams.

4.1.1 Vendors

The company with the most experience with the removal of siloxanes from digester gas using carbon adsorption is Applied Filter Technology (AFT) of Bellevue, WA.

The method for removing siloxanes from digester gas is the use of adsorber vessels that employ special grades of polymorphous porous graphite (PPG). PPG is a specific type of activated carbon that can accommodate contaminant loadings ranging from 25 to 58 percent by weight. The PPG is employed using SAG™ technology. SAG™ technology, an acronym for "segmented activity gradient," was developed for the removal of poorly adsorbed species in the presence of high concentrations of organic contaminants in air or gas streams. A number of the VOCs detected in the WWTF gas stream, including propylene and toluene, are more readily adsorbed than VMSs. Hydrogen sulfide (H_2S) also is more readily adsorbed than VMSs. For this technology, PPG media with varying properties are employed to accomplish several tasks:

- Adsorption
- Separation
- Concentration
- Removal

Adsorption takes place throughout the PPG media, and the separation is accomplished using the SAG™ technology. The technology allows segmentation of organics into discrete zones in specially engineered media, which enables siloxanes to be adsorbed without competition from other contaminants. To accomplish this, differing types of PPG, possessing different adsorbent characteristics, are placed in discrete zones within a steel vessel. The main difference in the three types of media is the pore size, with the basic assumption being that the larger sized molecules are adsorbed first.

The system includes a chiller to remove a good portion of the moisture from the digester gas. The gas is chilled to roughly 40°F and then reheated to 70 – 75°F for moisture removal. The final step is the carbon bed where polishing and VMS removal take place.

The system typically is supplied with two carbon vessels. A diagram of a typical system is shown on Figure 4-1. The footprint of a complete system would be approximately 12 feet long by 8 feet wide.

The installed capital cost for a PPG carbon adsorption system for full-scale use as a digester gas treatment system is estimated to be $190,000. Operating costs would include the electrical cost for the chiller and the cost for carbon replacement, which is anticipated to occur every 8 to 12 months. Annual operating costs are estimated to be approximately $4,300. Maintenance of the system will include the time to replace the PPG media and sampling for VMS removal. The digester building has extra room in the first floor where the full-scale carbon adsorption system could be accommodated.

4.1.2 Current Applications

AFT has supplied carbon systems for over 70 facilities throughout the world. The SAG™ carbon adsorption system has undergone the most extensive testing of all of the technologies considered. Two of the installations are highlighted below:

- Carson Ice Plant – Installed a full-scale carbon system to remove siloxanes from digester gas supplied by the Sacramento Sewage Treatment Plant. The system has been in operation for over six years and is cleaning the digester gas to levels below siloxane detection limit (<100 ppb).

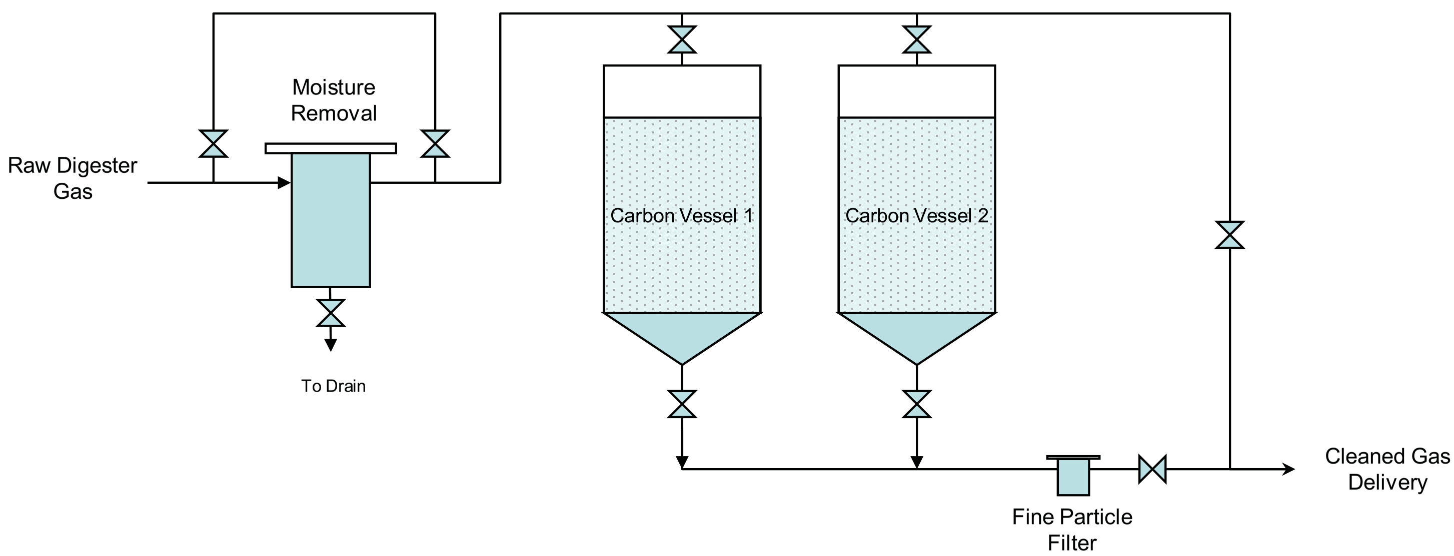


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FIGURE 4-1
Activated Carbon System

- Bergen County Utility Authority – Performed a pilot scale testing and installed a full-scale carbon adsorber system in 2002. The system has significantly reduced engine maintenance and has greatly extended the life of the post combustion catalysts that are used.

4.1.3 Evaluation Ratings

Carbon adsorption using PPG media and SAG™ technology has been implemented in many locations, which allows for a complete rating of the technology.

History of Operation – Carbon adsorption has been used for many years, and SAG™ technology has been implemented in a number of installations world-wide. This technology is the most extensively tested of those being considered. History of Operation – Good

Performance – A good deal of testing has been performed in recent years on the ability of carbon to remove siloxanes from gas streams. Testing has consistently shown total siloxane concentrations of <100 parts-per-billion (ppb) in carbon system outlets. Performance – Good

Implementability – Activated carbon systems have been implemented to remove VMSs from digester and landfill gas at dozens of locations throughout the world. The system can be skid-mounted for easy installation. A new structure may have to be built to house a full-scale carbon system. Implementability - Good

Installed Capital Cost – A carbon system is one of the least expensive options with an installed capital cost of $190,000. Installed Capital Cost – Good/Fair

Maintenance Level of Effort – The maintenance on carbon adsorption is relatively straightforward. Besides the compressor for moisture removal, there are no moving parts. The amount of carbon required for replacement is relatively low, and spent carbon can be disposed of as non-hazardous waste, which eliminates the need for regeneration. Maintenance Level of Effort - Good

4.2 REFRIGERATION/CONDENSATION TECHNOLOGY

Condensation can be used to remove selected compounds by dropping the temperature or pressure of the gas and letting the compound condense to a liquid form so that it can settle out as droplets. Condensing is achieved by either refrigeration or through depressurization of a pressurized system. The condensed contaminants are typically sent to the head of the wastewater treatment plant. This method typically is used for gas streams that contain high concentrations (50,000 ppm) of VOCs. The use of refrigeration/condensation alone has been shown to reduce the siloxanes in the digester gas stream by 95 percent. Refrigeration/condensation systems are not highly effective at removing H_2S from gas streams.

4.2.1 Vendors

Pioneer Air Systems has manufactured a condenser system for the reduction of VMSs in digester gas streams. The system uses several heat exchangers to drop the gas temperature to -10^{o}F. The first step uses chilled gas to reduce the digester gas temperature to 70^{o}F. The gas is then introduced into one of two heat exchangers that drop the temperature to -10^{o}F. One exchanger chills the gas while the other is defrosted. The chilling and defrosting cycles are alternated to maintain continuous gas treatment. Reducing the temperature to such low levels also significantly reduces moisture content. A diagram of a typical system is shown in Figure 4-2. The footprint of a complete system would be approximately 10 feet long by 8 feet wide.

The approximate installed capital cost of a refrigeration/condensation system is $125,000. Operating costs would include the electrical cost for the chilling and thawing cycles. Annual operating costs are estimated to be approximately $15,200. Maintenance could be somewhat intensive due to the nature of the system. The digester building has extra room in the first floor where the full-scale refrigeration/condensation system could be accommodated.

4.2.2 Refrigeration/Condensation Current Applications

Pioneer Air Systems has supplied gas cleaning systems to several locations. Some of the facilities implementing refrigeration/condensation systems are:

- Aurora, Canada – Installed a condenser system to treat landfill gas prior to use in 1000 kW engines.
- Shepard, Canada – Installed a condenser system to treat landfill gas prior to use in 375 kW engines.

4.2.3 Evaluation Ratings

History of Operation – The use of refrigeration/condensation for the removal of significant amounts of VMSs is a relatively recent development. Refrigeration/condensation systems have been used at several facilities, but the technology is not as extensively used as carbon adsorption. History of Operation – Fair

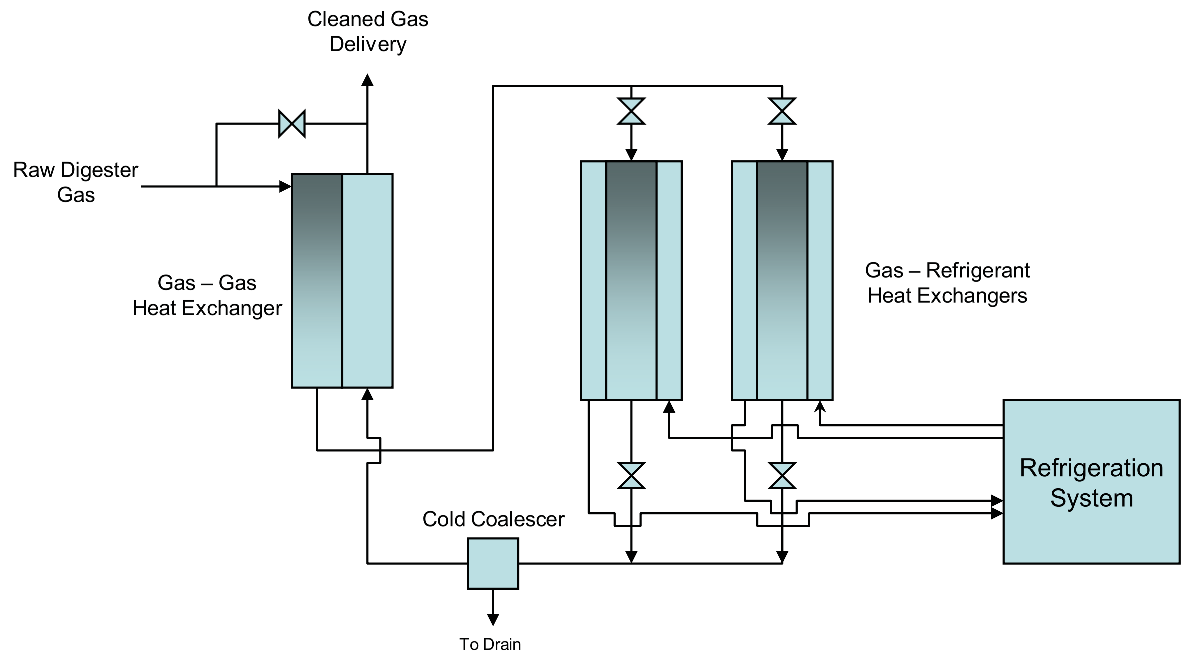

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FIGURE 4-2
Refrigeration/Condensation System

Performance – A refrigeration/condensation system typically is used for gas streams that contain relatively high contaminant levels. The reduction of temperature to sub-zero temperatures greatly increases the removal capacity of the system. Although the system may be capable of removing a wide array of contaminants, actual removals tend to vary. There is very little removal of hydrogen sulfide. Performance – Fair/Poor

Implementability – A refrigeration/condensation system can easily be installed. The systems can be skid mounted to allow for easy installation. An outdoor enclosure with heat and light also can be supplied. Implementability – Good
Installed Capital Cost – The installed capital cost of a refrigeration/condensation system is approximately $125,000. Installed Capital Cost –Good

Maintenance Level of Effort – There are a number of moving parts in a refrigeration/condensation system. The chilling units may require frequent repair. The freezing and thawing cycles need to be monitored on a regular basis. Maintenance Level of Effort – Fair/Poor

4.3 PSA/TSA TECHNOLOGY

The PSA/TSA process takes advantage of the fact that under pressure, gasses are more readily adsorbed onto surfaces. The PSA/TSA system uses two separate adsorbers, with one typically on-line and the other off-line for regeneration. The vessels are filled with a media that selectively adsorbs VMSs. The process is capable of reducing VMSs to levels less than 400 ppb. The units are set up to run through an automated regeneration cycle. The cycle involves the removal of a vessel from service followed by the introduction of heated air (~ 300^{o}F) to fully desorb the VMSs from the media. Typically, the exhaust gas from the regeneration process is sent to a flare.

4.3.1 Vendors

ProXiron Energy, located in Quebec, Canada, is a representative of the Xebec PSA/TSA siloxane removal system. The system is more of a TSA process due to the fact that it uses heated air to desorb VMSs from the media. The system consists of a coalescing prefilter that removes excess moisture from the digester gas. The prefilter is followed by one of two packed bed treatment vessels that are filled with a proprietary dessicant media that is selective to VMSs. Typically, the active towers are on-line for 3 to 7 days; once taken off-line, the tower undergoes a 6 to 8 hour regeneration cycle. A diagram of a typical system is shown on Figure 4-3.

The approximate installed capital cost of a PSA/TSA system is $180,000. Operating costs would include the electrical cost for the pressurization and regeneration cycles. Annual operating costs are estimated to be approximately $ 6,700. Maintenance could be somewhat intensive due to the nature of the system. The digester building has extra room in the first floor where the full-scale PSA/TSA system could be accommodated.

4.3.2 Current Applications

The ProXiron system is currently being tested at three facilities. There are two landfill test sites in New Jersey and North Carolina and one test site at a municipal WWTP in Toronto.

4.3.3 Evaluation Ratings

History of Operation – The system is relatively new and only now is undergoing testing at a limited number of locations. History of Operation – Poor

Performance - The system is capable of reducing siloxane concentrations to levels less than 400 ppb. The inlet concentrations at the WWTF are only slightly higher. The implementation of a PSA/TSA system may not result in sufficient removals to provide any significant reduction in engine maintenance requirements. Performance – Fair/Poor

Implementability – The PSA/TSA system can be skid mounted and would be relatively easy to place on-site. Implementability – Good

Installed Capital Cost – The installed capital cost of a PSA/TSA system is approximately $180,000. Installed Capital Cost – Good/Fair

Maintenance Level of Effort – The vessel switching and regeneration process introduce an increased level of maintenance that would be required to keep the unit running properly. Maintenance Level of Effort – Fair/Poor

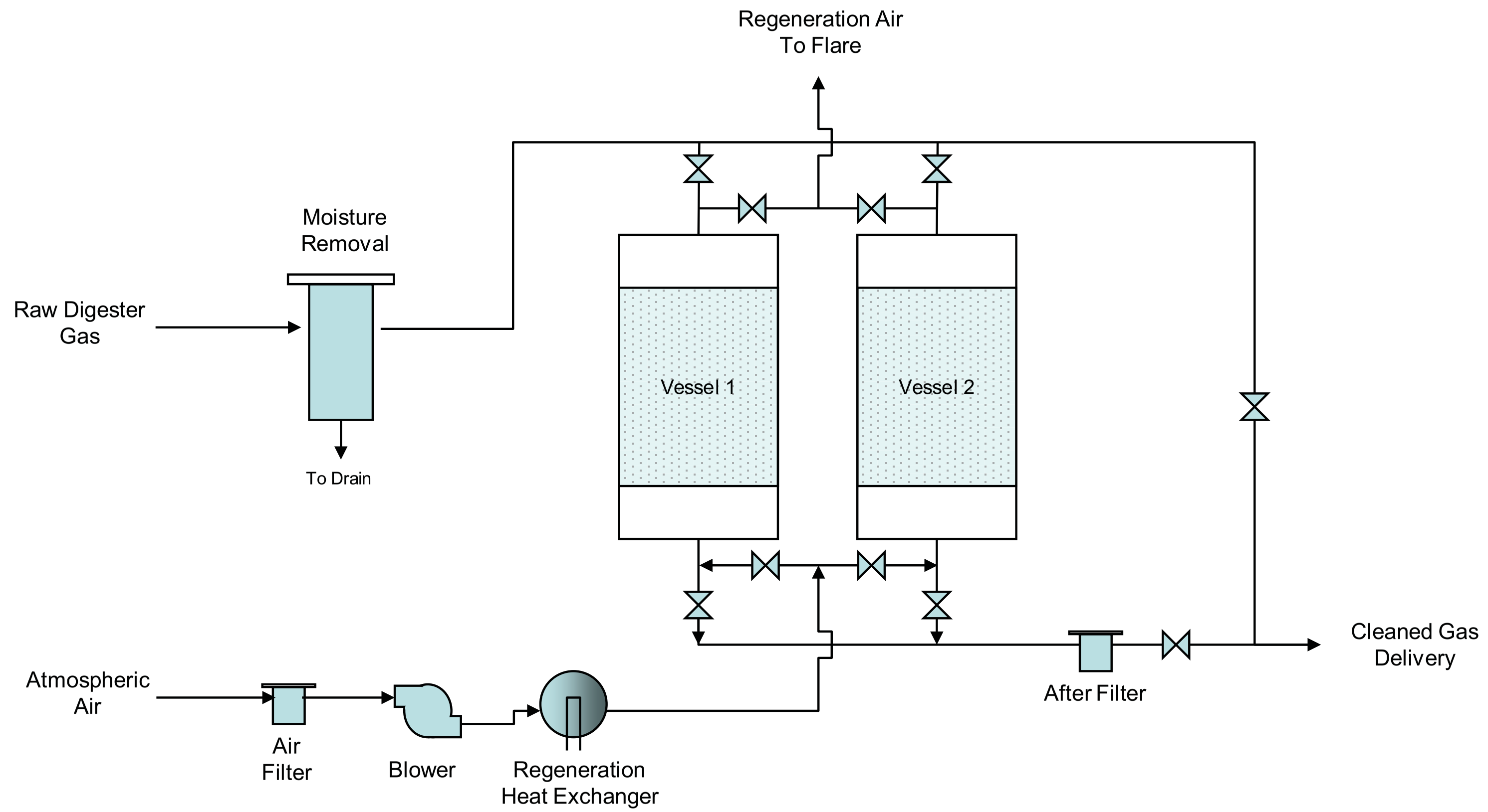

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FIGURE 4-3
PSA/TSA System

4.4 OTHER TECHNOLOGIES

There are several other gas cleaning technologies that have been used or are being further developed. A brief summary of these technologies is given below:

- Liquid Absorption – Passing the gas through a liquid absorbent has been used to treat biogases. A continuously regenerable solvent can be used in a tray-tower application. A commonly used liquid absorbent is Selexol, a dimethylether of polyethylene glycol. Selexol has been shown to be effective in the removal of siloxanes, as well as other gas contaminants, but typically, it is only cost effective for larger installations.
- Synthetic Resins – Synthetic resins, like activated carbon, can remove VMSs, as well as other VOCs, through adsorption onto their surface. Unlike carbon, resins do not readily adsorb hydrogen sulfide. Care must be taken to limit oil and particulate exposure; both can significantly reduce performance. The use of resins typically requires the use of a microwave regeneration system, which can be very maintenance intensive.

4.5 SUMMARY OF GAS CLEANING TECHNOLOGIES

A summary of the gas cleaning technology ratings is presented in Table 4-1. Overall, the combination of factors suggests that carbon adsorption is the most appropriate technology for the Gloversville-Johnstown WWTF. In many cases, for newer electrical generating technologies (i.e., microturbines and fuel cells), the manufacturers prefer to provide a biogas clean-up system specifically suited to their technology and the proposed application. For the economic evaluations included in Section 5, when a biogas clean-up system is not specifically included with the electrical generating equipment application, a carbon adsorption system has been included.

Table 4-1: Technology Rating Summary

Technology	History of Operation	Performance	Implementability	Capital Cost	Maintenance Effort ($/1,000 kWh)
Carbon Adsorption	Good	Good	Good	$190,000	$2.45
Refrigeration/ Condensation	Fair	Fair/Poor	Good	$125,000	$8.65
TSA/PSA	Poor	Fair/Poor	Good	$180,000	$3.81

5.0 EVALUATION OF GAS END USE ALTERNATIVES

5.1 END USE ALTERNATIVES CONSIDERED IN STUDY

In addition to evaluating biogas quality, biogas quantity, and biogas clean-up alternatives, alternatives for end use of the biogas were also considered. Specific alternatives that were evaluated include:

- Continue to use the existing generation equipment without biogas clean-up.
- Install a clean-up system to treat biogas for use in the current cogeneration operation and sell excess biogas to neighboring facilities.
- Install new cogeneration systems (internal combustion engines, microturbines, or biogas fuel cells) with sufficient capacity to use all biogas that is produced at the WWTF. Biogas clean-up is included with all cogeneration alternatives.
- Decommission the existing cogeneration facility, install biogas clean-up equipment, and sell all biogas to neighboring facilities to eliminate or offset the use of fossil fuels at those facilities.

To ensure an accurate assessment of each of the end use alternatives, the full production scenario, in which the dairy manufacturer discharges dairy whey to the WWTF at its full-scale operating level, was considered. The timeline for this scenario is late 2007.

5.2 AIR EMISSIONS REGULATIONS

Historically, the biogas-fueled equipment at the GJWWTF has been considered exempt from air permitting requirements because the equipment is below the size thresholds established in the registration and permitting provisions of Subpart 201 of the New York State Department of Environmental Conservation's (NYSDEC's) Rules and Regulations for natural gas-fired equipment. However, the NYSDEC recently issued an internal memorandum, dated May 4, 2006, to address uncertainty within the department about the specific permitting requirements for bio-fuel applications.

The May 4, 2006 memorandum recommends a case-by-case permit review for applications like GJWWTF and allows the size threshold exemptions only for bio-fuel blends or dual fuel fired sources that use traditional fossil fuels for at least 10 percent of their annual fuel consumption. GJWWTF currently has sufficient biogas to meets its fuel needs without natural gas purchase. As a result, while the output of the GJWWTF cogeneration facility is less than the historic threshold requiring Air Facility Registration, because of the NYSDEC's increased interest in bio-fuel applications, an Air Facility Registration has been prepared and submitted to the NYSDEC for the WWTF.

The NYSDEC issued proposed emissions regulations for distributed generation sources, Subpart 222, including biogas-fired applications. The effective date of the proposed regulation is June 1, 2008. Under the proposed regulations, existing sources with an output rating of greater than 200 HP in the severe ozone nonattainment area or 400 HP outside of a severe ozone nonattainment area, must conduct emissions testing by December 31, 2009, with subsequent emissions testing every 15,000 hours of operation or five years, whichever is later. NOx limits for biogas-fired existing sources are based on the type of generating equipment that is used. Compliance with the NOx limits shown below is required by January 1, 2010.

Microturbines	**Turbines**	**Lean Burn ICE**	**Rich Burn ICE**
1.5 g/bhp-h	50 ppm	3.0 g/bhp-h	2.0 g/bhp-h

Distributed generation sources with an output rating greater than 67 HP that commence operation after January 1, 2009 and that are not subject to U.S. EPA 40 CFR 60, Subpart IIII, Subpart JJJJ, and Subpart KKKK regulations, must conduct emissions testing within 120 days of start-up. Subsequent emissions testing must be completed every 15,000 operating hours or five years, whichever is later. Regardless of equipment type, new sources firing biogas and not meeting EPA regulations must meet emissions limits of 1.5 g/bhp-h and 3.4 g/bhp-h for NOx and CO, respectively.

Based on the proposed regulations, if GJWWTF continues to operate their current internal combustion engines or commences operation of new rich burn internal combustion engines prior to January 1, 2009, then the system must meet an emissions limit of 2.0 g/bhp-h for NOx. It is not clear if the existing engines will be to meet that limit. Most new, low emissions engines are able to meet the NOx limit of 2.0 g/bhp-h without aftertreatment. Standard emissions models typically are not able to meet the emissions limit without treatment. If new generating equipment is installed after January 1, 2009, then the equipment must meet either EPA regulations or emissions limits of 1.5 g/bhp-h and 3.4 g/bhp-h for NOx and CO, respectively. At this time, only a few engines are able to meet those limits without aftertreatment. Fuel cells, microturbines and turbines generally are able to meet the more stringent limits without aftertreatment.

5.3 STANDBY FEES

National Grid (formerly Niagara Mohawk Power Corporation) Filing No. 207 with the Public Service Commission (PSC) establishes Service Classification No. 7 (SC-7) for the sale of standby service to customers with on-site generation facilities. SC-7 allows National Grid to assess customer charges, standby contract demand charges, as used on-peak daily demand charges, as used daily energy charges, electricity supply service charges, and surcharges and adjustments. Of greatest concern to a facility like GJJWWTF, which meets approximately 30 to 40 percent of its annual electricity usage with its on-site generators, is the standby demand charge. This standby charge reduces the savings associated with on-site generation by requiring a user to pay for standby electricity should the user's on-site generation go down. The standby demand charge for an SC-3 user, which is the classification for GJJWWTF, ranges from \$0.87/kW to \$3.89/kW of contract demand, dependent upon the delivery voltage. At GJJWWTF's delivery voltage of 69kV, the standby demand charge of \$0.87/kW equates to approximately \$7,300/year based on a contract demand of 700 kW.

SC-7 identifies a number of exempt activities. Included in those exemptions are Environmentally Advantageous Technologies, including renewable technologies explicitly identified in the New York State Energy Plan, such as wastewater methane.

Specific conditions that must be met to maintain exemption include:

- The electricity supply is for use at the customer premises only and not for resale to any other party or for use at any other premises.

- The Renewable on-site generator is connected to the customer's electric system using an automated or manual transfer switch or the electrical equivalent of such a switch approved by National Grid consistent with Electric System Bulletin 750 as it may be amended from time to time.

- The customer executes and National Grid accepts a Form G as required under the special provisions of the applicable Service Classifications for all generators on the premises.

- The calculated deferral sub-account shall not exceed an aggregate of $2,000,000, with no more than $500,000 allowed for a single exempt technology on a prospective (forecast) basis.

- Savings realized from the exemption shall not exceed 20% of the annual deferral amount ($100,000) set aside for fuel cells and other renewable technologies explicitly identified in the New York State Plan.

The existing GJJWWTF cogeneration facility meets all requirements for exemption. For the purposes of this study, we have assumed that Standby Charges will not apply. If Standby Charges do apply, then the savings resulting from avoided electricity costs would be slightly reduced at the WWTF.

5.4 RENEWABLE PORTFOLIO STANDARD INCENTIVES

In an Order issued on June 26, 2006, the Public Service Commission (PSC) clarified the eligibility requirements for inclusion in the Customer Sited Tier of the Renewable Portfolio Standard (RPS). Prior to that clarification, it was unclear if wastewater treatment plants that employ on-site electrical generation using digester gas were eligible for incentives being offered through that program. The Order issued on June 26, 2006 clarifies that the authorization applies to anaerobic digestion systems in general, not just those that may be farm based, as long as the generator is connected in place behind the customer's meter, the customer pays into the RPS program fund, and the facility is sized not to exceed the approximate peak connected load at the customer's meter. Wastewater treatment facilities that meet these criteria are, therefore, eligible for RPS incentives. Facilities that cannot meet these requirements may still participate in the RPS Program, whether farm-based or not, if they were not constructed prior to January 1, 2003.

NYSERDA developed a program for implementation of the Customer Sited Tier of the RPS. Two types of incentives are available. An initial, $500 per kilowatt one-time incentive (capacity incentive), based on the incremental installed capacity of a new system, is available to support construction and installation of new distributed electrical generation using biogas. In addition, a production-based incentive is provided for a period of 3 years. The production-based incentive for new renewable distributed generation is \$0.10/kWh (performance incentive). Existing facilities constructed after January 1, 2003 will receive an incentive of \$0.02 /kWh produced (maintenance incentive). The cost evaluations included in this study are based on the following assumptions:

- The one-time \$500/kW capacity incentive under the RPS was applied to the incremental increase in electric power generation capacity. A maximum capacity incentive of \$350,000 or 50% of the total purchase, engineering services, and installation costs has been established.

- A maintenance incentive of \$0.02/kWh was applied to all electricity produced up to the current level of output, and a performance incentive of \$0.10/kWh was used for any incremental increase in electricity production from current levels for systems installed after January 1, 2003.

- Production-based incentives will be received for the first three years of operation only.

- No incentive is available for biogas that is recovered for on-site or off-site thermal uses.

- A maximum of \$1 million is available for each ADG system.

5.5 ELECTRICAL MODIFICATIONS

For each of the equipment configurations considered in Alternative 3, the installation would have to be reviewed by the utility company during the design phase. The review would include the new one-line diagram, protection provisions, and associated power quality issues on the electrical system. For all of these alternatives, the utility company requires installation of protective relaying, which will require the installation of new switchgear. Without conducting a detailed electrical evaluation, it is difficult to accurately estimate the total cost of the electrical upgrades that would be required. However, since it is likely that all expanded on-site generation alternatives would require a similar level of upgrade, an allowance of \$150,000 was included in the economic evaluation for each alternative.

5.6 SLUDGE HOLDING TANK CONSTRUCTION

The increased flow and loading to the digesters requires additional primary digester capacity. As stated in Section 3.2, for the purpose of this study it has been assumed that a sludge holding tank is constructed downstream of the digesters, with the existing secondary digester being converted to a primary digester, with sludge heating and mixing being employed. The construction of a new sludge holding tank, including the necessary modifications to the existing digesters, would be required for all alternatives. An allowance of $750,000, plus contingencies, engineering, construction, and administration costs, was included in the economic evaluation for each alternative.

5.7 WASTE HEAT RECOVERY

The conversion of the secondary digester to a primary digester will require heating and mixing of the sludge in both digesters to maintain a constant temperature near an optimum value (typically 95°F) and to maximize the rate of digestion, improving the overall performance of the process. Overall heating requirements include heating the influent sludge from its initial temperature to the optimal one and compensating for heat loss across the digester's external surfaces (floor, walls, and cover). Based on an annual average sludge feed rate to the digesters of approximately 105,000 gpd, an average sludge influent temperature of 64ºF (due in part to the higher temperature of the whey), a target operating temperature of 95°F, and compensating for heat losses through the external surfaces, an average of approximately 1,674,000 BTU/hour is required to meet the thermal needs of the proposed digester operating configuration. The maximum heat requirement, based on a worst day average ambient air temperature of 0°F, an incoming sludge temperature of 48°F, and the maximum sludge feed rate of 145,000 gpd, is approximately 3,324,000 BTU/hour.

None of the cogeneration alternatives that were considered have sufficient waste heat to meet the thermal demand of the new digester configuration on the worst day. However, for the purposes of this evaluation, thermal needs and heat recovery potential were considered on an annual average basis. For those alternatives that provide sufficient waste heat to meet the annual average thermal demand of the digesters, all biogas is recovered and used for electrical generation. For those alternatives that do not provide adequate waste heat, the volume of biogas used to generate electricity was reduced by an amount sufficient to address the gap between thermal demand and waste heat recovery using the on-site boiler. Alternatively, natural gas could be purchased to address digester heating during periods when thermal demand exceeds waste heat production, allowing all biogas to be used for electrical generation.

5.8 CALCULATION OF NET PRESENT WORTH OF ALTERNATIVES

The economic evaluations completed in the following sections are based on information provided by equipment manufacturers, identified in technical literature, and through correspondence with WWTF personnel. In addition to the specific items described in Sections 5.2 through 5.7, a number of other assumptions were necessary to complete the economic evaluation for this study. Specific items include:

- The evaluation was based on a 15-year timeframe, which is considered the approximate useful life of an internal combustion engine installed in a biogas application. For those technologies with less than a 15-year operating record, significant equipment overhauls were included in the economic assessment at intervals recommended by the manufacturer to provide a 15-year assessment period.

- An annual inflation rate of 3 percent was used to adjust annual operations and maintenance costs, the unit cost of electricity, and the unit cost of biogas that is sold.

- The Department of Interior's Discount Rate for Water Resources Planning of 5.125 percent, established in December 2005, was used to calculate the net present worth of each alternative.

- Given the conceptual level of this assessment, a contingency of 40 percent was included in the capital cost for all alternatives.

- Engineering, construction, and administration costs were estimated as 15 percent of the total construction cost for all alternatives.

5.9 ALTERNATIVE 1 – CONTINUE CURRENT OPERATIONS

Under Alternative 1, the WWTF will continue to use its current internal combustion engines without changing their operation and without incorporating biogas clean-up. The biogas will continue to cause significant wear and tear of the engines, high operation and maintenance costs, and frequent engine overhaul.

The future annual average electrical production remains unchanged at 1,850,880 kWh/year. Waste heat is not available to fully meet the thermal demands of the proposed digester configuration. On average, approximately 3,500 cf/d of biogas will be used for heating the converted secondary digester. For the purpose of the cost evaluation, it was assumed the increased biogas production is sufficient for cogeneration and heating, no natural gas will be purchased, and biogas in excess of that used to generate electricity and as fuel for the boiler, approximately 110,000 cf/d, will be flared.

5.9.1 Operations and Maintenance

Estimated Year 1 operating and maintenance costs are approximately $64,500, based on information provided by WWTF personnel on current operating costs. In addition to normal labor and materials costs, periodic engine overhaul also is included in the economic evaluation. One engine was overhauled in 2003, and the second is scheduled for overhaul in 2007. For the purposes of the evaluation, we have assumed that each engine will be overhauled on an approximately four-year cycle, and the head for each engine will be rebuilt once every two years.

5.9.2 Project Economics

The capital cost for Alternative 1 is $1,207,500. Under this alternative, the total value of the avoided electricity purchase over the 15-year period is approximately $5,163,500, with approximately $111,000 received through the Customer Sited Renewable Portfolio Standard incentive program. The total net revenue for Alternative 1 over the 15-year period is approximately $2,151,800. The net present worth of Alternative 1 is approximately $1,143,400. Table 5-1 summarizes the project economics for this alternative.

5.10 ALTERNATIVE 2 – CURRENT OPERATIONS WITH GAS CLEAN-UP

Under Alternative 2, the WWTF will continue to use its current internal combustion engines. However, unlike Alternative 1, a carbon adsorption system will be installed for

Table 5-1: Project Economics for Alternative 1 - Continue Current Operations

Year		Capital Costs	O&M Costs	Avoided Electrical Costs	Biogas Sale	RPS Incentive[1] Capacity	Performance	Annual Net Cost/Revenue	Present Worth
1	2008	$1,207,500	$ 64,570	$ 277,632	$ -	$ -	$ 37,012	$ (957,427)	($910,751)
2	2009	$ -	$ 66,507	$ 285,961	$ -	$ -	$ 37,012	$ 256,465	$232,069
3	2010	$ -	$ 153,382	$ 294,540	$ -	$ -	$ 37,012	$ 178,170	$153,361
4	2011	$ -	$ 70,558	$ 303,376	$ -	$ -	$ -	$ 232,818	$190,631
5	2012	$ -	$ 162,723	$ 312,477	$ -	$ -	$ -	$ 149,755	$116,641
6	2013	$ -	$ 74,855	$ 321,852	$ -	$ -	$ -	$ 246,997	$183,002
7	2014	$ -	$ 172,633	$ 331,507	$ -	$ -	$ -	$ 158,875	$111,973
8	2015	$ -	$ 79,413	$ 341,452	$ -	$ -	$ -	$ 262,039	$175,678
9	2016	$ -	$ 183,146	$ 351,696	$ -	$ -	$ -	$ 168,550	$107,492
10	2017	$ -	$ 84,250	$ 362,247	$ -	$ -	$ -	$ 277,997	$168,648
11	2018	$ -	$ 194,299	$ 373,114	$ -	$ -	$ -	$ 178,815	$103,190
12	2019	$ -	$ 89,380	$ 384,308	$ -	$ -	$ -	$ 294,927	$161,898
13	2020	$ -	$ 206,132	$ 395,837	$ -	$ -	$ -	$ 189,705	$99,060
14	2021	$ -	$ 94,824	$ 407,712	$ -	$ -	$ -	$ 312,888	$155,419
15	2022	$ -	$ 218,686	$ 419,943	$ -	$ -	$ -	$ 201,258	$95,096
TOTAL		**$1,207,500**	**$1,915,357**	**$5,163,654**	**$ -**	**$111,035**		**$ 2,151,831**	**$1,143,407**

Description	Future
Holding Tank	$ 750,000
subtotal	$ 750,000
contingency 40%	$ 300,000
total construction	$1,050,000
engineering, construction, and administration 15%	$ 157,500
total cost	**$1,207,500**

[1] The RPS Incentive shown is based on the following:

- A $500/kW capacity incentive is applied to the incremental increase in electric power generation with a cap of $350,000 or 50% of capital costs.
- A maintenance incentive of $0.02/kWh was applied to all electricity producted up the current level of electrical output.
- A performance incentive of $0.10/kWh was applied to any incremental increase in electricity production from current levels.
- Production-based incentives will be for the first three years of operation only.
- A maximum of $1,000,000 is available for each ADG system.

biogas clean-up. The clean-up system, which has a footprint of approximately 12 feet by 8 feet, can be installed in the first floor of the digester building. In addition to biogas clean-up, under Alternative 2, a small-diameter gas pipeline and compressor system will be installed to allow sale of excess biogas to adjacent facilities.

The quantity of electricity produced, and consequently the avoided electricity cost, is the same as that of Alternative 1. However, unlike Alternative 1, because the biogas is being treated, it is expected that wear and tear on the engines will decrease, which will reduce the frequency of engine overhaul and decrease overall operations and maintenance costs. In addition, because the biogas will be treated, it is expected that excess biogas can be sold to an adjacent industry to offset its fossil fuel consumption and costs, rather than being wasted to the WWTF's flare. At a unit cost of $0.66/therm, which is approximately 75 percent of the current cost of natural gas, the additional revenue from the sale of conditioned biogas during Year 1 is approximately $161,000.

5.10.1 Operations and Maintenance

Estimated Year 1 operating and maintenance costs are approximately $70,000. The annual operating and maintenance costs are based on information provided by WWTF personnel for the current cogeneration operations plus the estimated cost of operating and maintaining the biogas clean-up system. In addition to normal labor and materials costs, periodic engine overhaul also is included in the economic evaluation. One engine was overhauled in 2003, and the second is scheduled for overhaul in 2007. For the purposes of the evaluation, we have assumed that biogas clean-up will allow the frequency of engine overhaul to be reduced to once every six years. Head rebuild will still occur once every two years for each engine.

5.10.2 Project Economics

The capital cost for Alternative 2 is approximately $1,956,000. Under this alternative, the total value of the avoided electricity purchase over the 15-year period is approximately $5,163,500, with approximately $111,000 received through the Customer Sited Renewable Portfolio Standard incentive program. Because of the reduced operating and maintenance costs and the additional revenue resulting from the sale of excess biogas, the total net revenue for Alternative 2 over the 15-year period is approximately $4,652,700. The net present worth of Alternative 2 is approximately $2,583,100. Table 5-2 summarizes the project economics for this alternative.

5.11 ALTERNATIVE 3A – NEW INTERNAL COMBUSTION ENGINES

The existing generators are induction type; however, the manufacturer recommends replacing them with synchronous generating equipment. An induction generator is essentially a special purpose motor that is run slightly above synchronous speed by the engine. It receives its excitation from the utility and has no means of producing voltage until it is connected to the utility. Therefore, the frequency and voltage of the power produced with this type of generator is governed by the frequency and voltage of the incoming utility line.

A synchronous generator has an exciter that enables the generator to produce its own reactive power and regulate its voltage, even when it is not connected to another power source. This means that it can operate either in parallel with the utility or it can operate in "stand-alone" mode (independent of any other power source). Synchronous generators require a speed reduction gear, whereas induction systems are usually direct-drive.

In practical terms, the advantages and disadvantages of synchronous and induction generators can be summarized as follows:

Table 5-2: Project Economics for Alternative 2 - Current Operations with Gas Clean-Up

Year		Capital Costs	O&M Costs	Avoided Electrical Costs	Biogas Sale	RPS Incentive[1] Capacity	RPS Incentive[1] Performance	Annual Net Cost/Revenue	Present Worth
1	2008	$1,956,150	$ 69,961	$ 277,632	$ 160,955	$ -	$ 37,012	$ (1,550,513)	($1,474,923)
2	2009	$ -	$ 72,060	$ 285,961	$ 165,784	$ -	$ 37,012	$ 416,696	$377,057
3	2010	$ -	$ 74,222	$ 294,540	$ 170,757	$ -	$ 37,012	$ 428,087	$368,480
4	2011	$ -	$ 154,461	$ 303,376	$ 175,880	$ -	$ -	$ 324,795	$265,941
5	2012	$ -	$ 78,742	$ 312,477	$ 181,156	$ -	$ -	$ 414,891	$323,150
6	2013	$ -	$ 81,104	$ 321,852	$ 186,591	$ -	$ -	$ 427,338	$316,618
7	2014	$ -	$ 168,784	$ 331,507	$ 192,189	$ -	$ -	$ 354,912	$250,138
8	2015	$ -	$ 86,044	$ 341,452	$ 197,954	$ -	$ -	$ 453,363	$303,947
9	2016	$ -	$ 88,625	$ 351,696	$ 203,893	$ -	$ -	$ 466,964	$297,803
10	2017	$ -	$ 184,434	$ 362,247	$ 210,010	$ -	$ -	$ 387,822	$235,273
11	2018	$ -	$ 94,022	$ 373,114	$ 216,310	$ -	$ -	$ 495,402	$285,885
12	2019	$ -	$ 96,843	$ 384,308	$ 222,799	$ -	$ -	$ 510,264	$280,106
13	2020	$ -	$ 201,536	$ 395,837	$ 229,483	$ -	$ -	$ 423,784	$221,292
14	2021	$ -	$ 102,741	$ 407,712	$ 236,368	$ -	$ -	$ 541,339	$268,897
15	2022	$ -	$ 105,823	$ 419,943	$ 243,459	$ -	$ -	$ 557,579	$263,461
TOTAL		**$1,956,150**	**$1,659,403**	**$5,163,654**	**$2,993,589**	**$111,035**		**$ 4,652,725**	**$2,583,126**

Description	Future
Gas system (equipment + installation)	$ 190,000
Compressors	$ 50,000
installation	$ 25,000
Pipeline	$ 200,000
Holding Tank	$ 750,000
subtotal	$1,215,000
contingency 40%	$ 486,000
total construction	$1,701,000
engineering, construction, and administration 15%	$ 255,150
total cost	**$1,956,150**

[1] The RPS Incentive shown is based on the following:

- A $500/kW capacity incentive is applied to the incremental increase in electric power generation with a cap of $350,000 or 50% of capital costs.
- A maintenance incentive of $0.02/kWh was applied to all electricity producted up the current level of electrical output.
- A performance incentive of $0.10/kWh was applied to any incremental increase in electricity production from current levels.
- Production-based incentives will be for the first three years of operation only.
- A maximum of $1,000,000 is available for each ADG system.

	Induction generators	Synchronous generators
Parallel or stand-alone?	Can only run in parallel with the utility. Cannot provide back-up power during utility outage.	Can run in parallel or stand-alone. Can provide back-up power.
Typical price comparison*	Under 700 kW, less expensive.	Over 700 kW, less expensive.
Power factor issues	Should not be used for more than about 1/3 of total plant electrical load.	Can be used to improve power factor. Can provide up to 100% of plant load, or more.
Complexity	The common perception is that synchronous generators are complex and difficult to operate. With modern electronics, this is no longer an issue.	

* Prices compared include engine, generator, and complete switchgear, including circuit breaker, utility grade electrical protection, synchronizing equipment as required, and controls.

Table adapted from Turbo Steam Corporation.

Under Alternative 3A, the two existing 150-kW internal combustion engines would be replaced with new internal combustion engine(s). Two sub-alternatives were considered: replacement of the existing engines with one 600-kW engine and replacement of the existing engines with two 350-kW engines. For both sub-alternatives, a carbon adsorption system will be installed for biogas conditioning. Similarly, for both sub-alternatives, the new generating equipment will fit in the energy recovery building, replacing the existing units once they are removed. Engines manufactured by Caterpillar were considered for this option, since Caterpillar also manufactured the engines currently on-site. Other internal combustion engine manufacturers are available on the market, and they might be considered during detailed design.

The fuel demand of the single 600-kW engine matches up more closely with the projected biogas production, and this sub-alternative has a lower capital cost. However, because only a single unit is in place, no electricity generation would be possible if the equipment is down for maintenance or repair. Projected biogas production is insufficient to provide fuel to support the two 350-kW engines at full load. However, these are the smallest Caterpillar engines that can run on biogas. While the capital cost is greater for this sub-alternative, it provides equipment redundancy and additional generating capacity should other changes take place at the WWTF that result in biogas production in excess of projections. The total generated power from these engines would match the peak demand for the WWTF.

For both sub-alternatives, all biogas is used on-site for electricity generation and to meet the thermal demands of the new digester configuration. The waste heat that can be recovered from both the single large engine and the two smaller engines is sufficient to meet the annual average thermal needs of the digesters. However, because the waste heat recovery of the single large engine is less than that associated with the two smaller engines, during high thermal demand periods (i.e., winter) a greater amount of biogas will be used to meet the thermal needs of the digesters, reducing electricity generation during those periods. Because of the decrease in available biogas for electrical generation, a lower total generating capacity, and periods of no electrical production during equipment maintenance and repair, the use of the single large engine results in a reduction in overall electrical output when compared to the use of two smaller engines. A comparison of the electrical production and biogas requirement to meet the thermal needs of the digesters for each of the sub-alternatives is shown below:

Sub-Alternative	**Electricity Production (kwh/yr)**	**Biogas Requirement for Thermal Needs (cf/d)** [1]
Single, 600-kW Engine	3,400,000	65,000
Two, 350-kW Engines	3,711,000	54,000

[1] For illustrative purposes only, based on estimated worst case day.

5.11.1 Operations and Maintenance

The estimated Year 1 operating and maintenance costs for both sub-alternatives are based on a budgetary price provided by the manufacturer for a 15-year maintenance agreement for the engines, including engine head replacement once every two years and total engine rebuild once every four years. In addition to the cost of the service agreement, 25 percent of the current GJWWTF labor cost and the operations and maintenance costs for the biogas clean-up system were included in the annual operations and maintenance costs for the two sub-alternatives. Should GJWWTF choose to operate and maintain the equipment using their own personnel, the annual operations and maintenance costs may be lower than those shown.

The Year 1 operations and maintenance costs for the 600-kW internal combustion engine alternative are estimated to be approximately $98,000. The Year 1 operations and maintenance costs for the 350-kW internal combustion engines alternative are estimated to be approximately $113,000.

5.11.2 Project Economics

The capital cost for the single, 600-kW engine is approximately $3,209,500. Under this sub-alternative, the total value of the avoided electricity purchase over the 15-year period is approximately $9,477,000 with approximately $925,000 of revenue received through the Customer Sited Renewable Portfolio Standard incentive program. The total net revenue for this sub-alternative over the 15-year period is approximately $5,126,400. The net present worth of the single 600-kW engine sub-alternative is approximately $2,647,000.

The capital cost for the two 350-kW engines is approximately $3,451,000. Under this sub-alternative, the total value of the avoided electricity purchase over the 15-year period is $10,352,500 with $1,000,000 of revenue received through the Customer Sited Renewable Portfolio Standard incentive program. The total net revenue for this sub-alternative over the 15-year period is approximately $5,449,000. The net present worth of the two 350-kW engines sub-alternative is approximately $2,814,000. Table 5-3 summarizes the project economics for both sub-alternatives.

5.12 ALTERNATIVE 3B – MICROTURBINES

A microturbine is a compact turbine generator that mixes fuel with air to create combustion. This combustion turns a magnet generator, compressor, and turbine wheels at high speed. The result is a reliable, clean combustion generator with very low NOx emissions. Under Alternative 3B, like under Alternative 3A, two sub-alternatives were considered: microturbines manufactured by Capstone and microturbines manufactured by Ingersoll Rand.

Capstone has two sizes of microturbines available for use with anaerobic digester gas, 30 kW and 65 kW. These units can be configured to operate in groups. The 65 kW units are more appropriate for this application. Based on the published input fuel requirement of 842,000 BTU/hour for the microturbines, sufficient gas will be produced to supply eight 65 kW microturbines, with a total nominal output of 520 kW. High temperature heat can and

Table 5-3: Project Economics for Alternative 3A - New Internal Combustion Engines-1 600kW

Year		Capital Costs	O&M Costs	Avoided Electrical Costs	Biogas Sale	RPS Incentive [1] Capacity	RPS Incentive [1] Performance	Annual Net Cost/Revenue	Present Worth
1	2008	$3,209,535	$ 97,935	$ 509,557	$ -	$ 350,000	$ 191,658	$ (2,606,255)	($2,479,196)
2	2009	$ -	$ 94,714	$ 524,844	$ -		$ 191,658	$ 621,788	$562,640
3	2010	$ -	$ 97,555	$ 540,589	$ -		$ 191,658	$ 634,692	$546,317
4	2011	$ -	$ 100,482	$ 556,807	$ -			$ 456,325	$373,637
5	2012	$ -	$ 103,496	$ 573,511	$ -			$ 470,015	$366,085
6	2013	$ -	$ 106,601	$ 590,716	$ -			$ 484,115	$358,685
7	2014	$ -	$ 109,799	$ 608,438	$ -			$ 498,639	$351,434
8	2015	$ -	$ 113,093	$ 626,691	$ -			$ 513,598	$344,330
9	2016	$ -	$ 116,486	$ 645,492	$ -			$ 529,006	$337,370
10	2017	$ -	$ 119,980	$ 664,856	$ -			$ 544,876	$330,550
11	2018	$ -	$ 123,580	$ 684,802	$ -			$ 561,222	$323,869
12	2019	$ -	$ 127,287	$ 705,346	$ -			$ 578,059	$317,322
13	2020	$ -	$ 131,106	$ 726,507	$ -			$ 595,401	$310,908
14	2021	$ -	$ 135,039	$ 748,302	$ -			$ 613,263	$304,623
15	2022	$ -	$ 139,090	$ 770,751	$ -			$ 631,661	$298,465
TOTAL		**$3,209,535**	**$1,716,244**	**$ 9,477,209**	**$ -**	**$924,974**		**$ 5,126,404**	**$2,647,038**

Description	Future
IC Engines	$ 600,000
installation	$ 300,000
Gas system (equipment + installation)	$ 190,000
Air permit	$ 3,500
Electrical modifications	$ 150,000
Holding Tank	$ 750,000
subtotal	$1,993,500
contingency 40%	$ 797,400
total construction	$2,790,900
engineering, construction, and administration 15%	$ 418,635
total cost	**$3,209,535**

[1] The RPS Incentive shown is based on the following:

- A $500/kW capacity incentive is applied to the incremental increase in electric power generation with a cap of $350,000 or 50% of capital costs.
- A maintenance incentive of $0.02/kWh was applied to all electricity producted up the current level of electrical output.
- A performance incentive of $0.10/kWh was applied to any incremental increase in electricity production from current levels.
- Production-based incentives will be for the first three years of operation only.
- A maximum of $1,000,000 is available for each ADG system.

Table 5-3: Project Economics for Alternative 3A - New Internal Combustion Engines-2 350kW

Year		Capital Costs	O&M Costs	Avoided Electrical Costs	Biogas Sale	RPS Incentive [1] Capacity	RPS Incentive [1] Performance	Annual Net Cost/Revenue	Present Worth
1	2008	$3,451,035	$ 113,135	$ 556,622	$ -	$ 350,000	$ 223,035	$ (2,784,514)	($2,648,764)
2	2009	$ -	$ 116,515	$ 573,321	$ -		$ 223,035	$ 679,841	$615,170
3	2010	$ -	$ 119,996	$ 590,520	$ -		$ 203,931	$ 674,455	$580,544
4	2011	$ -	$ 123,581	$ 608,236	$ -			$ 484,655	$396,834
5	2012	$ -	$ 127,274	$ 626,483	$ -			$ 499,209	$388,823
6	2013	$ -	$ 131,078	$ 645,277	$ -			$ 514,199	$380,974
7	2014	$ -	$ 134,996	$ 664,636	$ -			$ 529,640	$373,283
8	2015	$ -	$ 139,032	$ 684,575	$ -			$ 545,543	$365,747
9	2016	$ -	$ 143,188	$ 705,112	$ -			$ 561,924	$358,363
10	2017	$ -	$ 147,469	$ 726,265	$ -			$ 578,796	$351,128
11	2018	$ -	$ 151,879	$ 748,053	$ -			$ 596,174	$344,039
12	2019	$ -	$ 156,421	$ 770,495	$ -			$ 614,074	$337,092
13	2020	$ -	$ 161,099	$ 793,610	$ -			$ 632,511	$330,286
14	2021	$ -	$ 165,918	$ 817,418	$ -			$ 651,500	$323,616
15	2022	$ -	$ 170,881	$ 841,941	$ -			$ 671,060	$317,082
TOTAL		**$3,451,035**	**$2,102,462**	**$10,352,565**	**$ -**	**$1,000,000**		**$ 5,449,068**	**$2,814,217**

Description	Future
IC Engines	$ 700,000
installation	$ 350,000
Gas system (equipment + installation)	$ 190,000
Air permit	$ 3,500
Electrical modifications	$ 150,000
Holding Tank	$ 750,000
subtotal	$2,143,500
contingency 40%	$ 857,400
total construction	$3,000,900
engineering, construction, and administration 15%	$ 450,135
total cost	$3,451,035

[1] The RPS Incentive shown is based on the following:

- A $500/kW capacity incentive is applied to the incremental increase in electric power generation with a cap of $350,000 or 50% of capital costs.
- A maintenance incentive of $0.02/kWh was applied to all electricity producted up the current level of electrical output.
- A performance incentive of $0.10/kWh was applied to any incremental increase in electricity production from current levels.
- Production-based incentives will be for the first three years of operation only.
- A maximum of $1,000,000 is available for each ADG system.

should be recovered from the exhaust of the microturbines, as is currently done with the engine generators. Each unit has a footprint of 77 inches by 30 inches; due to the built-in capability to array more units as one, the Capstone microturbines could be installed in the existing energy recovery building in place of the existing cogeneration units.

Ingersoll Rand has a 250 kW microturbine that can be operated with the anaerobic digester gas produced at the WWTF. Based on the published input fuel requirement of 77 scfm, the future gas production can supply two 250 kW microturbines, with a total nominal output of 500 kW. High temperature heat can and should be recovered from the exhaust of the microturbines, as is currently done with the engine generators. Each unit has a footprint of 127 inches by 85 inches, which allows the Ingersoll Rand microturbines to also be installed in the existing energy recovery building in place of the existing cogeneration units.

The microturbines can run effectively using low-BTU anaerobic digester gas. However, the equipment is more sensitive than internal combustion engines to biogas impurities. As such, some pre-treatment is required to improve operations. Fuel for the system needs to be at high pressure of 75 psig. Compressors would be required for the digester gas feed system. The fuel also should be treated to remove siloxane compounds and other impurities, as well as any remaining moisture. Fuel pretreatment typically is included with microturbines and, based on discussions with the manufacturers, can be accomplished with a skid-mounted activated carbon system in series with a desiccant. For the purposes of this evaluation, specific budgetary costs were provided by each manufacturer for the necessary biogas clean-up system, and operations and maintenance costs that were provided included operations and maintenance activities associated with the biogas clean-up system.

5.12.1 Operations and Maintenance

Operating and maintenance costs for the Capstone sub-alternative are based on unit pricing provided by the manufacturer. Operating and maintenance costs for the Ingersoll-Rand sub-alternative are based on pricing provided by the manufacturer for a service agreement. Neither manufacturer has installations that have been in place for 15 years. Based on discussions with the manufacturers, significant overhaul of the microturbines would be required after five to six years with significant overhaul of both the equipment and the electrical systems after 10 to 12 years.

The Year 1 operations and maintenance costs for the Capstone sub-alternative are estimated to be approximately $114,000. The Year 1 operations and maintenance costs for the Ingersoll-Rand sub-alternative are estimated to be approximately $68,000. Much of the difference in cost is simply due to the fact that only two microturbines require maintenance with the Ingersoll-Rand sub-alternative, whereas eight microturbines require maintenance with the Capstone sub-alternative.

5.12.2 Project Economics

The capital cost for the Capstone microturbines is approximately $3,437,000. The total value of the avoided electricity purchase over the 15-year period is approximately $11,437,500 with $1,000,000 of revenue received through the Customer Sited Renewable Portfolio Standard incentive program. The total net revenue for this sub-alternative over the 15-year period is approximately $5,450,600. The net present worth of the Capstone sub-alternative is approximately $2,892,000.

The capital cost for the Ingersoll-Rand microturbines is approximately $3,501,000. The total value of the avoided electricity purchase over the 15-year period is approximately $10,997,500 with $1,000,000 of revenue received through the Customer Sited Renewable Portfolio Standard incentive program. The total net revenue for this sub-alternative over the 15-year period is approximately $5,880,600. The net present worth of the Ingersoll-Rand sub-alternative is approximately $3,157,000.

For both alternatives, it was assumed that the units operate 90 percent of the time to account for downtime due to maintenance and repair activities. The difference between the two sub-alternatives in the values of the avoided electricity purchase and the incentive is due to the slightly larger total combined capacity of the eight Capstone units. Table 5-4 summarizes the project economics for both sub-alternatives.

Table 5-4: Project Economics for Alternative 3B - Capstone Microturbines

Year		Capital Costs	O&M Costs	Avoided Electrical Costs	Biogas Sale	RPS Incentive [1] Capacity	RPS Incentive [1] Performance	Annual Net Cost/Revenue	Present Worth
1	2008	$3,437,350	$ 113,880	$ 614,952	$ -	$ 350,000	$ 261,921	$ (2,674,357)	($2,543,978)
2	2009	$ -	$ 117,296	$ 633,401	$ -		$ 261,921	$ 778,025	$704,015
3	2010	$ -	$ 120,815	$ 652,403	$ -		$ 126,158	$ 657,745	$566,160
4	2011	$ -	$ 124,440	$ 671,975	$ -			$ 547,535	$448,320
5	2012	$ -	$ 346,116	$ 692,134	$ -			$ 346,017	$269,506
6	2013	$ -	$ 132,018	$ 712,898	$ -			$ 580,880	$430,378
7	2014	$ -	$ 135,979	$ 734,285	$ -			$ 598,306	$421,678
8	2015	$ -	$ 140,058	$ 756,313	$ -			$ 616,255	$413,155
9	2016	$ -	$ 144,260	$ 779,003	$ -			$ 634,743	$404,803
10	2017	$ -	$ 719,153	$ 802,373	$ -			$ 83,220	$50,486
11	2018	$ -	$ 153,045	$ 826,444	$ -			$ 673,399	$388,603
12	2019	$ -	$ 157,637	$ 851,237	$ -			$ 693,601	$380,748
13	2020	$ -	$ 162,366	$ 876,775	$ -			$ 714,409	$373,051
14	2021	$ -	$ 167,237	$ 903,078	$ -			$ 735,841	$365,511
15	2022	$ -	$ 465,152	$ 930,170	$ -			$ 465,018	$219,725
TOTAL		**$3,437,350**	**$3,199,451**	**$11,437,439**	**$ -**	**$1,000,000**		**$ 5,450,639**	**$2,892,161**

Description	Future
Capstone microturbines	$ 540,000
Gas system (compression,dehydration, filtration)	$ 195,000
Complete installation	$ 500,000
Electrical modifications	$ 150,000
Holding Tank	$ 750,000
subtotal	$2,135,000
contingency 40%	$ 854,000
total construction	$2,989,000
engineering, construction, and administration 15%	$ 448,350
total cost	$3,437,350

[1] The RPS Incentive shown is based on the following:

- A $500/kW capacity incentive is applied to the incremental increase in electric power generation with a cap of $350,000 or 50% of capital costs.
- A maintenance incentive of $0.02/kWh was applied to all electricity producted up the current level of electrical output.
- A performance incentive of $0.10/kWh was applied to any incremental increase in electricity production from current levels.
- Production-based incentives will be for the first three years of operation only.
- A maximum of $1,000,000 is available for each ADG system.

Table 5-4: Project Economics for Alternative 3B - Ingersoll Rand Microturbines

Year		Capital Costs	O&M Costs	Avoided Electrical Costs	Biogas Sale	RPS Incentive [1]		Annual Net Cost/Revenue	Present Worth
						Capacity	Performance		
1	2008	$3,500,945	$ 68,320	$ 591,300	$ -	$ 350,000	$ 246,153	$ (2,731,812)	($2,598,632)
2	2009	$ -	$ 70,370	$ 609,039	$ -		$ 246,153	$ 784,823	$710,165
3	2010	$ -	$ 72,481	$ 627,310	$ -		$ 157,694	$ 712,523	$613,311
4	2011	$ -	$ 74,655	$ 646,129	$ -			$ 571,474	$467,921
5	2012	$ -	$ 76,895	$ 665,513	$ -			$ 588,619	$458,463
6	2013	$ -	$ 351,399	$ 685,479	$ -			$ 334,080	$247,522
7	2014	$ -	$ 81,578	$ 706,043	$ -			$ 624,465	$440,115
8	2015	$ -	$ 84,025	$ 727,224	$ -			$ 643,199	$431,219
9	2016	$ -	$ 86,546	$ 749,041	$ -			$ 662,495	$422,502
10	2017	$ -	$ 89,142	$ 771,512	$ -			$ 682,370	$413,962
11	2018	$ -	$ 91,816	$ 794,658	$ -			$ 702,841	$405,594
12	2019	$ -	$ 817,685	$ 818,497	$ -			$ 813	$446
13	2020	$ -	$ 97,408	$ 843,052	$ -			$ 745,644	$389,362
14	2021	$ -	$ 100,330	$ 868,344	$ -			$ 768,014	$381,492
15	2022	$ -	$ 103,340	$ 894,394	$ -			$ 791,054	$373,780
TOTAL		**$3,500,945**	**$2,265,989**	**$10,997,538**	**$ -**	**$1,000,000**		**$ 5,880,604**	**$3,157,222**

Description	Future
Ingersoll Rand microturbines	$ 587,000
installation	$ 293,500
shipping	$ 4,000
Gas system (scrubber+coalescing filter)	$ 260,000
installation	$ 130,000
Electrical modifications	$ 150,000
Holding Tank	$ 750,000
subtotal	$2,174,500
contingency 40%	$ 869,800
total construction	$3,044,300
engineering, construction, and administration 15%	$ 456,645
total cost	$3,500,945

[1] The RPS Incentive shown is based on the following:

- A $500/kW capacity incentive is applied to the incremental increase in electric power generation with a cap of $350,000 or 50% of capital costs.
- A maintenance incentive of $0.02/kWh was applied to all electricity producted up the current level of electrical output.
- A performance incentive of $0.10/kWh was applied to any incremental increase in electricity production from current levels.
- Production-based incentives will be for the first three years of operation only.
- A maximum of $1,000,000 is available for each ADG system.

5.13 ALTERNATIVE 3C – FUEL CELLS

A fuel cell converts chemical energy from hydrogen and oxygen into electrical energy and produces a direct electrical current, which can then be converted to alternating current. It is similar to a battery. However, a battery is only capable of storing power, whereas the fuel cell can generate power as long as fuel is being supplied. High temperature systems can run on biogas that is first "reformed" into hydrogen. Steam may be recovered and used in hot water heaters and heat exchangers. Fuel cell benefits include ultra low emissions, high electrical efficiency, low noise, and power reliability.

The use of fuel cells using anaerobic digester gas is still in the early stages of development, and the costs generally are significantly higher than other electricity generating equipment. Although several fuel cell manufacturers exist, only the fuel cell produced by UTC Power was considered under this alternative. UTC Power has a 200-kW fuel cell available for use with anaerobic digester gas.

Based on the full production scenario, the gas production can supply two fuel cells, with a total nominal output of 400 kW. The footprint for each unit is approximately 17 feet 8 inches by 9 feet 6 inches, with a height of 10 feet. Although it does not appear that the units can be housed within the energy recovery building, the proposed units are equipped with enclosures that enable outside installation. The fuel cell is provided with a gas clean-up system that includes a coalescing filter, to remove entrained moisture and solids, and two activated carbon beds, to remove the H_2S.

For Alternative 3C, two alternative project delivery approaches were considered. The first approach is based on the WWTF owning the equipment with operations and maintenance handled through a service agreement with the manufacturer (WWTF-owned sub-alternative). The second alternative is based on the WWTF entering into a contract with the manufacturer to install, operate, and maintain the system for a period of 15 years at which point the WWTF has the opportunity to purchase the equipment or terminate the contract (manufacturer-owned sub-alternative). The second alternative has nominal up front costs for the fuel cell equipment but greater annual costs to allow the manufacturer to recoup their initial investment. The service contract price is based on 7.8 cents per kWh for the first 9 years and 9.5 cents per kWh for years 10 through 14.

5.13.1 Operations and Maintenance

Fuel cells have high maintenance costs. Like the other generating equipment, periodic overhaul is required. However, the cost of overhauling fuel cells is greater than that for more traditional generating equipment. Every six years, units need to be overhauled with a complete fuel stack replacement. Estimated Year 1 operating and maintenance costs for the WWTF-owned sub-alternative are $70,000. Estimated Year 1 operating and maintenance costs for the manufacturer-owned sub-alternative are approximately $419,000.

5.13.2 Project Economics

The capital cost for the WWTF-owned sub-alternative is approximately $6,602,000. The total value of the avoided electricity purchase over the 15-year period is approximately $9,017,000 with approximately $875,500 of revenue received through the Customer Sited Renewable Portfolio Standard incentive program. The total net revenue for this sub-alternative over the 15-year period is approximately $838,800. The net present worth of the WWTF-owned sub-alternative is approximately -$1,203,000.

The capital cost for the manufacturer-owned sub-alternative is $1,449,000. The total value of the avoided electricity purchase over the 15-year period is approximately $9,775,500 with approximately $875,500 of revenue received through the Customer Sited Renewable Portfolio Standard incentive program. The total net revenue for this sub-alternative over the 15-year period is approximately $2,268,500. The net present worth of the manufacturer-owned sub-alternative is approximately $1,154,600. Table 5-5 summarizes the project economics for both sub-alternatives.

5.14 EXTERNAL COMBUSTION ENGINES

Replacement of the existing internal combustion engines with an external combustion engine was another alternative that was considered. External combustion engines use the Stirling cycle and have low emissions and low maintenance requirements. STM Power offers an integrated 55-kW external combustion engine-generator. At the time of this study, external combustion engines primarily were being used in research projects, and no long-term commercial installation was available for comparison with the other alternatives

Table 5-5: Project Economics for Alternative 3C - Fuel Cells

Year		Capital Costs	O&M Costs	Avoided Electrical Costs	Biogas Sale	RPS Incentive [1] Capacity	RPS Incentive [1] Performance	Annual Net Cost/Revenue	Present Worth
1	2008	$6,602,224	$ 70,000	$ 484,833	$ -	$ 350,000	$ 175,175	$ (6,012,215)	($5,719,111)
2	2009	$ -	$ 72,100	$ 499,378	$ -		$ 175,175	$ 602,453	$545,144
3	2010	$ -	$ 74,263	$ 514,359	$ -		$ 175,175	$ 615,272	$529,601
4	2011	$ -	$ 76,491	$ 529,790	$ -			$ 453,299	$371,160
5	2012	$ -	$ 450,000	$ 545,684	$ -			$ 95,684	$74,526
6	2013	$ -	$ 81,149	$ 562,054	$ -			$ 480,905	$356,306
7	2014	$ -	$ 83,584	$ 578,916	$ -			$ 495,332	$349,104
8	2015	$ -	$ 86,091	$ 596,284	$ -			$ 510,192	$342,047
9	2016	$ -	$ 88,674	$ 614,172	$ -			$ 525,498	$335,133
10	2017	$ -	$ 520,000	$ 632,597	$ -			$ 112,597	$68,307
11	2018	$ -	$ 94,074	$ 651,575	$ -			$ 557,501	$321,721
12	2019	$ -	$ 96,896	$ 671,122	$ -			$ 574,226	$315,218
13	2020	$ -	$ 99,803	$ 691,256	$ -			$ 591,453	$308,846
14	2021	$ -	$ 102,797	$ 711,994	$ -			$ 609,196	$302,603
15	2022	$ -	$ 105,881	$ 733,354	$ -			$ 627,472	$296,486
TOTAL		**$6,602,224**	**$2,101,804**	**$9,017,369**	**$ -**	**$875,526**		**$ 838,867**	**($1,202,908)**

Description	Future
Fuel cells (incl.installation and fuel handling)	$2,700,760
Extended warranty w/ overhaul	$ 500,000
Electrical modifications	$ 150,000
Holding Tank	$ 750,000
subtotal	$4,100,760
contingency 40%	$1,640,304
total construction	$5,741,064
engineering, construction, and administration 15%	$ 861,160
total cost	$6,602,224

[1] The RPS Incentive shown is based on the following:

- A $500/kW capacity incentive is applied to the incremental increase in electric power generation with a cap of $350,000 or 50% of capital costs.
- A maintenance incentive of $0.02/kWh was applied to all electricity producted up the current level of electrical output.
- A performance incentive of $0.10/kWh was applied to any incremental increase in electricity production from current levels.
- Production-based incentives will be for the first three years of operation only.
- A maximum of $1,000,000 is available for each ADG system.

Table 5-5: Project Economics for Alternative 3C - Fuel Cells-Service Agreement

Year		Capital Costs	O&M Costs	Avoided Electrical Costs	Biogas Sale	RPS Incentive [1]		Annual Net Cost/Revenue	Present Worth
						Capacity	Performance		
1	2008	$1,449,000	$ 419,049	$ 525,600	$ -	$ 350,000	$ 175,175	$ (1,167,274)	($1,110,367)
2	2009	$ -	$ 419,049	$ 541,368	$ -		$ 175,175	$ 297,494	$269,195
3	2010	$ -	$ 419,049	$ 557,609	$ -		$ 175,175	$ 313,735	$270,051
4	2011	$ -	$ 419,049	$ 574,337	$ -			$ 155,288	$127,150
5	2012	$ -	$ 419,049	$ 591,567	$ -			$ 172,518	$134,371
6	2013	$ -	$ 419,049	$ 609,314	$ -			$ 190,265	$140,969
7	2014	$ -	$ 419,049	$ 627,594	$ -			$ 208,545	$146,980
8	2015	$ -	$ 419,049	$ 646,422	$ -			$ 227,373	$152,437
9	2016	$ -	$ 419,049	$ 665,814	$ -			$ 246,765	$157,373
10	2017	$ -	$ 419,049	$ 685,789	$ -			$ 266,740	$161,818
11	2018	$ -	$ 478,617	$ 706,362	$ -			$ 227,745	$131,427
12	2019	$ -	$ 478,617	$ 727,553	$ -			$ 248,936	$136,652
13	2020	$ -	$ 478,617	$ 749,380	$ -			$ 270,763	$141,388
14	2021	$ -	$ 478,617	$ 771,861	$ -			$ 293,244	$145,662
15	2022	$ -	$ 478,617	$ 795,017	$ -			$ 316,400	$149,502
TOTAL		**$1,449,000**	**$6,583,575**	**$9,775,589**	**$ -**	**$875,526**		**$ 2,268,540**	**$1,154,605**

Description	Future
Electrical modifications	$ 150,000
Holding Tank	$ 750,000
subtotal	$ 900,000
contingency 40%	$ 360,000
total construction	$1,260,000
engineering, construction, and administration 15%	$ 189,000
total cost	$1,449,000

[1] The RPS Incentive shown is based on the following:

- A $500/kW capacity incentive is applied to the incremental increase in electric power generation with a cap of $350,000 or 50% of capital costs.
- A maintenance incentive of $0.02/kWh was applied to all electricity producted up the current level of electrical output.
- A performance incentive of $0.10/kWh was applied to any incremental increase in electricity production from current levels.
- Production-based incentives will be for the first three years of operation only.
- A maximum of $1,000,000 is available for each ADG system.

considered in this study. For this reason, a detailed assessment of external combustion engines was not completed.

5.15 ALTERNATIVE 4 – SALE OF BIOGAS

Under Alternative 4, the WWTF will decommission the existing cogeneration system and install a carbon adsorption to treat the biogas. Part of the biogas will be supplied to the WWTF boilers to meet the thermal needs of the digesters, with all remaining biogas being sold to one or more industries in the industrial park. This alternative includes demolition of the existing cogeneration system, installation of a biogas clean-up system, installation of two compressors, and installation of 2,000 linear feet of gas pipeline. For the purpose of this evaluation, it has been assumed that the salvage value of the decommissioned cogeneration facility will offset the actual costs of demolition and decommissioning.

It is estimated that the thermal needs of the digesters can be met with approximately 24,445,000 cf/yr of digester gas, which equates to an average biogas consumption of approximately 67,000 cf/day. During the winter months, the percentage of total gas produced that will be available for sale will be at its least. Even so, during the worst month, it is estimated that over 25,000 therms of digester gas will be available for sale. A few industries have expressed interest in purchasing the treated biogas as a supplement to the natural gas for their heating and process needs.

5.15.1 Operations and Maintenance

Operations and maintenance costs for Alternative 4 include operations and maintenance of the biogas clean-up system, operation and maintenance of the compressors, and operations and maintenance of the gas pipeline. Estimated Year 1 operations and maintenance costs for this alternative are $14,300.

5.15.2 Project Economics

The capital cost for Alternative 4 is approximately $1,956,000. Since on-site electrical generation is eliminated under this alternative, the WWTF will be required to purchase all power from the commercial grid. As a result, there is no avoided electricity cost and no revenue as a result of the Customer Sited Renewable Portfolio Standard incentive program. The only source of revenue under this alternative is through sale of the biogas, which in Year 1 is estimated to amount to approximately $247,000. The total net revenue for this alternative over the 15-year evaluation period is approximately $2,376,500. The net present worth of Alternative 4 is approximately $1,031,500. Table 5-6 summarizes the project economics for the gas sale alternative.

5.16 SUMMARY OF FINDINGS

Table 5-7 summarizes the capital costs, operations and maintenance costs, value of avoided electricity purchase, revenue from sale of biogas, value of Customer-Sited Tier Renewable Portfolio Standard incentive, total net cost or revenue, and present worth for each of the alternatives described above. As illustrated in Table 5-7, Alternative 3b, using the Ingersoll-Rand microturbines, offers the most attractive present worth of all alternatives that were considered. The main reasons Alternative 3b, using Ingersoll-Rand microturbines, provides the most attractive present worth are:

- Close alignment of maximum fuel throughput and energy output with projected biogas production, which maximizes total electrical production and minimizes wasted biogas.

- The greatest amount of waste heat recovery potential of all alternatives considered, which minimizes the amount of biogas that must be used to meet the thermal demands of the new digester configuration.

Table 5-6: Project Economics for Alternative 4 - Sale of Biogas

Year		Capital Costs	O&M Costs	Avoided Electrical Costs	Biogas Sale	RPS Incentive [1] Capacity	RPS Incentive [1] Performance	Annual Net Cost/Revenue	Present Worth
1	2008	$1,956,150	$ 14,300	$ -	$ 247,253	$ -	$ -	$ (1,723,197)	($1,639,189)
2	2009	$ -	$ 14,729	$ -	$ 254,670	$ -	$ -	$ 239,941	$217,117
3	2010	$ -	$ 15,171	$ -	$ 262,311	$ -	$ -	$ 247,140	$212,728
4	2011	$ -	$ 15,626	$ -	$ 270,180	$ -	$ -	$ 254,554	$208,428
5	2012	$ -	$ 16,095	$ -	$ 278,285	$ -	$ -	$ 262,190	$204,215
6	2013	$ -	$ 16,578	$ -	$ 286,634	$ -	$ -	$ 270,056	$200,087
7	2014	$ -	$ 17,075	$ -	$ 295,233	$ -	$ -	$ 278,158	$196,042
8	2015	$ -	$ 17,587	$ -	$ 304,090	$ -	$ -	$ 286,503	$192,079
9	2016	$ -	$ 18,115	$ -	$ 313,213	$ -	$ -	$ 295,098	$188,197
10	2017	$ -	$ 18,658	$ -	$ 322,609	$ -	$ -	$ 303,951	$184,392
11	2018	$ -	$ 19,218	$ -	$ 332,287	$ -	$ -	$ 313,069	$180,665
12	2019	$ -	$ 19,795	$ -	$ 342,256	$ -	$ -	$ 322,461	$177,013
13	2020	$ -	$ 20,388	$ -	$ 352,523	$ -	$ -	$ 332,135	$173,435
14	2021	$ -	$ 21,000	$ -	$ 363,099	$ -	$ -	$ 342,099	$169,929
15	2022	$ -	$ 21,630	$ -	$ 373,992	$ -	$ -	$ 352,362	$166,494
TOTAL		**$1,956,150**	**$ 265,964**	**$ -**	**$4,598,634**	**$0**		**$ 2,376,520**	**$1,031,632**

Description	Future
Gas system (equipment + installation)	$ 190,000
Compressors	$ 50,000
installation	$ 25,000
Pipeline	$ 200,000
Holding Tank	$ 750,000
subtotal	$1,215,000
contingency 40%	$ 486,000
total construction	$1,701,000
engineering, construction, and administration 15%	$ 255,150
total cost	$1,956,150

[1] The RPS Incentive shown is based on the following:

- A $500/kW capacity incentive is applied to the incremental increase in electric power generation with a cap of $350,000 or 50% of capital costs.
- A maintenance incentive of $0.02/kWh was applied to all electricity producted up the current level of electrical output.
- A performance incentive of $0.10/kWh was applied to any incremental increase in electricity production from current levels.
- Production-based incentives will be for the first three years of operation only.
- A maximum of $1,000,000 is available for each ADG system.

Table 5-7: Summary of Project Economics for Biogas Recovery and Use Alternatives - Ranked by Present Worth

	Total capital costs	Total O&M costs	Avoided Electrical Costs	Biogas Sale	RPS Incentive	Net Cost/Revenue	Present Worth
Alternative 3b - New Microturbines (Ingersoll Rand)	$3,500,945	$2,265,989	$10,997,538	$0	$1,000,000	$5,880,604	$3,157,222
Alternative 3b - New Microturbines (Capstone)	$3,437,350	$3,199,451	$11,437,439	$0	$1,000,000	$5,450,639	$2,892,161
Alternative 3a - New Internal Combustion Engines (2x350KW)	$3,451,035	$2,102,462	$10,352,565	$0	$1,000,000	$5,449,068	$2,814,217
Alternative 3a - New Internal Combustion Engine (1x600KW)	$3,209,535	$1,716,244	$9,477,209	$0	$924,974	$5,126,404	$2,647,038
Alternative 2 - Current Operations with Biogas Clean-up	$1,956,150	$1,659,403	$5,163,654	$2,993,589	$111,035	$4,652,725	$2,583,126
Alternative 3c - New Fuel Cells (Service Agreement)	$1,449,000	$6,583,575	$9,775,589	$0	$875,526	$2,268,540	$1,154,605
Alternative 1 - Continue Current Operations	$1,207,500	$1,915,357	$5,163,654	$0	$111,035	$2,151,831	$1,143,407
Alternative 4 - Biogas Sale	$1,956,150	$265,964	$0	$4,598,634	$0	$2,376,520	$1,031,632
Alternative 3c - New Fuel Cells (Purchase)	$6,602,224	$2,101,804	$9,017,369	$0	$875,526	$838,867	-$1,202,908

6.0 CONCLUSIONS AND RECOMMENDATIONS

6.1 RECOMMENDATIONS FOR GJJWWTF

As shown in Section 5, Alternative 3b, using Ingersoll-Rand microturbines, offers the most attractive present worth over the 15-year evaluation period. However, for the reasons summarized below, Alternative 3a, installation of two new internal combustion engines, is recommended at GJJWWTF.

- The capital cost and annual operations and maintenance costs for Alternative 3a are less than the capital costs and annual operations and maintenance costs for the Ingersoll-Rand microturbine alternative.
- Microturbines, while gaining in popularity in biogas applications due to their ability to meet stringent emissions limits, do not have the long-term operating history that internal combustion engines do.
- New internal combustion engines with biogas cleanup are expected to meet the proposed emissions requirements at the GJJWWTF.
- GJJWWTF personnel are familiar with the operations and maintenance requirements for internal combustion engines, which minimizes the need for operator training and minimizes the effect on current operations.
- It is expected that the organic loading treated by GJJWWTF will continue to increase as additional sources of high-strength waste are accepted or current sources expand their manufacturing operations. The increased loading will result in greater biogas production than that used in this evaluation. At the biogas production rate used in this evaluation, the Ingersoll-Rand microturbines are able to operate at approximately 90% of their capacity whereas the engines, due to a limited number of available engine sizes, operate at less than two-thirds of their design capacity. The increased biogas production will allow the internal combustion engines to be operated more closely to their design capacity and would exceed the fuel demand of the Ingersoll-Rand microturbines, which would result in wasted biogas and lost electrical generation. With an approximately 5% increase in biogas production above the value used in the evaluation, the present worth of Alternative 3a becomes more attractive than that for the Ingersoll-Rand microturbines.

Given the relatively low capital cost and operating cost, it also is recommended that GJJWWTF install a biogas cleanup system using carbon adsorption to reduce engine maintenance and downtime and to extend engine life.

6.2 APPLICABILITY OF FINDINGS TO OTHER WWTFs

This study illustrates that, while energy production/recovery using digester gas is certainly no longer a new concept in the wastewater sector, the market for biogas treatment, recovery, and use is continuing to evolve. Proven biogas clean-up and electricity generating technologies do exist; however, a number of emerging, but not yet fully proven, technologies may offer advantages over these more traditional technologies. While it is clear that nearly all segments of the public and regulatory communities support the use of renewable generating technologies - like biogas recovery and use - the overlapping and sometimes conflicting aspects of the environmental and energy markets make the assessment of project feasibility difficult.

Widely varying sludge/waste characteristics, variations in treatment process performance, use of alternative delivery methods (i.e., role of Energy Service Companies), regional and size-based air emissions regulations, and limited available sizes of the various electrical generating equipment make it nearly impossible to offer accurate, broad-brushed guidance to the wastewater sector in this area. Similarly, changing emissions regulations; inconsistent capacity thresholds and ambiguous definitions for exemptions from electricity tariffs or emissions requirements; and the critical role that incentives, which may or may not be defined, play in project feasibility make comparison of varying technologies complex even for a specific, defined application. However, there are certain conclusions that have sector-wide applicability. These include:

- Facilities with anaerobic digesters that currently flare all biogas should implement some form of energy recovery or electricity production. At a minimum, biogas should be used in on-site boilers to meet digester or facility thermal needs.

- While the feasibility of projects generally should be determined based on their own economic merits, given the wide range of incentives being made available to support alternative and renewable energy sources, it is imperative that these incentives be considered when selecting a final alternative.

- Given the relatively low cost and high efficiency of basic biogas treatment systems (e.g., carbon adsorption), new electrical generating applications should incorporate biogas conditioning to reduce the maintenance requirements for the generating equipment.

- Biogas sale, while not as economically attractive as on-site electricity generation (due to the high cost of electricity and available incentives for electricity generation), may provide a reasonable energy recovery alternative for WWTFs with nearby buyers.

- Incoming waste characteristics, particularly in instances where high strength wastes are being discharged directly to the anaerobic digesters for treatment, can significantly affect biogas quantity and quality.

- WWTFs must consider air emissions regulations when evaluating biogas recovery alternatives. In severe non-attainment zones, both biogas clean-up and emissions treatment systems may be necessary to meet emissions requirements, which increase project implementation costs.

- WWTFs must consider standby fees and other tariff structures closely when evaluating biogas recovery alternatives, as they have the potential to significantly affect project economics, may vary by electric service provider, and are subject to various thresholds and restrictions.

- Waste heat recovery should be implemented with all but the smallest electrical generating applications.

APPENDIX A

Analytical Results
Air Toxics, Ltd.

Air Toxics Ltd. Introduces the Electronic Report

Thank you for choosing Air Toxics Ltd. To better serve our customers, we are providing your report by e-mail. This document is provided in Portable Document Format which can be viewed with Acrobat Reader by Adobe.

This electronic report includes the following:

- Work order Summary;
- Laboratory Narrative;
- Results; and
- Chain of Custody (copy).

180 BLUE RAVINE ROAD, SUITE B FOLSOM, CA - 95630

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Hours 8:00 A.M to 6:00 P.M. Pacific

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WORK ORDER #: 0605300A

Work Order Summary

CLIENT:	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614	**BILL TO:**	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614
PHONE:	585-327-3102	**P.O. #**	2255073
FAX:		**PROJECT #**	Gloversville - Johnstown
DATE RECEIVED:	05/12/2006	**CONTACT:**	Kelly Buettner
DATE COMPLETED:	05/24/2006		

FRACTION #	NAME	TEST	RECEIPT VAC./PRES.
01A	Raw Gas-1	Modified TO-15	Tedlar Bag
02A(on hold)	Raw Gas-1 duplicate	Modified TO-15	Tedlar Bag
03A	Filtered Gas-1	Modified TO-15	Tedlar Bag
04A(on hold)	Filtered Gas-1 duplicate	Modified TO-15	Tedlar Bag
05A	Lab Blank	Modified TO-15	NA
06A	CCV	Modified TO-15	NA
07A	LCS	Modified TO-15	NA

CERTIFIED BY: Linda L. Freeman DATE: 05/24/06

Laboratory Director

Certfication numbers: CA NELAP - 02110CA, LA NELAP/LELAP- AI 30763, NJ NELAP - CA004
NY NELAP - 11291, UT NELAP - 9166389892
Name of Accrediting Agency: NELAP/Florida Department of Health, Scope of Application: Clean Air Act,
Accreditation number: E87680, Effective date: 07/01/05, Expiration date: 06/30/06
Air Toxics Ltd. certifies that the test results contained in this report meet all requirements of the NELAC standards

180 BLUE RAVINE ROAD, SUITE B FOLSOM, CA - 95630
(916) 985-1000 . (800) 985-5955 . FAX (916) 985-1020

LABORATORY NARRATIVE
Modified TO-15
Malcolm Pirnie
Workorder# 0605300A

Four 1 Liter Tedlar Bag samples were received on May 12, 2006. The laboratory performed analysis via modified EPA Method TO-15 using GC/MS in the full scan mode. The method involves concentrating up to 0.2 liters of air. The concentrated aliquot is then flash vaporized and swept through a water management system to remove water vapor. Following dehumidification, the sample passes directly into the GC/MS for analysis.

Method modifications taken to run these samples are summarized in the below table. Specific project requirements may over-ride the ATL modifications.

Requirement	*TO-15*	*ATL Modifications*
Daily CCV	+- 30% Difference	</= 30% Difference with two allowed out up to </=40%.; flag and narrate outliers
Sample collection media	Summa canister	ATL recommends use of summa canisters to insure data defensibility, but will report results from Tedlar bags at client request
Method Detection Limit	Follow 40CFR Pt.136 App. B	The MDL met all relevant requirements in Method TO-15 (statistical MDL less than the LOQ). The concentration of the spiked replicate may have exceeded 10X the calculated MDL in some cases

Receiving Notes

There were no discrepancies

Analytical Notes

The reported LCS for each daily batch has been derived from more than one analytical file.

Carbon Disulfide was detected in the laboratory blank analyzed on 05/12/2006 at less than 5X the reporting limit. Associated samples had no detections for Carbon Disulfide.

Definition of Data Qualifying Flags

Eight qualifiers may have been used on the data analysis sheets and indicates as follows:

B - Compound present in laboratory blank greater than reporting limit (background subtraction not performed).
J - Estimated value.
E - Exceeds instrument calibration range.
S - Saturated peak.
Q - Exceeds quality control limits.
U - Compound analyzed for but not detected above the reporting limit.
UJ- Non-detected compound associated with low bias in the CCV
N - The identification is based on presumptive evidence.

File extensions may have been used on the data analysis sheets and indicates as follows:

a-File was requantified
b-File was quantified by a second column and detector
r1-File was requantified for the purpose of reissue

Summary of Detected Compounds
MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Client Sample ID: Raw Gas-1

Lab ID#: 0605300A-01A

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Vinyl Chloride	4.0	7.0	10	18
Methylene Chloride	4.0	13	14	47
Hexane	4.0	63	14	220
2-Butanone (Methyl Ethyl Ketone)	4.0	6.7	12	20
cis-1,2-Dichloroethene	4.0	44	16	170
Cyclohexane	4.0	9.0	14	31
2,2,4-Trimethylpentane	4.0	120	19	540
Benzene	4.0	12	13	40
Heptane	4.0	70	16	290
Trichloroethene	4.0	26	21	140
4-Methyl-2-pentanone	4.0	6.2	16	26
Toluene	4.0	1200	15	4600
Tetrachloroethene	4.0	20	27	140
Ethyl Benzene	4.0	36	17	160
m,p-Xylene	4.0	140	17	620
o-Xylene	4.0	48	17	210
Cumene	4.0	19	20	93
Propylbenzene	4.0	38	20	190
4-Ethyltoluene	4.0	110	20	550
1,3,5-Trimethylbenzene	4.0	70	20	340
1,2,4-Trimethylbenzene	4.0	140	20	680
1,4-Dichlorobenzene	4.0	4.4	24	27

Client Sample ID: Filtered Gas-1

Lab ID#: 0605300A-03A

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Hexane	10	63	35	220
2-Butanone (Methyl Ethyl Ketone)	10	14	29	43
cis-1,2-Dichloroethene	10	47	40	180
2,2,4-Trimethylpentane	10	120	47	540
Benzene	10	13	32	42
Heptane	10	76	41	310
Trichloroethene	10	29	54	160
4-Methyl-2-pentanone	10	12	41	51
Toluene	10	1400	38	5300
Tetrachloroethene	10	21	68	140

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Summary of Detected Compounds
MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Client Sample ID: Filtered Gas-1

Lab ID#: 0605300A-03A

Ethyl Benzene	10	47	43	200
m,p-Xylene	10	160	43	690
o-Xylene	10	48	43	210
Cumene	10	19	49	93
Propylbenzene	10	26	49	130
4-Ethyltoluene	10	79	49	390
1,3,5-Trimethylbenzene	10	48	49	240
1,2,4-Trimethylbenzene	10	69	49	340

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Client Sample ID: Raw Gas-1

Lab ID#: 0605300A-01A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	4.0	Not Detected	20	Not Detected
Freon 114	4.0	Not Detected	28	Not Detected
Chloromethane	16	Not Detected	33	Not Detected
Vinyl Chloride	4.0	7.0	10	18
1,3-Butadiene	4.0	Not Detected	8.8	Not Detected
Bromomethane	4.0	Not Detected	16	Not Detected
Chloroethane	4.0	Not Detected	10	Not Detected
Freon 11	4.0	Not Detected	22	Not Detected
Ethanol	16	Not Detected	30	Not Detected
Freon 113	4.0	Not Detected	31	Not Detected
1,1-Dichloroethene	4.0	Not Detected	16	Not Detected
Acetone	16	Not Detected	38	Not Detected
2-Propanol	16	Not Detected	39	Not Detected
Carbon Disulfide	4.0	Not Detected	12	Not Detected
3-Chloropropene	16	Not Detected	50	Not Detected
Methylene Chloride	4.0	13	14	47
Methyl tert-butyl ether	4.0	Not Detected	14	Not Detected
trans-1,2-Dichloroethene	4.0	Not Detected	16	Not Detected
Hexane	4.0	63	14	220
1,1-Dichloroethane	4.0	Not Detected	16	Not Detected
2-Butanone (Methyl Ethyl Ketone)	4.0	6.7	12	20
cis-1,2-Dichloroethene	4.0	44	16	170
Tetrahydrofuran	4.0	Not Detected	12	Not Detected
Chloroform	4.0	Not Detected	20	Not Detected
1,1,1-Trichloroethane	4.0	Not Detected	22	Not Detected
Cyclohexane	4.0	9.0	14	31
Carbon Tetrachloride	4.0	Not Detected	25	Not Detected
2,2,4-Trimethylpentane	4.0	120	19	540
Benzene	4.0	12	13	40
1,2-Dichloroethane	4.0	Not Detected	16	Not Detected
Heptane	4.0	70	16	290
Trichloroethene	4.0	26	21	140
1,2-Dichloropropane	4.0	Not Detected	18	Not Detected
1,4-Dioxane	16	Not Detected	58	Not Detected
Bromodichloromethane	4.0	Not Detected	27	Not Detected
cis-1,3-Dichloropropene	4.0	Not Detected	18	Not Detected
4-Methyl-2-pentanone	4.0	6.2	16	26
Toluene	4.0	1200	15	4600
trans-1,3-Dichloropropene	4.0	Not Detected	18	Not Detected
1,1,2-Trichloroethane	4.0	Not Detected	22	Not Detected

Client Sample ID: Raw Gas-1

Lab ID#: 0605300A-01A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Tetrachloroethene	4.0	20	27	140
2-Hexanone	16	Not Detected	66	Not Detected
Dibromochloromethane	4.0	Not Detected	34	Not Detected
1,2-Dibromoethane (EDB)	4.0	Not Detected	31	Not Detected
Chlorobenzene	4.0	Not Detected	18	Not Detected
Ethyl Benzene	4.0	36	17	160
m,p-Xylene	4.0	140	17	620
o-Xylene	4.0	48	17	210
Styrene	4.0	Not Detected	17	Not Detected
Bromoform	4.0	Not Detected	41	Not Detected
Cumene	4.0	19	20	93
1,1,2,2-Tetrachloroethane	4.0	Not Detected	27	Not Detected
Propylbenzene	4.0	38	20	190
4-Ethyltoluene	4.0	110	20	550
1,3,5-Trimethylbenzene	4.0	70	20	340
1,2,4-Trimethylbenzene	4.0	140	20	680
1,3-Dichlorobenzene	4.0	Not Detected	24	Not Detected
1,4-Dichlorobenzene	4.0	4.4	24	27
alpha-Chlorotoluene	4.0	Not Detected	21	Not Detected
1,2-Dichlorobenzene	4.0	Not Detected	24	Not Detected
1,2,4-Trichlorobenzene	16	Not Detected	120	Not Detected
Hexachlorobutadiene	16	Not Detected	170	Not Detected

Container Type: 1 Liter Tedlar Bag

Surrogates	%Recovery	Method Limits
Toluene-d8	97	70-130
1,2-Dichloroethane-d4	88	70-130
4-Bromofluorobenzene	80	70-130

Client Sample ID: Filtered Gas-1

Lab ID#: 0605300A-03A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	10	Not Detected	49	Not Detected
Freon 114	10	Not Detected	70	Not Detected
Chloromethane	40	Not Detected	83	Not Detected
Vinyl Chloride	10	Not Detected	26	Not Detected
1,3-Butadiene	10	Not Detected	22	Not Detected
Bromomethane	10	Not Detected	39	Not Detected
Chloroethane	10	Not Detected	26	Not Detected
Freon 11	10	Not Detected	56	Not Detected
Ethanol	40	Not Detected	75	Not Detected
Freon 113	10	Not Detected	77	Not Detected
1,1-Dichloroethene	10	Not Detected	40	Not Detected
Acetone	40	Not Detected	95	Not Detected
2-Propanol	40	Not Detected	98	Not Detected
Carbon Disulfide	10	Not Detected	31	Not Detected
3-Chloropropene	40	Not Detected	120	Not Detected
Methylene Chloride	10	Not Detected	35	Not Detected
Methyl tert-butyl ether	10	Not Detected	36	Not Detected
trans-1,2-Dichloroethene	10	Not Detected	40	Not Detected
Hexane	10	63	35	220
1,1-Dichloroethane	10	Not Detected	40	Not Detected
2-Butanone (Methyl Ethyl Ketone)	10	14	29	43
cis-1,2-Dichloroethene	10	47	40	180
Tetrahydrofuran	10	Not Detected	29	Not Detected
Chloroform	10	Not Detected	49	Not Detected
1,1,1-Trichloroethane	10	Not Detected	54	Not Detected
Cyclohexane	10	Not Detected	34	Not Detected
Carbon Tetrachloride	10	Not Detected	63	Not Detected
2,2,4-Trimethylpentane	10	120	47	540
Benzene	10	13	32	42
1,2-Dichloroethane	10	Not Detected	40	Not Detected
Heptane	10	76	41	310
Trichloroethene	10	29	54	160
1,2-Dichloropropane	10	Not Detected	46	Not Detected
1,4-Dioxane	40	Not Detected	140	Not Detected
Bromodichloromethane	10	Not Detected	67	Not Detected
cis-1,3-Dichloropropene	10	Not Detected	45	Not Detected
4-Methyl-2-pentanone	10	12	41	51
Toluene	10	1400	38	5300
trans-1,3-Dichloropropene	10	Not Detected	45	Not Detected
1,1,2-Trichloroethane	10	Not Detected	54	Not Detected

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Client Sample ID: Filtered Gas-1

Lab ID#: 0605300A-03A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Tetrachloroethene	10	21	68	140
2-Hexanone	40	Not Detected	160	Not Detected
Dibromochloromethane	10	Not Detected	85	Not Detected
1,2-Dibromoethane (EDB)	10	Not Detected	77	Not Detected
Chlorobenzene	10	Not Detected	46	Not Detected
Ethyl Benzene	10	47	43	200
m,p-Xylene	10	160	43	690
o-Xylene	10	48	43	210
Styrene	10	Not Detected	42	Not Detected
Bromoform	10	Not Detected	100	Not Detected
Cumene	10	19	49	93
1,1,2,2-Tetrachloroethane	10	Not Detected	69	Not Detected
Propylbenzene	10	26	49	130
4-Ethyltoluene	10	79	49	390
1,3,5-Trimethylbenzene	10	48	49	240
1,2,4-Trimethylbenzene	10	69	49	340
1,3-Dichlorobenzene	10	Not Detected	60	Not Detected
1,4-Dichlorobenzene	10	Not Detected	60	Not Detected
alpha-Chlorotoluene	10	Not Detected	52	Not Detected
1,2-Dichlorobenzene	10	Not Detected	60	Not Detected
1,2,4-Trichlorobenzene	40	Not Detected	300	Not Detected
Hexachlorobutadiene	40	Not Detected	430	Not Detected

Container Type: 1 Liter Tedlar Bag

Surrogates	%Recovery	Method Limits
Toluene-d8	101	70-130
1,2-Dichloroethane-d4	86	70-130
4-Bromofluorobenzene	84	70-130

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Lab Blank

Lab ID#: 0605300A-05A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	0.50	Not Detected	2.5	Not Detected
Freon 114	0.50	Not Detected	3.5	Not Detected
Chloromethane	2.0	Not Detected	4.1	Not Detected
Vinyl Chloride	0.50	Not Detected	1.3	Not Detected
1,3-Butadiene	0.50	Not Detected	1.1	Not Detected
Bromomethane	0.50	Not Detected	1.9	Not Detected
Chloroethane	0.50	Not Detected	1.3	Not Detected
Freon 11	0.50	Not Detected	2.8	Not Detected
Ethanol	2.0	Not Detected	3.8	Not Detected
Freon 113	0.50	Not Detected	3.8	Not Detected
1,1-Dichloroethene	0.50	Not Detected	2.0	Not Detected
Acetone	2.0	Not Detected	4.8	Not Detected
2-Propanol	2.0	Not Detected	4.9	Not Detected
Carbon Disulfide	0.50	0.70	1.6	2.2
3-Chloropropene	2.0	Not Detected	6.3	Not Detected
Methylene Chloride	0.50	Not Detected	1.7	Not Detected
Methyl tert-butyl ether	0.50	Not Detected	1.8	Not Detected
trans-1,2-Dichloroethene	0.50	Not Detected	2.0	Not Detected
Hexane	0.50	Not Detected	1.8	Not Detected
1,1-Dichloroethane	0.50	Not Detected	2.0	Not Detected
2-Butanone (Methyl Ethyl Ketone)	0.50	Not Detected	1.5	Not Detected
cis-1,2-Dichloroethene	0.50	Not Detected	2.0	Not Detected
Tetrahydrofuran	0.50	Not Detected	1.5	Not Detected
Chloroform	0.50	Not Detected	2.4	Not Detected
1,1,1-Trichloroethane	0.50	Not Detected	2.7	Not Detected
Cyclohexane	0.50	Not Detected	1.7	Not Detected
Carbon Tetrachloride	0.50	Not Detected	3.1	Not Detected
2,2,4-Trimethylpentane	0.50	Not Detected	2.3	Not Detected
Benzene	0.50	Not Detected	1.6	Not Detected
1,2-Dichloroethane	0.50	Not Detected	2.0	Not Detected
Heptane	0.50	Not Detected	2.0	Not Detected
Trichloroethene	0.50	Not Detected	2.7	Not Detected
1,2-Dichloropropane	0.50	Not Detected	2.3	Not Detected
1,4-Dioxane	2.0	Not Detected	7.2	Not Detected
Bromodichloromethane	0.50	Not Detected	3.4	Not Detected
cis-1,3-Dichloropropene	0.50	Not Detected	2.3	Not Detected
4-Methyl-2-pentanone	0.50	Not Detected	2.0	Not Detected
Toluene	0.50	Not Detected	1.9	Not Detected
trans-1,3-Dichloropropene	0.50	Not Detected	2.3	Not Detected
1,1,2-Trichloroethane	0.50	Not Detected	2.7	Not Detected

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Lab Blank

Lab ID#: 0605300A-05A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

File Name:	**1051209**	**Date of Collection: NA**
Dil. Factor:	**1.00**	**Date of Analysis: 5/12/06 05:35 PM**

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Tetrachloroethene	0.50	Not Detected	3.4	Not Detected
2-Hexanone	2.0	Not Detected	8.2	Not Detected
Dibromochloromethane	0.50	Not Detected	4.2	Not Detected
1,2-Dibromoethane (EDB)	0.50	Not Detected	3.8	Not Detected
Chlorobenzene	0.50	Not Detected	2.3	Not Detected
Ethyl Benzene	0.50	Not Detected	2.2	Not Detected
m,p-Xylene	0.50	Not Detected	2.2	Not Detected
o-Xylene	0.50	Not Detected	2.2	Not Detected
Styrene	0.50	Not Detected	2.1	Not Detected
Bromoform	0.50	Not Detected	5.2	Not Detected
Cumene	0.50	Not Detected	2.4	Not Detected
1,1,2,2-Tetrachloroethane	0.50	Not Detected	3.4	Not Detected
Propylbenzene	0.50	Not Detected	2.4	Not Detected
4-Ethyltoluene	0.50	Not Detected	2.4	Not Detected
1,3,5-Trimethylbenzene	0.50	Not Detected	2.4	Not Detected
1,2,4-Trimethylbenzene	0.50	Not Detected	2.4	Not Detected
1,3-Dichlorobenzene	0.50	Not Detected	3.0	Not Detected
1,4-Dichlorobenzene	0.50	Not Detected	3.0	Not Detected
alpha-Chlorotoluene	0.50	Not Detected	2.6	Not Detected
1,2-Dichlorobenzene	0.50	Not Detected	3.0	Not Detected
1,2,4-Trichlorobenzene	2.0	Not Detected	15	Not Detected
Hexachlorobutadiene	2.0	Not Detected	21	Not Detected

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Toluene-d8	100	70-130
1,2-Dichloroethane-d4	94	70-130
4-Bromofluorobenzene	97	70-130

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: CCV

Lab ID#: 0605300A-06A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	%Recovery
Freon 12	85
Freon 114	110
Chloromethane	98
Vinyl Chloride	77
1,3-Butadiene	86
Bromomethane	88
Chloroethane	75
Freon 11	94
Ethanol	85
Freon 113	96
1,1-Dichloroethene	93
Acetone	86
2-Propanol	92
Carbon Disulfide	92
3-Chloropropene	98
Methylene Chloride	104
Methyl tert-butyl ether	92
trans-1,2-Dichloroethene	87
Hexane	92
1,1-Dichloroethane	94
2-Butanone (Methyl Ethyl Ketone)	100
cis-1,2-Dichloroethene	98
Tetrahydrofuran	89
Chloroform	99
1,1,1-Trichloroethane	99
Cyclohexane	96
Carbon Tetrachloride	103
2,2,4-Trimethylpentane	101
Benzene	102
1,2-Dichloroethane	105
Heptane	102
Trichloroethene	106
1,2-Dichloropropane	105
1,4-Dioxane	97
Bromodichloromethane	109
cis-1,3-Dichloropropene	107
4-Methyl-2-pentanone	104
Toluene	104
trans-1,3-Dichloropropene	104
1,1,2-Trichloroethane	101

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: CCV

Lab ID#: 0605300A-06A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	%Recovery
Tetrachloroethene	104
2-Hexanone	97
Dibromochloromethane	107
1,2-Dibromoethane (EDB)	105
Chlorobenzene	97
Ethyl Benzene	95
m,p-Xylene	92
o-Xylene	91
Styrene	100
Bromoform	105
Cumene	92
1,1,2,2-Tetrachloroethane	90
Propylbenzene	92
4-Ethyltoluene	87
1,3,5-Trimethylbenzene	80
1,2,4-Trimethylbenzene	76
1,3-Dichlorobenzene	79
1,4-Dichlorobenzene	78
alpha-Chlorotoluene	86
1,2-Dichlorobenzene	75
1,2,4-Trichlorobenzene	93
Hexachlorobutadiene	100

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Toluene-d8	100	70-130
1,2-Dichloroethane-d4	94	70-130
4-Bromofluorobenzene	101	70-130

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: LCS

Lab ID#: 0605300A-07A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	%Recovery
Freon 12	81
Freon 114	102
Chloromethane	107
Vinyl Chloride	75
1,3-Butadiene	88
Bromomethane	50 Q
Chloroethane	82
Freon 11	90
Ethanol	83
Freon 113	93
1,1-Dichloroethene	94
Acetone	88
2-Propanol	89
Carbon Disulfide	95
3-Chloropropene	86
Methylene Chloride	97
Methyl tert-butyl ether	69
trans-1,2-Dichloroethene	87
Hexane	94
1,1-Dichloroethane	90
2-Butanone (Methyl Ethyl Ketone)	100
cis-1,2-Dichloroethene	94
Tetrahydrofuran	85
Chloroform	94
1,1,1-Trichloroethane	87
Cyclohexane	93
Carbon Tetrachloride	94
2,2,4-Trimethylpentane	115
Benzene	97
1,2-Dichloroethane	98
Heptane	97
Trichloroethene	99
1,2-Dichloropropane	99
1,4-Dioxane	94
Bromodichloromethane	97
cis-1,3-Dichloropropene	78
4-Methyl-2-pentanone	102
Toluene	96
trans-1,3-Dichloropropene	96
1,1,2-Trichloroethane	95

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: LCS

Lab ID#: 0605300A-07A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	%Recovery
Tetrachloroethene	99
2-Hexanone	91
Dibromochloromethane	96
1,2-Dibromoethane (EDB)	98
Chlorobenzene	92
Ethyl Benzene	97
m,p-Xylene	86
o-Xylene	84
Styrene	96
Bromoform	95
Cumene	108
1,1,2,2-Tetrachloroethane	96
Propylbenzene	109
4-Ethyltoluene	101
1,3,5-Trimethylbenzene	83
1,2,4-Trimethylbenzene	66 Q
1,3-Dichlorobenzene	89
1,4-Dichlorobenzene	88
alpha-Chlorotoluene	98
1,2-Dichlorobenzene	88
1,2,4-Trichlorobenzene	117
Hexachlorobutadiene	100

Q = Exceeds Quality Control limits.

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Toluene-d8	98	70-130
1,2-Dichloroethane-d4	93	70-130
4-Bromofluorobenzene	108	70-130

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This electronic report includes the following:

- Work order Summary;
- Laboratory Narrative;
- Results; and
- Chain of Custody (copy).

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(916) 985-1000 .FAX (916) 985-1020
Hours 8:00 A.M to 6:00 P.M. Pacific

WORK ORDER #: 0605300B

Work Order Summary

CLIENT:	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614	**BILL TO:**	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614
PHONE:	585-327-3102	**P.O. #**	2255073
FAX:		**PROJECT #**	Gloversville - Johnstown
DATE RECEIVED:	05/12/2006	**CONTACT:**	Kelly Buettner
DATE COMPLETED:	05/25/2006		

FRACTION #	NAME	TEST	RECEIPT VAC./PRES.
01A	Raw Gas-1	Modified ASTM D-1945	Tedlar Bag
02A(on hold)	Raw Gas-1 duplicate	Modified ASTM D-1945	Tedlar Bag
03A	Filtered Gas-1	Modified ASTM D-1945	Tedlar Bag
04A(on hold)	Filtered Gas-1 duplicate	Modified ASTM D-1945	Tedlar Bag
05A	Lab Blank	Modified ASTM D-1945	NA
05B	Lab Blank	Modified ASTM D-1945	NA
06A	LCS	Modified ASTM D-1945	NA
06B	LCS	Modified ASTM D-1945	NA

CERTIFIED BY: Linda L. Freeman DATE: 05/25/06

Laboratory Director

Certfication numbers: CA NELAP - 02110CA, LA NELAP/LELAP- AI 30763, NJ NELAP - CA004
NY NELAP - 11291, UT NELAP - 9166389892
Name of Accrediting Agency: NELAP/Florida Department of Health, Scope of Application: Clean Air Act,
Accreditation number: E87680, Effective date: 07/01/05, Expiration date: 06/30/06
Air Toxics Ltd. certifies that the test results contained in this report meet all requirements of the NELAC standards

AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

LABORATORY NARRATIVE
Modified ASTM D-1945
Malcolm Pirnie
Workorder# 0605300B

Four 1 Liter Tedlar Bag samples were received on May 12, 2006. The laboratory performed analysis via modified ASTM Method D-1945 for Methane and fixed gases in natural gas using GC/FID or GC/TCD. The method involves direct injection of 1.0 mL of sample. See the data sheets for the reporting limits for each compound.

On the analytical column employed for this analysis, Oxygen coelutes with Argon. The corresponding peak is quantitated as Oxygen.

Method modifications taken to run these samples include:

Requirement	*ASTM D-1945*	*ATL Modifications*
Normalization	Sum of original values should not differ from 100.0% by more than 1.0%.	Sum of original values may range between 75-125%. Normalization of data not performed.
Sample analysis	Equilibrate samples to 20-50° F. above source temperature at field sampling	No heating of samples is performed.
Sample calculation	Response factor is calculated using peak height for C5 and lighter compounds.	Peak areas are used for all target analytes to quantitate concentrations.
Reference Standard	Concentration should not be < half of nor differ by more than 2 X the concentration of the sample. Run 2 consecutive checks; must agree within 1%.	A minimum 3-point linear calibration is performed. The acceptance criterion is %RSD </= 25%. All target analytes must be within the linear range of calibration (with the exception of O2, N2, and C6+ Hydrocarbons).
Sample Injection Volume	0.50 mL to achieve Methane linearity.	1.0 mL.

Receiving Notes

Samples Raw Gas-1 duplicate and Filtered Gas-1 duplicate were placed on hold per the client's request.

Analytical Notes

There were no analytical discrepancies.

Definition of Data Qualifying Flags

Six qualifiers may have been used on the data analysis sheets and indicate as follows:

J - Estimated value.

E - Exceeds instrument calibration range.
S - Saturated peak.
Q - Exceeds quality control limits.
U - Compound analyzed for but not detected above the detection limit.
M - Reported value may be biased due to apparent matrix interferences.

File extensions may have been used on the data analysis sheets and indicates as follows:
a-File was requantified
b-File was quantified by a second column and detector
r1-File was requantified for the purpose of reissue

Summary of Detected Compounds
NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Client Sample ID: Raw Gas-1

Lab ID#: 0605300B-01A

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	0.13
Nitrogen	0.10	0.35
Methane	0.00010	62
Carbon Dioxide	0.010	39

Client Sample ID: Filtered Gas-1

Lab ID#: 0605300B-03A

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	0.25
Nitrogen	0.10	0.80
Methane	0.00010	61
Carbon Dioxide	0.010	38

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Client Sample ID: Raw Gas-1

Lab ID#: 0605300B-01A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	0.13
Nitrogen	0.10	0.35
Carbon Monoxide	0.010	Not Detected
Methane	0.00010	62
Carbon Dioxide	0.010	39
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	Not Detected
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected
Hydrogen	0.010	Not Detected

Container Type: 1 Liter Tedlar Bag

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Filtered Gas-1

Lab ID#: 0605300B-03A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	0.25
Nitrogen	0.10	0.80
Carbon Monoxide	0.010	Not Detected
Methane	0.00010	61
Carbon Dioxide	0.010	38
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	Not Detected
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected
Hydrogen	0.010	Not Detected

Container Type: 1 Liter Tedlar Bag

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Lab Blank

Lab ID#: 0605300B-05A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	Not Detected
Nitrogen	0.10	Not Detected
Carbon Monoxide	0.010	Not Detected
Methane	0.00010	Not Detected
Carbon Dioxide	0.010	Not Detected
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	Not Detected
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected

Container Type: NA - Not Applicable

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Lab Blank

Lab ID#: 0605300B-05B

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Compound	Rpt. Limit (%)	Amount (%)
Hydrogen	0.010	Not Detected

Container Type: NA - Not Applicable

AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: LCS

Lab ID#: 0605300B-06A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Compound	%Recovery
Oxygen	100
Nitrogen	99
Carbon Monoxide	98
Methane	101
Carbon Dioxide	101
Ethane	104
Ethene	102
Acetylene	100
Propane	98
Isobutane	105
Butane	107
Neopentane	107
Isopentane	101
Pentane	98
C6+	101

Container Type: NA - Not Applicable

@ **AIR TOXICS LTD.**

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: LCS

Lab ID#: 0605300B-06B

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Compound	%Recovery
Hydrogen	100

Container Type: NA - Not Applicable

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- Work order Summary;
- Laboratory Narrative;
- Results; and
- Chain of Custody (copy).

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

WORK ORDER #: 0605300C

Work Order Summary

CLIENT:	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614	**BILL TO:**	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614
PHONE:	585-327-3102	**P.O. #**	2255073
FAX:		**PROJECT #**	Gloversville - Johnstown
DATE RECEIVED:	05/12/2006	**CONTACT:**	Kelly Buettner
DATE COMPLETED:	05/17/2006		

FRACTION #	NAME	TEST	RECEIPT VAC./PRES.
01A	Raw Gas-1	ASTM D-5504	Tedlar Bag
02A(on hold)	Raw Gas-1 duplicate	ASTM D-5504	Tedlar Bag
03A	Filtered Gas-1	ASTM D-5504	Tedlar Bag
04A(on hold)	Filtered Gas-1 duplicate	ASTM D-5504	Tedlar Bag
05A	Lab Blank	ASTM D-5504	NA
06A	LCS	ASTM D-5504	NA

CERTIFIED BY: Linda L. Freeman DATE: 05/17/06

Laboratory Director

Certfication numbers: CA NELAP - 02110CA, LA NELAP/LELAP- AI 30763, NJ NELAP - CA004
NY NELAP - 11291, UT NELAP - 9166389892
Name of Accrediting Agency: NELAP/Florida Department of Health, Scope of Application: Clean Air Act,
Accreditation number: E87680, Effective date: 07/01/05, Expiration date: 06/30/06
Air Toxics Ltd. certifies that the test results contained in this report meet all requirements of the NELAC standards

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(916) 985-1000 . (800) 985-5955 . FAX (916) 985-1020

LABORATORY NARRATIVE
ASTM D-5504
Malcolm Pirnie
Workorder# 0605300C

Four 1 Liter Tedlar Bag samples were received on May 12, 2006. The laboratory performed the analysis of sulfur compounds via ASTM D-5504 using GC/SCD. The method involves direct injection of the air sample into the GC via a fixed 1.0 mL sampling loop. See the data sheets for the reporting limits for each compound.

Receiving Notes

Samples Raw Gas-1 duplicate and Filtered Gas-1 duplicate were placed on hold per the client's request.

Samples were received past the recommended hold time of 24 hours for sulfur samples. The discrepancy was noted in the Sample Receipt Confirmation email/fax and the analysis proceeded.

Sample collection time was not provided on the chain of custody for sample Raw Gas-1. The sampling time was taken from the tag and the discrepancy was noted in the Sample Receipt Confirmation email/fax.

Analytical Notes

Diethyl Sulfide coelutes with 2-Ethyl Thiophene. The corresponding peak is reported as 2-Ethyl Thiophene.

Definition of Data Qualifying Flags

Seven qualifiers may have been used on the data analysis sheets and indicate as follows:
B - Compound present in laboratory blank greater than reporting limit.
J - Estimated value.
E - Exceeds instrument calibration range.
S - Saturated peak.
Q - Exceeds quality control limits.
U - Compound analyzed for but not detected above the detection limit.
M - Reported value may be biased due to apparent matrix interferences.
File extensions may have been used on the data analysis sheets and indicates as follows:
a-File was requantified
b-File was quantified by a second column and detector
r1-File was requantified for the purpose of reissue

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Summary of Detected Compounds
SULFUR GASES BY ASTM D-5504 GC/SCD

Client Sample ID: Raw Gas-1

Lab ID#: 0605300C-01A

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	600	140000
n-Butyl Mercaptan	600	1400

Client Sample ID: Filtered Gas-1

Lab ID#: 0605300C-03A

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	600	86000

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Client Sample ID: Raw Gas-1

Lab ID#: 0605300C-01A

SULFUR GASES BY ASTM D-5504 GC/SCD

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	600	140000
Carbonyl Sulfide	600	Not Detected
Methyl Mercaptan	600	Not Detected
Ethyl Mercaptan	600	Not Detected
Dimethyl Sulfide	600	Not Detected
Carbon Disulfide	600	Not Detected
Isopropyl Mercaptan	600	Not Detected
tert-Butyl Mercaptan	600	Not Detected
n-Propyl Mercaptan	600	Not Detected
Ethyl Methyl Sulfide	600	Not Detected
Thiophene	600	Not Detected
Isobutyl Mercaptan	600	Not Detected
Diethyl Sulfide	600	Not Detected
n-Butyl Mercaptan	600	1400
Dimethyl Disulfide	600	Not Detected
3-Methylthiophene	600	Not Detected
Tetrahydrothiophene	600	Not Detected
2-Ethylthiophene	600	Not Detected
2,5-Dimethylthiophene	600	Not Detected
Diethyl Disulfide	600	Not Detected

Container Type: 1 Liter Tedlar Bag

Client Sample ID: Filtered Gas-1

Lab ID#: 0605300C-03A

SULFUR GASES BY ASTM D-5504 GC/SCD

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	600	86000
Carbonyl Sulfide	600	Not Detected
Methyl Mercaptan	600	Not Detected
Ethyl Mercaptan	600	Not Detected
Dimethyl Sulfide	600	Not Detected
Carbon Disulfide	600	Not Detected
Isopropyl Mercaptan	600	Not Detected
tert-Butyl Mercaptan	600	Not Detected
n-Propyl Mercaptan	600	Not Detected
Ethyl Methyl Sulfide	600	Not Detected
Thiophene	600	Not Detected
Isobutyl Mercaptan	600	Not Detected
Diethyl Sulfide	600	Not Detected
n-Butyl Mercaptan	600	Not Detected
Dimethyl Disulfide	600	Not Detected
3-Methylthiophene	600	Not Detected
Tetrahydrothiophene	600	Not Detected
2-Ethylthiophene	600	Not Detected
2,5-Dimethylthiophene	600	Not Detected
Diethyl Disulfide	600	Not Detected

Container Type: 1 Liter Tedlar Bag

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Client Sample ID: Lab Blank

Lab ID#: 0605300C-05A

SULFUR GASES BY ASTM D-5504 GC/SCD

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	4.0	Not Detected
Carbonyl Sulfide	4.0	Not Detected
Methyl Mercaptan	4.0	Not Detected
Ethyl Mercaptan	4.0	Not Detected
Dimethyl Sulfide	4.0	Not Detected
Carbon Disulfide	4.0	Not Detected
Isopropyl Mercaptan	4.0	Not Detected
tert-Butyl Mercaptan	4.0	Not Detected
n-Propyl Mercaptan	4.0	Not Detected
Ethyl Methyl Sulfide	4.0	Not Detected
Thiophene	4.0	Not Detected
Isobutyl Mercaptan	4.0	Not Detected
Diethyl Sulfide	4.0	Not Detected
n-Butyl Mercaptan	4.0	Not Detected
Dimethyl Disulfide	4.0	Not Detected
3-Methylthiophene	4.0	Not Detected
Tetrahydrothiophene	4.0	Not Detected
2-Ethylthiophene	4.0	Not Detected
2,5-Dimethylthiophene	4.0	Not Detected
Diethyl Disulfide	4.0	Not Detected

Container Type: NA - Not Applicable

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Client Sample ID: LCS

Lab ID#: 0605300C-06A

SULFUR GASES BY ASTM D-5504 GC/SCD

Compound	%Recovery
Hydrogen Sulfide	97
Carbonyl Sulfide	87
Methyl Mercaptan	88
Ethyl Mercaptan	94
Dimethyl Sulfide	93
Carbon Disulfide	87
Isopropyl Mercaptan	90
tert-Butyl Mercaptan	103
n-Propyl Mercaptan	104
Ethyl Methyl Sulfide	106
Thiophene	82
Isobutyl Mercaptan	107
Diethyl Sulfide	101
n-Butyl Mercaptan	81
Dimethyl Disulfide	98
3-Methylthiophene	98
Tetrahydrothiophene	94
2-Ethylthiophene	101
2,5-Dimethylthiophene	97
Diethyl Disulfide	98

Container Type: NA - Not Applicable

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This electronic report includes the following:

- Work order Summary;
- Laboratory Narrative;
- Results; and
- Chain of Custody (copy).

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AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

WORK ORDER #: 0605308

Work Order Summary

CLIENT:	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614	**BILL TO:**	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614
PHONE:	585-327-3102	**P.O. #**	2255073
FAX:		**PROJECT #**	Gloversville - Johnstown
DATE RECEIVED:	05/12/2006	**CONTACT:**	Kelly Buettner
DATE COMPLETED:	05/18/2006		

FRACTION #	NAME	TEST
01AB(cancelled)	Raw Gas-1/Raw Gas-2	Siloxanes
02AB	Filtered Gas-1/Filtered Gas-2	Siloxanes
03A	Lab Blank	Siloxanes
04A	LCS	Siloxanes

CERTIFIED BY: Linda L. Freeman DATE: 05/25/06

Laboratory Director

180 BLUE RAVINE ROAD, SUITE B FOLSOM, CA - 95630
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LABORATORY NARRATIVE
Siloxanes
Malcolm Pirnie
Workorder# 0605308

Four Vial samples were received on May 12, 2006. The laboratory performed analysis for siloxanes by GC/MS. A sample volume of 1.0 uL was injected directly onto the GC column. Initial results are in ug/mL. The units are converted to total micrograms (ug) by multiplying the result (ug/mL) by the total volume (mL) contained in the impinger. See the data sheets for the reporting limits for each compound.

Receiving Notes

A Temperature Blank was included with the shipment. The temperature was measured and was not within 4 ± 2°C. Coolant in the form of blue ice was present. Internal stability studies at Air Toxics Ltd. indicate Siloxane compounds may be stable for up to five days from collection at room temperature. The discrepancy was noted in the Sample Receipt Confirmation email/fax and the analysis proceeded.

Sample Raw Gas-1/Raw Gas-2 was cancelled per client's request.

Analytical Notes

Impinger volumes were measured at the laboratory using a graduated cylinder and documented in the analytical logbook.

A front and back impinger was received for each sample. Each impinger was analyzed separately. The results for each analyte were then additively combined and reported as a single concentration. The reported surrogate recovery is derived from the front impinger analysis only.

Definition of Data Qualifying Flags

Six qualifiers may have been used on the data analysis sheets and indicate as follows:
B - Compound present in laboratory blank greater than reporting limit.
J - Estimated Value.
E - Exceeds instrument calibration range.
S - Saturated peak.
Q - Exceeds quality control limits.
M - Reported value may be biased due to apparent matrix interferences.

File extensions may have been used on the data analysis sheets and indicates as follows:
a-File was requantified
b-File was quantified by a second column and detector
r1-File was requantified for the purpose of reissue

Summary of Detected Compounds
SILOXANES - GC/MS

Client Sample ID: Filtered Gas-1/Filtered Gas-2

Lab ID#: 0605308-02AB

Compound	Rpt. Limit (ug)	Amount (ug)
Octamethylcyclotetrasiloxane (D4)	26	36
Decamethylcylopentasiloxane (D5)	26	95

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Client Sample ID: Filtered Gas-1/Filtered Gas-2

Lab ID#: 0605308-02AB

SILOXANES - GC/MS

Compound	Rpt. Limit (ug)	Amount (ug)
Octamethylcyclotetrasiloxane (D4)	26	36
Decamethylcylopentasiloxane (D5)	26	95
Dodecamethylcyclohexasiloxane (D6)	52	Not Detected
Hexamethyldisiloxane	26	Not Detected
Octamethyltrisiloxane	26	Not Detected

Impinger Total Volume(mL): 25.8

Container Type: Vial

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	110	70-130

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Lab Blank

Lab ID#: 0605308-03A

SILOXANES - GC/MS

Compound	Rpt. Limit (ug)	Amount (ug)
Octamethylcyclotetrasiloxane (D4)	1.0	Not Detected
Decamethylcylopentasiloxane (D5)	1.0	Not Detected
Dodecamethylcyclohexasiloxane (D6)	2.0	Not Detected
Hexamethyldisiloxane	1.0	Not Detected
Octamethyltrisiloxane	1.0	Not Detected

Impinger Total Volume(mL): 1.00

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	113	70-130

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: LCS

Lab ID#: 0605308-04A

SILOXANES - GC/MS

Compound	%Recovery
Octamethylcyclotetrasiloxane (D4)	109
Decamethylcylopentasiloxane (D5)	124
Dodecamethylcyclohexasiloxane (D6)	Not Spiked
Hexamethyldisiloxane	120
Octamethyltrisiloxane	122

Impinger Total Volume(mL): 1.00

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	117	70-130

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- Work order Summary;
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- Chain of Custody (copy).

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AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

WORK ORDER #: 0606245A

Work Order Summary

CLIENT:	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614	**BILL TO:**	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614
PHONE:	585-327-3102	**P.O. #**	2255073
FAX:		**PROJECT #**	2255073 Gloversville - Johnstown
DATE RECEIVED:	06/09/2006	**CONTACT:**	Kelly Buettner
DATE COMPLETED:	06/22/2006		

FRACTION #	NAME	TEST	RECEIPT VAC./PRES.
01A	Raw Gas	Modified TO-15	Tedlar Bag
02A	Filtered Gas	Modified TO-15	Tedlar Bag
03A(on hold)	Raw Gas Dup	Modified TO-15	Tedlar Bag
04A(on hold)	Filtered Gas Dup	Modified TO-15	Tedlar Bag
05A	Lab Blank	Modified TO-15	NA
06A	CCV	Modified TO-15	NA
07A	LCS	Modified TO-15	NA

CERTIFIED BY: Linda L. Freeman DATE: 06/22/06

Laboratory Director

Certfication numbers: CA NELAP - 02110CA, LA NELAP/LELAP- AI 30763, NJ NELAP - CA004
NY NELAP - 11291, UT NELAP - 9166389892
Name of Accrediting Agency: NELAP/Florida Department of Health, Scope of Application: Clean Air Act,
Accreditation number: E87680, Effective date: 07/01/05, Expiration date: 06/30/06
Air Toxics Ltd. certifies that the test results contained in this report meet all requirements of the NELAC standards

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

LABORATORY NARRATIVE
Modified TO-15
Malcolm Pirnie
Workorder# 0606245A

Four 1 Liter Tedlar Bag samples were received on June 09, 2006. The laboratory performed analysis via modified EPA Method TO-15 using GC/MS in the full scan mode. The method involves concentrating up to 0.2 liters of air. The concentrated aliquot is then flash vaporized and swept through a water management system to remove water vapor. Following dehumidification, the sample passes directly into the GC/MS for analysis.

Method modifications taken to run these samples are summarized in the below table. Specific project requirements may over-ride the ATL modifications.

Requirement	*TO-15*	*ATL Modifications*
Daily CCV	+- 30% Difference	</= 30% Difference with two allowed out up to </=40%.; flag and narrate outliers
Sample collection media	Summa canister	ATL recommends use of summa canisters to insure data defensibility, but will report results from Tedlar bags at client request
Method Detection Limit	Follow 40CFR Pt.136 App. B	The MDL met all relevant requirements in Method TO-15 (statistical MDL less than the LOQ). The concentration of the spiked replicate may have exceeded 10X the calculated MDL in some cases

Receiving Notes

Samples Raw Gas Dup and Filtered Gas Dup were placed on hold per the client's request.

Analytical Notes

The reported LCS for each daily batch has been derived from more than one analytical file.

Dilution was performed on sample Filtered Gas due to the presence of high level non-target species.

The reported result for 4-Ethyltoluene in samples Raw Gas and Filtered Gas may be biased high due to co-elution with a non target compound with similar characteristic ions. Both the primary and secondary ion for 4-Ethyltoluene exhibited potential interference.

Definition of Data Qualifying Flags

Eight qualifiers may have been used on the data analysis sheets and indicates as follows:

B - Compound present in laboratory blank greater than reporting limit (background subtraction not performed).

J - Estimated value.

E - Exceeds instrument calibration range.

S - Saturated peak.

Q - Exceeds quality control limits.

U - Compound analyzed for but not detected above the reporting limit.

UJ- Non-detected compound associated with low bias in the CCV
N - The identification is based on presumptive evidence.

File extensions may have been used on the data analysis sheets and indicates as follows:
a-File was requantified
b-File was quantified by a second column and detector
r1-File was requantified for the purpose of reissue

AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Summary of Detected Compounds
MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Client Sample ID: Raw Gas

Lab ID#: 0606245A-01A

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Methylene Chloride	22	40	77	140
Hexane	22	26	78	94
cis-1,2-Dichloroethene	22	350	88	1400
Heptane	22	31	91	130
Toluene	22	4600	84	17000
Ethyl Benzene	22	58	96	250
m,p-Xylene	22	190	96	840
o-Xylene	22	67	96	290
Cumene	22	30	110	150
Propylbenzene	22	61	110	300
4-Ethyltoluene	22	200	110	990
1,3,5-Trimethylbenzene	22	180	110	910
1,2,4-Trimethylbenzene	22	340	110	1700

Client Sample ID: Filtered Gas

Lab ID#: 0606245A-02A

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Methylene Chloride	20	30	69	100
Hexane	20	34	70	120
cis-1,2-Dichloroethene	20	580	79	2300
Heptane	20	38	82	160
Trichloroethene	20	48	110	260
Toluene	20	2800	75	10000
Ethyl Benzene	20	57	87	250
m,p-Xylene	20	170	87	740
o-Xylene	20	53	87	230
Cumene	20	22	98	110
Propylbenzene	20	39	98	190
4-Ethyltoluene	20	130	98	640
1,3,5-Trimethylbenzene	20	130	98	620
1,2,4-Trimethylbenzene	20	240	98	1200

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Raw Gas

Lab ID#: 0606245A-01A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	22	Not Detected	110	Not Detected
Freon 114	22	Not Detected	160	Not Detected
Chloromethane	89	Not Detected	180	Not Detected
Vinyl Chloride	22	Not Detected	57	Not Detected
1,3-Butadiene	22	Not Detected	49	Not Detected
Bromomethane	22	Not Detected	86	Not Detected
Chloroethane	22	Not Detected	58	Not Detected
Freon 11	22	Not Detected	120	Not Detected
Ethanol	89	Not Detected	170	Not Detected
Freon 113	22	Not Detected	170	Not Detected
1,1-Dichloroethene	22	Not Detected	88	Not Detected
Acetone	89	Not Detected	210	Not Detected
2-Propanol	89	Not Detected	220	Not Detected
Carbon Disulfide	22	Not Detected	69	Not Detected
3-Chloropropene	89	Not Detected	280	Not Detected
Methylene Chloride	22	40	77	140
Methyl tert-butyl ether	22	Not Detected	80	Not Detected
trans-1,2-Dichloroethene	22	Not Detected	88	Not Detected
Hexane	22	26	78	94
1,1-Dichloroethane	22	Not Detected	90	Not Detected
2-Butanone (Methyl Ethyl Ketone)	22	Not Detected	65	Not Detected
cis-1,2-Dichloroethene	22	350	88	1400
Tetrahydrofuran	22	Not Detected	65	Not Detected
Chloroform	22	Not Detected	110	Not Detected
1,1,1-Trichloroethane	22	Not Detected	120	Not Detected
Cyclohexane	22	Not Detected	76	Not Detected
Carbon Tetrachloride	22	Not Detected	140	Not Detected
2,2,4-Trimethylpentane	22	Not Detected	100	Not Detected
Benzene	22	Not Detected	71	Not Detected
1,2-Dichloroethane	22	Not Detected	90	Not Detected
Heptane	22	31	91	130
Trichloroethene	22	Not Detected	120	Not Detected
1,2-Dichloropropane	22	Not Detected	100	Not Detected
1,4-Dioxane	89	Not Detected	320	Not Detected
Bromodichloromethane	22	Not Detected	150	Not Detected
cis-1,3-Dichloropropene	22	Not Detected	100	Not Detected
4-Methyl-2-pentanone	22	Not Detected	91	Not Detected
Toluene	22	4600	84	17000
trans-1,3-Dichloropropene	22	Not Detected	100	Not Detected
1,1,2-Trichloroethane	22	Not Detected	120	Not Detected

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Raw Gas

Lab ID#: 0606245A-01A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Tetrachloroethene	22	Not Detected	150	Not Detected
2-Hexanone	89	Not Detected	360	Not Detected
Dibromochloromethane	22	Not Detected	190	Not Detected
1,2-Dibromoethane (EDB)	22	Not Detected	170	Not Detected
Chlorobenzene	22	Not Detected	100	Not Detected
Ethyl Benzene	22	58	96	250
m,p-Xylene	22	190	96	840
o-Xylene	22	67	96	290
Styrene	22	Not Detected	94	Not Detected
Bromoform	22	Not Detected	230	Not Detected
Cumene	22	30	110	150
1,1,2,2-Tetrachloroethane	22	Not Detected	150	Not Detected
Propylbenzene	22	61	110	300
4-Ethyltoluene	22	200	110	990
1,3,5-Trimethylbenzene	22	180	110	910
1,2,4-Trimethylbenzene	22	340	110	1700
1,3-Dichlorobenzene	22	Not Detected	130	Not Detected
1,4-Dichlorobenzene	22	Not Detected	130	Not Detected
alpha-Chlorotoluene	22	Not Detected	110	Not Detected
1,2-Dichlorobenzene	22	Not Detected	130	Not Detected
1,2,4-Trichlorobenzene	89	Not Detected	660	Not Detected
Hexachlorobutadiene	89	Not Detected	950	Not Detected

Container Type: 1 Liter Tedlar Bag

Surrogates	%Recovery	Method Limits
Toluene-d8	89	70-130
1,2-Dichloroethane-d4	100	70-130
4-Bromofluorobenzene	94	70-130

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Client Sample ID: Filtered Gas

Lab ID#: 0606245A-02A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	20	Not Detected	99	Not Detected
Freon 114	20	Not Detected	140	Not Detected
Chloromethane	80	Not Detected	160	Not Detected
Vinyl Chloride	20	Not Detected	51	Not Detected
1,3-Butadiene	20	Not Detected	44	Not Detected
Bromomethane	20	Not Detected	78	Not Detected
Chloroethane	20	Not Detected	53	Not Detected
Freon 11	20	Not Detected	110	Not Detected
Ethanol	80	Not Detected	150	Not Detected
Freon 113	20	Not Detected	150	Not Detected
1,1-Dichloroethene	20	Not Detected	79	Not Detected
Acetone	80	Not Detected	190	Not Detected
2-Propanol	80	Not Detected	200	Not Detected
Carbon Disulfide	20	Not Detected	62	Not Detected
3-Chloropropene	80	Not Detected	250	Not Detected
Methylene Chloride	20	30	69	100
Methyl tert-butyl ether	20	Not Detected	72	Not Detected
trans-1,2-Dichloroethene	20	Not Detected	79	Not Detected
Hexane	20	34	70	120
1,1-Dichloroethane	20	Not Detected	81	Not Detected
2-Butanone (Methyl Ethyl Ketone)	20	Not Detected	59	Not Detected
cis-1,2-Dichloroethene	20	580	79	2300
Tetrahydrofuran	20	Not Detected	59	Not Detected
Chloroform	20	Not Detected	98	Not Detected
1,1,1-Trichloroethane	20	Not Detected	110	Not Detected
Cyclohexane	20	Not Detected	69	Not Detected
Carbon Tetrachloride	20	Not Detected	120	Not Detected
2,2,4-Trimethylpentane	20	Not Detected	93	Not Detected
Benzene	20	Not Detected	64	Not Detected
1,2-Dichloroethane	20	Not Detected	81	Not Detected
Heptane	20	38	82	160
Trichloroethene	20	48	110	260
1,2-Dichloropropane	20	Not Detected	92	Not Detected
1,4-Dioxane	80	Not Detected	290	Not Detected
Bromodichloromethane	20	Not Detected	130	Not Detected
cis-1,3-Dichloropropene	20	Not Detected	91	Not Detected
4-Methyl-2-pentanone	20	Not Detected	82	Not Detected
Toluene	20	2800	75	10000
trans-1,3-Dichloropropene	20	Not Detected	91	Not Detected
1,1,2-Trichloroethane	20	Not Detected	110	Not Detected

Client Sample ID: Filtered Gas

Lab ID#: 0606245A-02A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Tetrachloroethene	20	Not Detected	140	Not Detected
2-Hexanone	80	Not Detected	330	Not Detected
Dibromochloromethane	20	Not Detected	170	Not Detected
1,2-Dibromoethane (EDB)	20	Not Detected	150	Not Detected
Chlorobenzene	20	Not Detected	92	Not Detected
Ethyl Benzene	20	57	87	250
m,p-Xylene	20	170	87	740
o-Xylene	20	53	87	230
Styrene	20	Not Detected	85	Not Detected
Bromoform	20	Not Detected	210	Not Detected
Cumene	20	22	98	110
1,1,2,2-Tetrachloroethane	20	Not Detected	140	Not Detected
Propylbenzene	20	39	98	190
4-Ethyltoluene	20	130	98	640
1,3,5-Trimethylbenzene	20	130	98	620
1,2,4-Trimethylbenzene	20	240	98	1200
1,3-Dichlorobenzene	20	Not Detected	120	Not Detected
1,4-Dichlorobenzene	20	Not Detected	120	Not Detected
alpha-Chlorotoluene	20	Not Detected	100	Not Detected
1,2-Dichlorobenzene	20	Not Detected	120	Not Detected
1,2,4-Trichlorobenzene	80	Not Detected	590	Not Detected
Hexachlorobutadiene	80	Not Detected	850	Not Detected

Container Type: 1 Liter Tedlar Bag

Surrogates	%Recovery	Method Limits
Toluene-d8	91	70-130
1,2-Dichloroethane-d4	98	70-130
4-Bromofluorobenzene	92	70-130

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Lab Blank

Lab ID#: 0606245A-05A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Freon 12	0.50	Not Detected	2.5	Not Detected
Freon 114	0.50	Not Detected	3.5	Not Detected
Chloromethane	2.0	Not Detected	4.1	Not Detected
Vinyl Chloride	0.50	Not Detected	1.3	Not Detected
1,3-Butadiene	0.50	Not Detected	1.1	Not Detected
Bromomethane	0.50	Not Detected	1.9	Not Detected
Chloroethane	0.50	Not Detected	1.3	Not Detected
Freon 11	0.50	Not Detected	2.8	Not Detected
Ethanol	2.0	Not Detected	3.8	Not Detected
Freon 113	0.50	Not Detected	3.8	Not Detected
1,1-Dichloroethene	0.50	Not Detected	2.0	Not Detected
Acetone	2.0	Not Detected	4.8	Not Detected
2-Propanol	2.0	Not Detected	4.9	Not Detected
Carbon Disulfide	0.50	Not Detected	1.6	Not Detected
3-Chloropropene	2.0	Not Detected	6.3	Not Detected
Methylene Chloride	0.50	Not Detected	1.7	Not Detected
Methyl tert-butyl ether	0.50	Not Detected	1.8	Not Detected
trans-1,2-Dichloroethene	0.50	Not Detected	2.0	Not Detected
Hexane	0.50	Not Detected	1.8	Not Detected
1,1-Dichloroethane	0.50	Not Detected	2.0	Not Detected
2-Butanone (Methyl Ethyl Ketone)	0.50	Not Detected	1.5	Not Detected
cis-1,2-Dichloroethene	0.50	Not Detected	2.0	Not Detected
Tetrahydrofuran	0.50	Not Detected	1.5	Not Detected
Chloroform	0.50	Not Detected	2.4	Not Detected
1,1,1-Trichloroethane	0.50	Not Detected	2.7	Not Detected
Cyclohexane	0.50	Not Detected	1.7	Not Detected
Carbon Tetrachloride	0.50	Not Detected	3.1	Not Detected
2,2,4-Trimethylpentane	0.50	Not Detected	2.3	Not Detected
Benzene	0.50	Not Detected	1.6	Not Detected
1,2-Dichloroethane	0.50	Not Detected	2.0	Not Detected
Heptane	0.50	Not Detected	2.0	Not Detected
Trichloroethene	0.50	Not Detected	2.7	Not Detected
1,2-Dichloropropane	0.50	Not Detected	2.3	Not Detected
1,4-Dioxane	2.0	Not Detected	7.2	Not Detected
Bromodichloromethane	0.50	Not Detected	3.4	Not Detected
cis-1,3-Dichloropropene	0.50	Not Detected	2.3	Not Detected
4-Methyl-2-pentanone	0.50	Not Detected	2.0	Not Detected
Toluene	0.50	Not Detected	1.9	Not Detected
trans-1,3-Dichloropropene	0.50	Not Detected	2.3	Not Detected
1,1,2-Trichloroethane	0.50	Not Detected	2.7	Not Detected

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Lab Blank

Lab ID#: 0606245A-05A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	Rpt. Limit (ppbv)	Amount (ppbv)	Rpt. Limit (uG/m3)	Amount (uG/m3)
Tetrachloroethene	0.50	Not Detected	3.4	Not Detected
2-Hexanone	2.0	Not Detected	8.2	Not Detected
Dibromochloromethane	0.50	Not Detected	4.2	Not Detected
1,2-Dibromoethane (EDB)	0.50	Not Detected	3.8	Not Detected
Chlorobenzene	0.50	Not Detected	2.3	Not Detected
Ethyl Benzene	0.50	Not Detected	2.2	Not Detected
m,p-Xylene	0.50	Not Detected	2.2	Not Detected
o-Xylene	0.50	Not Detected	2.2	Not Detected
Styrene	0.50	Not Detected	2.1	Not Detected
Bromoform	0.50	Not Detected	5.2	Not Detected
Cumene	0.50	Not Detected	2.4	Not Detected
1,1,2,2-Tetrachloroethane	0.50	Not Detected	3.4	Not Detected
Propylbenzene	0.50	Not Detected	2.4	Not Detected
4-Ethyltoluene	0.50	Not Detected	2.4	Not Detected
1,3,5-Trimethylbenzene	0.50	Not Detected	2.4	Not Detected
1,2,4-Trimethylbenzene	0.50	Not Detected	2.4	Not Detected
1,3-Dichlorobenzene	0.50	Not Detected	3.0	Not Detected
1,4-Dichlorobenzene	0.50	Not Detected	3.0	Not Detected
alpha-Chlorotoluene	0.50	Not Detected	2.6	Not Detected
1,2-Dichlorobenzene	0.50	Not Detected	3.0	Not Detected
1,2,4-Trichlorobenzene	2.0	Not Detected	15	Not Detected
Hexachlorobutadiene	2.0	Not Detected	21	Not Detected

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Toluene-d8	86	70-130
1,2-Dichloroethane-d4	99	70-130
4-Bromofluorobenzene	107	70-130

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: CCV

Lab ID#: 0606245A-06A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	%Recovery
Freon 12	115
Freon 114	115
Chloromethane	125
Vinyl Chloride	106
1,3-Butadiene	102
Bromomethane	121
Chloroethane	106
Freon 11	112
Ethanol	107
Freon 113	111
1,1-Dichloroethene	106
Acetone	100
2-Propanol	108
Carbon Disulfide	103
3-Chloropropene	100
Methylene Chloride	109
Methyl tert-butyl ether	101
trans-1,2-Dichloroethene	104
Hexane	102
1,1-Dichloroethane	106
2-Butanone (Methyl Ethyl Ketone)	104
cis-1,2-Dichloroethene	107
Tetrahydrofuran	113
Chloroform	115
1,1,1-Trichloroethane	108
Cyclohexane	102
Carbon Tetrachloride	113
2,2,4-Trimethylpentane	108
Benzene	97
1,2-Dichloroethane	114
Heptane	107
Trichloroethene	111
1,2-Dichloropropane	106
1,4-Dioxane	102
Bromodichloromethane	113
cis-1,3-Dichloropropene	104
4-Methyl-2-pentanone	104
Toluene	99
trans-1,3-Dichloropropene	117
1,1,2-Trichloroethane	117

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: CCV

Lab ID#: 0606245A-06A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	%Recovery
Tetrachloroethene	120
2-Hexanone	112
Dibromochloromethane	128
1,2-Dibromoethane (EDB)	115
Chlorobenzene	110
Ethyl Benzene	109
m,p-Xylene	114
o-Xylene	108
Styrene	108
Bromoform	130
Cumene	120
1,1,2,2-Tetrachloroethane	110
Propylbenzene	109
4-Ethyltoluene	109
1,3,5-Trimethylbenzene	111
1,2,4-Trimethylbenzene	108
1,3-Dichlorobenzene	114
1,4-Dichlorobenzene	116
alpha-Chlorotoluene	115
1,2-Dichlorobenzene	115
1,2,4-Trichlorobenzene	115
Hexachlorobutadiene	121

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Toluene-d8	91	70-130
1,2-Dichloroethane-d4	105	70-130
4-Bromofluorobenzene	101	70-130

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: LCS

Lab ID#: 0606245A-07A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	%Recovery
Freon 12	107
Freon 114	113
Chloromethane	116
Vinyl Chloride	101
1,3-Butadiene	102
Bromomethane	114
Chloroethane	109
Freon 11	109
Ethanol	106
Freon 113	106
1,1-Dichloroethene	103
Acetone	100
2-Propanol	103
Carbon Disulfide	106
3-Chloropropene	113
Methylene Chloride	108
Methyl tert-butyl ether	94
trans-1,2-Dichloroethene	102
Hexane	101
1,1-Dichloroethane	104
2-Butanone (Methyl Ethyl Ketone)	100
cis-1,2-Dichloroethene	104
Tetrahydrofuran	106
Chloroform	110
1,1,1-Trichloroethane	100
Cyclohexane	94
Carbon Tetrachloride	105
2,2,4-Trimethylpentane	111
Benzene	96
1,2-Dichloroethane	116
Heptane	105
Trichloroethene	111
1,2-Dichloropropane	104
1,4-Dioxane	98
Bromodichloromethane	102
cis-1,3-Dichloropropene	81
4-Methyl-2-pentanone	98
Toluene	95
trans-1,3-Dichloropropene	118
1,1,2-Trichloroethane	116

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: LCS

Lab ID#: 0606245A-07A

MODIFIED EPA METHOD TO-15 GC/MS FULL SCAN

Compound	%Recovery
Tetrachloroethene	121
2-Hexanone	111
Dibromochloromethane	118
1,2-Dibromoethane (EDB)	113
Chlorobenzene	113
Ethyl Benzene	117
m,p-Xylene	112
o-Xylene	98
Styrene	114
Bromoform	115
Cumene	124
1,1,2,2-Tetrachloroethane	112
Propylbenzene	118
4-Ethyltoluene	117
1,3,5-Trimethylbenzene	97
1,2,4-Trimethylbenzene	78
1,3-Dichlorobenzene	117
1,4-Dichlorobenzene	118
alpha-Chlorotoluene	115
1,2-Dichlorobenzene	118
1,2,4-Trichlorobenzene	119
Hexachlorobutadiene	113

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Toluene-d8	87	70-130
1,2-Dichloroethane-d4	102	70-130
4-Bromofluorobenzene	102	70-130

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Thank you for choosing Air Toxics Ltd. To better serve our customers, we are providing your report by e-mail. This document is provided in Portable Document Format which can be viewed with Acrobat Reader by Adobe.

This electronic report includes the following:

- Work order Summary;
- Laboratory Narrative;
- Results; and
- Chain of Custody (copy).

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

WORK ORDER #: 0606245B

Work Order Summary

CLIENT:	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614	**BILL TO:**	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614
PHONE:	585-327-3102	**P.O. #**	2255073
FAX:		**PROJECT #**	2255073 Gloversville - Johnstown
DATE RECEIVED:	06/09/2006	**CONTACT:**	Kelly Buettner
DATE COMPLETED:	06/22/2006		

FRACTION #	NAME	TEST	RECEIPT VAC./PRES.
01A	Raw Gas	Modified ASTM D-1945	Tedlar Bag
02A	Filtered Gas	Modified ASTM D-1945	Tedlar Bag
02AA	Filtered Gas Duplicate	Modified ASTM D-1945	Tedlar Bag
03A(on hold)	Raw Gas Dup	Modified ASTM D-1945	Tedlar Bag
04A(on hold)	Filtered Gas Dup	Modified ASTM D-1945	Tedlar Bag
05A	Lab Blank	Modified ASTM D-1945	NA
05B	Lab Blank	Modified ASTM D-1945	NA
06A	LCS	Modified ASTM D-1945	NA
06B	LCS	Modified ASTM D-1945	NA

CERTIFIED BY: Linda L. Freeman DATE: 06/22/06

Laboratory Director

Certfication numbers: CA NELAP - 02110CA, LA NELAP/LELAP- AI 30763, NJ NELAP - CA004
NY NELAP - 11291, UT NELAP - 9166389892
Name of Accrediting Agency: NELAP/Florida Department of Health, Scope of Application: Clean Air Act,
Accreditation number: E87680, Effective date: 07/01/05, Expiration date: 06/30/06
Air Toxics Ltd. certifies that the test results contained in this report meet all requirements of the NELAC standards

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LABORATORY NARRATIVE
Modified ASTM D-1945
Malcolm Pirnie
Workorder# 0606245B

Four 1 Liter Tedlar Bag samples were received on June 09, 2006. The laboratory performed analysis via modified ASTM Method D-1945 for Methane and fixed gases in natural gas using GC/FID or GC/TCD. The method involves direct injection of 1.0 mL of sample. See the data sheets for the reporting limits for each compound.

On the analytical column employed for this analysis, Oxygen coelutes with Argon. The corresponding peak is quantitated as Oxygen.

Method modifications taken to run these samples include:

Requirement	*ASTM D-1945*	*ATL Modifications*
Normalization	Sum of original values should not differ from 100.0% by more than 1.0%.	Sum of original values may range between 75-125%. Normalization of data not performed.
Sample analysis	Equilibrate samples to 20-50° F. above source temperature at field sampling	No heating of samples is performed.
Sample calculation	Response factor is calculated using peak height for C5 and lighter compounds.	Peak areas are used for all target analytes to quantitate concentrations.
Reference Standard	Concentration should not be < half of nor differ by more than 2 X the concentration of the sample. Run 2 consecutive checks; must agree within 1%.	A minimum 3-point linear calibration is performed. The acceptance criterion is %RSD </= 25%. All target analytes must be within the linear range of calibration (with the exception of O2, N2, and C6+ Hydrocarbons).
Sample Injection Volume	0.50 mL to achieve Methane linearity.	1.0 mL.

Receiving Notes

Samples Raw Gas Dup and Filtered Gas Dup were placed on hold per the client's request.

Analytical Notes

There were no analytical discrepancies.

Definition of Data Qualifying Flags

Six qualifiers may have been used on the data analysis sheets and indicate as follows:
J - Estimated value.

E - Exceeds instrument calibration range.
S - Saturated peak.
Q - Exceeds quality control limits.
U - Compound analyzed for but not detected above the detection limit.
M - Reported value may be biased due to apparent matrix interferences.

File extensions may have been used on the data analysis sheets and indicates as follows:
a-File was requantified
b-File was quantified by a second column and detector
r1-File was requantified for the purpose of reissue

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Summary of Detected Compounds
NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Client Sample ID: Raw Gas

Lab ID#: 0606245B-01A

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	0.18
Nitrogen	0.10	0.33
Methane	0.00010	59
Carbon Dioxide	0.010	41

Client Sample ID: Filtered Gas

Lab ID#: 0606245B-02A

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	0.24
Nitrogen	0.10	0.54
Methane	0.00010	62
Carbon Dioxide	0.010	38

Client Sample ID: Filtered Gas Duplicate

Lab ID#: 0606245B-02AA

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	0.24
Nitrogen	0.10	0.54
Methane	0.00010	62
Carbon Dioxide	0.010	38

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Client Sample ID: Raw Gas

Lab ID#: 0606245B-01A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	0.18
Nitrogen	0.10	0.33
Carbon Monoxide	0.010	Not Detected
Methane	0.00010	59
Carbon Dioxide	0.010	41
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	Not Detected
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected
Hydrogen	0.010	Not Detected

Container Type: 1 Liter Tedlar Bag

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Filtered Gas

Lab ID#: 0606245B-02A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	0.24
Nitrogen	0.10	0.54
Carbon Monoxide	0.010	Not Detected
Methane	0.00010	62
Carbon Dioxide	0.010	38
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	Not Detected
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected
Hydrogen	0.010	Not Detected

Container Type: 1 Liter Tedlar Bag

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Filtered Gas Duplicate

Lab ID#: 0606245B-02AA

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	0.24
Nitrogen	0.10	0.54
Carbon Monoxide	0.010	Not Detected
Methane	0.00010	62
Carbon Dioxide	0.010	38
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	Not Detected
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected
Hydrogen	0.010	Not Detected

Container Type: 1 Liter Tedlar Bag

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Lab Blank

Lab ID#: 0606245B-05A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Compound	Rpt. Limit (%)	Amount (%)
Oxygen	0.10	Not Detected
Nitrogen	0.10	Not Detected
Carbon Monoxide	0.010	Not Detected
Methane	0.00010	Not Detected
Carbon Dioxide	0.010	Not Detected
Ethane	0.0010	Not Detected
Ethene	0.0010	Not Detected
Acetylene	0.0010	Not Detected
Propane	0.0010	Not Detected
Isobutane	0.0010	Not Detected
Butane	0.0010	Not Detected
Neopentane	0.0010	Not Detected
Isopentane	0.0010	Not Detected
Pentane	0.0010	Not Detected
C6+	0.010	Not Detected

Container Type: NA - Not Applicable

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AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Lab Blank

Lab ID#: 0606245B-05B

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Compound	Rpt. Limit (%)	Amount (%)
Hydrogen	0.010	Not Detected

Container Type: NA - Not Applicable

Client Sample ID: LCS

Lab ID#: 0606245B-06A

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Compound	%Recovery
Oxygen	100
Nitrogen	100
Carbon Monoxide	93
Methane	102
Carbon Dioxide	102
Ethane	104
Ethene	102
Acetylene	101
Propane	98
Isobutane	105
Butane	107
Neopentane	107
Isopentane	101
Pentane	98
C6+	100

Container Type: NA - Not Applicable

AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: LCS

Lab ID#: 0606245B-06B

NATURAL GAS ANALYSIS BY MODIFIED ASTM D-1945

Compound	**%Recovery**
Hydrogen	95

Container Type: NA - Not Applicable

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This electronic report includes the following:

- Work order Summary;
- Laboratory Narrative;
- Results; and
- Chain of Custody (copy).

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WORK ORDER #: 0606245C

Work Order Summary

CLIENT:	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614	**BILL TO:**	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614
PHONE:	585-327-3102	**P.O. #**	2255073
FAX:		**PROJECT #**	2255073 Gloversville - Johnstown
DATE RECEIVED:	06/09/2006	**CONTACT:**	Kelly Buettner
DATE COMPLETED:	06/14/2006		

FRACTION #	NAME	TEST	RECEIPT VAC./PRES.
01A	Raw Gas	ASTM D-5504	Tedlar Bag
02A	Filtered Gas	ASTM D-5504	Tedlar Bag
03A(on hold)	Raw Gas Dup	ASTM D-5504	Tedlar Bag
04A(on hold)	Filtered Gas Dup	ASTM D-5504	Tedlar Bag
05A	Lab Blank	ASTM D-5504	NA
06A	LCS	ASTM D-5504	NA

CERTIFIED BY: Linda L. Fruman DATE: 06/14/06

Laboratory Director

Certfication numbers: CA NELAP - 02110CA, LA NELAP/LELAP- AI 30763, NJ NELAP - CA004
NY NELAP - 11291, UT NELAP - 9166389892
Name of Accrediting Agency: NELAP/Florida Department of Health, Scope of Application: Clean Air Act,
Accreditation number: E87680, Effective date: 07/01/05, Expiration date: 06/30/06
Air Toxics Ltd. certifies that the test results contained in this report meet all requirements of the NELAC standards

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AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

LABORATORY NARRATIVE
ASTM D-5504
Malcolm Pirnie
Workorder# 0606245C

Four 1 Liter Tedlar Bag samples were received on June 09, 2006. The laboratory performed the analysis of sulfur compounds via ASTM D-5504 using GC/SCD. The method involves direct injection of the air sample into the GC via a fixed 1.0 mL sampling loop. See the data sheets for the reporting limits for each compound.

Receiving Notes

Samples were received past the recommended hold time for sulfur analysis of 24 hours. The discrepancy was noted in the Sample Receipt Confirmation email/fax and the analysis proceeded.

Samples Raw Gas Dup and Filtered Gas Dup were placed on hold per the client's request.

Analytical Notes

Diethyl Sulfide coelutes with 2-Ethyl Thiophene. The corresponding peak is reported as 2-Ethyl Thiophene.

Definition of Data Qualifying Flags

Seven qualifiers may have been used on the data analysis sheets and indicate as follows:
B - Compound present in laboratory blank greater than reporting limit.
J - Estimated value.
E - Exceeds instrument calibration range.
S - Saturated peak.
Q - Exceeds quality control limits.
U - Compound analyzed for but not detected above the detection limit.
M - Reported value may be biased due to apparent matrix interferences.
File extensions may have been used on the data analysis sheets and indicates as follows:
a-File was requantified
b-File was quantified by a second column and detector
r1-File was requantified for the purpose of reissue

Summary of Detected Compounds
SULFUR GASES BY ASTM D-5504 GC/SCD

Client Sample ID: Raw Gas

Lab ID#: 0606245C-01A

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	1200	220000

Client Sample ID: Filtered Gas

Lab ID#: 0606245C-02A

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	670	140000

Client Sample ID: Raw Gas

Lab ID#: 0606245C-01A

SULFUR GASES BY ASTM D-5504 GC/SCD

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	1200	220000
Carbonyl Sulfide	1200	Not Detected
Methyl Mercaptan	1200	Not Detected
Ethyl Mercaptan	1200	Not Detected
Dimethyl Sulfide	1200	Not Detected
Carbon Disulfide	1200	Not Detected
Isopropyl Mercaptan	1200	Not Detected
tert-Butyl Mercaptan	1200	Not Detected
n-Propyl Mercaptan	1200	Not Detected
Ethyl Methyl Sulfide	1200	Not Detected
Thiophene	1200	Not Detected
Isobutyl Mercaptan	1200	Not Detected
Diethyl Sulfide	1200	Not Detected
n-Butyl Mercaptan	1200	Not Detected
Dimethyl Disulfide	1200	Not Detected
3-Methylthiophene	1200	Not Detected
Tetrahydrothiophene	1200	Not Detected
2-Ethylthiophene	1200	Not Detected
2,5-Dimethylthiophene	1200	Not Detected
Diethyl Disulfide	1200	Not Detected

Container Type: 1 Liter Tedlar Bag

@ **AIR TOXICS LTD.**

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Filtered Gas

Lab ID#: 0606245C-02A

SULFUR GASES BY ASTM D-5504 GC/SCD

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	670	140000
Carbonyl Sulfide	670	Not Detected
Methyl Mercaptan	670	Not Detected
Ethyl Mercaptan	670	Not Detected
Dimethyl Sulfide	670	Not Detected
Carbon Disulfide	670	Not Detected
Isopropyl Mercaptan	670	Not Detected
tert-Butyl Mercaptan	670	Not Detected
n-Propyl Mercaptan	670	Not Detected
Ethyl Methyl Sulfide	670	Not Detected
Thiophene	670	Not Detected
Isobutyl Mercaptan	670	Not Detected
Diethyl Sulfide	670	Not Detected
n-Butyl Mercaptan	670	Not Detected
Dimethyl Disulfide	670	Not Detected
3-Methylthiophene	670	Not Detected
Tetrahydrothiophene	670	Not Detected
2-Ethylthiophene	670	Not Detected
2,5-Dimethylthiophene	670	Not Detected
Diethyl Disulfide	670	Not Detected

Container Type: 1 Liter Tedlar Bag

@ **AIR TOXICS LTD.**

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Lab Blank

Lab ID#: 0606245C-05A

SULFUR GASES BY ASTM D-5504 GC/SCD

Compound	Rpt. Limit (ppbv)	Amount (ppbv)
Hydrogen Sulfide	4.0	Not Detected
Carbonyl Sulfide	4.0	Not Detected
Methyl Mercaptan	4.0	Not Detected
Ethyl Mercaptan	4.0	Not Detected
Dimethyl Sulfide	4.0	Not Detected
Carbon Disulfide	4.0	Not Detected
Isopropyl Mercaptan	4.0	Not Detected
tert-Butyl Mercaptan	4.0	Not Detected
n-Propyl Mercaptan	4.0	Not Detected
Ethyl Methyl Sulfide	4.0	Not Detected
Thiophene	4.0	Not Detected
Isobutyl Mercaptan	4.0	Not Detected
Diethyl Sulfide	4.0	Not Detected
n-Butyl Mercaptan	4.0	Not Detected
Dimethyl Disulfide	4.0	Not Detected
3-Methylthiophene	4.0	Not Detected
Tetrahydrothiophene	4.0	Not Detected
2-Ethylthiophene	4.0	Not Detected
2,5-Dimethylthiophene	4.0	Not Detected
Diethyl Disulfide	4.0	Not Detected

Container Type: NA - Not Applicable

Client Sample ID: LCS

Lab ID#: 0606245C-06A

SULFUR GASES BY ASTM D-5504 GC/SCD

Compound	%Recovery
Hydrogen Sulfide	116
Carbonyl Sulfide	91
Methyl Mercaptan	101
Ethyl Mercaptan	117
Dimethyl Sulfide	115
Carbon Disulfide	113
Isopropyl Mercaptan	109
tert-Butyl Mercaptan	117
n-Propyl Mercaptan	125
Ethyl Methyl Sulfide	90
Thiophene	96
Isobutyl Mercaptan	126
Diethyl Sulfide	119
n-Butyl Mercaptan	107
Dimethyl Disulfide	84
3-Methylthiophene	116
Tetrahydrothiophene	120
2-Ethylthiophene	119
2,5-Dimethylthiophene	128
Diethyl Disulfide	133 Q

Q = Exceeds Quality Control limits.

Container Type: NA - Not Applicable

AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Air Toxics Ltd. Introduces the Electronic Report

Thank you for choosing Air Toxics Ltd. To better serve our customers, we are providing your report by e-mail. This document is provided in Portable Document Format which can be viewed with Acrobat Reader by Adobe.

This electronic report includes the following:

- Work order Summary;
- Laboratory Narrative;
- Results; and
- Chain of Custody (copy).

180 BLUE RAVINE ROAD, SUITE B FOLSOM, CA - 95630

(916) 985-1000 .FAX (916) 985-1020
Hours 8:00 A.M to 6:00 P.M. Pacific

AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

WORK ORDER #: 0606231

Work Order Summary

CLIENT:	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614	**BILL TO:**	Mr. Scott Tudman Malcolm Pirnie 300 State Street Suite 501 Rochester, NY 14614
PHONE:	585-327-3102	**P.O. #**	2255073
FAX:		**PROJECT #**	2255073 Gloversville - Johnstown
DATE RECEIVED:	06/09/2006	**CONTACT:**	Kelly Buettner
DATE COMPLETED:	06/21/2006		

FRACTION #	NAME	TEST
01AB	Raw Gas-1/2	Siloxanes
01ABB	Raw Gas-1/2 Duplicate	Siloxanes
02AB	Filtered Gas-1/2	Siloxanes
03A	Lab Blank	Siloxanes
03B	Lab Blank	Siloxanes
04A	LCS	Siloxanes
04B	LCS	Siloxanes

CERTIFIED BY: Linda L. Freeman DATE: 06/21/06

Laboratory Director

180 BLUE RAVINE ROAD, SUITE B FOLSOM, CA - 95630
(916) 985-1000 . (800) 985-5955 . FAX (916) 985-1020

LABORATORY NARRATIVE
Siloxanes
Malcolm Pirnie
Workorder# 0606231

Four Vial samples were received on June 09, 2006. The laboratory performed analysis for siloxanes by GC/MS. A sample volume of 1.0 uL was injected directly onto the GC column. Initial results are in ug/mL. The units are converted to total micrograms (ug) by multiplying the result (ug/mL) by the total volume (mL) contained in the impinger. See the data sheets for the reporting limits for each compound.

Receiving Notes

A Temperature Blank was included with the shipment. The temperature was measured and was not within 4 ± 2°C. Coolant in the form of blue ice was present. Internal stability studies at Air Toxics Ltd. indicate Siloxane compounds may be stable for up to five days from collection at room temperature. The discrepancy was noted in the Sample Receipt Confirmation email/fax and the analysis proceeded.

Analytical Notes

Impinger volumes were measured at the laboratory using a graduated cylinder and documented in the analytical logbook.

A front and back impinger was received for each sample. Each impinger was analyzed separately. The results for each analyte were then additively combined and reported as a single concentration. The reported surrogate recovery is derived from the front impinger analysis only.

Definition of Data Qualifying Flags

Six qualifiers may have been used on the data analysis sheets and indicate as follows:
B - Compound present in laboratory blank greater than reporting limit.
J - Estimated Value.
E - Exceeds instrument calibration range.
S - Saturated peak.
Q - Exceeds quality control limits.
M - Reported value may be biased due to apparent matrix interferences.

File extensions may have been used on the data analysis sheets and indicates as follows:
a-File was requantified
b-File was quantified by a second column and detector
r1-File was requantified for the purpose of reissue

Summary of Detected Compounds
SILOXANES - GC/MS

Client Sample ID: Raw Gas-1/2

Lab ID#: 0606231-01AB

Compound	Rpt. Limit (ug)	Amount (ug)
Octamethylcyclotetrasiloxane (D4)	26	40
Decamethylcylopentasiloxane (D5)	26	130

Client Sample ID: Raw Gas-1/2 Duplicate

Lab ID#: 0606231-01ABB

Compound	Rpt. Limit (ug)	Amount (ug)
Octamethylcyclotetrasiloxane (D4)	26	39
Decamethylcylopentasiloxane (D5)	26	130

Client Sample ID: Filtered Gas-1/2

Lab ID#: 0606231-02AB

Compound	Rpt. Limit (ug)	Amount (ug)
Octamethylcyclotetrasiloxane (D4)	25	41
Decamethylcylopentasiloxane (D5)	25	130

@ AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Raw Gas-1/2

Lab ID#: 0606231-01AB

SILOXANES - GC/MS

Compound	Rpt. Limit (ug)	Amount (ug)
Octamethylcyclotetrasiloxane (D4)	26	40
Decamethylcylopentasiloxane (D5)	26	130
Dodecamethylcyclohexasiloxane (D6)	53	Not Detected
Hexamethyldisiloxane	26	Not Detected
Octamethyltrisiloxane	26	Not Detected

Impinger Total Volume(mL): 26.3

Container Type: Vial

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	108	70-130

AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Raw Gas-1/2 Duplicate

Lab ID#: 0606231-01ABB

SILOXANES - GC/MS

Compound	Rpt. Limit (ug)	Amount (ug)
Octamethylcyclotetrasiloxane (D4)	26	39
Decamethylcylopentasiloxane (D5)	26	130
Dodecamethylcyclohexasiloxane (D6)	53	Not Detected
Hexamethyldisiloxane	26	Not Detected
Octamethyltrisiloxane	26	Not Detected

Impinger Total Volume(mL): 26.3

Container Type: Vial

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	109	70-130

@ **AIR TOXICS LTD.**

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Filtered Gas-1/2

Lab ID#: 0606231-02AB

SILOXANES - GC/MS

Compound	Rpt. Limit (ug)	Amount (ug)
Octamethylcyclotetrasiloxane (D4)	25	41
Decamethylcylopentasiloxane (D5)	25	130
Dodecamethylcyclohexasiloxane (D6)	51	Not Detected
Hexamethyldisiloxane	25	Not Detected
Octamethyltrisiloxane	25	Not Detected

Impinger Total Volume(mL): 25.4

Container Type: Vial

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	109	70-130

Client Sample ID: Lab Blank

Lab ID#: 0606231-03A

SILOXANES - GC/MS

Compound	Rpt. Limit (ug)	Amount (ug)
Octamethylcyclotetrasiloxane (D4)	1.0	Not Detected
Decamethylcylopentasiloxane (D5)	1.0	Not Detected
Dodecamethylcyclohexasiloxane (D6)	2.0	Not Detected
Hexamethyldisiloxane	1.0	Not Detected
Octamethyltrisiloxane	1.0	Not Detected

Impinger Total Volume(mL): 1.00

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	114	70-130

AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: Lab Blank

Lab ID#: 0606231-03B

SILOXANES - GC/MS

Compound	Rpt. Limit (ug)	Amount (ug)
Octamethylcyclotetrasiloxane (D4)	1.0	Not Detected
Decamethylcylopentasiloxane (D5)	1.0	Not Detected
Dodecamethylcyclohexasiloxane (D6)	2.0	Not Detected
Hexamethyldisiloxane	1.0	Not Detected
Octamethyltrisiloxane	1.0	Not Detected

Impinger Total Volume(mL): 1.00

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	112	70-130

@ AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: LCS

Lab ID#: 0606231-04A

SILOXANES - GC/MS

Compound	%Recovery
Octamethylcyclotetrasiloxane (D4)	106
Decamethylcylopentasiloxane (D5)	115
Dodecamethylcyclohexasiloxane (D6)	Not Spiked
Hexamethyldisiloxane	117
Octamethyltrisiloxane	118

Impinger Total Volume(mL): 1.00

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	113	70-130

AIR TOXICS LTD.

AN ENVIRONMENTAL ANALYTICAL LABORATORY

Client Sample ID: LCS

Lab ID#: 0606231-04B

SILOXANES - GC/MS

Compound	%Recovery
Octamethylcyclotetrasiloxane (D4)	111
Decamethylcylopentasiloxane (D5)	122
Dodecamethylcyclohexasiloxane (D6)	Not Spiked
Hexamethyldisiloxane	121
Octamethyltrisiloxane	121

Impinger Total Volume(mL): 1.00

Container Type: NA - Not Applicable

Surrogates	%Recovery	Method Limits
Hexamethyl disiloxane -d18	115	70-130

APPENDIX B

NYSDEC – May 4, 2006 Memorandum

New York State Department of Environmental Conservation

Division of Air Resources

Bureau of Stationary Sources, 2nd Floor
625 Broadway, Albany, New York 12233-3254

Phone: (518) 402-8403 · **FAX:** (518) 402-9035

Website: www.dec.state.ny.us

May 4, 2006

MEMORANDUM

TO: Regional Air Pollution Control Engineers

FROM: Rob Sliwinski /S/

SUBJECT: **Biodiesel and Other Bio-fuels**

ISSUE:

Over the past year the Department has received several requests to permit facilities to fire nontraditional fuels. Specifically, biodiesel, biodiesel and diesel blends, biogas, landfill gas, biogas blends, landfill gas blends, biodiesel residual oil blends, and waste cooking oils and greases have been discussed. Regional staff has inquired about permitting guidance regarding these types of fuels. This memo will address the regional concerns. This memo will not address the use of waste oils/greases. Used plant and animal derived oils (cooking oils) that are not re-refined are defined in Subpart 225-2 as waste oil. Waste cooking oil/grease used at a residence for domestic heat or hot water production is listed as a trivial activity under Section 201-3.3. Therefore, the existing permitting requirements in Subpart 225-2 and Part 201 already apply to waste cooking oils/greases.

BACKGROUND:

Why the interest in bio-fuels?

The combination of price increases of fossil fuels and wood and the perceived decrease in supply of these fuels has sparked an interest in converting to alternative fuel sources. There are currently tens of thousands of people throughout the country "refining" their own fuels to use in their personal vehicles or for home heating. Many people get the feedstock for these fuels free from restaurants, farms, and grocery stores. Based on the current trend of price increases it is conceivable that we will face significantly more requests to fire bio based alternative fuels. Also, there are programs being developed that give tax breaks for switching from fossil fuels to renewable sources of energy. Bio-fuels are considered to be a renewable source of energy.

What constitutes a bio-fuel?

1) Biodiesel is derived from plant and animal oils (both used and virgin oils). It is refined from its base state to resemble diesel oil. It generally lacks the sulfur of diesel oil, but is biodegradable. Biodiesel is unblended with other oils. Blends of biodiesel are named B and the percent blend of biodiesel. For example, a 20 percent biodiesel blend is named B 20 (and so on and so forth). Biodiesel and biodiesel blends are currently being fired in reciprocating engines and boilers throughout the United States.

2) Biogases and landfill gas are the volatile emissions from human, animal, and plant wastes. Biogases and landfill gas are emitted when one of these wastes decomposes (anaerobic digestion by bacteria). The decomposition of these materials can be accelerated with the addition of some heat (up to about 140 degrees Fahrenheit) and moisture. Generally, the gases will contain other contaminants not found in natural gas, like ammonia and sulfur compounds. These gasses can be collected and concentrated to be fired in traditional natural gas fired equipment (like engines, turbines, and boilers).

3) Bioresidual oil is simply just a blend of biodiesel and residual oil (I have not yet seen a naming system for this type of fuel blend). This blend can be fired in residual oil boilers.

PERMITTING GUIDANCE:

Fuel Blends and Dual Fuel Equipment.

Biodiesel, biogas, and landfill gas that are blended with fossil fuel should be permitted as if they are entirely the base fossil fuel that they are mixed with. To be eligible as a fuel blend, the mixture must consist of a minimum of ten percent fossil fuel. For example, the B fuels would be treated like diesel or distillate oil or biodiesel residual oil blends would be treated like residual oil. Where the source is dual fueled (equipment that fires two or more fuels simultaneously), the source should be required to fire a minimum of ten percent fossil fuel on an annual basis. Fuel blends and dual fuel fired sources should be required to meet the applicable regulations for fuel sulfur content, NOx emission limits, and opacity that currently apply to combustion sources firing fossil fuels. The applicable combustion source size threshold exemptions in Subpart 201-3 would apply, except where the modification or new project would "trigger" new source review.

Biodiesel, Biogases, and Landfill Gas.

A case-by-case permitting approach, for new or existing sources proposing to fire biodiesel, biogases, and landfill gas, should be used until the fuel and combustion regulations can be revised to accommodate these fuels. These sources should be permitted under the Part 227 combustion regulations. However, the Subpart 201-3 Exemptions should not apply to sources proposing to fire biodiesel, biogases, and landfill gas.

CONCLUSIONS

Bio-fuels are becoming a significant permitting topic throughout New York State and the country. Current fuel and combustion regulations need to be updated and revised to deal with these alternative fuels. At present, it is recommended that bio-fuel blends (minimum ten percent fossil fuel) and dual fuel fired sources (minimum actual annual ten percent fossil fuel use) be permitted under the traditional combustion and fuel regulations. Where the base fossil fuel dictates what limitations apply. Also, it is strongly suggested that the applicable equipment size threshold exemptions in Subpart 201-3 apply for bio-fuel blends, except where the modification or new project would "trigger" new source review. A case-by-case permit review is recommended for sources proposing to fire biodiesel, biogas, and landfill gas. Sources proposing to fire these substances should be permitted under the combustion source regulations, however, the combustion source exemptions under Subpart 201-3 would not apply.

cc: D. Shaw
J. Higgins
M. Jennings
R. Orr
S. Flint
J. Hyde
D. Barnes
J. Barnes
M. Cronin

MJ:ld

H:\My Files\SourceControlTechnologySection\BioDieselMemofor MJ042706.wpd

For information on other
NYSERDA reports, contact:

New York State Energy Research
and Development Authority
17 Columbia Circle
Albany, New York 12203-6399

toll free: 1 (866) NYSERDA
local: (518) 862-1090
fax: (518) 862-1091

info@nyserda.org
www.nyserda.org

Evaluating Alternatives for Biogas Clean-up and Use

Final Report 08-23

State of New York
David A. Paterson, Governor

New York State Energy Research and Development Authority
Vincent A. DeIorio, Esq., Chairman