Optical Measurement Technology for Fugitive Emissions from Upstream Oil and Gas Facilities

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Another component of this project was the gas leak visualization camera measurements. Leak Surveys Inc., Texas, completed these measurements with their proprietary technology, with the assistance of Maverick Inspections of Sherwood Park, Alberta.

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Executive Summary

The objectives of this project were to:

- review available optical methods for characterizing and quantifying hydrocarbon emissions from upstream oil and gas (UOG) facilities,
- perform hydrocarbon emissions measurements with the optical methods at two gas processing plants and compare the measured data with the accepted CAPP methods for calculating estimated emissions from UOG facilities,
- review available optical methods or the potential to develop methods to characterize particulate matter (PM) emissions.

The main focus of this project was a hydrocarbon emissions survey of one sweet gas processing plant and one sour gas processing plant. This survey was performed from July 27 to August 4, 2004 and included:

- quantification of the emissions of methane, C_{2+} hydrocarbons and benzene from each plant using a mobile Differential Absorption Lidar (DIAL) unit operated by Spectrasyne Ltd.,
- identification of hydrocarbon leaks using the Hawk gas-leak imaging camera operated by Leak Surveys Inc.

The sour gas plant surveyed during this project had also been surveyed with the DIAL unit during 2003.

Table I summarizes the Time Weighted Mean (TWM) emissions of methane, C_{2+} hydrocarbons and benzene recorded for the sweet gas processing plant, including a breakdown of the emissions into the main process plant, LPG storage, tanks and process flare. Prior to the DIAL survey a heat exchanger had been installed at the site to cool the condensate going to the condensate tank in order to reduce emissions from the tank. Installation of the cooler resulted in a 6% reduction in methane emissions, a 17.8% reduction in C_{2+} emissions and a 33% reduction in benzene emissions for the total plant. As grand totals the site emissions after cooler installation were 144 kg/h of methane, 41 kg/h of C_2+ and 0.06 kg/h benzene. At the time of the survey, maintenance to a produced water tank and a failed liquids level control valve may have increased fugitive emissions above normal levels for the plant

Table II gives a summary of the TWM emissions recorded in both 2003 and 2004 for the sour gas plant, excluding emissions from the flares on site. The overall TWM emission figures for the whole plant in 2004 amounted to 100 kg/h of methane, 58.4 kg/h of C_{2+} and 0.24 kg/h of benzene. In the 2004 survey, the condensate tanks were the single largest source of hydrocarbon emissions, contributing 42.6 % of the site methane emissions, 60.4% of the site C_{2+} emissions and 12% of the benzene emissions. In the Deep Cut area, a source within the top half of the de-methanizer column contributed 20 kg/h of methane emissions or 20% of the plant total emissions of methane.

Table I: Summary of Fugitive Emissions from Sweet Gas Plant E Measured with DIAL Unit in 2004

Area	CH_4	C_{2+}	Benzene	Total HC
	(all data in kg/h)			
Process Plant (TWM for 3 days)	133	34.0	0.06	167
C3/C4 bullets	bdl	0.82	bdl	0.82
Tanks				
before cooler installed	12.4	11.1	0.03	23.5
after cooler installed	2.2	3.5	bdl	5.7
Flare	9.1	2.7		11.9
Total (before condensate cooler)	**153**	**49.9**	**0.09**	**203**
Total (after condensate cooler)	**144**	**41.0**	**0.06**	**185**

1. bdl – below detection limit

Table II: Summary of Fugitive Emissions from Sour Gas Plant C Measured with DIAL Unit (flare emissions not included)

	2003 Survey (kg/h)		2004 Survey (kg/h)		
Area	**CH_4**	**C_2+**	**CH_4**	**C_{2+}**	**Benzene**
Deepcut Plant	91	167	30.9	14.5	0.17
Sulphur Plant & Tank	23	140	26.5	7.6	0.03
Total Process	**114**	**307**	**57.4**	**22.1**	**0.20**
Condensate Tanks	16	24.7	42.6	[35.3]	0.03
Ponds		4.7	0.41	0.93	0.01
Total Site	**130**	**337**	**100**	**58.4**	**0.24**

A leak detection survey using the Hawk gas leak imaging camera was performed at both of the gas plants to coincide with the DIAL survey. The camera proved to be an effective method to rapidly locate leaks. Common sources of leaks included valve stem packings, unions, pipe thread fittings, tank vents and hatches and compressor packing vents.

During the 2003 DIAL survey of the sour gas processing plant, the deep cut area was responsible for the majority of the site's hydrocarbon emissions. Between 2003 and 2004 the site made efforts to track down and repair individual leaks, including a survey in the spring of 2004 using the Hawk gas-leak imaging camera (performed by Maverick Inspections Ltd., Sherwood Park). As a result, between 2003 and 2004, the methane and C_{2+} emissions from the deep cut area were reduced by 50% and 93%, respectively. This reduction was partly offset by an increase in hydrocarbon emissions from the condensate storage tanks. Even with the increased tank emissions, at a gas price of \$218 CDN/1000 m^3, the 309 kg/h reduction in hydrocarbon emissions between 2003 and 2004 represents increased revenue on the order of \$800,000 per year.

Table III compares the hydrocarbon emissions measured with the DIAL to the CAPP recommended emissions estimation methods. The DIAL measured emissions of methane and VOCs were 4 to 8 times higher than the CAPP detailed estimates. The CAPP short form method of estimating methane emissions was 2.5 to 4.5 times higher than the DIAL measurements. The DIAL measurement of benzene emissions at the sweet gas plant was 15% higher than the CAPP Level 2 estimate. The DIAL measurement of benzene emissions at the sour gas plant was 5 times higher than the CAPP Level 2 estimate.

Table III: Comparison of DIAL Fugitives Measurements and CAPP Method Estimations

Plant	**Methane (t/y)**		
	CAPP Short Form	**CAPP Detailed**	**DIAL Measured**
Sweet Gas Plant E	3015	188	1264
Sour Gas Plant C	4665	251	1020
	VOCs (t/y)		
	CAPP Level 1	**CAPP Level 2**	**DIAL Measured**
Sweet Gas Plant E	84.9	14.9	129
Sour Gas Plant C	340	94.4	545
	Benzene (t/y)		
		CAPP Level 2	**DIAL Measured**
Sweet Gas Plant E		0.45	0.52
Sour Gas Plant C		0.39	2.10

At present, there are no remote optical technologies that can measure particulate matter emissions to satisfy NPRI reporting requirements. Light Detection and Ranging (Lidar) was the leading candidate identified as a means to potentially remotely measure particulate emissions from upstream oil and gas facilities. Lidar is currently used as a research tool to track particulate plumes but quantitative information on particle size distribution or mass emissions cannot be extracted from the measurements.

All of the project objectives were successfully completed. The gas leak imaging camera was shown to be an effective tool for locating hydrocarbon leaks at gas processing plants. The DIAL method can quantify emissions of methane, C_{2+} and benzene from gas plants and the results demonstrated the significant cost savings achieved through improved leak identification and repair. For the two plants surveyed in this project, the detailed CAPP fugitive emission estimation methods based on installed equipment and standard emission factors significantly under-estimated the actual hydrocarbon emissions.

Gas leak imaging cameras are recommended as an effective tool for leak detection and repair programs at upstream oil and gas facilities. The DIAL method is recommended as a means of directly measuring hydrocarbon emissions from a facility and quantifying emissions reductions achieved through leak repair. If recognized by the appropriate regulators, the DIAL measurement of fugitive emissions may be considered as an alternative to estimating fugitive emissions of hydrocarbons.

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Glossary

API	- American Petroleum Institute
AVHRR	- Advanced Very High Resolution Radiometer
BAGI	- Backscatter Absorption Gas Imaging
bdl	- below detection limit
CAC	- Criteria Air Contaminants
CAPP	- Canadian Association of Petroleum Producers
COSPEC	- Correlation Spectroscopy
DIAL	- Differential Absorption Lidar
GHG	- Greenhouse Gases
GOES	- Geostationary Orbiting Environmental Satellites
IMSS	- Image Multi-Spectral Sensing
IR	- Infra-red
Lidar	- Light Detection and Ranging
LPG	- Liquified Petroleum Gas
MODIS	-Moderate Resolution Imaging Spectroradiometer
NPRI	- National Pollutant Release Inventory
PM	- Particulate Matter
PM10	- Particulate Matter smaller than 10 µm
PM2.5	- Particulate Matter smaller than 2.5 µm
Ppb	- parts per billion (by volume)
PTAC	- Petroleum Technology Alliance Canada
SeaWiFS	- Sea-viewing Wide Field-of-view Sensor
TOMS	- Total Ozone Mapping Spectrometer
TWM	- Time Weighted Mean
UOG	- Upstream Oil and Gas industry
USEPA	- United States Environmental Protection Agency
UV	- Ultra violet
VOC’s	- Volatile Organic Hydrocarbons, excluding methane and ethane

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Optical Measurement Technology for Fugitive Emissions from Upstream Oil and Gas Facilities

1. Background

The natural gas processing industry is facing increased scrutiny concerning emissions of hydrocarbons and other pollutants to the atmosphere. In addition, many plants must now submit annual emissions reports to regulatory bodies such as Alberta Environment and Environment Canada's National Pollutant Release Inventory (NPRI) program. This project was performed under the guidance of the Air Issues Research Committee of the Petroleum Technology Alliance Canada (PTAC) to investigate optical methods to measure fugitive emissions of hydrocarbons and fugitive emissions of particulate.

Currently, a significant fraction of greenhouse gas (GHG) and criteria air contaminant (CAC) emissions data reported for inclusion in emission(s) inventories are estimates, generated through use of emission factors based on equipment installed and operating at a site. Optical emissions measurement technology is continually advancing and some of the available optical methods may be suitable to verify the accuracy of currently accepted emission factors and/or be used to report measured values as opposed to estimates.

Emissions of particulate matter (PM) are of increasing concern. Current estimation methods rely on ambient point-sample monitoring and dispersion modelling to attempt to quantify particulate emissions from industrial sources. Also emissions factors for particulate emissions have not been developed to the same extent as hydrocarbon emissions factors. Optical methods may offer the potential to better characterize PM emissions from UOG facilities.

Differential Absorption Light Detection and Ranging (DIAL) is a laser-based optical method that can remotely measure the concentration of gases in the atmosphere up to 2 km distant with detection limits in the order of parts per billion. The DIAL method was identified in a previous PTAC project as a potential method to remotely measure SO_2 concentrations (Chambers, 2001). By combining DIAL measured 2D concentration maps with measured wind speed, the mass emissions of the species in a plume can be calculated. Spectrasyne Ltd., UK, has commercially operated a DIAL system in Europe for over 15 years to measure fugitive emissions of hydrocarbons from oil and gas processing and storage facilities, combustion efficiency flares, hydrocarbon emissions from airports, benzene emissions from petrochemical facilities and NO_x emissions from flares. During a four week period in 2003, the Spectrasyne Ltd. equipment was demonstrated in Alberta during a previous PTAC project. The 2003 test program included:

- tracking of SO_2 plumes from tail gas incinerator stacks at two gas processing plants and a well test flare,
- demonstration of accuracy of SO_2 mass flux measurement in the plume from a tail gas incinerator,
- demonstration of remote measurement of SO_2 up to 2 km at the well test flare site,
- measurement of fugitive emissions of methane and C_{2+} hydrocarbons at four gas processing plants and
- measurement of the combustion efficiency of the well test flare and two solution gas flares and the efficiency of conversion of H_2S to SO_2 in sour gas flares.

The results of this work were reported in a final report titled 'Well Test Flare Plume Monitoring Phase II: DIAL Testing in Alberta' (Chambers, 2003).

During the DIAL testing in Alberta in 2003, fugitive emissions surveys were completed at one sweet gas and three sour gas processing plants. Time at each site was limited to two to three days and at two of the sites part of the time was spent on SO_2 plume tracking. Surveys were completed for fugitive emissions of CH_4 and C_{2+} at all of the gas plants. Table 1 summarizes the results of total emissions of hydrocarbons from the plants surveyed during 2003 and 2004. Measurements of benzene emissions with DIAL were only completed at the two plants visited in 2004.

Table 1: Summary of Fugitive Emissions at Alberta Gas Plants as Measured with DIAL

Gas Plant	Surveyed	Type	Plant Nominal Flow Rate ($E6m^3/d$)	CH_4 Emissions (kg/hr)	C_{2+} Emissions (kg/hr)	Benzene Emissions (kg/hr)
A	2003	sour gas	1.45	8 (tanks only)	38	-
B	2003	sweet gas	3.5	104	42	-
C	2003	sour gas	10	146	342	-
C	2004	sour gas	10	100	58.4	0.24
D	2003	sour gas	6	124	86	-
E	2004	sweet gas		144	41	0.06

During the 2003 testing, the Spectrasyne team also demonstrated the ability of the DIAL method to identify and quantify large leaks at a site. On the second day of testing at Gas Plant B, a pressure relief valve was located that was leaking over 200 kg/hr of methane.

2. Objective

The objective of this project was to determine the ability of optical emissions measurement technology to verify the accuracy of currently accepted emission factors in characterizing and quantifying emissions from the Canadian Upstream Oil and Gas (UOG) facilities. Specific objectives of the project include:

- a review of available optical methods for characterizing and quantifying GHG and CAC emissions for UOG facilities,
- a review of available optical methods or the potential to develop methods to characterize particulate matter (PM) emissions from UOG facilities,
- perform hydrocarbon emissions measurements with the identified optical method(s) at a UOG facility and compare the measured data with the accepted methods for calculating estimated emissions from UOG facilities,
- report on discrepancies between measurements and estimates and identify any required improvements.

The following report summarizes the results of the review of new optical methods for measuring fugitive emissions and the results of testing two of the methods at both a sweet and a sour gas processing facility in Alberta.

3. Overview of DIAL Fugitive Emissions Survey Method

Spectrasyne Ltd, UK, has commercially measured fugitive emissions of methane and other hydrocarbons from oil and gas facilities and refineries for over 15 years in Europe using a mobile DIAL unit (www.spectrasyne.ltd.uk). Measurement of fugitive emissions with the DIAL method relies on wind carrying the volatile hydrocarbons through a vertical plane downwind of the area of interest. DIAL is then used to scan through this plume and measure a two dimensional (2D) profile of the gas concentration of interest that, when combined with wind speed measurement, enables the calculation of the mass rate of the species moving through the vertical plane. The DIAL equipment can be tuned to measure specific hydrocarbon species, such as benzene or methane, or can be tuned to measure a class of species, such as C_{2+} alkanes. When a class of species is measured, such as C_{2+}, air samples are collected from the emissions plume for later analysis of the detailed hydrocarbon composition and a calculation of an average molecular weight. Appendix A describes the Spectrasyne Ltd. mobile DIAL unit in more detail.

Spectrasyne Ltd. has over 15 years of experience performing fugitive emission surveys using their DIAL instrument. General comments about DIAL emissions surveys from this experience are:

1. Some variation in emissions occurs over daily, hourly and even shorter times as a result of operational and meteorological changes. To average out these changes, DIAL measurements should be taken over about two hours to provide a significant number of separate scans and each area should be visited on different days with different wind conditions.
2. Quantifying emissions from specific areas of a plant require either a wind direction that provides uncontaminated upwind regions or the ability to take DIAL measurements upwind and subtract this from the total downwind amount. Measurements taken under a variety of wind directions improve the ability to allocate emissions to certain areas of the plant without the need for upwind measurements and subtractions.
3. Placing meteorological towers directly in the plume for wind speed and direction measurements is preferred. Spectrasyne Ltd. has portable 6 or 8 meter meteorological stations that can be placed in the plume in addition to the 14.5 meter tower mounted on the DIAL unit.
4. With measurements downwind of complex structural areas, wind shadows can be created that are periodically purged as wind speed or direction changes. This can cause scan to scan variation overlaid on the real emission variation caused by plant changes. To offset these effects, Time Weighted Mean (TWM) emission values are calculated for each series of individual scans.
5. Several calibration tests of the Spectrasyne DIAL method of measuring mass emissions in plumes have quantified the error as –18% to +5%. The DIAL method typically measures lower values as some areas of the plume will be below the detection limit and the mass in these areas would not be accounted for.
6. As separate emission plumes can be seen in the DIAL results, the DIAL unit can also be used to detect, quantify and source significant leaks by performing successive scans closer to the source.

When performing an emission survey, the Spectrasyne DIAL truck is optimally located about 50 metres from the closest area to be measured and approximately orthogonal to the wind direction. Ideally, the truck position relative to the plant and wind direction enables measurement of emissions from the plant area of interest with minimal contamination from other areas of the plant. The laser beams are then directed along a plane downwind of the target areas and scanned upwards to include the complete emission plume from the target area. These concentration measurements are combined with wind speed measurements from the remote meteorological stations in the plume to calculate a mass emission figure for the scan. The emissions from several scans are combined to average out fluctuations and to calculate a TWM emission rate.

Figure 1 is a photograph of the Spectrasyne DIAL unit performing a fugitive emissions survey at one of the gas plants in Alberta during 2003. The unit was parked outside of the fence with the met tower extended. During the current survey, conducted in July 27 to August 4, 2004, the DIAL unit was used to measure emissions of CH_4, C_{2+} hydrocarbons and benzene at one sweet gas processing plant and one sour gas processing plant. The sour gas plant was one of the plants visited during 2003 (Plant C in Table 1). The Spectrasyne DIAL unit contains two laser systems, one operating in the ultraviolet (UV) spectrum and one operating in the infrared (IR) spectrum. The same laser system (IR) was used for methane and C_{2+}, requiring a short time for tuning of the laser system when switching from one gas to the other. During this year's survey the UV laser system was used to measure benzene.

Figure 1: Spectrasyne DIAL Unit Measuring Fugitive Emissions at a Gas Plant in Alberta

The following presents the methane, C_{2+} and benzene fugitive emissions measurements at each of the two gas plants surveyed. Also discussed is the quantification of emissions reductions achieved at both of the gas plants.

4. Results of Survey at the Sweet Gas Processing Plant

The sweet gas plant surveyed (Plant E) gathers sweet natural gas from numerous wells in the area, removes the condensate as a C5 plus fraction and also separates a heavier fraction for use as Frac Oil. Propane and butane are then split from the gas and the remainder is exported as sales gas. Gas and condensate are exported by pipeline. Condensate, via a storage tank, and liquid propane, butane and frac oil are exported by road tankers. The plant is relatively small in size, with the whole process area covering about 100 m^2.

The objective of the survey was to measure fugitive emissions of methane, C_2+ hydrocarbons and benzene from the process plant and tankage areas. The visit had originally been planned for two days but measurements were made on three days from 27th to 29th July. On July 28 and 29, the survey was conducted in parallel with measurements made by Leak Surveys Inc., a Texas based company specialising in the use of a modified infrared camera to visualise hydrocarbon gas leaks.

4.1 Canister Sampling and Analysis of Fugitive Hydrocarbons at Sweet Plant

The DIAL scans downwind of the main process plant area on the afternoon of July 27 were used to identify the main hydrocarbon plume from the plant. A sample of ambient air was collected in a Silco-steel lined canister over a one hour period in the emission plume at a height of 4 m above ground level and 50 m downwind of the plant. The canister sampling and analysis method is described in Appendix B. The concentrations of hydrocarbons in the plume, as determined from the canister sample, are given in Table 2.

The analysis method used for the canister sample had a detection limit for C1 to C3 hydrocarbons of 50 ppb and a detection limit for C4+ hydrocarbons of <1 ppb. The majority of hydrocarbons present in the fugitive emissions plume were light hydrocarbons, including methane, ethane, butanes and pentanes. C2 hydrocarbons other than ethane and C3 hydrocarbons were likely also present, but at concentrations below 50 ppb. The DIAL method measures the concentration of C_{2+} compounds as a group. To convert the DIAL concentrations to a mass flux of C_{2+}, the detailed composition from the canister sample was used to calculate an average molecular weight of the C_{2+} fraction.

Aromatic compounds were also present in the emission plume including benzene, toluene and xylene. Benzene concentrations in the canister sample were 4 ppb, less than half of the Alberta Ambient Air Guideline of 9 ppb. The concentrations of hydrocarbons given in Table 2 may be higher closer to the emission source. Thus ambient benzene concentrations may be a concern for staff working in some areas of the plant. This is discussed further in Section 4.2.1 reporting the DIAL measurements of benzene concentration.

Table 2: Canister Sample from the Downwind Area at the Sweet Gas Plant

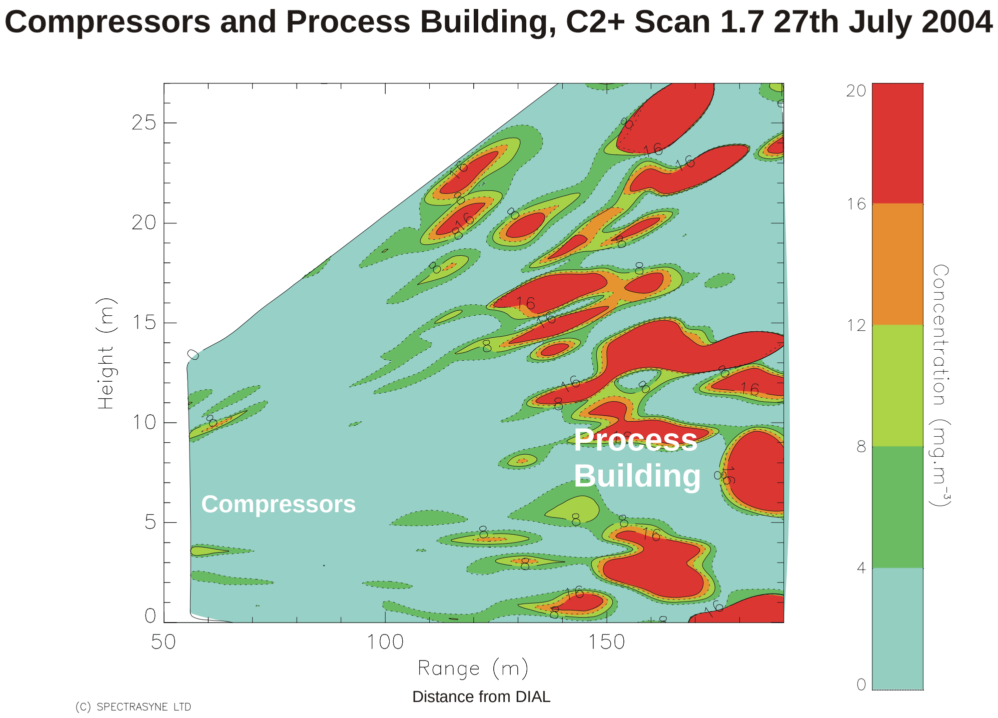
Compound Name	Formula	Concentration (ppb)	Concentration (ug/m^3)
Methane	CH4	5.52 ppm	3617
Ethane	C2H6	0.51ppm	623
Ethylene, acetylene		<50	
C3 compounds		<50	
Isobutane	C4H10	9.68	22.96
Butane	C4H10	25.23	59.83
Cyclopentane	C5H10	0.50	1.42
Isopentane	C5H12	7.34	21.62
Pentane	C5H12	16.47	48.49
Isoprene	C5H8	0.42	1.16
Methane, dichloro-	CH2Cl2	1.10	3.77
Methylcyclopentane	C6H12	1.35	4.64
Cyclohexane	C6H12	2.60	8.94
Methyl isobutyl ketone	C6H12O	0.64	2.63
2,3-Dimethylbutane	C6H14	0.45	1.59
3-Methylpentane	C6H14	1.73	6.09
2-Methylpentane	C6H14	3.11	10.92
Hexane	C6H14	4.55	16.00
Benzene	C6H6	4.03	12.85
1-Hexene, 5-methyl-	C7H14	0.60	2.40
Cyclopentane, 1,3-dimethyl-, trans-	C7H14	0.69	2.75
Cyclopentane, 1,2-dimethyl-	C7H14	0.78	3.11
Methylcyclohexane	C7H14	3.99	15.97
2,3-Dimethylpentane	C7H16	0.25	1.00
2-Methylhexane	C7H16	0.92	3.77
Heptane	C7H16	1.92	7.83
Hexane, 3-methyl-	C7H16	2.09	8.56
Toluene	C7H8	4.20	15.80
Ethyl benzene	C8H10	0.18	0.77
o-Xylene	C8H10	0.20	0.85
m,p-Xylene	C8H10	1.12	4.84
Cyclohexane, 1,2-dimethyl- (cis/trans)	C8H16	0.58	2.65
Cyclohexane, ethyl-	C8H16	0.58	2.66
Cyclohexane, 1,3-dimethyl-, cis-	C8H16	2.12	9.70
Heptane, 3-methyl-	C8H18	0.39	1.84
3-Methylheptane	C8H18	0.46	2.16
2-Methylheptane	C8H18	0.57	2.67
Octane	C8H18	1.28	5.95
Styrene	C8H8	0.30	1.29
Nonane	C9H20	0.35	1.84
Decane	C10H22	0.11	0.64
Naphthalene, 2-methyl	C11H10	4.30	24.95
Tetradecane	C14H30	0.85	6.87

4.2 DIAL Measurements of Emissions at Sweet Gas Plant E

The DIAL surveys of fugitive emissions at Gas Plant E were collected with the DIAL unit positioned at three different locations over the three day period. A low overhead pipe rack prevented access to the east side of the plant so the DIAL location was restricted to the west and south boundaries of the gas plant. All measurements were completed with the DIAL unit outside of any hazardous areas. Winds over the three days were mainly from the southeast and northwest.

4.2.1 Emissions from Main Process Plant

On the first day of the survey, measurements of methane, C_2+ and benzene emissions were acquired for the main plant, not including the tanks area. The wind direction was oblique to the main plant, which limited the extent to which it could be split into sections, but notional splits were made, initially between the compressors/coolers and the main process area excluding the glycol, refrigeration and oil heaters. Later in the day the wind direction changed slightly and the area was split between the south-western part of the process area, including the process building and compressors and glycol, and the north-eastern part, including the refrigeration plant and hot oil heaters. Because of the variable nature of the wind the exact delineation between the two notional sections of the plant were changing from scan to scan and thus the emission figures for the individual sections must be taken as approximate. There was an intermediate wind condition during scans 1.6 to 1.10 when only the compressors and process building areas were measured. Figure 2 shows the resultant two dimensional concentration contour plot of C_{2+} for one of these scans (Scan 1.7).



Compressors and Process Building, C2+ Scan 1.7 27th July 2004

Figure 2 Concentration profile of C_{2+} Emissions from the Compressors & Process Building

Table 3 summarizes the results of the July 27 measurements. The first few scans (Scans 1.1 to 1.5) returned TWM methane emissions of 7.3 kg/h, C_{2+} emissions of 5.4 kg/h and benzene emissions of 0.05 kg/h for the Compressors/Coolers. For the Process Plant (excluding the Glycol Plant, Refrigeration and Hot Oil Heaters) the TWM emissions were 39.9 kg/h of methane, 17.1 kg/h of C_{2+} emissions and 0.03 kg/h of benzene emissions. During these measurements one of the Gas Turbine/Compressor units was off-line.

The methane measurements were followed by a series of C_2+ and benzene scans (Scans 1.6 to 1.10) that covered the Compressors/Coolers and Process Building combined. These scans gave TWM emissions of 28.1 kg/h of C_2+ and 0.09 kg/h of benzene. The Gas Turbine was still off-line during these measurements.

The next series of measurements (Scans 1.11 to 1.17, Table 3) also included the Glycol Plant, the Compressors/Coolers and the Process Building combined. These measurements gave a TWM emission of 31.1 kg/h of C_{2+} and a TWM emission of 0.11 kg/h of benzene. The difference between this set and Scans 1.6 to 1.10 implied that the glycol plant was responsible for approximately 3 kg/h of C_2+ and 0.02 kg/h of benzene. The DIAL was then switched back to measure methane and benzene; the initial methane emission recorded was 32.3 kg/h for the combined area. This was followed by methane figures of 88.6 kg/h, 179 kg/h and 104 kg/h while benzene stayed constant at about 0.13 kg/h. At the time of these peak measurements (Scans 1.15 – 1.17) the Gas Turbine was being started using a natural gas drive. This turbine startup was likely the cause of the increased methane emissions.

Table 3: Main Process Plant DIAL Results from July 27

Scan No	Scan time	Mean Wind Speed (m/s)	Mean Wind Dir'n (deg)	HC Flux (kg/h)	HC Specie	Benzene Flux (kg/h)
Compressors & Coolers						
1.1 -1	27-Jul-04 11:31 - 11:39	5.3	301	7.3	CH4	0.02
1.2 -1	27-Jul-04 11:57 - 12:03	6.4	306	7.3	CH4	0.05
TWM				**7.3**		
1.4 -1	27-Jul-04 12:16 - 12:22	4.7	280	1.2	C2+	0.04
1.5 -1	27-Jul-04 12:24 - 12:31	6.3	297	9.0	C2+	0.08
TWM				**5.4**		
TWM						**0.05**
Most of Process excluding Glycol						
1.1 -2	27-Jul-04 11:31 - 11:39	5.3	301	40.0	CH4	0.02
1.2 -2	27-Jul-04 11:57 - 12:03	6.1	307	39.8	CH4	0.06
TWM				**39.9**		
1.4 -2	27-Jul-04 12:16 - 12:22	4.8	280	7.4	C2+	0.01
1.5 -2	27-Jul-04 12:24 - 12:31	6.1	298	25.4	C2+	0.05
TWM				**17.1**		
TWM						**0.03**
Compressors & Process Building						
1.6 1-2	27-Jul-04 12:35 - 12:42	6.2	280	18.7	C2+	0.03
1.7 1-2	27-Jul-04 12:49 - 12:55	6.7	300	28.8	C2+	0.10
1.8 1-2	27-Jul-04 13:08 - 13:13	4.2	309	30.8	C2+	0.06
1.9 1-2	27-Jul-04 13:16 - 13:22	6.4	298	39.1	C2+	0.13
1.10 1-2	27-Jul-04 13:23 - 13:29	4.9	300	23.5	C2+	0.11
TWM				**28.1**		**0.09**
Compressors, Process Building & Glycol Plant						
(Gas Turbine being started during Scans 1.15 - 1.17)						
1.14 1-2	27-Jul-04 14:09 - 14:15	2.9	297	32.3	CH4	0.11
1.15 1-2	27-Jul-04 14:21 - 14:27	4.1	300	88.6	CH4	0.14
1.16 1-2	27-Jul-04 14:35 - 14:40	5.6	313	179	CH4	0.14
1.17 1-2	27-Jul-04 14:50 - 14:56	4.0	313	104	CH4	0.12
TWM				**97.6**		**0.13**
1.11 1-2	27-Jul-04 13:40 - 13:46	5.1	297	28.1	C2+	0.09
1.12 1-2	27-Jul-04 13:49 - 13:56	5.7	299	43.6	C2+	0.14
1.13 1-2	27-Jul-04 13:58 - 14:04	3.3	302	19.8	C2+	0.09
TWM				**31.1**		**0.11**

The remainder of the results for the main process plant area are given in Table 4. For the final measurements on the first day (Scans 1.18 – 1.24) the plant was split between the Compressors, Process Building and Glycol Plant and the Refrigeration and Hot Oil Heaters. These gave TWM methane emission figures of 51.8 kg/h for the Compressors, Main Process Building and Glycol Plant and 81.2 kg/h for the Refrigeration/Hot Oil Heaters. For the C_2+ measurements, the two areas could not be split reliably owing to an emission feature across the boundary. The total C_2+ emissions gave a TWM of 57.4 kg/h, although it was evident that the emissions were reducing throughout the series of measurements. In the case of benzene the emission splits were 0.07 kg/h for the Main Plant and 0.08 kg/h for the Refrigeration/Hot Oil. Taking the whole plant together the emission measurements produced TWM figures of 133 kg/h of methane, 57.4 kg/h of C_2+ and 0.11 kg/h of benzene.

Towards the end of July 27 the methane and C_{2+} emission levels detected in the Refrigeration/Hot Oil section were traced back to an area just northwest of the most northerly hot oil heater. Close identification was limited by line of sight considerations. The most likely source of the leak appeared to be the valves on the pipelines from the gas wells or other equipment located outside the plant area.

Later in the day a short series of C_2+ and benzene measurements were made covering the whole Process Plant (Scans 2.30 to 2.33, Table 4). At this time plant conditions were more stable than on the previous day. The C_2+ emissions recorded gave a TWM figure of 18.7 kg/h with a benzene TWM of 0.04 kg/h. These emission figures were a significant improvement over the previous day when the plant throughput was changing.

A further set of whole Process Plant scans, not including tank storage, were also completed around noon on July 29 for C_2+ and benzene emissions (Scans 5.3 to 5.7, Table 4). The TWM levels recorded on this occasion were 32.3 kg/h of C_2+ and 0.07 kg/h of benzene both of which fell in the range of the levels recorded on the previous two days.

Table 4: Main Process Plant Measurements on July 27 and 28

Scan No	Scan time	Mean Wind Speed (m/s)	Mean Wind Dir'n (deg)	HC Flux (kg/h)	HC Specie	Benzene Flux (kg/h)
Compressors, Process Building & Glycol Plant						
1.18 -1	27-Jul-04 15:27 - 15:33	4.8	317	57.9	CH4	0.07
1.19 -1	27-Jul-04 15:35 - 15:41	5.1	321	39.9	CH4	0.10
1.20 -1	27-Jul-04 15:44 - 15:50	4.4	319	68.2	CH4	0.07
1.21 -1	27-Jul-04 15:52 - 15:58	4.0	323	41.2	CH4	0.05
TWM				**51.8**		**0.07**
Refrigeration & Oil Heaters						
1.18 -2	27-Jul-04 15:27 - 15:33	4.6	319	79.6	CH4	0.05
1.19 -2	27-Jul-04 15:35 - 15:41	5.2	321	76.3	CH4	0.08
1.20 -2	27-Jul-04 15:44 - 15:50	4.5	320	79.8	CH4	0.07
1.21 -2	27-Jul-04 15:52 - 15:58	4.1	323	89.3	CH4	0.11
TWM				**81.2**		**0.08**
Total Process Plant				**133**		**0.15**
All Plant						
1.22 1-2	27-Jul-04 16:13 - 16:20	4.9	322	73.6	C2+	0.10
1.23 1-2	27-Jul-04 16:21 - 16:27	3.0	321	38.3	C2+	0.04
1.24 1-2	27-Jul-04 16:29 - 16:35	4.1	329	39.8	C2+	-
TWM				**57.4**		**0.07**
TWM						**0.11**
2.30 -1	28-Jul-04 16:00 - 16:08	2.6	003	16.3	C2+	-
2.31 -1	28-Jul-04 16:09 - 16:16	3.3	019	19.0	C2+	0.06
2.32 -1	28-Jul-04 16:19 - 16:27	3.3	345	25.0	C2+	0.05
2.33 -1	28-Jul-04 16:29 - 16:36	2.5	349	14.2	C2+	0.02
TWM				**18.7**		**0.04**
5.3 -2	29-Jul-04 11:58 - 12:06	2.5	358	38.0	C2+	0.10
5.4 -2	29-Jul-04 12:11 - 12:16	1.4	025	26.1	C2+	0.06
5.5 -2	29-Jul-04 12:32 - 12:36	2.6	005	50.3	C2+	0.06
5.6 -2	29-Jul-04 12:41 - 12:46	2.4	010	34.1	C2+	0.06
5.7 -2	29-Jul-04 12:55 - 13:10	2.2	016	25.8	C2+	0.06
TWM				**32.3**		**0.07**
Weighted Mean, all 3 days				**34.0**		**0.06**

The benzene concentration profile in the plume from the Process Plant area measured with the DIAL is shown in Figure 3. Benzene concentration was peaking around 70 $\mu g/m^3$ (~ 20 ppb) about 5 m above ground level with some pockets near ground level. This concentration is more than double the Alberta Ambient Air Guideline maximum one-hour average concentration of 9 ppb. The canister sample of ambient air taken in this area in the early afternoon of July 27 at about 4 m height and 50 m downwind of the process area revealed a concentration of 13 ug/m^3 (~4 ppb) (Table 2). As benzene concentrations may be higher closer to the source, the benzene levels could be of concern for staff working in the area.

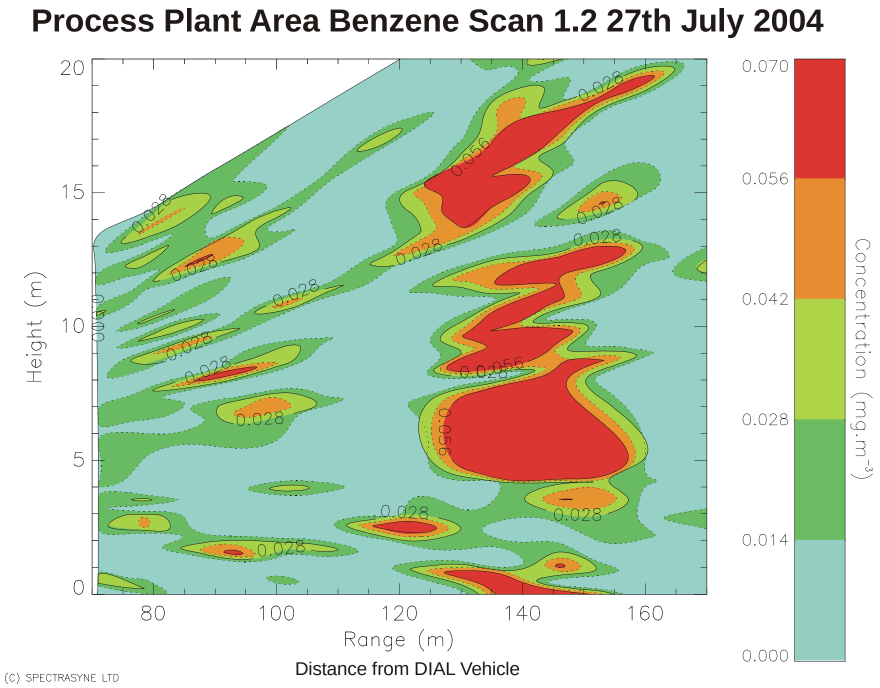


Figure 3 Concentration profile of benzene from the Process Plant

4.2.2 Emissions from the Process Flare

During the afternoon of July 28, measurements were made on the process flare plume. The process flare was air assisted and was reported to be operating primarily on purge gas during the time of the measurements. There was only a small visible flame. Table 5 gives the results of the DIAL measurements for the flare. Initially methane emissions were monitored which gave levels of between 3.1 and 13.0 kg/h with a TWM of 9.1 kg/h. Subsequently C_2+ levels were also recorded and these returned levels between 2.5 and 3.1 kg/h with a TWM of 2.7 kg/h. Taking these two together gives a total hydrocarbon emission from the flare of 11.8 kg/h. The emissions of methane from the current plant's process flare of 9.1 kg/h are similar to the emissions of 11.5 and 15.6 kg/h measured at the two process flares at Sweet Gas Plant B during the 2003 survey.

Table 5: Process Flare Measurements at Gas Plant E

Scan No	Scan time	Mean Wind Speed (m/s)	Mean Wind Dir'n (deg)	HC Flux (kg/h)	HC Specie	Benzene Flux (kg/h)
Flare						
2.20 -3	28-Jul-04 14:35 - 14:42	2.2	004	6.7	CH4	-
2.21 -1	28-Jul-04 14:53 - 14:57	2.8	338	10.6	CH4	0.01
2.22 -1	28-Jul-04 14:59 - 15:02	3.2	343	12.9	CH4	-
2.23 -1	28-Jul-04 15:05 - 15:08	2.8	342	12.9	CH4	-
2.24 -1	28-Jul-04 15:13 - 15:17	3.3	330	3.1	CH4	-
2.25 -1	28-Jul-04 15:24 - 15:27	3.0	001	8.9	CH4	-
2.26 -1	28-Jul-04 15:29 - 15:33	4.5	352	13.0	CH4	-
TWM				**9.1**		**0.01**
2.27 -1	28-Jul-04 15:43 - 15:46	4.1	340	3.1	C2+	-
2.28 -1	28-Jul-04 15:48 - 15:52	2.5	346	2.5	C2+	-
2.29 -1	28-Jul-04 15:54 - 15:58	3.1	008	2.7	C2+	-
TWM				**2.7**		**-**

4.2.3 Emissions from the LPG Bullets

The results of the DIAL measurement of emissions from the LPG bullets are summarized in Table 6. The methane emission levels recorded were below the detection limit for the LPG bullets, as might be expected. The C_2+ emissions (assuming an average molecular weight equivalent to C3.5) for each scan varied from 0.31 to 1.1 kg/h for the bullets with a TWM emission of 0.82 kg/h. Benzene emissions from the bullets were very close to or below the detection limit (bdl), with a TWM emission of 0.01 kg/h.

Table 6: Emissions from the Propane and Butane Bullets at Sweet Gas Plant E

Scan No	Scan time	Mean Wind Speed (m/s)	Mean Wind Dir'n (deg)	HC Flux (kg/h)	HC Specie	Benzene Flux (kg/h)
C3/C4 Bullets						
2.11 -1	28-Jul-04 11:29 - 11:35	1.2	218	0.02	CH4	bdl
2.12 -1	28-Jul-04 11:36 - 11:39	1.6	166	bdl	CH4	0.01
2.13 -1	28-Jul-04 11:45 - 11:49	1.1	144	bdl	CH4	0.01
2.14 -1	28-Jul-04 11:57 - 12:04	1.5	180	bdl	CH4	0.01
2.15 -1	28-Jul-04 12:05 - 12:08	0.6	178	bdl	CH4	-
2.16 -1	28-Jul-04 12:30 - 12:33	1.2	121	bdl	CH4	bdl
2.18 -1	28-Jul-04 13:43 - 13:49	1.8	171	bdl	CH4	bdl
TWM				**bdl**		
2.1 -1	28-Jul-04 09:43 - 9:47	0.9	134	0.75	C2+	0.01
2.2 -1	28-Jul-04 09:57 - 10:02	0.4	170	0.31	C2+	0.02
2.3 -1	28-Jul-04 10:07 - 10:14	1.7	152	0.96	C2+	0.01
2.4 -1	28-Jul-04 10:17 - 10:20	1.5	165	0.43	C2+	0.01
2.5 -1	28-Jul-04 10:28 - 10:31	1.4	128	1.00	C2+	0.01
2.6 -1	28-Jul-04 10:37 - 10:40	1.8	159	1.10	C2+	0.01
2.7 -1	28-Jul-04 10:50 - 10:53	1.4	144	0.85	C2+	0.01
2.8 -1	28-Jul-04 11:03 - 11:07	1.9	147	0.87	C2+	0.01
2.9 -1	28-Jul-04 11:12 - 11:16	1.0	150	1.06	C2+	bdl
2.10 -1	28-Jul-04 11:20 - 11:23	0.8	179	0.93	C2+	bdl
TWM				**0.82**		
TWM						**0.01**

Note: the estimated mean molecular weight of fugitive emissions from the LPG bullets was equivalent to C3.5.

4.2.4 Emissions from Storage Tanks at Gas Plant E

The tanks on-site consisted of one condensate tank and two frac oil tanks located southwest of the main process area. These three tanks were of fixed roof design, vented by pressure/vacuum valves, with no blanket gas. To reduce hydrocarbon emissions from the condensate tank, the facility had installed heat exchangers to cool the flow of condensate into the tank. On the first day of testing, the temperature of condensate in the tank was 37°C. The heat exchangers were operating on the second day that the DIAL measured emissions from the condensate tank, with condensate tank temperature reduced to 28.5°C. The expectation for the cooler was to bring the tank temperature below 30°C.

On the first day the bullets and tanks were measured simultaneously but the emissions could be discriminated with the south-easterly wind. Emissions from the bullets were discussed in Section 4.2.3. The wind direction was aligned with the centreline of the three tanks and thus the three tanks were measured in combination. The level in the condensate tank (Tank 5) increased 2% during the first hour of the measurements followed by a reduction in level of 2% during the next two hours of the measurements. The level in Tank 6 was initially static but then fell by about 3% due to a withdrawal by a road tanker. Tank 7 remained static throughout the day.

The methane emissions from the three tanks were between 4.2 and 22.3 kg/h, with a TWM of 12.4 kg/h. C_{2+} emissions (expressed as C3.5) were between 2.0 and 86.2 kg/h with a TWM 29.8 kg/h and with a TWM of 0.03 kg/h for the tanks. Benzene emissions from the tanks were a TWM of 0.03 kg/h.

Emission levels for tanks normally vary considerably as the tanks breath but the higher C_2+ emission levels recorded in Scans 2.3-2 and 2.4-2 (Table 7) seemed unusual and were investigated further. This revealed that a road tanker was on station loading frac oil and the highest emissions were just before the tanker left and therefore probably corresponded with emissions from the tanker loading area. Scan 2.3-2 is shown in Figure 4, where an emission plume at the height of the tanker is clearly seen. It is clear from this that tankers loading frac oil were responsible for significantly increasing the emissions from the area; this is consistent with Spectrasyne's experience of loading operations at other sites. Even heavier products can give high emission levels during high turbulence operations such as loading to tanks. If Scan 2.3-2 and 2.4-2 are removed, the resulting C_{2+} emission from the tanks was a TWM of 11.1 kg/h.

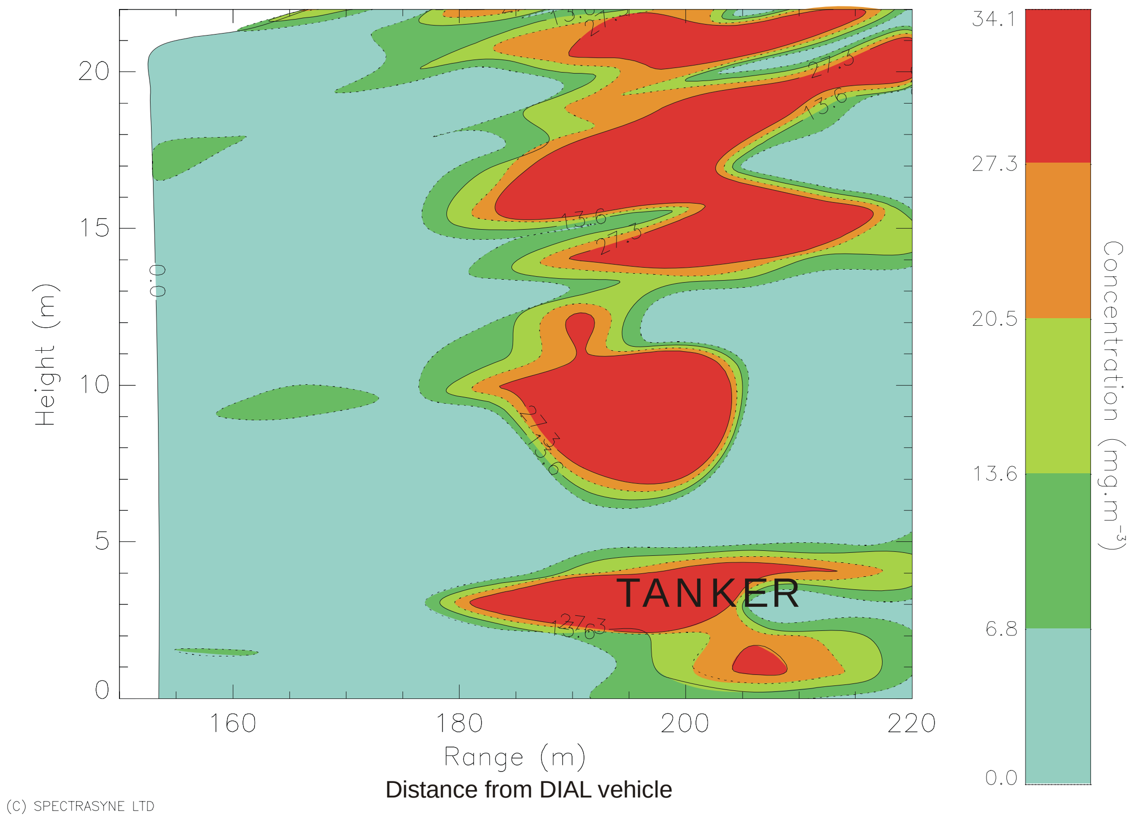


Figure 4: Concentration profile of emissions from tanker "topping off"

Table 7: Emission Measurements from Condensate Tanks at Sweet Gas Plant E

Scan No	Scan time	Mean Wind		HC Flux (kg/h)	HC Specie	Benzene Flux (kg/h)
		Speed (m/s)	Dir'n (deg)			
Condensate Tanks						
2.11 -2	28-Jul-04 11:29 - 11:35	1.1	228	4.2	CH4	0.01
2.12 -2	28-Jul-04 11:36 - 11:39	1.7	177	14.1	CH4	0.04
2.13 -2	28-Jul-04 11:45 - 11:49	1.1	139	12.4	CH4	0.02
2.14 -2	28-Jul-04 11:57 - 12:04	1.5	180	13.9	CH4	0.02
2.15 -2	28-Jul-04 12:05 - 12:08	0.8	186	8.9	CH4	-
2.16 -2	28-Jul-04 12:30 - 12:33	1.5	127	7.3	CH4	0.02
2.18 -2	28-Jul-04 13:43 - 13:49	1.8	176	22.3	CH4	0.06
TWM				**12.4**		
2.1 -2	28-Jul-04 09:43 - 9:47	0.9	131	2.0	C2+	0.07
2.2 -2	28-Jul-04 09:57 - 10:02	0.8	174	8.5	C2+	0.02
2.3 -2	28-Jul-04 10:07 - 10:14	1.7	152	86.2	C2+	0.02
2.4 -2	28-Jul-04 10:17 - 10:20	1.7	158	68.3	C2+	0.03
2.5 -2	28-Jul-04 10:34 - 10:35	1.7	126	17.0	C2+	0.03
2.6 -2	28-Jul-04 10:37 - 10:40	1.7	158	27.0	C2+	0.03
2.7 -2	28-Jul-04 10:50 - 10:53	1.7	160	5.6	C2+	0.04
2.8 -2	28-Jul-04 11:03 - 11:07	1.9	144	16.7	C2+	0.03
2.9 -2	28-Jul-04 11:12 - 11:16	1.1	152	9.9	C2+	0.01
2.10 -2	28-Jul-04 11:20 - 11:23	1.1	161	11.0	C2+	0.01
TWM				**29.8**		
TWM *exclding 2.3 & 2.4*				**11.1**		
TWM						**0.03**
3.1 -2	29-Jul-04 08:58 - 9:00	0.5	198	13.1	C2+	0.03
3.2 -2	29-Jul-04 09:27 - 9:29	0.5	207	14.0	C2+	0.01
TWM				**13.6**		**0.02**
5.8 -1	29-Jul-04 13:41 - 13:46	3.2	009	2.2	CH4	bdl
5.9 -1	29-Jul-04 13:50 - 13:51	1.4	037	2.0	CH4	bdl
5.10 -1	29-Jul-04 13:52 - 13:55	2.5	010	2.2	CH4	bdl
TWM				**2.2**		**bdl**
5.1 -1	29-Jul-04 11:37 - 11:43	2.2	006	4.9	C2+	bdl
5.2 -1	29-Jul-04 11:44 - 11:55	2.3	349	5.6	C2+	bdl/trace
5.3 -1	29-Jul-04 11:58 - 12:06	2.4	001	4.3	C2+	bdl
5.4 -1	29-Jul-04 12:11 - 12:16	1.3	023	3.7	C2+	bdl
5.5 -1	29-Jul-04 12:32 - 12:36	2.2	004	3.0	C2+	bdl
5.6 -1	29-Jul-04 12:41 - 12:46	2.4	007	2.0	C2+	bdl
5.7 -1	29-Jul-04 12:55 - 13:10	2.1	013	1.5	C2+	bdl
TWM				**3.5**		**bdl**

On the final day of the survey the cooler on the condensate inlet line to Tank 5 had been commissioned and the temperature of the condensate in the tank had reduced from 37°C to 28.5°C. Further measurements of the tanks were done to evaluate the effectiveness of the cooler. Initially the wind was from the south and the three tanks were measured in combination from the same location as the previous day. The first two scans (Scans 3.1 and 3.2, Table 7) recorded TWM figures of 13.6 kg/h of C_2+ for the Tanks and benzene emissions were 0.02 kg/h for the Tanks. The Tank emissions at this time were broadly similar to the levels seen on the previous day after exclusion of the ‘tanker top-off’ scans.

Later in the morning measurements on the Tanks were taken from a location outside the site boundary with a northerly wind. At this time the level in Tank 5 was falling from 34% to about 32%, the levels in Tanks No 6 and 7 remained static and there was no tanker loading. The C_2+ emissions recorded from the three tanks (Scans 5.1 to 5.7, Table 7) ranged from a peak of 5.6 kg/h with a falling trend throughout the measurement sequence to 1.5 kg/h. The falling emission levels were probably because the level and temperature in Tank 5 were falling and thus the PV valve would have been letting in air more often than venting it. Subsequent measurements of methane emissions from the Tanks gave stable and low figures with a TWM of 2.2 kg/h (Scans 5.8 to 5.10, Table 7). The benzene emission measurements were below the detection limit.

Compared with the emission levels recorded from the Tanks on July 28, before the commissioning of the condensate cooler, the final series of with-cooler measurements show reductions of 82% in methane emissions, 68% in C_2+ emissions and 100% reduction in benzene emissions from the tanks. For total plant fugitive emissions, this represents a 6% reduction of methane, a 17.8% reduction in C_{2+} emissions and a 33% reduction in benzene emissions. The final stabilised emissions from the tanks could be different from the TWM figures seen immediately following the installation of the cooler. By December of 2004, the plant was reporting condensate tank temperatures of 12°C, suggesting emissions from the tanks would be even lower than those measured on July 29.

At the time of the commissioning of the condensate cooler, the plant experienced a malfunction of a level control valve that dumps C5+ material to the tank. This valve failure may have resulted in higher than normal flow rate of light ends sent to the storage tank. This may have affected both the initial and post cooler measurement of vented emissions from the condensate tank.

4.3 Summary of Fugitive Emissions from Sweet Gas Plant E

Table 8 gives a summary of the TWM emissions recorded for the various sections of the Plant E and grand total emissions for the whole site. The overall TWM emission figures for the whole process area amounted to 133 kg/h of methane, 34.0 kg/h of C_{2+} and 0.06 kg/h of benzene. Methane measurements were only captured from the process plant on the first day when the highest TWM C_{2+} emissions were recorded. The methane emissions on the second and third day may have been lower corresponding with the lower C2+ levels on those days.

Before the installation of the condensate cooler the TWM figures for the three Tanks were 12.4 kg/h of methane, 11.1 kg/h of C_{2+} and 0.03 kg/h of benzene. After the introduction of the cooler, when conditions had stabilised, the TWM emissions were 2.2 kg/h of methane, 3.5 kg/h of C_{2+} and below detection limit for benzene. The LPG Bullets contributed 0.82 kg/h of C3.5 emissions. As grand totals the site emissions after condensate cooler installation were thus 144 kg/h of methane, 41 kg/h of C_{2+} and 0.06 kg/h benzene.

Table 8: Summary of Fugitive Emissions from Sweet Gas Plant E

Area	CH_4	C_{2+}	Benzene	Total HC
	(all data in kg/h)			
Main Process Plant				
July 27	133	57.4	0.11	
July 28	(2)	18.3	0.04	
July 29	(2)	32.3	0.07	
Process Plant TWM for 3 days	133	34.0	0.06	167
C3/C4 bullets	bdl (1)	0.82	bdl	0.82
Tanks (3)				
before cooler installed (tank 37°C)	12.4	11.1	0.03	23.5
after cooler installed (tank 28.5°C)	2.2	3.5	bdl	5.7
Flare	9.1	2.7	(2)	11.9
Total (before condensate cooler)	**153**	**49.9**	**0.09**	**203**
Total (after condensate cooler)	**144**	**41.0**	**0.06**	**185**

(1) bdl – below detection limit

(2) blank cells represent no data collected

(3) a failed level control valve may have increased light hydrocarbon emissions from the condensate tank before and after cooler installation

5. Results from Survey of Sour Gas Processing Plant

Gas Plant C was a sour gas processing plant with a normal throughput of 10 x 10^6 Sm^3/d of gas containing 37% H_2S. The main elements of the plant were:

- Two parallel trains of condensate and acid gas removal
- Deep cut section to recover C_{2+} from sweetened gas
- Claus plant and SCOT unit
- Tail gas incinerator
- Two condensate storage tanks (fixed roof)
- Liquid sulphur storage tanks (fixed roof)
- Water treatment area with open lagoons

This plant was visited during the 2003 DIAL demonstration campaign when methane, C_{2+} and sulphur dioxide measurements were made with the DIAL system on the process plant, the waste water ponds, the condensate tanks, sulphur storage tank, the main flare and the incinerator stack plume. During 2003 the incinerator stack SO_2 plume was a significant focus of the measurements.

In 2004 the main focus of the survey at gas Plant C was the measurement of fugitive emissions of methane, C_{2+} and benzene from the sweet section of the process plant and from the condensate tanks. The survey during 2003 indicated that the sweet section of the process plant and the condensate tanks were responsible for the majority of fugitive emissions of hydrocarbons.

The plant survey took place over three days, on July 30, August 3 and August 4. On the first day a team from Leak Surveys Inc., a Texas based company, were on site using a modified infrared camera to identify hydrocarbon leaks from the Deep Cut plant section. The Plant throughput on July 30 was 9.56 x 10^6 m^3/day. During the second and third days of the survey the No 2 Sour Gas Train was out of commission and this reduced the plant throughput to 4.98 x 10^6 m^3/day on August 3 and 4.97 x 10^6 m^3/day on August 4.

5.1 Canister Sampling and Analysis of Fugitive Hydrocarbons from Sour Plant

The DIAL scans downwind of the Deep Cut area on the afternoon of July 30 were used to identify the main hydrocarbon plume from this area of the plant. A sample of gas from this emission plume was collected over a one hour period in an evacuated canister sample and analysed using the method described in Appendix B. The analysis method used for the canister sample had a detection limit for C1 to C3 hydrocarbons of 50 ppb while the C4+ hydrocarbons were detected to <1 ppb.

The concentrations of hydrocarbons in the Deep Cut area plume as determined from the canister sample are given in Table 9. The majority of hydrocarbons present in the fugitive emissions plume were light hydrocarbons, including methane, ethane, butanes and pentanes. C2 compounds other than ethane and C3 hydrocarbons, such as propane, were likely present in the emission plume but at concentrations below 50 ppb.

Aromatic compounds were also present in the emission plume, including benzene and toluene. Benzene concentrations in the canister sample were 0.23 ppb, well below the 9 ppb limit of the Alberta Ambient Air Guideline. The concentrations of hydrocarbons given in Table 9 may be higher closer to the source of the emission.

Table 9: Canister Sample from the Fractionator Area at the Sour Gas Plant

Compound Name	Formula	Concentration (ppb)	Concentration (ug/m^3)
Methane	CH4	3.29 ppm	2153.39
Ethane	C2H6	0.22 ppm	267.38
Ethylene, acetylene		<50	
C3 compounds		<50	
Isobutane	C4H10	8.02	19.03
Butane	C4H10	23.57	55.89
Cyclopentane	C5H10	0.32	0.91
Isopentane	C5H12	5.49	16.16
Pentane	C5H12	12.54	36.92
Cyclobutane, methylene-	C5H8	0.23	0.64
3-Methylpentane	C6H14	0.14	0.51
2-Methylpentane	C6H14	0.21	0.74
Hexane	C6H14	0.46	1.60
Benzene	C6H6	0.23	0.75
Methylcyclohexane	C7H14	0.19	0.74
Heptane	C7H16	0.20	0.83
Toluene	C7H8	0.12	0.47
Cyclohexane, 1,3-dimethyl-, trans-	C8H16	0.27	1.25
Hexane, 3-ethyl-	C8H18	0.22	1.03

A canister sample was also collected from the emissions plume from the condensate tanks. This sample was analysed for both hydrocarbons and reduced sulphur species. The results are summarized in Table 10. As compared to the plant sample, the condensate tank sample contained relatively more hydrocarbons >C5. The concentration of benzene was also higher, at 1.55 ppb, although still well below the 9 ppb limit of the Alberta Ambient Air Guideline. C2 and C3 hydrocarbons were likely present in the plume from the tanks, but were at a concentration below the detection limit (50 ppb) of the canister method. The canister sample for the condensate tanks did not contain any reduced sulphur species above the detection limit of the sampling and analysis method (about 3 to 5 ppb).

Table 10: Canister Sample from Condensate Tank Area at the Sour Gas Plant

Compound Name	Formula	Concentration (ppb)	Concentration (ug/m^3)
Methane	CH_4	2.41 ppm	1576.45
C2 compounds		<50	
C3 compounds		<50	
Isobutane	C_4H_{10}	2.98	7.07
Butane	C_4H_{10}	11.73	27.81
Cyclopentane	C_5H_{10}	1.49	4.26
Isopentane	C_5H_{12}	4.01	11.79
Pentane	C_5H_{12}	12.84	37.79
Isoprene	C_5H_8	0.58	1.61
Cyclohexane	C_6H_{12}	0.94	3.24
Methylcyclopentane	C_6H_{12}	1.22	4.17
3-Methylpentane	C_6H_{14}	1.10	3.86
2-Methylpentane	C_6H_{14}	2.02	7.09
Hexane	C_6H_{14}	6.70	23.55
Benzene	C_6H_6	1.55	4.94
Cyclopentane, 1,3-dimethyl-, cis-	C_7H_{14}	0.19	0.74
Cyclopentane, 1,2-dimethyl-, trans-	C_7H_{14}	0.22	0.87
1-Hexene, 5-methyl-	C_7H_{14}	0.44	1.75
Methylcyclohexane	C_7H_{14}	0.67	2.67
2-Methylhexane	C_7H_{16}	0.24	0.98
Heptane	C_7H_{16}	0.85	3.48
Toluene	C_7H_8	1.48	5.55
o-Xylene	C_8H_{10}	0.20	0.86
m,p-Xylene	C_8H_{10}	0.70	3.03
Cyclohexane, 1,3-dimethyl-, trans-	C_8H_{16}	0.18	0.82
2-Methylheptane	C_8H_{18}	0.12	0.57
Hexane, 2,4-dimethyl-	C_8H_{18}	0.20	0.95
Octane	C_8H_{18}	0.31	1.44
Benzene, 1,2,4-trimethyl-	C_9H_{12}	0.36	1.77
Nonanal	$C_9H_{18}O$	0.87	5.04
Decanal	$C_{10}H_{20}O$	1.02	6.50

5.2 Fugitive Emissions at Sour Gas Plant C in 2004

Fugitive emissions measurements were made with the DIAL unit located at 11 different positions in the plant over the three day period. Winds were mainly from the northeast to southeast, with some southwest winds on the third day. Wind speed ranged from 0.9 to 6.6 m/s (3.2 to 24 km/h).

Gas Plant C was surveyed with the DIAL during the 2003 measurement campaign (Chambers, 2003). During the 2003 measurements the sweet portion of the plant, the Deepcut area, was the major source of fugitive emissions. Thus the majority of the measurements during 2004 emphasized this part of the plant. Major areas of the plant included the Gas Trains (where sour gas is treated to remove acid gas), Sulphur Plant (where H_2S is converted to sulphur), Deepcut area (where condensate and light hydrocarbons are separated and recovered), Water Treatment Ponds and Condensate Tanks.

The DIAL method measured the concentration of methane directly but measured the concentration of C_{2+} hydrocarbons as a group. An average molecular weight of the C_{2+} hydrocarbons is needed to convert the concentration and wind speed measurements to a mass flux. The detailed composition from the analysis of the canister sample (Table 9) was used to calculate an average molecular weight of the C_{2+}.

5.2.1 Emissions from the Sweet Gas Processing Area

On the first day some brief methane measurements were made addressing the Process Plant as a whole. The results are given in Table 11. These measurements were made on the southern side of the plant with a wind direction slightly east of north. Under these conditions some emission from the northwest corner of the Plant may have escaped the scan plane by virtue of being carried along the valley on the western side of the site, which was hidden from the scans. The methane emission measurements gave a TWM figure of 40.3 kg/h. Most of this emission likely came from the Deep Cut Section as gas leaks in the Gas Trains that handle sour gas are rapidly detected and repaired. The Utilities plant may possibly have contributed some emission but this is the part most likely to have escaped along the valley. These methane emissions do not include emissions from the condensate tanks, water ponds or process flare.

Table 11: Measurement of Methane Emissions from the Process Plant

		Mean Wind			
Scan No.	**Scan Time**	**Speed (m/s)**	**Dir'n (deg)**	**Flux (kg/h)**	**HC Specie**
1.1 -1	30-Jul-04 10:53 – 10:58	2.3	039	34.6	CH4
1.2 -1	30-Jul-04 11:06 – 11:11	2.1	013	52.6	CH4
1.3 -1	30-Jul-04 11:13 – 11:18	2.4	013	21.2	CH4
1.4 -1	30-Jul-04 11:25 – 11:34	3.1	019	47.6	CH4
TWM				**40.3**	

The remainder of the day emphasized measurement of hydrocarbon emissions from the Deepcut section of the plant. During the measurements on the Deep Cut Plant it was evident that there were some incoming methane and C_2+ fluxes from upwind regions, including the Waste Water Storage Pond and gas incomer area. An indication of the extent of these fluxes was made at the time by scanning upwind of the Plant, the DIAL location was, however, not ideal for this, particularly during the C_2+ measurements and so more extensive upwind measurements were made later in the survey when an opportunity arose. These upwind measurements provided data for upwind subtracting from the Deep Cut measurements as well as providing data specific to the Waste Water Storage Pond. These upwind emissions of methane were less than 2% of the emissions from the Deepcut area and less than 6% of the C_{2+} and benzene emissions from the Deepcut area.

The results of these measurements of methane, C_{2+} and benzene emissions are summarized in Table 12. The measurements on the Deep Cut Section returned TWM emission figures of 30.9 kg/h of methane, 14.5 kg/h of C_{2+} and 0.17 kg/h of benzene. By analyzing the DIAL scan information, the emissions from the Deep Cut Section were split into two ranges, the first covering the compressor house, cooling banks and adjacent plant and the second covering the southern half of the Deep Cut plant including the de-methaniser column and process plant. The TWM emissions were split into:

- 3.9 kg/h methane, 3.7 kg/h of C_{2+}, 0.08 kg/h of benzene for the compressor house, cooling banks and adjacent plant,
- 27.0 kg/h methane, 10.8 kg/h of C_{2+}, 0.09 kg/h of benzene for the process plant including the de-methaniser column.

Later on July 30 measurements were made downwind of the two sour Gas Trains in combination with the Deep Cut section to confirm that the sour Gas Trains were not contributing significant emissions. These measurements are given in Table 13. The emission measurements gave combined TWM figures for the Gas Trains and Deep Cut of 29.8 kg/h for methane, 12.9 kg/h for C_{2+} and 0.13 kg/h for benzene. These figures were very similar to the emission levels recorded for the Deep Cut plant alone and it is evident that the Gas Trains were not responsible for significant gas leaks.

Table 12: Hydrocarbon Emissions from the Deepcut Section of Gas Plant C

Scan No.	Scan Time	Mean Wind Speed (m/s)	Mean Wind Dir'n (deg)	Flux (kg/h)	HC Specie	Benzene Flux (kg/h)
Deepcut Compressors & Coolers						
2.1 -1	30-Jul-04 12:41 -12:49	1.5	073	5.6	C2+	0.05
2.2 -1	30-Jul-04 12:50 -12:57	2.8	039	5.2	C2+	0.07
2.3 -1	30-Jul-04 12:59 -13:06	2.0	048	1.7	C2+	0.08
2.4 -1	30-Jul-04 13:13 -13:20	3.0	061	4.6	C2+	0.10
2.5 -1	30-Jul-04 13:22 -13:28	2.2	059	3.0	C2+	0.09
2.6 -1	30-Jul-04 13:32 -13:39	2.5	055	2.1	C2+	0.12
2.7 -1	30-Jul-04 13:43 -13:50	1.6	031	2.5	C2+	0.06
2.8 -1	30-Jul-04 13:51 -13:58	3.5	086	4.8	C2+	0.15
TWM				**3.7**		
2.9 -1	30-Jul-04 14:10 -14:16	3.6	094	1.9	CH4	0.04
2.10 -1	30-Jul-04 14:18 -14:24	3.6	090	4.4	CH4	0.08
2.11 -1	30-Jul-04 14:26 -14:33	2.6	085	3.1	CH4	0.09
2.12 -1	30-Jul-04 14:36 –14:42	2.6	069	5.6	CH4	0.07
2.17 -1	30-Jul-04 15:20 -15:27	3.4	076	4.3	CH4	-
TWM				**3.9**		
TWM						**0.08**
Southern Half Deepcut Plant						
2.1 -2	30-Jul-04 12:41 -12:49	1.5	072	10.8	C2+	0.06
2.2 -2	30-Jul-04 12:50 -12:57	2.5	037	12.4	C2+	0.05
2.3 -2	30-Jul-04 12:59 -13:06	2.1	051	15.1	C2+	0.11
2.4 -2	30-Jul-04 13:13 -13:20	2.9	063	13.2	C2+	0.06
2.5 -2	30-Jul-04 13:22 -13:28	2.1	056	7.7	C2+	0.06
2.6 -2	30-Jul-04 13:32 -13:39	2.4	057	7.1	C2+	0.08
2.7 -2	30-Jul-04 13:43 -13:50	1.5	035	5.9	C2+	0.04
2.8 -2	30-Jul-04 13:51 -13:58	3.6	089	13.8	C2+	0.17
TWM				**10.8**		
2.9 -2	30-Jul-04 14:10 -14:16	3.5	093	28.1	CH4	0.16
2.10 -2	30-Jul-04 14:18 -14:24	3.6	089	27.2	CH4	0.10
2.11 -2	30-Jul-04 14:26 -14:33	2.6	084	22.2	CH4	0.10
2.12 -2	30-Jul-04 14:36 -14:42	2.5	072	25.5	CH4	0.08
2.17 -2	30-Jul-04 15:20 -15:27	3.3	072	31.6	CH4	-
TWM				**27.0**		**0.09**
Total Deepcut Plant				**14.5**	C2+	**0.17**
				30.9	CH4	

Table 13: Hydrocarbon Emissions from the Sour Gas Trains and Deepcut Section Combined

Scan No.	Scan Time	Mean Wind Speed (m/s)	Mean Wind Dir'n (deg)	HC Flux (kg/h)	HC Specie	Benzene Flux (kg/h)
Gas Trains & Deepcut						
3.1 -1	30-Jul-04 15:47 -15:51	4.0	064	27.0	CH4	0.13
3.2 -1	30-Jul-04 15:52 -15:56	4.0	058	25.7	CH4	0.12
3.3 -1	30-Jul-04 16:01 -16:04	4.5	052	35.6	CH4	0.12
3.4 -1	30-Jul-04 16:05 -16:08	4.1	055	29.7	CH4	0.11
3.5 -1	30-Jul-04 16:11 -16:16	3.7	056	31.9	CH4	0.10
TWM				**29.8**		
3.6 -1	30-Jul-04 16:20 -16:23	5.0	050	7.5	C2+	0.15
3.7 -1	30-Jul-04 16:24 -16:27	4.8	039	12.5	C2+	0.15
3.8 –1	30-Jul-04 16:30 -16:33	4.3	051	14.2	C2+	0.16
3.9 -1	30-Jul-04 16:36-16:40	3.6	058	16.2	C2+	0.14
TWM				**12.9**		**0.13**

5.2.2 Emissions from the De-methanizer Column

An example concentration profile of methane emissions from the Deep Cut Section is shown in Figure 5. The profile indicated a 'hot spot' about 35 meters above ground level, corresponding with the top half of the de-methanizer column. A measurement specific to this area was made and a net methane emission from the column of approximately 20 kg/h was recorded. The de-methanizer was thus apparently responsible for about two thirds of the methane emissions from the Deep Cut Plant, with the leak located 30 to 40 meters above ground level.

5.2.3 Emissions from the Condensate Tanks

There were two condensate tanks located at Gas Plant C. These tanks were surveyed during a wind direction that had no other parts of the site upwind of the tanks. Methane, C_{2+} and benzene emissions from the tanks were measured. The tanks were of the fixed roof internal floating deck type fitted with single rim seals; the space above the internal deck was freely vented. The tanks were operated in parallel with the inlet and outlet flows balanced. The outlet was pumped to large off-site storage. The DIAL measurements resulted in separate measurements for each tank, but because of the wind direction some cross contamination between them was likely.

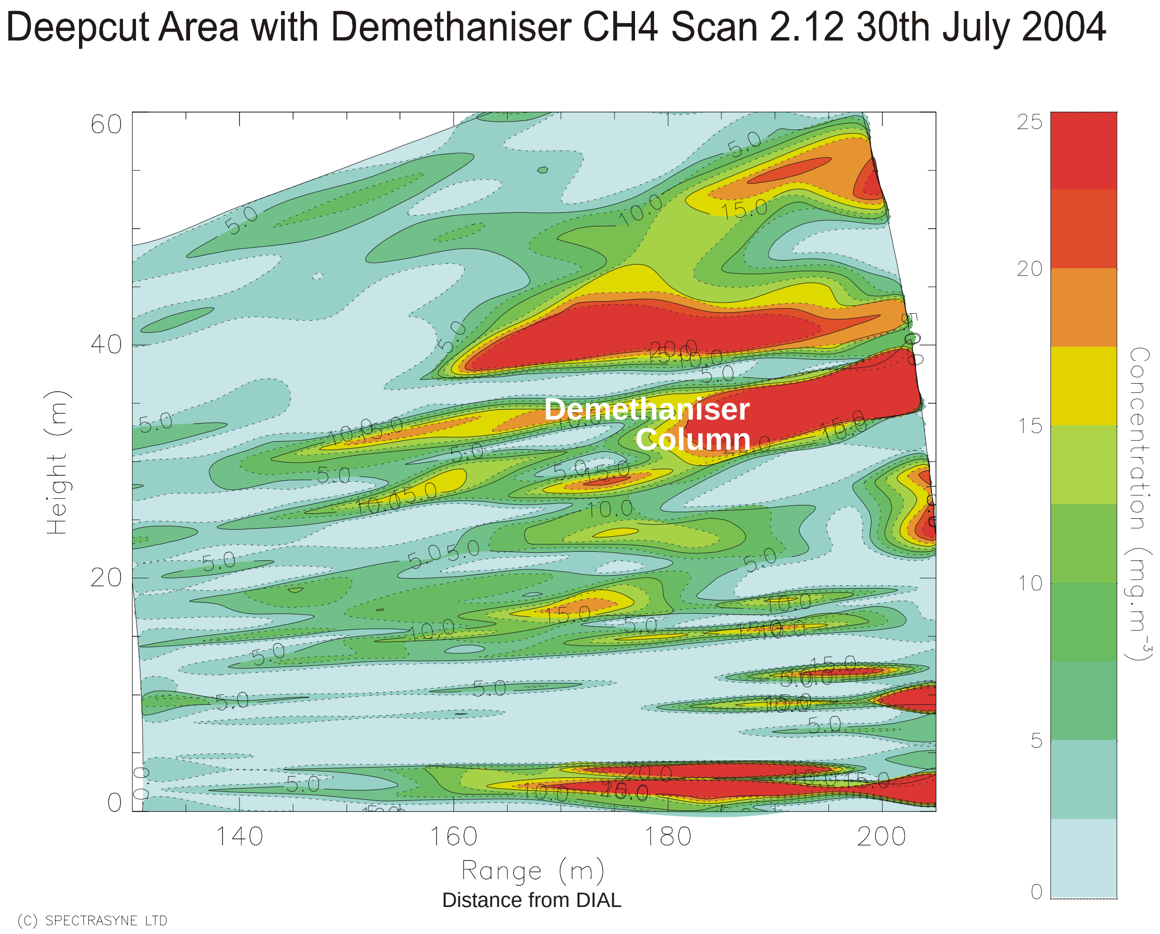


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Figure 5: Profile of Emission from Demethanizer Column at Sour Gas Plant C

The DIAL measurements of emissions from the Condensate Tanks are summarized in Table 14. The TWM methane emissions were 21.6 kg/h for the A Tank and 21.1 kg/h for the B Tank. The TWM $C_{4.5}$ emission levels were 18.8 kg/h for the A Tank and 16.5 kg/h for the B Tank. It should be noted that the canister sample (Table 10) was not sufficiently sensitive to detect C2 and C3 hydrocarbons. Thus the average molecular weight determined during the 2003 measurement campaign was used to convert the measured DIAL C_{2+} concentrations to mass fluxes. This average molecular weight corresponded to $C_{4.5}$.

Benzene emissions from the Tanks were very low, many of the measurements being below the detection limit. The TWM emission figures recorded were 0.02 kg/h for the A Tank and mostly trace levels for the B Tank.

Table 14: Hydrocarbon Emissions from the Condensate Tanks at Gas Plant C

Scan No.	Scan Time	Mean Wind Speed (m/s)	Mean Wind Dir'n (deg)	HC Flux (kg/h)	HC Specie	Benzene Flux (kg/h)
Condensate Tank A						
5.1 -1	3-Aug-04 10:25 - 10:30	3.1	093	10.5	C4.5	0.01
5.2 -1	3-Aug-04 10:35 - 10:38	4.1	086	19.1	C4.5	bdl
5.3 -1	3-Aug-04 10:44 - 10:48	3.5	094	20.3	C4.5	bdl
5.4 -1	3-Aug-04 10:52 - 10:56	3.6	087	12.6	C4.5	bdl
5.5 -1	3-Aug-04 10:59 - 11:04	4.3	090	24.4	C4.5	0.01
5.6 -1	3-Aug-04 11:06 - 11:12	4.6	089	22.8	C4.5	bdl
5.7 -1	3-Aug-04 11:15 - 11:19	5.1	098	22.6	C4.5	bdl
TWM				**18.8**		**0.01**
5.8 -1	3-Aug-04 11:29 - 11:32	5.4	086	24.4	CH4	0.02
5.9 -1	3-Aug-04 11:36 - 11:42	4.5	083	19.5	CH4	0.02
5.10 -1	3-Aug-04 11:43 - 11:49	5.1	084	18.0	CH4	0.03
5.11-1	3-Aug-04 11:51 - 11:57	6.3	072	26.3	CH4	0.01
5.12 -1	3-Aug-04 11:58 - 12:04	5.4	082	18.5	CH4	0.02
5.13 -1	3-Aug-04 12:06 - 12:12	5.3	089	19.4	CH4	0.03
5.14 -1	3-Aug-04 12:14 - 12:20	5.1	093	26.5	CH4	0.04
TWM				**21.6**		**0.02**
Condensate Tank B						
5.1 -2	3-Aug-04 10:25 - 10:30	3.1	094	16.4	C4.5	0.07
5.2 -2	3-Aug-04 10:35 - 10:38	4.1	087	16.9	C4.5	0.05
5.3 -2	3-Aug-04 10:44 - 10:48	3.5	096	12.9	C4.5	0.04
5.4 -2	3-Aug-04 10:52 - 10:56	3.5	087	13.8	C4.5	0.01
5.5 -2	3-Aug-04 10:59 - 11:04	4.3	091	21.9	C4.5	trace
5.6 -2	3-Aug-04 11:06 - 11:12	4.6	088	19.5	C4.5	0.01
5.7 -2	3-Aug-04 11:15 - 11:19	5.1	100	13.7	C4.5	0.01
TWM				**16.5**		**0.03**
5.8 -2	3-Aug-04 11:29 - 11:32	5.4	085	21.0	CH4	0.01
5.9 -2	3-Aug-04 11:36 - 11:42	4.5	083	22.5	CH4	bdl
5.10 -2	3-Aug-04 11:43 - 11:49	5.1	084	21.3	CH4	trace
5.11-2	3-Aug-04 11:51 - 11:57	6.3	072	28.6	CH4	trace
5.12 -2	3-Aug-04 11:58 - 12:04	5.4	082	13.3	CH4	bdl
5.13 -2	3-Aug-04 12:06 - 12:12	5.3	089	23.0	CH4	bdl
5.14 -2	3-Aug-04 12:14 - 12:20	5.1	093	17.8	CH4	bdl
TWM				**21.1**		**trace**
Total Tanks A & B				**35.3** **42.6**	**C2+** **CH4**	**0.03**

5.2.4 Emissions from the Water Treatment Ponds

The water treatment and storage ponds were not a significant source of hydrocarbon emissions during the 2003 survey. They were surveyed during 2004 as the ponds were upwind of the Deepcut area during most of the Deepcut measurements. In addition, benzene emission measurements were collected in 2004.

The results of the waste water storage pond scans are summarized in Table 15. The Waste Water Surge Pond holds process waste prior to re-injection into gas wells. The TWM measurement of methane, C_{2+} and benzene from the Waste Water Surge Pond was 0.41 kg/h, 0.93 kg/h and 0.01 kg/h, respectively.

Table 15: Emissions from the Waste Water Storage Pond at Gas Plant C

Scan No.	Scan Time	Mean Wind Speed (m/s)	Mean Wind Dir'n (deg)	HC Flux (kg/h)	HC Specie	Benzene Flux (kg/h)
9.5 -1	4-Aug-04 11:56 - 12:02	1.2	106	1.3	C2+	0.01
9.6-1	4-Aug-04 12:06 - 12:10	2.0	091	0.58	C2+	0.01
9.7 -1	4-Aug-04 12:12 - 12:17	1.7	089	0.91	C2+	-
9.8 -1	4-Aug-04 12:20 - 12:22	1.0	078	0.92	C2+	trace
9.9 -1	4-Aug-04 12:29 - 12:31	1.7	073	0.75	C2+	0.01
TWM				**0.93**		**0.01**
9.10 -1	4-Aug-04 12:40 - 12:45	1.2	035	0.37	CH4	0.01
9.11 -1	4-Aug-04 12:47 - 12:52	1.4	026	0.38	CH4	0.01
9.12 -1	4-Aug-04 12:58 - 13:04	1.8	024	0.11	CH4	0.01
9.13 -1	4-Aug-04 13:06 - 13:11	1.4	032	0.77	CH4	trace
TWM				**0.41**		**0.01**

5.2.5 Emissions from the Sulphur Plant

Hydrocarbon emissions from the Sulphur Plant and sulphur storage pit were also completed, with the data summarized in Table 16. The measurements made on the Sulphur Plant provided TWM figures of 26.5 kg/h for methane, 7.6 kg/h for C_{2+} and 0.03 kg/h for benzene. Benzene was only present at trace levels for most of the scans of the Sulphur Plant. For the C_{2+} measurements some degree of segregation of the plant was possible. The C_{2+} emissions were mainly concentrated in the southern region of the plant, in the area including the Scott Contactors. The hydrocarbon emissions may have been partly due to cross contamination from other areas of the plant or possibly from the fuel gas supply to the Sulphur Plant.

Table 16: Hydrocarbon Emissions from the Sulphur Plant at Gas Plant C

Scan No.	Scan Time	Mean Wind Speed (m/s)	Mean Wind Dir'n (deg)	HC Flux (kg/h)	HC Specie	Benzene Flux (kg/h)
Sulphur Plant						
10.2 -1	4-Aug-04 14:50 - 15:22	1.6	341	26.4	CH4	trace
10.3 -1	4-Aug-04 15:27 - 15:35	3.3	316	24.5	CH4	trace
10.4 -1	4-Aug-04 15:37 - 15:46	3.6	350	29.4	CH4	trace
10.5 -1	4-Aug-04 15:47 - 15:56	3.2	342	25.5	CH4	trace
TWM				**26.5**		**trace**
Sulphur Plant to Pit (Incl'd Contactors)						
11.2 -1	4-Aug-04 17:06 - 17:12	1.1	279	4.7	C2+	0.06
11.3 -1	4-Aug-04 17:14 - 17:20	0.9	238	7.4	C2+	0.02
11.4 -1	4-Aug-04 17:22 - 17:26	1.7	213	6.2	C2+	0.03
11.5 -1	4-Aug-04 17:29 - 17:35	1.6	246	8.1	C2+	-
TWM				**6.5**		0.04
Pit & Rest of Plant						
11.2 -2	4-Aug-04 17:06 - 17:12	0.9	284	2.2	C2+	bdl
11.3 -2	4-Aug-04 17:14 - 17:20	1.0	246	0.45	C2+	bdl
11.4 -2	4-Aug-04 17:22 - 17:26	1.7	214	1.0	C2+	bdl
11.5 -2	4-Aug-04 17:29 - 17:35	1.6	244	0.50	C2+	-
TWM				**1.1**		**bdl**
Total Sulphur Plant				**7.6** **26.5**	**C2+** **CH4**	**0.04**

5.3 Summary of Fugitive Emissions at Sour Gas Plant C

Table 17 gives a summary of the TWM emissions recorded in both 2003 and 2004 for the various sections of the Sour Gas Plant C, excluding emissions from the flares on site. During the 2004 survey, the overall TWM emission figures for the whole plant amounted to 100 kg/h of methane, 58.4 kg/h of C_{2+} and 0.24 kg/h of benzene. The condensate tanks were the single largest source of hydrocarbon emissions, contributing 42.6 % of the site methane emissions, 60.4% of the site C_{2+} emissions and 12% of the benzene emissions. In the Deepcut area that processes sweet gas, a source within the top half of the de-methanizer column contributed 20 kg/h of methane emissions or 20% of the plant total emissions of methane.

Table 17: Summary of Fugitive Emissions from Sour Gas Plant C (without flare emissions)

	2003 Survey (kg/h)		**2004 Survey (kg/h)**		
Area	**CH_4**	**C_2+**	**CH_4**	**C_{2+}**	**Benzene**
Deepcut Plant	91	167	30.9	14.5	0.17
Sulphur Plant & Tank	23	140	26.5	7.6	0.03
Total Process	**114**	**307**	**57.4**	**22.1**	**0.20**
Condensate Tanks	16	24.7	42.6	35.3	0.03
Ponds		4.7	0.41	0.93	0.01
Total Site	**130**	**337**	**100**	**58.4**	**0.24**

During the visit to the site in 2003 the DIAL emission survey identified that the Deep Cut area of the plant was responsible for the majority of the site's hydrocarbon emissions. Between the 2003 and 2004 DIAL survey's, the site made efforts to track down and repair individual leaks. These efforts included a survey performed in the early spring of 2004 by Maverick Inspections Ltd., Sherwood Park using the Hawk gas-leak imaging camera. These efforts were clearly rewarded through the much lower emission levels seen from the Deep Cut plant. Taking the Deep Cut and Sulphur Plant together, as some of the Sulphur Plant emissions may have been a cross-contamination from the Deep Cut area, reduction in emissions from the gas processing area were a 50% reduction of methane and a 93% reduction in C_{2+} emissions between 2003 and 2004. At a gas price of \$218 CDN/1000 m^3, the 341 kg/h reduction in methane and C_2+ emissions from the gas processing area represent annual savings on the order of \$900,000. The actual savings would depend on the market value of the C_{2+} component of the emissions.

The measurements made on the Condensate Tanks in 2003 gave emission levels of 16.0 kg/h of methane and 24.7 kg/h of $C_{4.5}$ for the two tanks combined. The levels recorded in 2004 thus show increases of 167% in the methane emissions and 43% in the C_2+ emissions. There was no clear reason for the increased emissions from the tanks. This increase in emissions from the tanks represents an annual loss of about \$99,000.

For the plant, condensate tanks and water treatment ponds combined, the methane emissions were reduced by 23% and the C_{2+} emissions were reduced by 83% between the 2003 and 2004 DIAL surveys.

6. Demonstration of Optical Leak Detection Methods

Research and development has taken place for new methods to detect hydrocarbon gas leaks in oil and gas processing facilities, refineries and pipelines. Much of this research was driven by the American refinery industry and the natural gas pipeline industry. U.S. refineries are mandated to perform regular Leak Detection and Repair (LDAR) surveys using EPA Method 21. The cost of these surveys can be over $1MM annually. In addition, several studies have demonstrated the high variability of Method 21 results and the high number of missed leaks. Gas leak imaging cameras could potentially reduce these costs by more quickly identifying leaks and focusing repair efforts on the worst leaks.

6.1 Review of Optical Leak Detection Methods

A literature review and Internet search were completed to identify gas leak imaging technologies under development. The US EPA published a review of the various leak detection and measurement methods, both conventional and under development, in 1999 (USEPA report titled, "Compendium of Sensing Technologies to Detect and Measure VOCs and HAPs in the Air"). A recent American Petroleum Institute (API) report describes a proposed LDAR method using gas leak imaging cameras (API Report titled "Smart Leak Detection and Repair for Control of Fugitive Emissions", June 2004).

The following briefly describes some of the methods under development or near commercial application.

6.1.1 Image Multi-Spectral Sensing (IMSS)

Pacific Advanced Technology (www.patinc.com) has developed a field portable IMSS camera for numerous defence related applications, including detection and analysis of targets such as missile plumes and chemical warfare agents. The IMSS camera can be adjusted to measure in wavelengths absorbed by hydrocarbon gases and potentially tuned for selective gases. One application studied extensively by the company is methane leak detection. Recent breakthroughs in digital signal processors and field programmable gate arrays permit these sophisticated image-processing techniques developed for the military to be applied to display fugitive gas leaks to the operator in real time. Figure 6 shows an image of a methane vent taken in daylight to show methane concentrations. The unit is sensitive enough to operate at night using infrared radiation from terrain as its light source. The unit is still in a prototype phase of development.

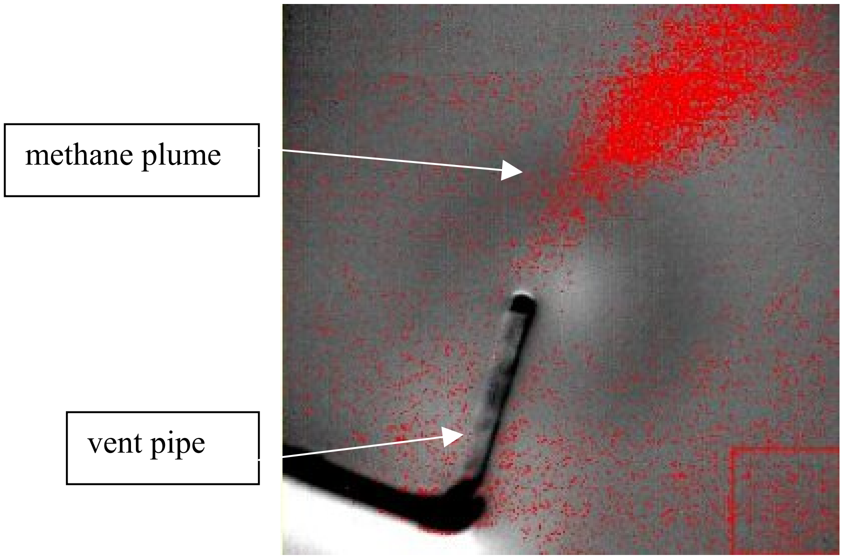

Figure 6: IMSS Image of Methane Vent

6.1.2 Modified Infra-red Cameras

Infra-red (IR) cameras were originally developed for thermal imaging inspection of equipment. Continuous improvements in these video camera systems have resulted in high sensitivity to the infrared radiation in a compact, portable size. Some of the wavelengths absorbed by methane and other hydrocarbon gases fall within the range of modern infrared cameras. With filters in the appropriate wavelengths, an infrared camera can be modified to produce an image of hydrocarbon gas plumes. Although these cameras cannot measure the mass emissions of the leak, with appropriate lighting and some temperature difference between the gas and the surroundings, they can be used to efficiently locate leaks.

Leak Surveys Inc., Texas, (www.leaksurveysinc.com) has developed a commercial prototype and is offering a leak survey service using their Hawk camera. The Hawk camera was the primary leak imaging camera in commercial application at the time of this project. The Hawk camera cannot currently discriminate between specific hydrocarbon gases nor quantify the amount of the gas leak. Results that can be achieved with a Hawk camera are described further in Section 6.2

A group at the Lund Institute of Technology, Sweden, (www-atom.fysik.lth.se/JonasSandsten/GasVisualisation.htm) have also developed a method using an IR cameras and gas filter correlation techniques for imaging specific gases. Their recent work uses a camera sensitive in the 8-12 μm region, enabling passive gas imaging from the absorption of the natural thermal background radiation (Sandsten, et al., 2000). Field studies have been performed on open gas flows of ammonia, methane, and ethylene. The technique uses an IR sensitive camera equipped with filters for the selection of specific molecular IR bands, with a gas cell in front of one of the openings of a split-mirror telescope. The captured images are processed on a computer using a gas correlation scheme. The result is presented as a colour coded image of a specific gas merged with a visible image, as shown in Figure 7. A movie of the gas flow can be produced with up to 30 frames per second. The distance from the camera system to the petrochemical plant can be chosen between 20-1000 m

Figure 7: Ethylene Emissions from Flare
(from http://www-atom.fysik.lth.se/JonasSandsten/GasVisualisation.htm)

6.1.3 Backscatter Absorption Gas Imaging (BAGI)

The BAGI method uses an infrared laser tuned to a wavelength absorbed by the gas of interest for illumination, combined with a modified infrared camera for detection. If a gas plume is present in the imaged zone, the gas absorbs a portion of the laser light reflected back to the camera and the plume appears as a dark cloud. A BAGI system is limited in that the leak must have a reflecting surface behind it and that the laser must be in a wavelength that is absorbed by the gas but in which the atmosphere is transparent. The need for an artificial lighting system and the associated weight and power requirements reduces the ability to make a compact, portable system with this method.

A commercial system, GasVue®, is being developed by Laser Imaging Systems, Florida (www.laserimagingsystems.com/gasvue.htm).

6.1.4 Correlation Spectroscopy

A correlation spectrometer (COSPEC) is a remote sensing device that can repeatedly measure ambient concentrations of either sulfur dioxide or nitrogen dioxide in the air column extending along its line of site. Measurements are made using scattered solar radiation as the light source. The instrument measures the absorption of the gases in the UV to visible spectral range (290 to 320 nm) a wavelength range with strong absorption by the target gases and minimal interference from other atmospheric compounds. Source intensity changes are compensated by additionally measuring the intensity of radiation at nearby wavelengths known to have little or no absorption to the target gas. This modulated signal is then processed to produce output signals directly proportional to target gas concentrations (in this case, the SO_2 concentrations) in the air column being measured.

Synodon (www.synodon.com) is an Edmonton based company that has developed an airborne survey service called realSens. Synodon is targeting remote leak detection in buried natural gas pipelines as their initial market. Their technology uses correlation spectroscopy based on technology developed by Canada's space program for satellite surveillance. Solar radiation is used as the light source limiting the method to daytime use. The instrument and data acquisition are installed on an airborne platform that can travel at a rate of 100km/hr. The instrument is sensitive enough to detect early stage leaks. Data is transferred to the data processing centre where the gas concentrations are determined using a custom designed software. A report using GIS reference maps quantifies and pinpoints the leak location for the customer over a secure website.

6.1.5 Differential Absorption Lidar (DIAL)

DIAL is a laser-based optical method capable of measuring the concentration of a gas species at a remote point in the atmosphere. The DIAL method uses a pulsed laser operating at two wavelengths, one strongly absorbed by the gas species of interest and one weakly absorbed. A system of mirrors and lenses is used to direct the laser beam toward the target gas volume. A telescope collects light back-scattered from particles and aerosols in the atmosphere at each of the two wavelengths. From the time taken for the return signal and the relative strength of absorbed and non-absorbed wavelengths, a gas species concentration profile along the light path can be calculated. A steering mirror system can be used to scan an area of interest and develop a 2D or 3D map of gas species concentration in the atmosphere. Combining the gas concentration maps with measured wind speed enables the calculation of mass emissions of a gas species from a source.

The complexity of equipment and laser power required for the DIAL method would make it difficult to develop a portable system suitable for valve to valve leak detection at a facility. Spectrasyne Ltd., (www.spectrasyneltd.uk) has developed a mobile system for surveying fugitive emissions of hydrocarbons from UOG and refinery facilities, as described in Appendix A and Section 3. The system is unique in its ability to quantify 'whole facility' fugitive emissions and identify and quantify significant leaks (Chambers, 2003).

The DIAL method is also being applied as an airborne system for natural gas pipeline leak detection. LaSen Inc. (www.laseninc.com) has developed an Airborne Lidar Pipeline Inspection System based on a DIAL operating in the mid-infrared (3 to 5 µm) range. The laser beam is transmitted down from the aircraft to illuminate the area on the ground above the buried pipe. The sensor's receiver collects the laser reflected from the ground and the amount of received energy is measured. This absorption signature is used to locate pipeline leaks and assess their magnitude.

6.2 Field Demonstration of Optical Leak Detection

The Hawk camera from Leak Surveys Inc., Texas, (www.leaksurveysinc.com) was the primary leak imaging camera in commercial application at the time of this project. Figure 8 is a photograph of the prototype Hawk camera in use. The result of the leak camera survey is a video record of a walk through the plant, with hydrocarbon leaks visible as light or dark clouds in the video. Ideally plant personnel should accompany the camera survey crew in order to tag and/or repair leaking equipment as it is identified.

The Hawk camera was used to survey both the sweet and sour gas plants during this study, coinciding with the DIAL survey at each site, described in Section 4. In addition, Maverick Inspection Ltd., Sherwood Park, AB, also used the Hawk camera in the spring of 2004 to identify leaks at the sour gas plant (Plant C) for repair after the 2003 DIAL survey. Most of the identified leaks were repaired prior to the 2004 DIAL survey at Gas Plant C.

Figure 8: Hawk Leak Imaging Camera (from www.leaksurveysinc.com)

Figure 9 is an image from the Hawk camera survey performed by Leak Surveys Inc., Texas, at the sour gas plant (Plant C). The circled dark area in the image indicates the hydrocarbon plume from a small leak around the valve stem packing. The indication of a leak is much clearer in the video image as the plume is continually moving and easily seen. Hydrocarbon plumes will appear as either a dark cloud or a light cloud in the image, depending on the relative temperatures of the gas leak and the surrounding background.

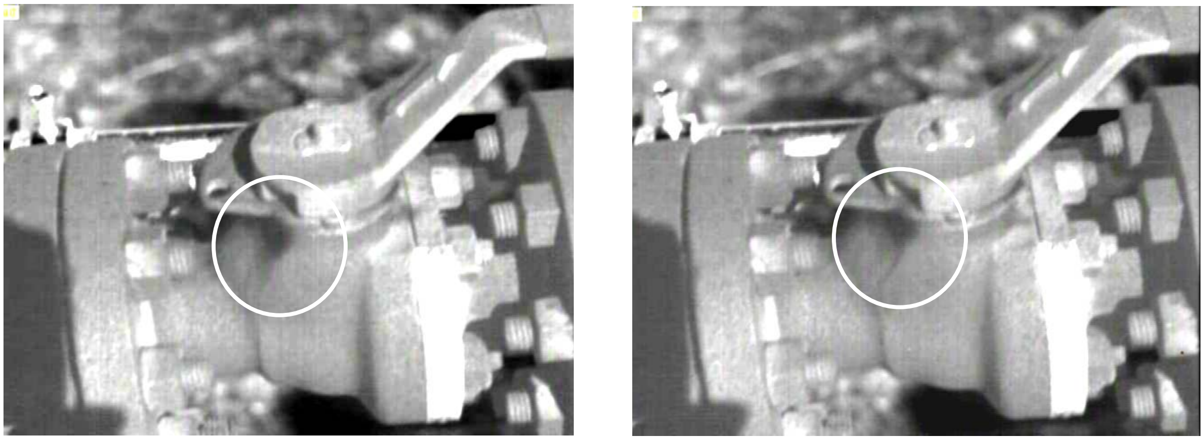

Figure 9: Gas Leak Imaging Camera Indication of Hydrocarbon Leak around Valve Stem (image from Leak Surveys Inc., Texas)

Primary sources of leaks identified by the Hawk camera varied between the two sites, but at both sites commonly occurring leak sources included:

- packing around valve stems,
- union fittings,
- pipe thread fittings, such as pressure gauges,
- tank vents and hatches,
- compressor packing vents.

Gas leak imaging cameras were shown to be an efficient and effective way to identify leaking equipment. As discussed in Section 5.3, fugitive emissions of hydrocarbons from the sour gas Plant C were reduced by about 60% between the DIAL survey performed in 2003 and 2004. This was achieved by repairing leaks identified during a Hawk camera survey performed in early 2004. The camera survey prior to leak repair identified 33 leaks, while the camera survey after leak repair identified only 7 leaks. The 60% reduction in hydrocarbon fugitive emissions demonstrated the power of the method and the rapid payback by retaining hydrocarbons that were previously lost to the atmosphere.

7. Comparison of Measured Data with Calculated Emissions of GHG and CAC

Some gas processing plants in Alberta are now required to report emissions of Criteria Air Contaminants (CAC) to the National Pollutant Release Inventory (NPRI) and other government bodies and emissions of Greenhouse Gas (GHG) to Statistics Canada. Volatile organic hydrocarbons (VOCs) are one of the CACs emitted from a gas plant while methane is a GHG emitted by a gas plant. Fugitive emissions from leaking equipment form a significant component of both GHG and CAC emissions.

Currently the fugitive emission component is estimated based on the natural gas throughput of the plant or based on installed equipment and standard emission factors for each piece of equipment. The estimation methods are detailed in:

- CAPP Guide 2004-0008 'A Recommended Approach to the National Pollutant Release Inventory (NPRI) for the Upstream Oil and Gas Industry – 2003 Reporting Year: CAC Emissions', and
- CAPP Guide 2003-0003 'Calculating Greenhouse Gas Emissions'.

CAPP is continuing to develop these guidelines, with a new fugitive emissions guideline planned by the end of 2006.

The main CAC contained in fugitive emissions from a gas processing plant is Volatile Organic Hydrocarbons (VOCs). The NPRI defines VOC's as volatile organic compounds that participate in atmospheric photochemical reactions, excluding methane, ethane and a variety of other hydrocarbons listed in the NPRI Guide (http://www.ec.gc.ca/pdb/npri/2003Guidance/Guide2003/NPRI_Guide_2003.pdf).

7.1 Calculation of Methane Emissions

Methane and carbon dioxide are the primary GHG emitted from a gas processing facility. Methane emissions at a gas processing plant are primarily due to fugitive emissions from leaks and/or venting of methane to the atmosphere.

In calculating GHG emissions, two methods are suggested. The **short-form method** is a simplified approach based on plant throughput, energy used at the site, volume of flared gas and amount of CO_2 vented. With this method, fugitive emissions of methane are estimated based on the plant production multiplied by a standard emissions factor. The CAPP guide suggests that the short-form calculation may result in overestimation of actual emissions (CAPP Guide 2004-008). The fugitive emission estimation includes losses from pipe fittings, gas operated field instrumentation and solution gas venting.

The **detailed emissions calculation method** is considered more accurate as emissions factors used are specific to the equipment type installed at the plant. For the calculation of fugitive emissions of methane with this method, the following is generally required:

- total number of valves and fittings in gas service (separated into sweet and sour service)
- total number of flanges/connectors in gas service (separated into sweet and sour service)

- total number and types of gas compressors
- pressure relief valves and other equipment venting to atmosphere
- gas processing data (e.g. gas dehydrators)
- inlet raw gas composition
- sales gas total volume

Once this data is collected, standard emissions factors for the different types of equipment are used to calculate total fugitive emissions of methane from the plant.

7.2 Calculation of VOC Emissions

Similar to calculation of methane emissions, two methods are suggested for estimating VOCs emissions. The **Level 1 method** of estimating fugitive and vented emissions of VOCs is a simplified approach based on plant throughput, with the CAPP Guide recommended factor of 0.093 kg of VOCs per 10^3 m^3 of sales gas. Emissions from tanks are estimated based on material loaded with recommended factors of 1.75 kg/m^3 of condensate loaded and 0.213 kg/m^3 of frac oil loaded. The **Level 2 method** is based on equipment installed and emissions factors for each piece of equipment to determine the total hydrocarbon losses from fugitives and venting. VOC emissions are then estimated by multiplying total hydrocarbon losses from fugitives by the fraction of C3 to C7 fraction in the gas plus total hydrocarbon losses from liquid by the fraction of C3 to C12 fraction in the liquids. Calculations of fugitive emissions of VOC's using the estimation methods make some broad assumptions that may reduce the accuracy of the estimate. Assumptions include:

- emission factors are the same whether equipment is new or old
- ratio of methane to VOC in the leak is the same as the ratio of methane to VOC in the raw gas even though some areas of the plant may handle gas with higher or lower concentration of VOCs
- emission factor is the same for all sizes and types of valves over 3/4 inch
- equipment is operated as per design
- emission factor is the same whether or not equipment is regularly maintained.

The **Level 3 method** of calculating VOC emissions for NPRI is based on actual site emissions data collected through sampling and or performance testing.

The DIAL method can directly measure emissions of methane and other hydrocarbons from a whole facility. The availability of direct DIAL measurements of methane and C_{2+} emissions from gas plants in Alberta was an ideal opportunity to compare the DIAL measurement and the CAPP estimation methods. The following discusses this comparison for the sweet and the sour gas plant surveyed during 2004.

7.3 Comparison of Measured and Calculated Emissions for the Sweet Gas Plant E

The operator of the Sweet Gas Plant E had recently calculated the plant's emissions of GHG and VOCs. Fugitive emissions of methane and VOC's were estimated based on installed equipment, standard emission factors for the type of equipment and the processed gas flow rate and composition as discussed in Section 7.1 and 7.2.

Table 18 and Table 19 compare the calculated estimates and the DIAL measured data for the sweet gas plant emissions of methane and VOC's, respectively. To convert the DIAL hourly data to yearly data, a factor of 8,760 hr/y of operation was used. Ethane is not considered a VOC but it was a component of the C_{2+} measured by the DIAL. Thus the DIAL measured C_{2+} emissions were multiplied by 0.36, the ratio of C_{3+} to C_{2+} based on the fugitive gas analysis given in Table 2. The short form and detailed estimate of fugitive methane emissions and the Level 2 estimate of fugitive VOCs were obtained from the plant operator. The Level 1 estimate of fugitive VOCs was calculated using the CAPP method.

The short form estimate of methane emissions of 3,015 t/y was 2.4 times the DIAL measured methane emission of 1,264 t/y. The emissions of methane measured using the DIAL method were 6.7 times the CAPP detailed emission calculation of 188 t/y. The DIAL measurements indicated that the fugitive emission of methane was by far the dominant source of methane emissions from the plant.

The plant experienced two operation issues during the time of the DIAL survey that may have resulted in higher than normal hydrocarbon emissions. Repairs on a produced water tank required a temporary bypass of produced water with possible flashing of vapours to atmosphere. In addition, a level control valve for liquids to a storage tank had failed and may have resulted in an increased amount of light ends going to the storage tank. Either of these problems would have led to higher than normal emissions of methane and other hydrocarbons.

Table 18: Comparison of Estimated Methane Emissions to DIAL Measurements at the Sweet Gas Plant E

Item	CAPP Short Form (t/y)	CAPP Detailed Estimate (t/y)	DIAL Measurement 2004 (t/y)
tanks	0.3	0	19.3[1]
flare		17.4	79.7
combustion sources		93.2	
plant fugitives	3,015	77.4	1,165
Total	**3,015**	**188**	**1,264**

[1] after installation of cooler on condensate line to tank

As shown in Table 19, the DIAL measured emissions of VOCs of 129 t/y were 1.5 times the Level 1 estimates of 84.9 t/y and 8.6 times the Level 2 estimate of 14.9 t/y. The DIAL measurements indicated that the process plant was the largest source of VOCs emissions at the Sweet Gas Plant E site.

Table 19: Comparison of Estimated VOC Emissions to DIAL Measurement at the Sweet Gas Plant E

Item	CAPP Level 1 (t/y)	CAPP Level 2 (t/y)	DIAL Measurement 2004[1] (t/y)
tanks		4.91	11.0[2]
flare		0.72	8.5
combustion sources		4.93	
plant fugitives + glycol dehy		2.69	107
other		1.63	2.6
Total	**84.9**	**14.9**	**129**

[1] DIAL measurement of C_{2+} adjusted to remove ethane component
[2] after installation of cooler on condensate line to tank

NPRI also requires the reporting of benzene emissions above a certain threshold. Table 20 compares the Level 2 estimate of benzene emissions for the Sweet Gas Plant with the DIAL measurement of benzene. The DIAL measurement was 15% higher than the estimate. The estimation method indicated that the tanks were the largest source of benzene emissions as opposed to the DIAL measurement indicating the process plant as the largest source. Any efforts to reduce leaks in the process plant area should also reduce benzene emissions.

Table 20: Comparison of Estimated Benzene to DIAL Measurement at the Sweet Gas Plant E

Item	CAPP Level 2 Benzene (t/y)	DIAL Measurement 2004 (t/y)
tanks	0.27	0[1]
plant fugitives + glycol dehy	0.10	0.52
other	0.08	
Total	**0.45**	**0.52**

[1] after installation of cooler on condensate line to tank

7.4 Comparison for the Sour Gas Plant C

The operator of the Sour Gas Plant C had recently calculated the plant emissions of GHG and CAC based on the CAPP Guides. Fugitive emissions of methane and VOCs were estimated based on installed equipment, standard emission factors for the type of equipment and the processed gas flow rate and composition as discussed in Section 7.1 and 7.2.

Table 21 and Table 22 compare the calculated estimates and the DIAL measured data for methane and VOCs, respectively. The plant estimates of VOCs and the DIAL measurements both included ethane as a component. To convert the DIAL data reported in kg/h to t/yr, a factor of 8,760 hr/y was used.

The CAPP short form method gave a methane emission estimate of 4,665 t/y that was 4.6 times the 2004 DIAL measured methane emissions of 1020 t/y. The emissions of methane measured using the DIAL method were 4.1 times the CAPP detailed estimate of 251 t/y.

The CAPP Level 1 estimate of VOC emission was 340 tonnes/y of VOCs or about 0.62 times the 2004 DIAL measured VOC emission of 545 t/y. The 2004 DIAL measured emissions of VOCs were 5.8 times the CAPP Level 2 estimate of VOC emissions.

The DIAL measurements in 2004 attributed over 36% of the methane emissions and 57% of the VOC to the condensate tanks. This contrasts with the CAPP estimation method prediction that the flare and tanks would contribute less than 2% of overall emissions of methane or VOC's.

Table 21: Comparison of Estimated Methane Emissions to DIAL Measurement at the Sour Gas Plant C

Item	CAPP Short Form (t/y)	CAPP Detailed Estimate 2003 (t/y)	DIAL Measurement 2003 (t/y)	DIAL Measurement 2004 (t/y)
tanks		2.9	140	373
flare		2.4	141	141[1]
combustion sources		5.5		
plant fugitives		240	1000[2]	503[2]
Total	**4665**	**251**	**1280**	**1020**

[1] data from 2003, flare emissions were not measured in 2004

[2] plant fugitives does not include emissions from water treatment ponds

Table 22: Comparison of Estimated VOC Emissions to DIAL Measurement at the Sour Gas Plant C (ethane included)

Item	CAPP Level 1 Estimate (t/y)	CAPP Level 2 Estimate 2003 (t/y)	DIAL Measurement 2003 (t/y)	DIAL Measurement 2004 (t/y)
tanks		0.69	216	309
flare		1.26	42	42[1]
combustion sources		8.38		
plant fugitives		84.03	2689	193
Total	**340**	**94.36**	**2952**	**545**

[1] data from 2003, flare emissions were not measured in 2004

NPRI also requires the reporting of benzene emissions above a certain threshold. Table 23 compares the Level 2 estimate of benzene emissions for the Sour Gas Plant with the DIAL measurement of benzene. The DIAL measurement was 5.4 times higher than the estimated benzene. The DIAL measurement showed the process plant as the largest source of benzene emissions. The tanks resulted in about 12% of the total benzene emissions. Any further efforts to reduce leaks in the process plant area should reduce benzene emissions.

Table 23: Comparison of Estimated Benzene to DIAL Measurement at the Sweet Gas Plant E

Item	CAPP Level 2 Benzene (t/y)	DIAL Measurement 2004 (t/y)
tanks		0.26
process area		1.75
ponds		0.09
Total	**0.392**	**2.10**

8. Review of Optical Methods for Measuring Emissions of Particulates

The quantification of atmospheric emissions is becoming more important as greater focus is being applied to air quality. The human respiratory system can be adversely affected by particulate emissions, especially particles smaller than 2.5 micrometers in diameter (PM 2.5) (Bell, 1999). Studies have suggested links between fine particulates and asthma, bronchitis, and premature death (US EPA, 1). It is in the interest of atmospheric regulatory agencies to be able to accurately quantify particulate emissions to determine significant sources.

Particulate matter is included as a CAC and some facilities will be required to report to the NPRI their total particulate matter (PM), particulate matter smaller than 10 microns (PM10) and particulate matter smaller than 2.5 microns (PM2.5). Particulate matter is defined as dispersed airborne solid and liquid particles larger than single molecules (about 0.0002 microns), other than road dust. Currently, calculation methods are used to estimate PM emissions from a facility. However emission factors based on installed equipment and processes can be inaccurate and often do not account for leaks.

This task reviewed the scientific and engineering literature to identify new methods that might be used to quantify PM emissions from a facility, similar to the way that DIAL can be used to measure gas emissions. The ideal method would be able to measure both the mass emissions of particulates, discriminate between pollutants and water droplets and segregate emissions by PM2.5, PM10 and total PM. Optical methods offer the most potential for remotely measuring particulates and could in future become the standard means for identifying and quantifying particulate emissions.

The objectives of this review were to determine current passive optical measurement technologies that might be capable of remotely identifying, sizing, and quantifying mass emissions of particulates and assess their current state of development.

8.1 Particulate Nomenclature, Types and Sources

Atmospheric particulate matter is airborne suspended particles, sometimes called aerosols. “Fine” particulate is smaller than 2.5μm in diameter, also known as PM2.5. “Coarse fraction” particles are greater than 2.5μm but smaller than 10μm in diameter. PM10 refers to particulate smaller than 10μm. Particulate can be solid or liquid and can have different compositions. The composition can have a determining effect on its size, as shown in Figure 10.

For this discussion, particulate type can be grouped into six categories. Table 24 presents the common compositions of each category as well as their natural and anthropogenic sources for PM2.5. Combustion is the major anthropogenic contributor of PM2.5, while forest fires are the main natural source.

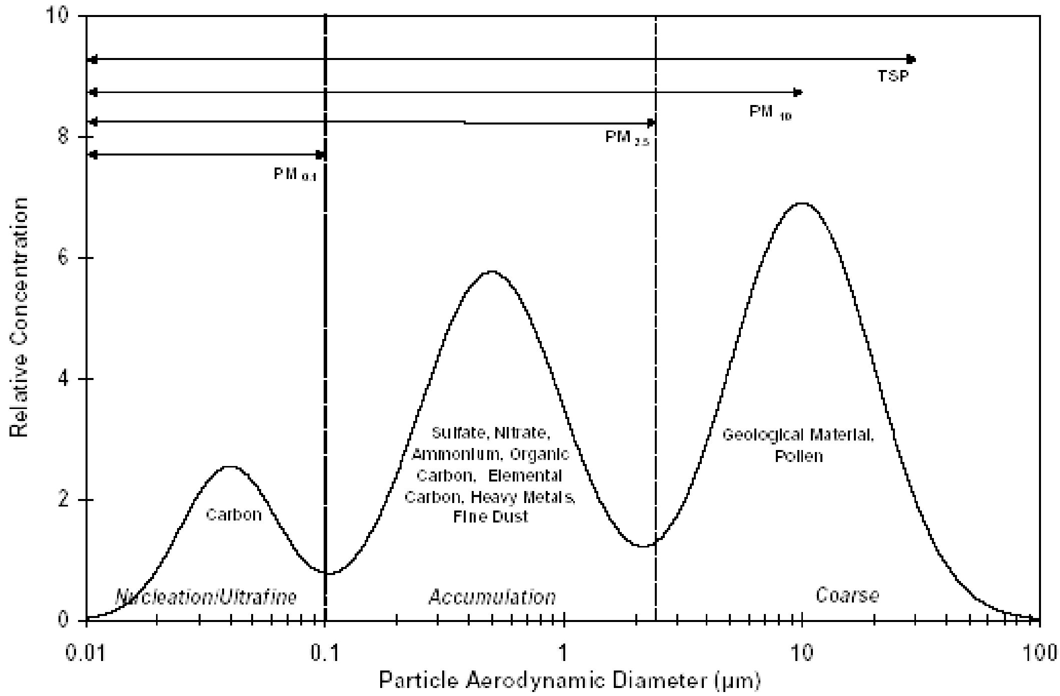

Figure 10: Size Distribution of Particulate Species (source US EPA)

Table 24: Sources and Types of Airborne Particulate – PM2.5

Particulate	Common Compositions	Sources		Typical Size Range (micron)
		Natural	Anthropogenic	
Sulphate	$(NH_4)_2SO_4$ NH_4HSO_4 H_2SO_4	Sea spray, oxidation of SO_2 and H_2S	Fossil fuel combustion	0.1 – 2.5
Nitrate	NH_4NO_3 HNO_3	Oxidation of NO_x produced by lightning and forest fires	Oxidation of NO_x produced by fossil fuel combustion and motor vehicle exhaust	0.1 – 2.5
Organic Carbon	C+ (all organic compounds)	Wildfires, oxidation of hydrocarbons emitted by wildfires and vegetation	Open burning, motor vehicle exhaust, oxidation of emitted hydrocarbons, incineration	0.1 – 2.5
Elemental Carbon	C (soot)	Wildfires	Motor vehicle exhaust (especially diesel), wood burning, open flares	0.01 – 2.5
Crustal Material	Fine soil, dust	Wind erosion	Agriculture, construction, unpaved roads	0.1 - 100
Metals	Mercury, lead	Volcanoes	Fossil fuel combustion, smelting operations	0.1 – 2.5

Source: "Visibility in Mandatory Federal Class I Areas (1994-1998)" US EPA, EPA-452/R-01-008, November 2001

8.2 Current Methods for Measurement of PM10 and PM2.5 Concentration

Currently, various techniques are employed to measure concentration of particulates in the atmosphere. Most techniques involve point sampling of air into a receptacle that is used to analyze the sample to obtain measurements. They can be categorized into continuous or non-continuous methods. The most common techniques for measuring particulate concentrations are point source monitors and in-line monitors.

A fundamental weakness of point sampling methods is that numerous monitors are required to collect information on the distribution of particulate concentration around a facility and that typically only ground level concentrations are measured. Dispersion models are required to back-calculate the mass emissions of particulate and the likely source of the particulate from the discrete point sample information and wind information. This can introduce many inaccuracies into the mass emissions estimation. In addition, some method is required to determine the relative contribution of the facility particulate sources versus upwind sources of particulates.

8.2.1 Batch Particulate Measurement Technologies

Batch processes for measuring particulate matter are common. Batch point source monitors usually consist of a pump (or air sampler) that provides a constant flow of sampled air into a cyclone that directs air samples onto a filter cassette. The filter cassette is periodically removed from the monitor housing and weighed to determine the mass of collected particulate matter. Once the mass of particulate and flow rate of sample air is known (usually 1-2 m^3/min), a time-weighted average of particulate concentration in the air can be determined. In many cases, the particulate is blown off the filter and analyzed to determine its chemical composition and particle size distribution, using techniques such as scanning electron microscopes, electron probe X-ray microanalysis, gas chromatography and neutron activation, to name a few (Sipin, 2003). The US EPA has installed a network of 1500 gravimetric monitors and 240 chemical speciation monitors nationwide to determine if air quality standards are being met. A photo showing particulate monitoring stations used by the EPA is shown in Figure 11.

Figure 11: Particulate Monitoring Stations Used by the US EPA

Source: US EPA website: http://www.epa.gov/pmresearch/pm_research_accomplishments/05_tools.html

Each monitor currently costs approximately US$7000 and the filters are removed for sampling at least twice a week (often daily). The results are not known until at least 47 hours after a 24-hour sample period commences, and errors up to 50 per cent have been reported (US EPA, 2). Due to the time constraints and capital and manpower costs of this monitoring network, continuous and/or remote measurements would be an attractive alternative.

8.2.2 Continuous Particulate Measurement Technologies

Most commercially available continuous monitors are in-line instruments for measuring particulate size and concentration in an enclosed pipe flow, and there is greater diversity of continuous measurement technologies than batch methods. A summary of the most common continuous particulate measurement technologies is presented in Table 25.

Table 25: Continuous Particulate Measurement Technologies

Technology	Instruments	Summary	Output
Mass and Mass Equivalent Measurement	• Tapered Element Oscillating Microbalance • Beta Attenuation Monitor • Piezoelectric Microbalance • Pressure Drop Tape Sampler	• Use filters, microbalances, optical components, beta rays • Low detection limits (down to 2μg/m^3 for one hour average)	• Correlates to concentration • Particle size distribution
Visible Light Scattering	• Nephelometer • Optical Particle Counter/Size Spectrometer • Aerodynamic Particle Sizer • Condensation Nuclei Counter	• All are in situ measurements • Measure light scattering using visible light, lasers in infrared to ultraviolet wavelengths • Cannot measure in wet stacks	• Concentration • Particle size distribution
Visible Light Absorption	• Particle Soot/Absorption Photometer • Aethalometer • Opacity Meter	• Measure light absorbed by carbon black • Use LEDs and filters with analyzed deposition areas.	• Correlates to concentration • No particle size information

Sources: US EPA 3, UK DEFRA website

A major drawback of continuous measurement methods is that the particulate mass is not actually measured; it is calculated from secondary properties of the particulate. These methods must also be calibrated using a manual reference method. Continuous methods require significant manpower as well, and the accuracy of the measurements can be questionable under non-ideal conditions. None of these methods can currently be used to measure PM2.5 or PM10 mass flux in a particulate plume in the atmosphere.

8.2.3 Particle Size Distribution Methods

Most technologies that are able to separate particulate matter into different particle sizes utilize inertial impactors or dichotomous samplers. Inertial impactors draw the sample through a series of nozzles that are progressively smaller the farther the sample travels. Generally, the larger the particle, the more inertia it has, so it is collected on a filter or impaction surface before a smaller particle. Dichotomous samplers separate particles by accelerating a sample through a nozzle into a 90-degree bend. The larger particles continue through the bend, while the smaller particles travel around the bend (US EPA, 2). These technologies are limited in that:

- Particles are sized into few particle size groups
- The aerodynamic properties (i.e. shape) and density of the particle can influence its sizing

Another technique available is the Differential Mobility Analyzer. It samples aerosols in an air stream and particles are separated based on their electrical mobility. Voltages are applied across the sample stream that can be used to separate the aerosols into narrow particle size ranges (NIST website). This method works well for spherical aerosols, but is limited for particulate matter, which can be of differing irregular shapes, thus making aerodynamics a greater factor than electrical mobility.

8.3 Measuring Particulates with Light Detection and Ranging (Lidar)

Lidar is a remote optical method based on the interaction of light with suspended particulate in the atmosphere. A laser (the emitter) is used to send a pulse of light at a prescribed wavelength into the atmosphere and a telescope (the receiver) measures the intensity of the light that is backscattered from particles or aerosols in the air. Analysis of the backscattered light can determine location and concentration of the particulate. Location is calculated using the speed of light and the transit time of the signal. Concentration of particulates is determined by the backscatter intensity and how this intensity changes with distance from the laser source. The Lidar method is very rapid, with kilometer by kilometer areas scanned in the order of a few minutes. The method can potentially measure three-dimensional profiles of particulate plumes and would be a useful tool for locating sources particulate emissions. A basic diagram of LIDAR operation is presented in Figure 12.

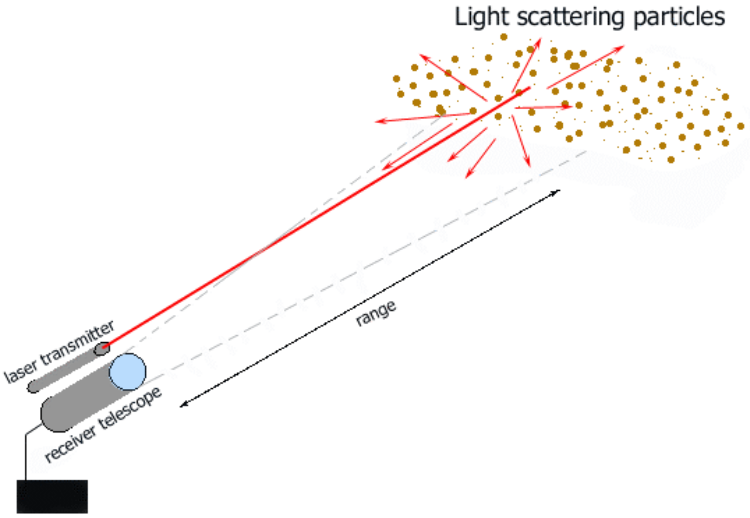

Figure 12: Diagram of LIDAR Operation

Source: http://www.rap.ucar.edu/staff/tardif/CUprojects/ATOC5235/lidar_remote_sensing.htm

The Lidar has been demonstrated to be a useful tool to collect qualitative information on particulate emissions and particulate plumes. However, unlike the DIAL method, the Lidar method does not have a reference wavelength capability. As a result, the interpretation of the return signal is much more complicated and deriving quantitative particle size and concentration information is problematic. More tightly focused laser beams are required to achieve the signal return strengths needed for a sufficient signal to noise ratio. As a result, several of the systems that have been used to measure particulate in the atmosphere are not eye-safe, and thus would not be practical for industrial application. Some of the research groups have developed eye-safe Lidar systems for measuring particulate plumes (e.g. www.atd.ucar.edu/lidar/index.html). A review of the organizations currently involved in LIDAR development for particulate measurement is given in Appendix C.

At least two groups in Canada have active research programs developing Lidar as a particulate emissions tool. Spectral Applied Research (www.spectral.ca) has a mobile scanning Lidar system that can provide three dimensional maps of suspended particulate matter over a 10 km range in all directions. Their system has been used to study particulate emissions from highway traffic. Environment Canada in the Air Quality Processes Research Division also has a mobile scanning Lidar that has been used to study particulates in the atmosphere (www.smc-msc.ec.gc.ca/arqp/care_e.cfm#lidar). Figure 13 is an example of particulate data in a plume from an industrial stack collected with the Environment Canada mobile Lidar unit.

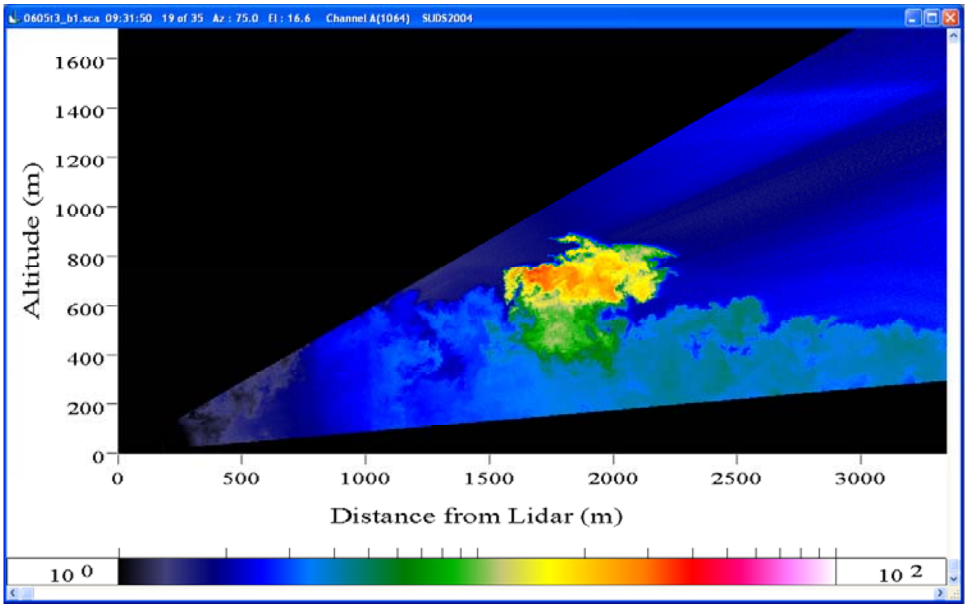

Figure 13: Lidar Cross Section through the Plume from a Stack showing the Particulate Concentration (from Kevin Strawbridge, Environment Canada)

Lidar can rapidly identify particulate plumes and locate major sources of particulates. However, to collect quantitative information on particle size distribution and particle mass emissions in a plume is not possible with current technology. Some of the obstacles that would have to be addressed include:

1. A Lidar that operates in several different wavelengths is required to collect particle size distribution information, along with a complex mathematical interpretation of the return signal.
2. Development of eye-safe Lidar systems.
3. Adequate understanding of and compensation for atmospheric temperature and humidity effects on return signal analysis.
4. Cannot currently distinguish between solid particles, aerosols and water droplets.
5. Mixture of spherical and non-spherical particles complicates return signal analysis.
6. Cannot distinguish between man-made and natural sources of particulates.

At this time, using the Lidar method to locate and track plumes combined with point sampling of particulate from the plume for concentration and size distribution data would be a powerful method to better understand particulate emissions from industrial sites. The Lidar method could also rapidly measure qualitatively sources of particulates upwind of the industrial site.

8.4 Satellite Technology

Satellites have been used for many years to detect aerosols in the atmosphere, such as weather satellites measuring cloud height and thickness. There have been recent developments in satellite technology aimed at measuring particulate matter for air quality forecasting. Current satellite systems include the Sea-viewing Wide Field-of-view Sensor (SeaWiFS), Total Ozone Mapping Spectrometer (TOMS), Moderate Resolution Imaging Spectroradiometer (MODIS), Advanced Very High Resolution Radiometer (AVHRR) and Geostationary Orbiting Environmental Satellites (GOES). Most satellites (except for the GOES satellites) orbit the earth so measurements taken for a given area can only be performed on the order of days. Most of these systems are only capable of mapping particulate plumes from large-scale events, such as wildfires, volcanoes and dust storms, at a resolution of the order of kilometres (SAIC, 2002). One example is an African dust storm imaged by SeaWiFS shown in Figure 14.

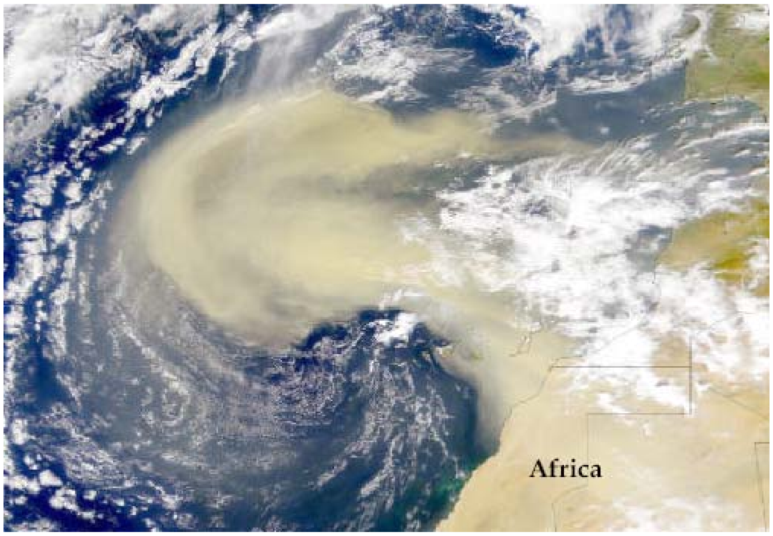

Figure 14: African Dust Storm Detected by SeaWiFS, February 26, 2000

Source: SAIC 2002

Development is continuing on the 8-wavelength, 1km resolution SeaWiFS, aimed at measuring smoke optical thickness, size distribution and particulate mass (Belsma, 2004). Studies have been conducted using MODIS technology in the United States. It has been used by the US EPA to detect high concentrations of airborne PM2.5, and the data is used to position ground-based point source monitors to determine the particulate concentration in the atmosphere. This data has been used to predict air quality in populated areas.

The low resolution of satellite data and the time required for a scan for most satellites prohibits their use as a particulate matter measurement tool for local sources such as industrial sites. However, combinatorial mapping and merging data from different satellite systems may provide results that are more accurate. Satellite technology is advancing rapidly and may be able to accurately measure particle size distribution and mass emissions of particulates in the future.

9. Conclusions

During this project, field tests were completed at one sweet and one sour natural gas processing plant in Alberta. Differential Absorption Lidar (DIAL) was used to quantify fugitive emissions of methane, C_{2+} hydrocarbons and benzene from these plants. A gas leak imaging camera was used as a method to rapidly locate leaks at both facilities. In addition, a literature review of remote particulate emissions measurement technology was completed.

Conclusions from this project include:

1. The DIAL method can be used to quickly measure the total emissions of methane and other hydrocarbons from a gas processing plant. Total fugitive hydrocarbon emissions from the sweet gas plant were 185 kg/h. Total fugitive hydrocarbon emissions from the sour gas plant were 159 kg/h.

2. Gas leak imaging cameras can be used to quickly and efficiently identify leaking equipment at natural gas processing plants. The camera gave a visual indication of the leak but could not quantify the leak rate.

3. Leak identification with the gas leak imaging camera followed by leak repair at the sour gas plant resulted in a reduction of methane emissions of 23% and reduction of C_{2+} emissions of 83% between DIAL surveys performed in 2003 and 2004. The reduced hydrocarbon losses had a value of about $800,000 per year.

4. The current CAPP methods for estimating fugitive emissions of methane and volatile organic carbons and the DIAL measurements for the two gas plants surveyed did not match. The CAPP short form method overestimated methane emissions by 3 to 4 times while the CAPP detailed estimate method prediction was less than 25% of DIAL measured methane emissions. Both the CAPP Level 1 and Level 2 estimation of volatile organic carbon were significantly less than DIAL measurements.

5. At present, there are no remote optical technologies that can measure particulate emissions to satisfy NPRI reporting requirements for mass emissions of PM2.5 or PM10 particulates.

6. LIDAR systems can locate and measure relative concentrations of particulate in plumes originating from industrial facilities. A combination of LIDAR to locate plumes and conventional sampling from the plume to measure particle size distribution and concentration may improve the quality of particulate emission data.

10. Recommendations

Recommendations based on the results of this study include:

1. Gas leak imaging cameras may be used by the upstream oil and gas industry to improve leak detection and repair. Based on DIAL quantification of the value of fugitive hydrocarbon losses, the savings to the industry of improved leak repair would be significant.

2. The DIAL method may be used to quantify the hydrocarbon losses due to fugitive emissions from significant upstream oil and gas facilities, such as natural gas processing plants. Direct measurement of fugitive emissions would document both current emissions and the future reductions in emissions resulting from improved leak identification and repair.

3. Process and emergency flares operating on pilot were a significant source of hydrocarbon emissions at the plants visited. A program to reduce these emissions by improving the combustion efficiency of flares operated on pilot and/or minimizing pilot and purge gas flow rate is recommended.

4. Future advancements in LIDAR technology for monitoring particulate emissions should be monitored. These developments could lead to remote measurements of particle size distribution and mass emissions using LIDAR in the future.

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Appendix A DIAL Background

Spectrasyne Ltd., UK

History

Light/laser based technology systems for the remote monitoring of gaseous species in the atmosphere has been under development for the past decade and a half. The flagship of these developments is a Differential Absorption LIDAR or DIAL system. DIAL is a development of LIDAR, a light based range-finding system similar to RADAR. If a laser is used as the LIDAR light source, the collimated, coherent light emitted can be used to define the range of specific small objects with great precision. A tuneable laser source can give LIDAR an additional spectroscopic capability as the source laser can alternately be tuned onto then off an absorption feature in the known 'spectral fingerprint' of a specific gas. The concentration of gas in the path length between the laser and the detector is determined by comparing the energies in the two return signals.

Until 1986 the DIAL development programme had concentrated on the UV and visible spectral regions where gases such as sulphur dioxide, nitric oxide, nitrogen dioxide and ozone have specific absorption features. Many other gases including the majority of the hydrocarbons have strong absorption features in the infrared region. The significance and potential of a system that could operate in the infrared was realised by all concerned and a further research programme was established to enable the technology development for DIAL hydrocarbon species monitoring. This programme involved a number of British companies, a laser manufacturer and the creation of a unique infrared source assembly, which with the customised laser system, provided tuneable infrared laser radiation. During the prototype testing phase, and subsequently, a more commercially orientated DIAL system was designed and constructed. This system was built on the experience of the prototype and incorporated many recent technological improvements in optics, laser equipment, fast data transfer and communications hardware. Two parallel laser systems were installed to enable simultaneous measurement in the UV, visible, and IR spectral regions. The acquisition software was improved, and fast data handling programs were designed to speed up the processing of the vast amount of data generated by the system. This data processing development is continuing to provide, ultimately, a real-time read-out capability.

The construction of the new, commercial DIAL was completed, installed in the 12 metre mobile Environmental Surveying System (ESS, Figure right), in September 1990, 6 months ahead of the original schedule. The ESS (which was the basis of a management buyout by Spectrasyne from BP Research in 1992) also houses a unique in-stack, emissions monitoring system, which along with its current Spectrasyne operating team has been engaged by a number of national authorities to make emission measurements from various refinery sources. Throughout the 1980s and early 90s, at various critical development stages, validation and correlation work was carried out with the DIAL. This work ranged from making measurements through gas cells, which had been filled with gravimetric standard gas mixtures to correlation exercises between DIAL concentration measurements and stack gas analyses collected using conventional gas analysers and gas chromatography equipment. Concentration correlations at ambient/ environmental levels against accredited thermal sorption tube data were also undertaken. In all cases the DIAL measured concentrations were within 10-15% of the standard or the data generated by the more conventional technologies. However, since 1988, DIAL concentration data has been used with wind speed and direction to produce mass emission fluxes (kg/h) and some further validation work on the production of mass emission fluxes was considered necessary. A number of mass emission correlation exercises between the SPECTRASYNE DIAL and other measurement techniques have been carried out during recent years. The other methods include SF6, calibrated releases of methane from a point source and marine tanker vent measurements. In all of these exercises the maximum divergence from the DIAL measurements recorded was 15%.

One of the most significant correlation exercises was carried out with personnel from the European oil industries association, CONCAWE. The correlation exercise was carried out during one complete loading schedule of a river barge loading motor spirit as this represented a discrete emission source. The CONCAWE team calculated the mass hydrocarbon emission levels throughout the loading from the tank vent measurements and knowledge of the loading rate and thus vapours displacement rate. The Spectrasyne DIAL measurements were made some distance downwind of the barge. The sequential measurement data derived from the two methods were integrated over the loading period to provide total mass emission figures for each measurement technique. The resultant correlation was within 12%.

DIAL Equipment

The Spectrasyne DIAL is based on two high energy (1.4J), 10Hz pulsed Nd:YAG pumped dye lasers. Tuneable ultraviolet and visible radiation is generated in one of the laser sets by selective use of frequency doubling and tripling crystals. The second laser set, which has an injection seeded Nd:YAG, is used to generate tuneable infrared radiation by means of the unique infrared source assembly. The DIAL is single ended and its output beam is directed by means of a mirror steering system which rotates in two planes. The backscattered light, which returns along the same path, is collected in a cassegrain-type receiving telescope and delivered to the appropriate detector through a multi-dichroic, beam splitting, collimating and focusing system. In order to collect, store, handle and process the DIAL signals a sophisticated, high speed data communication network has been developed in parallel with a unique PC based software package.

PCs are also used to perform a number of ancillary control functions and to store essential spectroscopic and other databases. The vehicle is also equipped with an extendible meteorological mast and a number of portable telemetric stations, which are used along the DIAL scan lines to measure wind speed and direction, temperature and humidity. These data are displayed in real time and digitally logged for subsequent use with DIAL concentration data to produce mass emission fluxes. A sophisticated 3D computational fluid dynamics (CFD) model can also be connected to the processing system and can be used to provide interpolation between measured wind speed data points for flux calculation and to assist in the definition of suitable measurement positions where the wind fields are complex.

Telephoto and wide-angle TV cameras are used on the steering system to facilitate beam pointing, the wide angle image is recorded on a time-lapse video recorder to be used if necessary to identify problems visually during subsequent data analysis.

Appendix B Canister Analysis Method

The canister sample system preparation and gas analysis was performed by the Environmental Monitoring Unit of the Alberta Research Council, Vegreville.

The sampling method used for the detailed identification of hydrocarbon and sulphur compounds consisted of drawing ambient air samples into evacuated silco steel lined canisters as specified in the EPA Compendium of Methods for the Determination of Toxic Organic Compounds in Ambient Air (Method TO-15). The canisters were equipped with fixed orifices to collect the air samples over a one-hour period. Initial results from the DIAL measurements were used to determine optimal positioning of the samplers. Sufficient air samples were collected to allow subsequent analyses for the light hydrocarbon gases, for volatile organic compounds and for sulphur containing compounds. The following is a description of these analyses.

C1 to C4 Section of the Analysis

Direct injection into a GC/FID system is used to analyse gas samples. Typically methane through butane components are reported from this system. No sample concentration is performed in this scan. The typical minimum detection limit for this group of compounds is 50 ppbv.

C5 through C12 are typically reported with the VOC section of the analysis as described below.

Reduced Sulphur Compound Section of the Analysis

Reduced sulphur compounds are analysed by GC/SCD (sulphur chemiluminescence detector). H_2S, COS, CS_2, sulphides, mercaptans, and thiophenes are routinely analysed. The calibration mixtures contain approximately 20 components and the minimum detection limits for these compounds is ~3 to 5 ppbv.

VOC Section of the Analysis

The VOC scan is equivalent to EPA method TO-15. A Tekmar Autocan system is used to concentrate the sample on a chemical trap. The trap is then back flushed and cryo focused prior to GC/MS full scan analysis.

Calibration of this analytical system is achieved with the commercially available ozone precursor and TO-14 calibration mixtures. These compounds (approximately 80) are treated as calibrated target compounds.

The minimum detection limit for these components is 0.5 ppbv or less.

Any other non-target components eluting in the chromatographic run are identified by their mass spectral data via a library search. The match quality data is reported. These tentatively identified compounds (tic) are quantified against an appropriate internal standard assuming a 1:1 response factor.

Appendix C

Organizations Involved in LIDAR Development

Note: Reference numbers in square brackets []

Table A1. Universities, Research and Technical Institution Involved in LIDAR Development

Universities, Research and Technical Institutions	Method Used	Summary of Activities
Centre for Atmospheric Research Experiments - Environment Canada [1]	LIDAR – types not specified	• Used ground-based LIDAR and aircraft to study atmospheric aerosol particles in smelter and power plant emissions • Involved in LIDAR In-Space Technology Experiment (LITE)
CO.RI.S.T.A. (Consortium for Research on Advanced Remote Sensing Systems), Naples, Italy [2]	Prototype LIDAR – Nd;YAG laser with 2 acquisition channels	• Developed lightwiegt, portable LIDAR unit • Able to measure atmospheric aerosol concentration from heights of 150m to 7km
Dalhousie University – Atmospheric-Optics Laboratory [3]	Various LIDARs	• Measure aerosols, cloud, water vapour and middle atmospheric temperatures and their effect on air quality. Working with various groups using LIDARS
Desert Research Institute (DRI) [4]	LORAX - Ultraviolet LIDAR & Transmissometer	• Measure particulate matter from the exhaust plumes of vehicles • Uses a main and retro unit – 3 lasers involved
Federal Aviation Administration (FAA) Volpe National Transportation Systems Center [5]	• OPAL • HRDL	• Used LIDAR to monitor aircraft plumes • OPAL (Ozone Profiling Atmospheric LIDAR) proved to be the more effective of the two systems in determining plume parameters • HRDL (High Resolution Solid State Doppler LIDAR) measured air movements to determine wind speed as a function of height, mixing height, and wind direction
Hampton University – Center for LIDAR and Atmospheric Sciences Students (CLASS) [6]	Portable backscatter LIDAR with OPO	• Joint venture with NASA & ITT • Designed 3D portable scanning aerosol LIDAR that is eye safe by using an Optical Parametric Oscillator (OPO, ITT fabricated the

		design)
Howard University and the Lawrence Livermore National Laboratory [7]	LIDAR – no system specified	- Patent application of a laser heterodyne amplifier - Developing a multi-wavelength laser probe to determine the range resolved size distribution of particulate matter in the atmosphere
NASA Langley Research Center [8]	- Aircraft-mounted UV LIDAR and DIAL	- Measure ozone and atmospheric aerosols
NOAA - Environmental Technology Laboratory [9]	- Airborne Aerosol LIDAR (ABAEL) - Depolarization and Backscatter Unattended LIDAR (DABUL) - High Resolution Solid State Doppler LIDAR (HRDL) - Mini-MOPA CO_2 LIDAR - Nd:YAG-based Ozone Profiling Atmospheric LIDAR (OPAL)	- Use several LIDAR units - Measure wind, turbulence, cloud and aerosol properties, water vapour, ozone and carbon dioxide. - Current and projected research is aimed at development of a new aerosol LIDAR for air quality studies from the NOAA P-3 - ABAEL detects aerosol from aircraft - Have a mobile LIDAR unit
Risø National Laboratory, Roskilde Denmark [10]	Riso Mini LIDAR –Mie Scatter Theory	- Quantify atmospheric aerosol concentrations - Compact mobile system using single laser Mie scatter theory with LIDAR - Cross-sectional scans of plumes
The Universities Facility for Atmospheric Measurement (UFAM) [11]	- Salford Doppler LIDAR - Mobile Ozone LIDAR	- Used for forecasting air quality by creating 3-D wind flow data - Developed a two-LIDAR method to profile mean particle size
University of California & Pennsylvania State University [12]	SESI scanning micro-pulse LIDAR	- Used LIDAR at two wavelengths to evaluate deposit rates of airborne particulate matter and mapped PM plumes - Measured particles near 1µm at wavelengths of 523nm and 1047nm
University of Wales, Aberystwyth [13]	Aerosol LIDAR	- Use combined Raman elastic-backscatter LIDAR to determine height profiles of aerosol extinction - Involved in EARLINET (European Aerosol Research LIDAR Network)
University of Western Ontario [14]	- Purple Crow LIDAR - Rayleigh LIDAR	- Measure air composition, density, pressure and temps - Measure water vapour and nitrogen in atmosphere using Raman

	- Raman LIDAR - Fluorescence LIDAR	Lidar and sodium resonance using Fluorescence Lidar
Utah State University Atmospheric LIDAR Observatory [15]	Rayleigh LIDAR	- Atmospheric model and temperature profiles

Table A2. Companies Involved in LIDAR Development

Companies	Methods Used	Summary of Activities
Caravan International Corporation [16]	M10 LIDAR	• **Can build specialized LIDAR units to measure airborne particulates and wind speed**
Coherent Technologies Inc. [17]	Differential Scattering LIDAR (DISC) Polarametric LIDAR Sensors	• Use LIDAR for wind and aerosol sensing. • Develop simulation codes applied to Doppler LIDAR systems
Hovemere Ltd. [18]	Mobile Doppler Wind LIDAR Rayleigh and Ozone LIDAR	• Measure wind speed and direction and aerosol concentrations • Current mobile LIDAR system only functional at night
ITT Industries, Advanced Engineering and Sciences [19]	LIDAR and DIAL	• Develop LIDAR and DIAL to detect chemical and biological weapons
Light Age Inc. [20]	PAL/PRO Lasers for LIDAR	• Manufacture alexandrite UV lasers for use in LIDAR
Optech [21]	LIDAR and DIAL	• Use DIAL to measure atmospheric ozone concentrations • Use LIDAR for remote 3-dimensional surface mapping
Sandia National Laboratories [22]	LIDAR	• Use UV LIDAR to detect biological weapons • Have two mobile units
Science & Engineering Services, Inc. (SESI) [23]	Micro pulsed LIDAR Dual wavelength (MPL) Portable Digital LIDAR (PDL)	• Produce mobile UV LIDAR to detect and characterize biological weapons • PDL is a modification of the MPL • Low-power lasers (microjoules) at high pulse rates (10 kHz)
Spectral Applied Research [24]	Mobile Scanning LIDAR	• Particulate measurement from roads and industrial sites

APPENDIX A References

[1] Centre for Atmospheric Research Experiments
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[2] CO.RI.S.T.A.
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[3] Dalhousie University – Atmospheric-Optics Laboratory
http://aolab.phys.dal.ca/
http://aolab.phys.dal.ca/lidar/#measurements
[4] Desert Research Institute
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[5] Federal Aviation Administration (FAA)
http://www.aee.faa.gov/emissions/EDMS/LIDAR.htm
[6] Hampton University Center for LIDAR and Atmospheric Sciences (CLASS)
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[7] Howard University and Lawrence Livermore National Laboratory
http://www.llnl.gov/urp/HBCU/LIDAR.html
http://www.physics1.howard.edu/Research.html
[8] NASA Langley Research Center
http://oea.larc.nasa.gov/PAIS/DIAL.html
[9] NOAA - Environmental Technology Laboratory
http://www.etl.noaa.gov/et2/
[10] Riso National Laboratory, Roskilde Denmark
http://www.risoe.dk/vea-atu/atm_disp/lidar.htm
http://www2.dmu.dk/RoskildeProject/Airprog.htm
[11] The Universities Facility for Atmospheric Measurement (UFAM)
http://www.env.leeds.ac.uk/ufam/instruments/enhancementdoppler.php
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http://www.epa.gov/ttn/chief/conference/ei12/fugdust/fitz.pdf
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