Under normal operation, waste gas volumes from blowdown or depressurization events are sent to the flare system. If the valves do not properly reseat after one of these events, gas will continuously leak through the valves. The Physical Acoustics Corporation VPAC™ model 5131 ultrasonic detectors were used to detect through- valve leakage into closed loop vent systems routed to flares.

Figure 3. Physical Acoustics VPAC

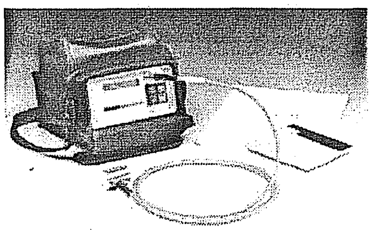
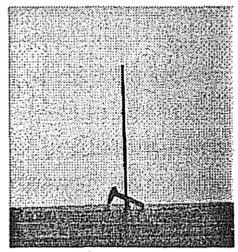


Figure 4. Residual Flaring



Ultrasonic measurements coupled with data on valve size, type, and differential pressure is used to derive mass rate loss estimates. The hand held instrument uses an acoustically coupled sensor that is held against the pipe upstream and downstream of the pressure relief valve and the relief valve body. At each location the sound level in decibels is detected. Leaking valves will have a larger signal than completely sealed valves. Appendix VII provides measurement details.

All identified leaking components were tagged (shown in Figure 4) and the specific leak source and date were noted on the tag. The emission rates for all leakers were determined using the procedures described in Sections 3.1.2 and 3.1.3. All leaker tags were left in place after the leak rate measurement to allow follow-up action by facility personnel. A total of 74,438 individual equipment components and numerous process vents, natural gas-fueled compressor and generator engines, process heaters, and flare/vent systems were surveyed. Sufficient process information was collected to determine total annual emissions from the compiled measurement results.

Additionally, specific emission-control opportunities were identified, and a preliminary cost-benefit analysis was performed to evaluate these opportunities. The analysis considers the estimated cost of repair and corresponding lifetime and the conserved gas value. Site personnel were solicited to provide input and assistance in identifying site-specific constraints and to help ensure that cost data were satisfactorily considered.

3.1.2 Leak Detection Methods

Conventional leak detection techniques, including bubble tests, handheld organic vapor analyzers and acoustic ultrasonic leak detection equipment, have traditionally been used to screen equipment components for leaks in accordance with Method 21 (U.S. EPA, 1997). These traditional leak detection techniques are thorough; however, they tend to be quite time consuming. More recently, optical passive infrared camera technologies have been developed in an effort to improve the leak detection process efficiency. Although the optical IR cameras have performed well during numerous field trials, there are not yet sufficient data to demonstrate that the technology should be adopted in lieu of traditional screening techniques.

Although separated and excluded from the EPA portion of the scope of work, all five facilities integrated a passive midwave infrared camera in the leak surveys. A secondary program objective was to compare the performance of the passive IR camera optical leak detection method with conventional leak detection methods. Although individual DI&M surveys did not yield sufficient data to provide a quantitative comparison of the conventional methods and the camera, sufficient information for a qualitative comparison of the methodologies and performance exists.

As optical infrared technology advancements rapidly progress the state of the science, it is likely that EPA will consider addressing remote leak detection methods within future revisions to the New Source Performance Standard (Under the settlement terms of a recent Consent Decree, deadlines are established for EPA to review and, if appropriate, revise the NSPS standards for Subparts J, VV and GGG, 40 CFR 60.100–109, 60.480–498, 60.590–593.) The findings discussed below highlight considerations for future method development.

Noteworthy findings from integrating optical remote sensing in DI&M include:

- The IR camera is capable of screening leaks approximately 3 times faster than conventional methods (for two people: typically 2,400 components/day for conventional versus 6,400 components/day for the optical);
- The IR camera is not currently capable of quantifying a leak and can only be used to identify leak sources. The camera is capable of identifying leaks (using a variety of lenses) that are inaccessible to conventional techniques that principally rely on direct access.
- The camera offers visual confirmation of leaking emissions sources and allows rapid source identification; however, ambient hydrocarbon concentrations may interfere with the camera ability to isolate a leak source. Engine magnetos caused interference and precluded leak screening on fuel gas headers, individual cylinder connections, and fuel injectors, significant leakage sources on older engines;
- Water vapor overlays the hydrocarbon absorption spectra and therefore steam plumes are visually comparable to hydrocarbon leaks and very difficult to differentiate;
- Rain and fog limit the IR camera utilization; and
- The IR camera cost is approximately $75,000 to $100,000 compared to $5,000 to $10,000 for conventional leak screening tools. Typical daily costs for a conventional leak screening team is $1,500 plus expenses while a typical daily charge for an experienced IR camera team is $3,000 plus expenses.

Leaks can occur through valves and pressure relief valves that have not seated properly after activation. This leak is not out of the process equipment and so cannot be seen with optical methods or by organic vapor analyzers. Instead an acoustic method has been developed that measures the noise generated by gas flowing through a small gap. The acoustic detector compares the sound before the valve, at the valve and downstream from the valve and compares the sound to a database of previously measured leaks. This instrument was used to measure leaks at pressure relief valves.

Due to the high volume of flared hydrocarbons at several sites and the large number of possible sources tied into the flare system (e.g., leaking pressure-relief devices, drains, and blowdown valves connected to the header), connecting the flare to a vapor recovery unit should be considered as a cost effective option for capturing the residual gas flow. Another option is to target the individual residual gas flow sources; however, these sources are often difficult to isolate, usually require a major plant shutdown to fix (i.e., resulting in significant indirect costs), and are likely to reoccur.

Figure 5. Soap Solution Screening on a Two Inch Leaking Threaded Connector

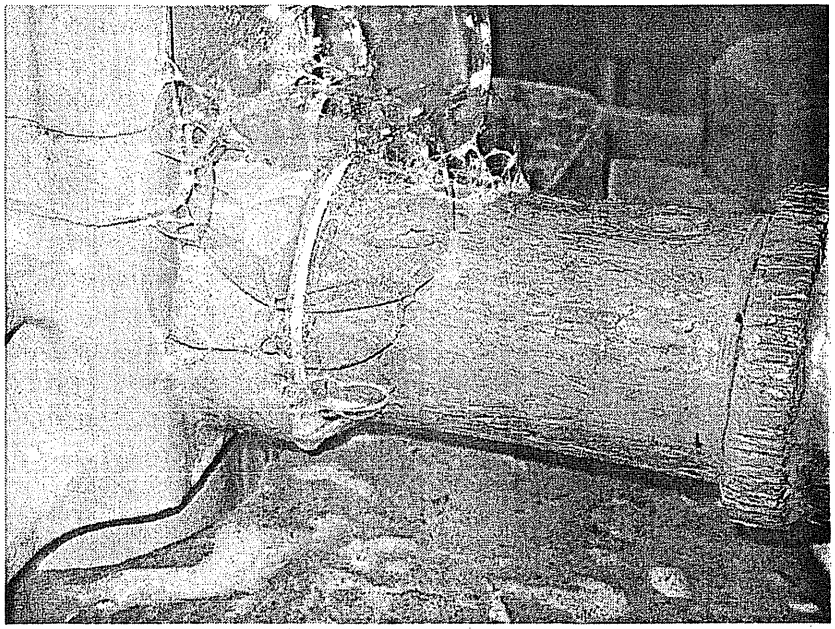


Figure 6. Tagged Leaking Components

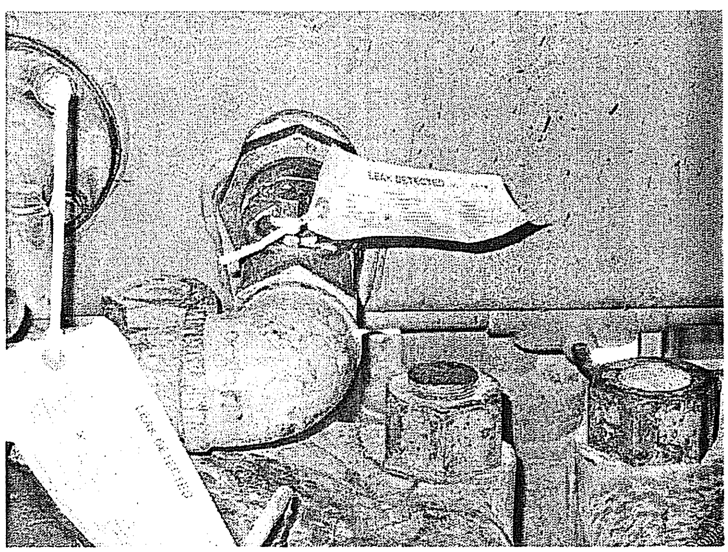
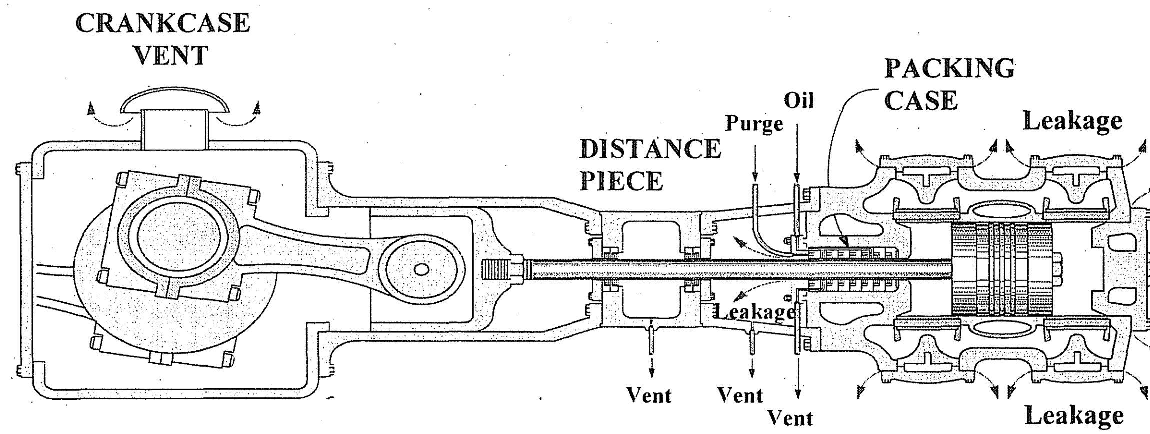
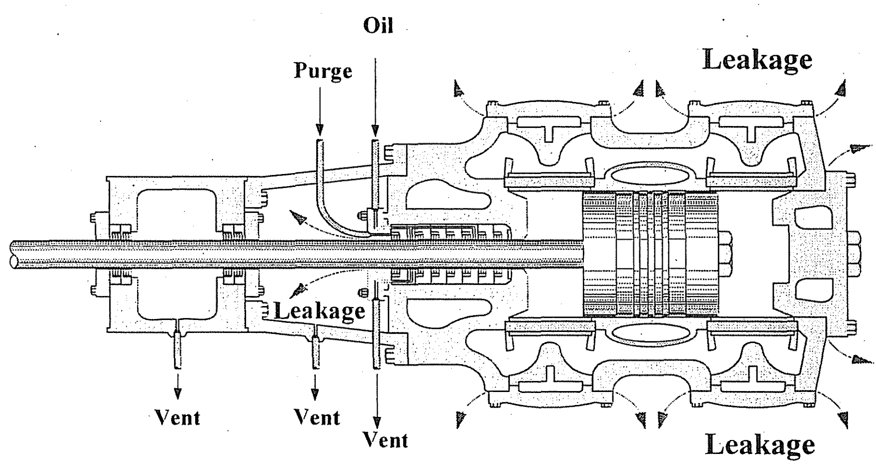


Figure 7. Cut-Away View Of A Natural Gas Compressor Showing The Potential Leak Points Including The Compressor Seals And Crankcase Vent.



RECIPROCATING COMPRESSOR
PACKING & VENT SYSTEM



EXPANDED VIEW OF THE
COMPRESSOR HEAD

The following basic information was recorded for each leaking component:

- Type
- Model or Style
- Service
- Size
- Process Unit
- Process Stream
- Pressure and Temperature

3.1.3 Leak-Rate Measurements

The HiFlow™ Sampler was the primary emission rates measurement method for leaking equipment components. The HiFlow™ Sampler was not used for components leaking at rates above the equipment upper limit (i.e., about 14 m^3/h for the current HiFlow™ design) and for most open-ended lines and vents. Either bagging or direct measurement techniques, as appropriate, were used in these cases (see Section 3.1.3). The same HiFlow™ prototype was used between Phase I and Phase II for consistency. The following provides a brief description of the HiFlow™ Sampler.

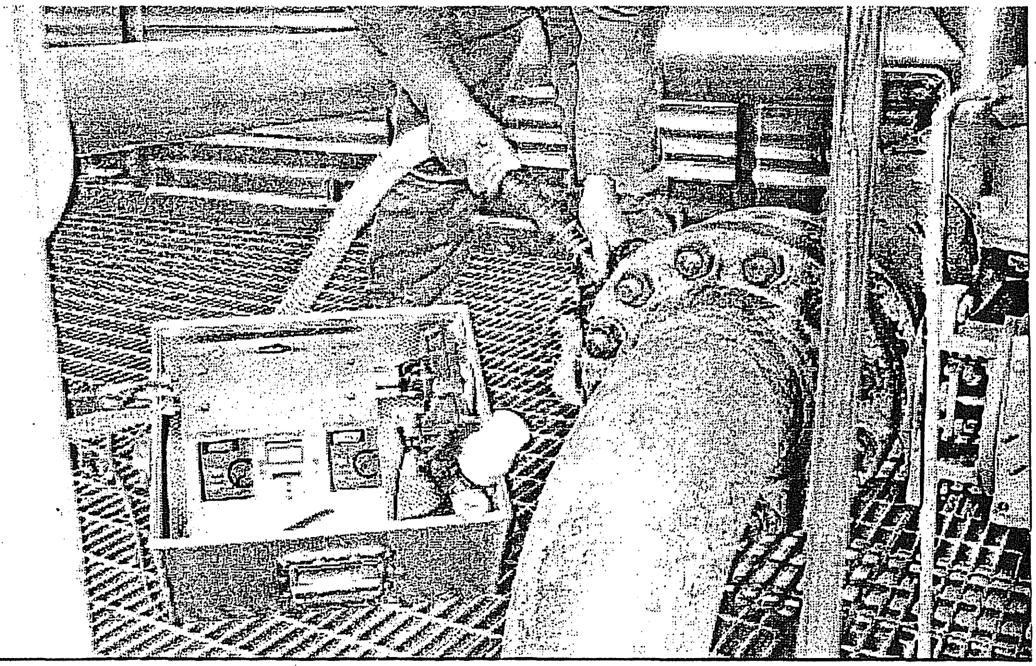
The HiFlow™ Sampler is an economic means of measuring individual leaking equipment components emission rates with sufficient accuracy for objective repair opportunities cost-benefit analyses. Bagging all leakers to differentiate between economic-to-repair and uneconomic-to-repair components is expensive and, therefore, is not normally done (typically, 10 to 30 leak-rate measurements per hour can be performed using the HiFlow™ Sampler compared to only 2 per hour using bagging techniques). Furthermore, compiling Method 21 (U.S. EPA, 1997) components screening data and then applying leak-rate correlations or stratified emission factors to determine leak rates does not provide sufficient accuracy for economic analysis. The correlation leak rate uncertainty for individual components is ± two orders of magnitude and the stratified emission factors are even less reliable. In comparison, the HiFlow™ Sampler and bagging measurements uncertainties are only about ±10 to 15%. Accordingly, the HiFlow™ Sampler (shown in Figure 6) provides a practicable means of making objective repair decisions. The reliability and use of the HiFlow™ Sampler has been demonstrated in a number of studies (Howard *et al.*, 1994; Lott *et al.*, 1995).

The HiFlow™ Sampler operating principle is simple – a variable-rate induced-flow sampling system provides total or near total leaking component emissions capture. Specially-designed attachments are used to encapsulate the leaking component and allow ambient air to flow over the component; the air-leaking gas mixture is drawn into the Sampler with a vacuum pump. A dual-element hydrocarbon detector (i.e., catalytic-oxidation/thermal-conductivity), inserted directly in the HiFlow™ sample line, measures hydrocarbon concentrations in the captured air-gas stream ranging from 0.01 to 100%. A background sample-collection line and hydrocarbon detector allow the sample readings to be corrected for ambient gas concentrations, which is particularly important in buildings and confined areas. A thermal anemometer, also inserted directly into the sample line, monitors the sampled air-hydrocarbon gas mixture flow rate. The HiFlow™ Sampler is intrinsically safe and is equipped with a grounding wire to dissipate static charge formed as air passes through the sample collection line and instrument.

The HiFlow™ Sampler battery-operated fan can generate a maximum sampling velocity of approximately 366 m/min (1200 ft/min), which corresponds to a maximum leak rate measurement capacity of 14 m^3/h (8.5 scfm). Increasing the sampling rate generally improves the leak capture efficiency up to the point of total capture. Increasing sampling rates beyond this point causes increased emissions dilution with ambient air. Excessive dilution may cause the pollutant concentration to either fall below the sample detector range or to decrease to background levels resulting in a zero reading. The sampling rate is adjusted manually using a backpressure valve mounted on the fan outlet. For large leaks, the backpressure valve is left open; while for small leaks, the airflow rate is reduced so that the hydrocarbon concentration is within the detector sensing range.

The HiFlow™ Sampler sample and background hydrocarbon detectors were calibrated with 100% methane and 2.5% methane-in-air to cover both ranges of the dual-element detector system. The detectors were zeroed using ambient air upwind of the facilities. The calibrations were done prior to HiFlow™ Sampler use at each site, and then periodically thereafter to ensure that no significant drift occurred. The HiFlow™ Sampler was also periodically calibrated by releasing known methane flows, determined using a bubblometer or diaphragm meter, into the sampler and comparing the leak rate measured by the HiFlow™ to the metered gas release rate. Three correction factors are applied to the raw data.

Figure 8. Prototype GRI HiFlow™ Sampler



3.1.4 Vents and Open-ended Lines Emissions Measurements

The emission rates from open-ended lines and vents were measured using an appropriate flow-through measurement device (i.e., a precision rotary meter, diaphragm flow meter, or rotameter, depending on the flow rate) if total flow capture was safe and practicable to achieve and the resulting backpressure on the vent system did not impact the gas flow. Otherwise, flows were determined by measuring the flow area and velocity profile across the vent line.

Where total flow capture was possible, the vent or open ended line pipe or tube was connected to the flow-through measurement device with PVC tubing. The tubing-pipe and tubing-flow meter connections were sealed with custom-fabricated slip-on sheaths made of neoprene or plastic sheeting. Each flow measurement was averaged over a 2 to 20 minute interval, depending on the flow volume and variability.

When measuring flows from vents, a distinction was made between continuous and intermittent vent systems. Emissions from intermittent vents during inactive periods (i.e. non-venting operation) were defined as leakage. Emissions from continuous vent systems and intermittent vent systems during active periods were defined as venting emissions. Vent and open-ended line leaks were detected by hydrocarbon sensor screening.

3.1.5 Residual Flaring Rates Determination

Flare line flows were determined using two methods:

- **Flare Line Velocity Profile and Flow Area Measurement** - Flow velocities were measured using a pitot tube, hot-wire anemometer or thermal dispersion anemometer. The traverse points were selected in accordance with U.S. EPA Methods 1 and 1A. Safe-to-access ports on the stack, the common line to the flare, or on each branch line connected to the flare system are required.

- **Flow Rate Calculated from Pressure Drops Measurements** - the pressure drop between the flare tip and a suitable upstream point on the flare line is measured and the gas flow required to produce that pressure drop is calculated. Several inches of water column pressure drop is needed for reasonable flow rate estimation. Low flow velocities in large diameter pipes may not produce measurable pressure drops despite significant volumetric flows.

The direct measurement method is more accurate and was used when sample ports were accessible. The gas stream hydrocarbon concentrations were either determined using a portable combustible-gas detector or from flare gas laboratory analyses (where available).

Continuous flare systems flows include purge gas flows and equipment fugitive leaks into the flare system. To distinguish between purge gas flows and leakage, the minimum required purge gas rate was calculated using the procedure presented by Stone *et al.* (1992). The difference between the total flare system gas flow rate and the calculated purge gas flow rate was assumed to be the leakage or potentially avoidable natural gas loss. The economics of conserving the gas losses can then be determined.

Primary sources of flaring and vented emissions include disposal of waste associated gas at oil production facilities, casing gas vents at heavy oil wells, gas operated devices, still column off-gas vents on glycol dehydrators, leakage into vent/flare header (5-10% of valves leak and 1-2% of these contribute 75%), excessive purge gas rates and inspection and maintenance activities including well testing, servicing, and pipeline tie-ins.

3.1.6 Natural Gas-Fueled Equipment Performance Testing

Natural gas-fueled engines, process heaters, and boilers were tested to identify avoidable inefficiencies causing excessive fuel consumption and emissions. The focus was on identifying situations where equipment required tuning, optimization, or repairs, or was mismatched with the current process demands causing operation outside the performance curve. The identification of opportunities to recoup waste heat from the units or to reduce energy requirements through process modifications was beyond the project scope.

The testing on each unit involved analyzing the flue gas, measuring the flue gas temperature, obtaining a fuel gas composition analysis, and where possible, measuring the flow rate of one or more of the following: fuel gas, combustion air, and flue gas. The flue gas analyses were conducted using an Enerac 2000E Portable Combustion Analyzer equipped with detectors for O_2, CO, CO_2, NO_x, and combustibles and thermocouples for measuring ambient and stack-gas temperatures. The flue gas was sampled through either an exhaust stack sampling port or at the stack top. Additionally, the unit, make, and model and site ambient conditions (i.e., temperature and barometric pressure) were recorded.

Typically, insufficient process data were available to reliably estimate the total useful process work done by each unit, or to determine overall unit performance. Consequently, a simplified approach was used where the following parameters were evaluated and their deviations from proper operating conditions were indicators of improvement opportunities:

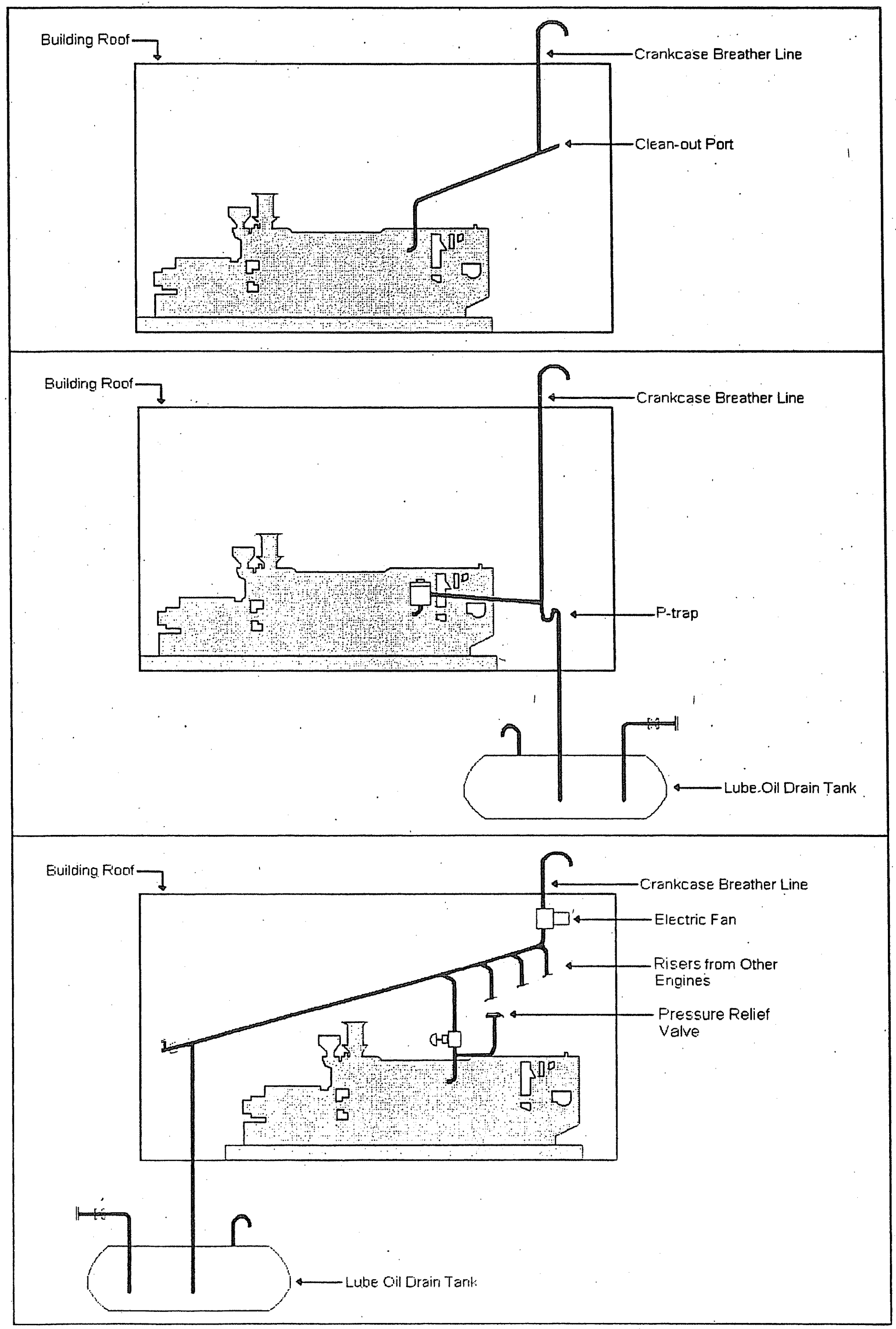
- flue gas residual heat content (i.e., stack losses);
- excess air setting; and
- flue gas concentrations of carbon monoxide and unburned hydrocarbons.

Additionally, reciprocating engines crankcase vents were checked for significant blow-by (i.e., leakage past the piston rings into the crankcase) because blow by reduces cylinder compression that causes inefficient operation and contributes to unburned and partially burned fuel emissions. As a first approximation of the resulting performance loss, measurements were performed to quantify the combustible gases emitted as crankcase vent blow-by. These results are presented as fugitive equipment leaks. On integral compressor units (i.e., compressor units where the engine and compressor share a common crankshaft and crankcase), crankcase vent emissions potentially include engine cylinders blow-by and compressor seals leakage which enters the crankcase through the distance piece. This is shown in Figure 5.

In many cases, the engine crankcase was vented inside a building or work area. This poses a potential health and safety risk. Figure 7 depicts various venting configurations recommended by the engine manufacturers.

Key sources of combustion emissions include, oversized engines, heaters and boilers, poor tuning (e.g., air/fuel ratio), leakage past pistons in engines, lack of waste heat utilization, and fouled burner tubes.

Figure 9. Typical Stationary Compressor Engines Crankcase Vent Configurations Recommended by Manufacturers.



Where possible, equipment-specific emissions factors on either a kilogram-per-cubic-meter fuel basis (if the unit fuel consumption rate was known) or on a kilogram-per-day basis (if the flue gas flow rate was known) were generated for estimating CO, NO_x, CO_2 and combustibles emissions. A detailed calculations summary and a discussion of normal operating efficiencies and losses are provided in Appendix III.

3.1.7 Compression Equipment Analysis

This section outlines calculation methodology used in analyzing the compressor efficiencies and presents detailed results of the calculations. A reciprocating gas compression equipment analysis was conducted to identify avoidable compression inefficiencies caused by pulsation losses and internal gas leakage past the valves and piston rings. An acceptable energy loss from compression inefficiencies is 5% of the ideal energy requirement and excessive losses are generally avoidable (Hanlon, 2001). Another avoidable inefficiency associated with gas compression is excessive pressure drop through interstage coolers. Typically, interstage coolers have a design pressure drop of about 101 kPa, and excessive pressure drops may indicate cooler fouling.

The compression process is nearly adiabatic when no attempt is made to cool the gas internally as it is being compressed. If the process is assumed to be adiabatic and changes to the kinetic and potential energies of the gas are neglected, the work of compression varies with the change in enthalpy according to the following equation:

$$W = \dot{m}(h_d - h_s) \qquad \textbf{(D.1)}$$

Where:

- W is the compressor work
- $\dot{m}$ is the mass flow rate of gas
- h_s is the suction enthalpy
- h_d is the discharge enthalpy

The following property data was collected for each stage of compression:.

- $P_{s,m}$ – measured suction pressure
- $T_{s,m}$ – measured suction temperature
- $P_{d,m}$ – measured discharge pressure
- $T_{d,m}$ – measured discharge temperature

For a simple compressible system the state is specified by two independent intensive properties. Therefore, other properties of interest such as enthalpy and entropy follow from the temperature and pressure measurements and the actual work of compression can be calculated using Equation D.1.

For adiabatic compression the ideal process is isentropic. The suction state for the ideal process is still defined by the measured suction properties. Where as the ideal discharge state is defined is defined by the discharge entropy and measured discharge pressure. For an isentropic process entropy is conserved and the discharge entropy is determined from the suction state. The suction enthalpy follows from the state definition and the ideal compression work can be calculated using Equation D.1. This ideal compressor work is corrected to account for valve pressure drop based on the method presented in Figure 13-14 of Gas Processors Suppliers Association Engineering Data Book Volume 1. The corrected ideal state is then defined by the enthalpy calculated using equation D.1 and the measured discharge pressure. The corrected ideal discharge temperature follows from the state definition.

In practice the extent to which the corrected ideal compressor efficiency can be achieved is limited by physical constraints such as pulsation losses and valve slippage. For the purpose of this analysis an acceptable energy loss is taken as 5% of the corrected ideal energy requirements (Hanlon, 2001). The acceptable discharge state is then defined by the enthalpy calculated using Equation D.1 and the measure discharge pressure. The acceptable discharge temperature follows from the acceptable discharge state.

For situations where the actual compressor work is greater then the acceptable compressor work a potential savings is estimated. This estimate takes into account the efficiency of the compressor driver and the price of natural gas.

Key sources of compressor inefficiencies include, internal valve and cylinder leakage in reciprocating compressors, pulsation losses, excessive gas recirculation, non-optimal loading.

3.1.8 Storage Tanks Excess Emissions Evaluations

Storage tanks are a potentially significant emission sources due to evaporation losses, particularly where intentional product boiling or flashing occurs. Primary sources of storage tank emissions include:

- Flashing losses at production facilities;
- Unintentional gas carry-through to storage tanks;
- Leaking drain and dump valves;
- Malfunctioning level controllers;
- Inefficient upstream gas/liquid separation;
- Piping changes resulting in unstabilized product going to tanks;
- Malfunctioning vapor recovery systems;
- Faulty blanket gas regulators or pressure controllers; and
- Fouled vapor collection lines.

However, other less recognized, and often unnoticed; contributions to atmospheric emissions or vapor losses from storage tanks include the following:

- Process gas or volatile product leakage past drain or blowdown valves seats into the product header leading to the tanks;
- Inefficient upstream gas/liquid separation allowing some gas carry-through (by entrainment) to the tanks. This usually occurs where facility inlet liquid production (e.g., produced water) has increased significantly over time causing inlet separators to be undersized for current conditions;
- Piping modifications causing unintentional routing of high vapor pressure product to tanks not equipped with appropriate vapor controls;
- Storage tanks overheating or hot product rundown to tanks containing volatile material;
- Malfunctioning or improperly set blanket gas regulators and vapor control valves can cause excessive blanket gas use and, consequently, increased flows to a vent or control device (e.g., flare or vapor recovery compressor). The blanket gas is both a product vapors carrier and a potential pollutant itself (i.e., natural gas is usually used as the blanket medium for blanketed tanks at gas processing plants); and
- Leaking hatches and pressure-vacuum valves on tanks equipped with gas blanketing systems result in direct atmospheric emissions of product vapors and blanket gas.

The last two leaks are reported under flare systems and fugitive equipment leaks, respectively. The other leaks were determined by measuring venting rates (see Section 3.1.3) and comparing the observed emissions to calculated working losses for conditions at the time of testing.

3.1.9 Component Counts

Equipment component counts were prepared based on an initial review of the process and instrumentation drawings, followed by a site walk-though inspection of each process unit. The following component information was collected:

- type (e.g., connector, valve, control valve, pressure relief valve, pressure regulator, orifice meter, other flow meter, blowdown, open-ended line, etc.);
- style (e.g., threaded and flanged connection, coupling, ball valve, plug valve, globe valve, gate valve, butterfly valve, pump seal, compressor seal, regulator, sampling connection, etc.);
- nominal size;
- process temperature and pressure;
- service (i.e., natural gas, light hydrocarbon liquid); and
- application (i.e. process stream and unit).

3.1.10 Average Emission Factors Development

The average emission factor for each component type was determined by dividing the aggregate component emissions by the number of components. Total emissions are the sum of emissions from both leaking and non-leaking components. Leaking components (i.e., those with screening values of ≥ 10,000 ppm) emission rates were quantified using the methods described in Section 3.1.2. Non-leaking components were assigned the average non-leaking emission rates presented in the Protocol for Equipment Leak Emission Estimates (U.S. EPA, 1995).

3.1.11 Emission Control Guidelines

There are currently no regulations or codes of practice that apply specifically to fugitive equipment leaks emissions control for natural gas processing facilities. Guidelines typically used are maximum leak frequencies of 10% for compressor seals, 0.5% for connectors, and 2% for other component types

3.2 Equipment Repair Cost-Benefit Analyses

Practicable opportunities for reducing fugitive equipment leak and process venting emissions were assessed on a source-by-source basis. The net cost/benefits of identified control options were determined in dollars per tonne of CO_2-equivalent annual emissions reduction. The information and assumptions regarding the cost estimates, the lost gas value, and repair lives used in these analyses are summarized below. The financial discount rate and other financial considerations applied in these analyses are summarized in Appendix V.

3.2.1 Equipment Repair Cost Estimating

Detection and control costs are assessed on an individual-source or per-component basis according to estimated average site-specfic costs. Actual costs will vary with the facility location and layout, the required work, the service type (i.e., sweet or sour), and the actual repairs or control measures required.

The basic cost to repair or replace a leaking equipment component is estimated based on the component type and size, typical billing rates quoted by the service providers (e.g., compressor maintenance and repair companies, and valve repair and servicing companies) and the estimated labour and materials requirements. Where possible, both direct and indirect costs are considered. Direct costs are the actual costs for parts, onsite labour, equipment, tools and disbursements, and are summarized in Appendix VI. Indirect costs are revenue losses due to any process shutdowns or interruptions beyond normally scheduled facility turnarounds, and the value of gas vented or flared during the specified repair or replacement activity. Where indirect costs render the repair or replacement cost ineffective, it is assumed that the work will be delayed until the next scheduled plant turnaround. Otherwise, it is assumed that the repairs are made soon after the leak detection and evaluation.

3.2.2 Natural Gas Value

The value of natural gas was assumed to be \$7.15/Mscf (\$6.78/GJ). The propane, butane and condensate values were assumed to be: propane \$8.13/GJ; butanes \$9.63/GJ and condensate \$9.63/GJ. The actual value of avoided natural gas losses is very site-specific and can depend on many factors including:

- Local market pricing;
- Impact of emission reductions on specific energy consumption, equipment life, workplace safety, and system operability, reliability and deliverability;
- Contract terms;
- Facility remoteness;
- Gas concentrations of contaminants and NMHCs;
- Applicable taxes and tax shields.

3.2.3 Repair Life

It was assumed that a leak, once repaired, will remain fixed for some finite time period, and then will reoccur. The mean time between failures depends on the component type, style, quality, application, and activity levels (e.g., number of valve operations) and site maintenance practices. Estimates of the mean time between failures for each component type are provided in Appendix VI. These values are very crude estimates based on the author's experiences and limited host facilities feedback. The relatively low mean time between failures for connectors reflects wear and tear from inspection and maintenance of associated equipment units. In a formal leak detection and repair program, information on maintenance practices and mean times between failures is tracked and is used to identify problem service applications and to evaluate the need to change to component specifications and maintenance practices.

3.2.4 Cost Curves

A cost curve shows the estimated net cost required for different levels of site emission reductions. Each point on the curve represents the impact of implementing a different emission-reduction measure. The costs are based on a mix of facility and vendor data and consensus estimates developed in consultation with the facilities The presented costs do not include those to find and evaluate emissions reduction opportunities and are therefore biased slightly low (typically, these costs are small compared to the control costs). Different control actions have different lifetimes; therefore, for comparison purposes, the credited emission reduction for each control option on the cost curve only includes the first year emission reduction (for these analyses, the shortest repair lifetime is assumed to be one year). Control measures with lifetimes greater than one year will have reduced costs per unit emission reduction.

4 RESULTS

This section provides an overview of the atmospheric emissions and natural gas losses determined for each of the five sites, and delineate the main cost-effective loss-reduction opportunities. Additionally, average total hydrocarbon (THC) emission factors and leak statistics are presented for fugitive equipment leaks at these facilities.

Tagged-component information and individual leak rates for all leaking components are presented in Appendices I and II. Detailed results of the performance tests done on all active combustion sources are provided in Appendix III.

4.1 Emission Inventory

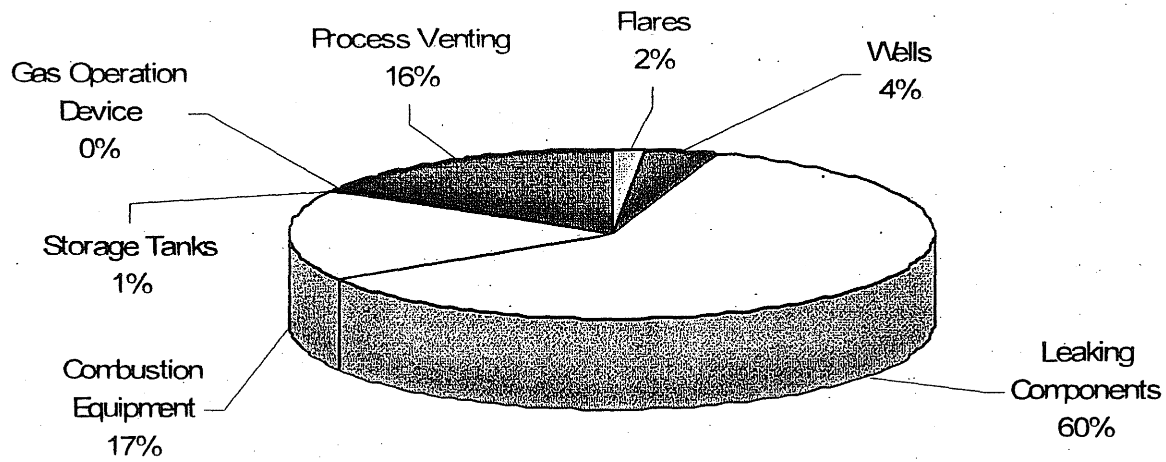
Total atmospheric emissions of methane, NMHC and GHG emissions from the five host gas processing plants amounted to 8,072 and 3,625 tonnes per year and 598,184 tonnes CO_2E per year, respectively. The relative distributions of these emissions by source category are presented in Figures 8 to 10. The carbon dioxide equivalent GHG emissions were calculated using the most recent 100-year global warming potentials (IPCC, 1996) (i.e., 1 for CO_2 and 21 for CH_4). GHG emissions consider methane and CO_2 only and do not include Nitrous Oxide (N_2O) emissions from combustion sources. The methane content of the measured THC emissions was determined based on typical gas analyses for the site and the analysis results for samples collected during the measurement program. Emissions of nitrous oxide were not evaluated but would be expected to contribute only a few % to total GHG emissions at each site.

As shown in Figure 8, fugitive equipment leaks (leaking components) are the dominant source of methane emissions, accounting for 60% from all sources. This is followed by incomplete fuel combustion (17%), process venting (16%), wells (4%), incomplete flare gas combustion (2%), and a small amount (1%) from storage tanks and gas operated devices.

Figure 9 shows fugitive leaks (leaking components) are the major source of NMHC emissions (73%). The rest (27%) was contributed primarily by combustion equipment and wells.

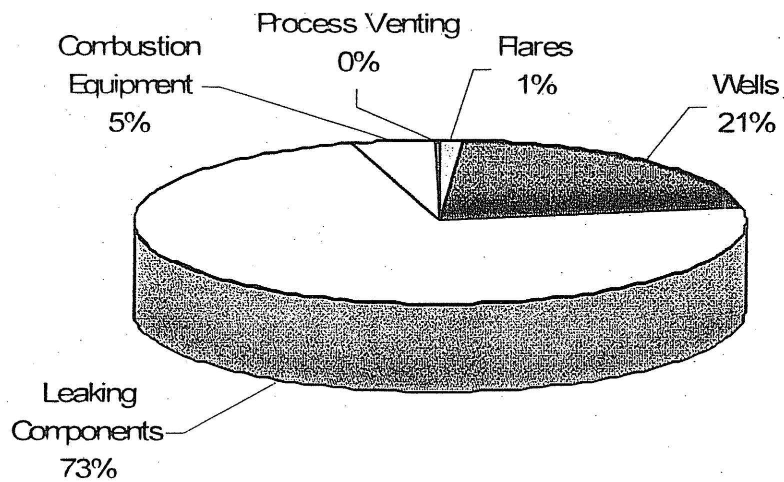
The CO_2E GHG emissions are predominantly from fuel consumption by combustion equipment (74%) as shown in Figure 10. However, fugitive equipment leaks (17%), as well as process vents (5%) may generally offer more cost-effective control opportunities.

Figure 10 Distribution of Methane by Source Category for All Sources.



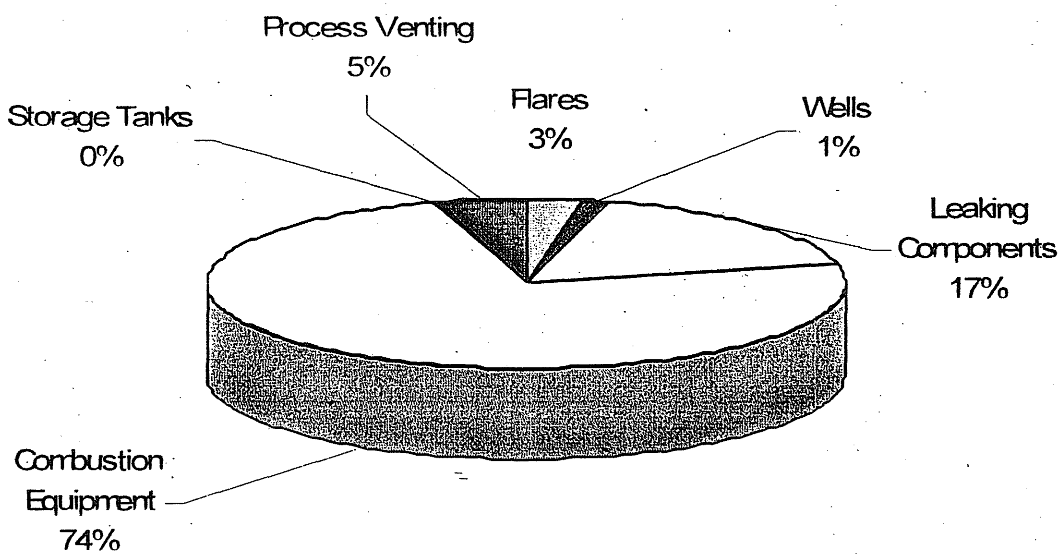
Methane Emissions = 8,072 tonne/yr

Figure 11 Distribution Of Non-Methane Hydrocarbon Emissions By Source Category



NMHC Emissions = 3,625 tonne/yr

Figure 12 Distribution Of Total GHG Emissions By Source Category.



GHG Emissions = 598,184 CO_2E tonne/yr

4.2 Natural Gas Losses

The value of natural gas is taken to be \$7.15 Mscf (\$6.78/GJ). The values for propane, butane and condensate are taken to be as follows: propane \$8.13/GJ; butanes \$9.63/GJ and condensate \$9.63/GJ. The determined gas losses include direct leakage and venting of natural gas to the atmosphere as well as losses into the process (e.g., excess fuel consumption by out-of-tune or inefficiently-operated engines and heaters, and gas leakage into flare systems). These latter losses lead to increased combustion emissions without any net process benefit.

The relative distribution of natural gas losses by source category is shown in Figure 11. Leaking equipment components are the greatest source of natural gas losses at the gas plants, accounting for 55% of the total. Other major sources include leakage into flare systems (24%), process venting (9%) and wells (8%). As shown in figure 12, natural gas losses from equipment leaks are contributed by open-ended lines, connectors, compressor seals and block valves, accounting for 32, 30, 20 and 15%, respectively. The top ten leakers at each site (other than site 1) contributed over half of the total natural gas losses from fugitive equipment leaks (refer to Table 2).

4.3 Fugitive Equipment Leaks

The following subsections characterize the fugitive equipment leaks for components in natural gas service at the surveyed gas plants. An overview of the fugitive leaks from gas processing plants, gathering compressor stations, and well sites is shown in Table 3. The lost values from these sources are \$536,270 from gas plants, \$49,018 from gathering compressor stations, and \$3,183 from well sites per year.

4.3.1 Average Emission Factors

Average emission factors were determined for each type of equipment component in natural gas service at the surveyed sites. The results are presented in Table 4 and are compared to corresponding factors published by U.S. EPA (1995) for oil and gas production operations and by U.S. EPA and GRI (1996) for natural gas facilities. Overall, the developed average emission factors are greater than those for oil and gas production facilities, and more comparable to the previous values for natural gas facilities.

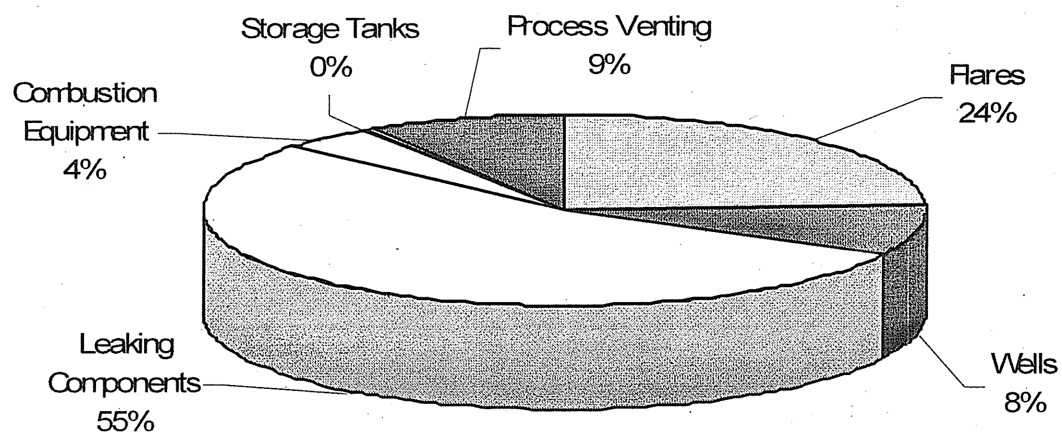
The average emission factors are simply the total emissions from all tested components divided by the total number of components of that type surveyed. Quantification of emissions from non-leaking components (i.e., components with screening values between zero and 10,000 parts per million) was not attempted. Instead, emissions from these components were assumed to be represented by the average no-leak emission rates presented in the Protocol for Equipment Leak Emission Estimates (U.S. EPA, 1995).

Table 2. Summary of Fugitive Losses from the Top Ten Leakers[1].				
Plant No.	Gas Losses from Top 10 Leakers (Mscfd)	Gas Losses from Measurable Fugitive Leaks (Mscfd)	% Contribution by Top 10 Leakers	% of Total Leakers
1	78	271	29	0.04
2	13	23	56	0.08
3	53	117	45	0.05
4	60	69	87	0.06
5	317	423	75	0.21
Combined	521	903		

[1] Excluding leakage into flare systems.

Table 3. Summary Of Fugitive Leaks For Gas Plants, Gathering Compressor Stations, and Well Sites.							
Facility Type	Number of facility surveyed	Number of Components Screened (Components /facility)	Number of Leaks Identified (leaks /facility)	THC Emissions From leaking Components (Tonne /Yr/Facility)	Methane Emissions (Tonne /Yr/Facility)	**GHG Emissions from Leaking Components (Tonne /yr/facility)**	**Value of Emissions From Leaking Components ($/year /facility)**
Gas Plant	5	12.243	232	1.348	882	18,561	$536,270
Gathering Compressor Station	7	2,423	87	131	97	2,044	$49,018
Well Site	12	238	11	8	6	117	$3.183

Figure 13 Distributions of Natural Gas Losses By Source Category



Total Natural Gas Emissions = 14,457 tonne/yr

Figure 14 Distribution Of Natural Gas Losses From Equipment Leaks By Type Of Component

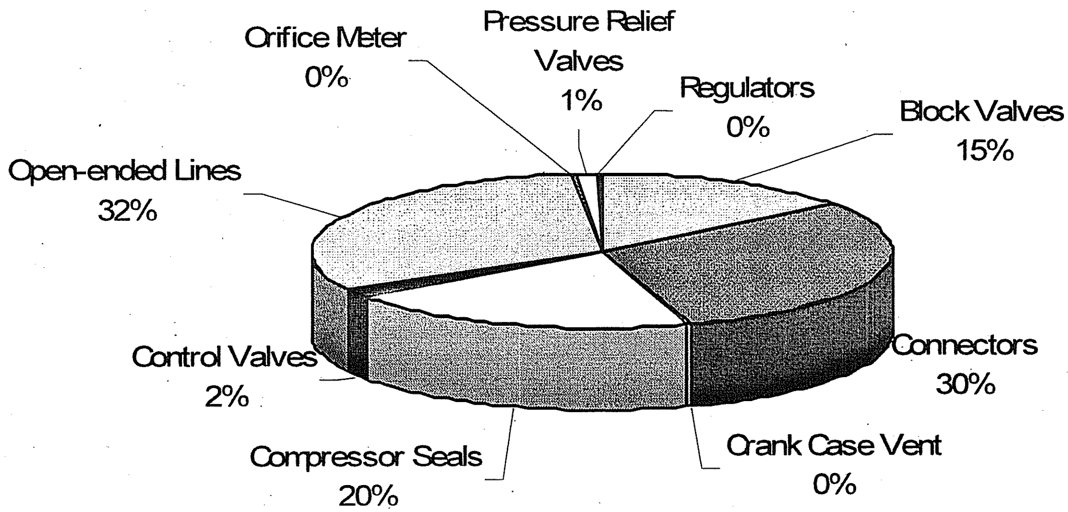


Table 4. Comparison Of Average THC Emission Factors Derived From Data Collected In Both Phases To Other Published Values.				
	Average Emission Factors (kg/h/source)			
Source	Phase I Study	Phase II Study	U.S. EPA[A]	U.S. EPA Gas Facilities[B,C]
Connectors	2.22E-03	3.30E-03	2.00E-04	3.05E-04
Block Valves	1.10E-02	1.47E-02	4.50E-04	3.40E-03
Control Valves	4.85E-02	3.73E-02	4.50E-04	N/A
Pressure Relief Valves	6.73E-02	4.70E-04	8.8 E-03	2.24E-03
Pressure Regulators	1.74E-02	6.31E-03	8.8 E-03	N/A
Orifice Meters	3.58E-03	2.70E-03	8.8 E-03	N/A
Crank Case Vents	8.83E-01	1.20E-01	N/A	N/A
Open-Ended Lines	5.18E-02	2.39E-01	2.00E-03	9.02E-02
Compressor Seals[D]	8.52E-01	5.20E-01	8.8 E-03	1.17E+00

N/A Emission factor for this source type is not available.

A Source: U.S. EPA. 1995. Protocol for Equipment Leak Emission Estimates. Research Triangle Park, NC 27711.

B Source: U.S. EPA and GRI. 1996. Methane Emissions from the Natural Gas Industry. Volume 8: Equipment Leaks. Research Triangle Park, NC 27711.

C The factors presented in the column are for methane emissions only but should be comparable to, although slightly less than, the corresponding THC values for the applicable component categories. The factors presented in the other two columns are for THC emissions.

D Compressor seals component category accounts for emissions from individual compressor seals. As compressor seal leakage was typically measured from common vent and drain lines, emissions have been divided evenly among the seals on units with detected leakage.

4.3.2 Average Leak-Rate Trends

A statistical analysis of the compiled leak data was performed to identify any trends or correlations that could be used to help focus leak detection and control efforts. The effects of component type and style, process temperature and pressure, component size, application (i.e., type of process unit on which the component is used), and type of process stream (e.g., fuel gas, residue gas, acid gas, etc) were evaluated. In the following section, the average emission factors are given as total hydrocarbons on a kg/h/source basis to be consistent with published average emission factors (U.S. EPA, 1995). The main findings are as follows:

- Average hydrocarbon fugitive emission rates for connectors, open-ended lines and block valves are shown by stream types as shown in Figure 13, 14, and 15, respectively. These three components account for 77% of the total natural gas fugitive emissions. Components in fuel gas and process gas services, even though not registered to have the highest average emission rates, have consistently to be on the highest four averaged emission rates among these three component types. In Figure 14, open-ended lines in propane and C_4 streams have significantly higher average emissions rates. This resulted from a combination of low component counts and was dominated by a large leak identified in the categories. Each point on figures 13-15 denotes the average emission factor for the corresponding streams the component is serving on the horizontal axis. The integer shown adjacent to each emission factor value is the number of data used to develop the factor. The vertical line through each average emission factor denotes the 95% confidence limits based on the variance in the compiled data and number of data points assuming a normal distribution. Under each of the component categories shown, one can not conclude an average emission rate is a function of stream type due to the large 95% confidence interval. However, general trends were implicated.

- Average hydrocarbon fugitive emission rates for connectors, open-ended lines and block valves are shown ***by process unit*** as shown in Figures 16, 17, and 18, respectively. For all three component types shown, their average emission rates in compressors and mole sieve units are among the top three process unit types. While connectors, and block valves in sales units have relatively low average emission rates, open-ended line in sales unit registered the highest average emission rate among all process units. This resulted from the combination of low overall component counts of open-ended lines in sale unit and one single big leaker identified in this category.

- Components tend to have greater average emissions where subjected to frequent thermal cycling, vibrations, or cryogenic service (see figures 16-18).

- All other parameters had little or no impact on average emissions.

In the Figures below, C_2 = ethane, R = residue gas, FG = fuel gas, PG = process gas, P= propane refrigerant, C_4= butane, NGL = natural gas liquids, C_3= propane , LPG = liquefied petroleum gas.

Figure 15 Average THC Emissions For Connectors By Gas Streams

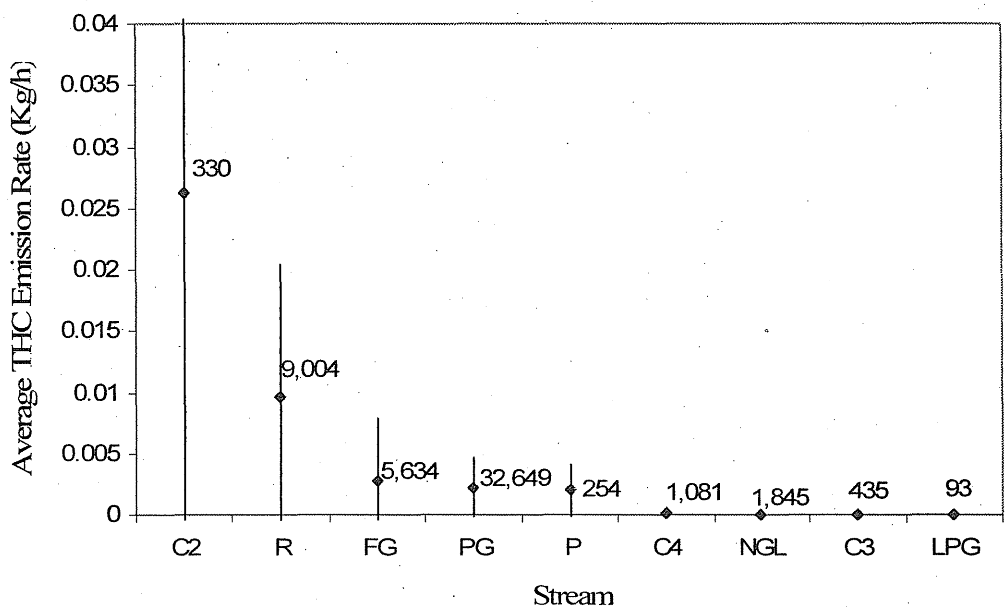


Figure 16 Average THC Emissions For Open-Ended Lines By Gas Stream

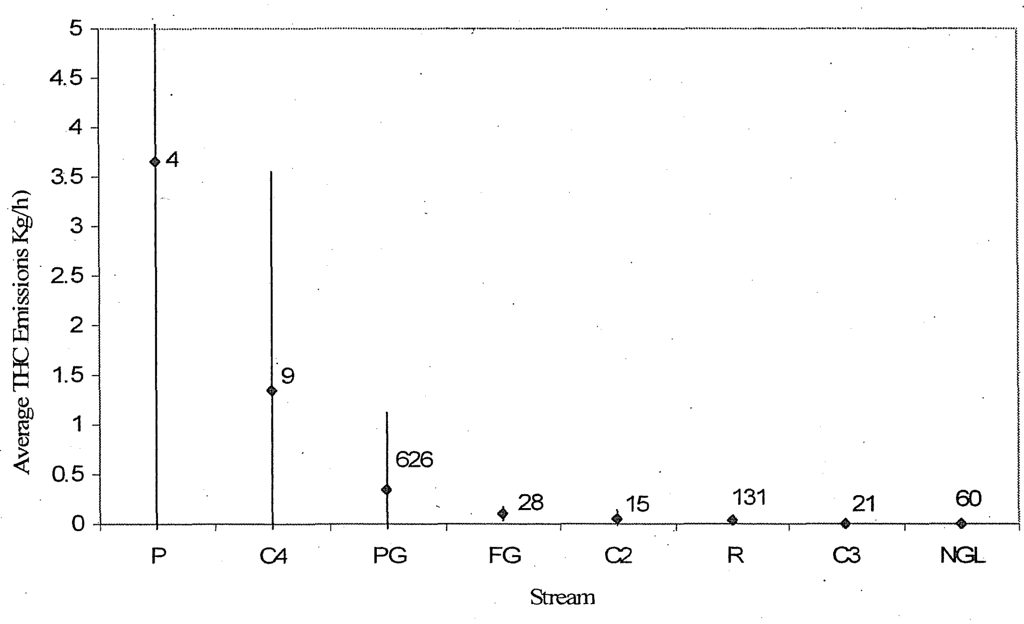


Figure 17 Average THC Emissions For Block Valves By Gas Stream

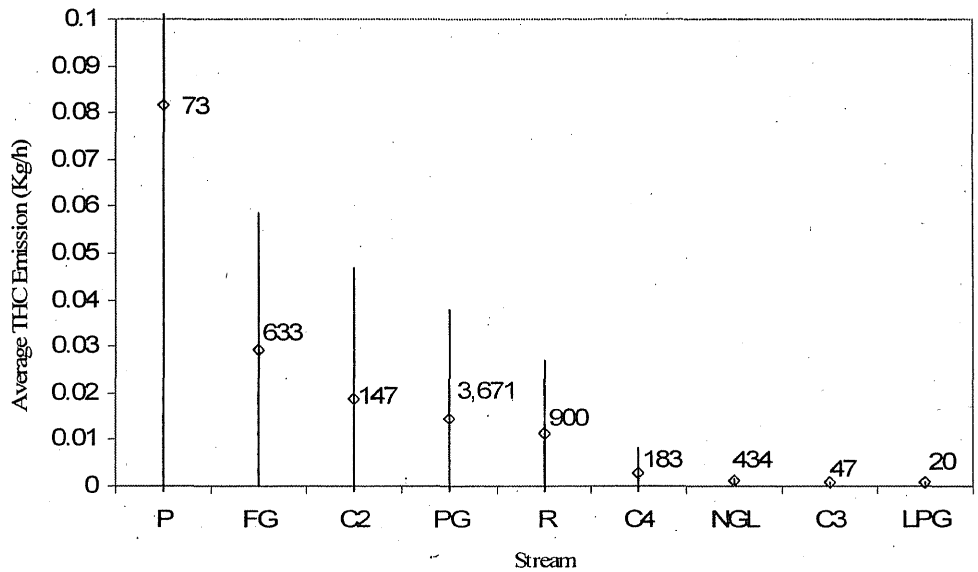


Figure 18 Average THC Emissions For Connectors By Process Unit

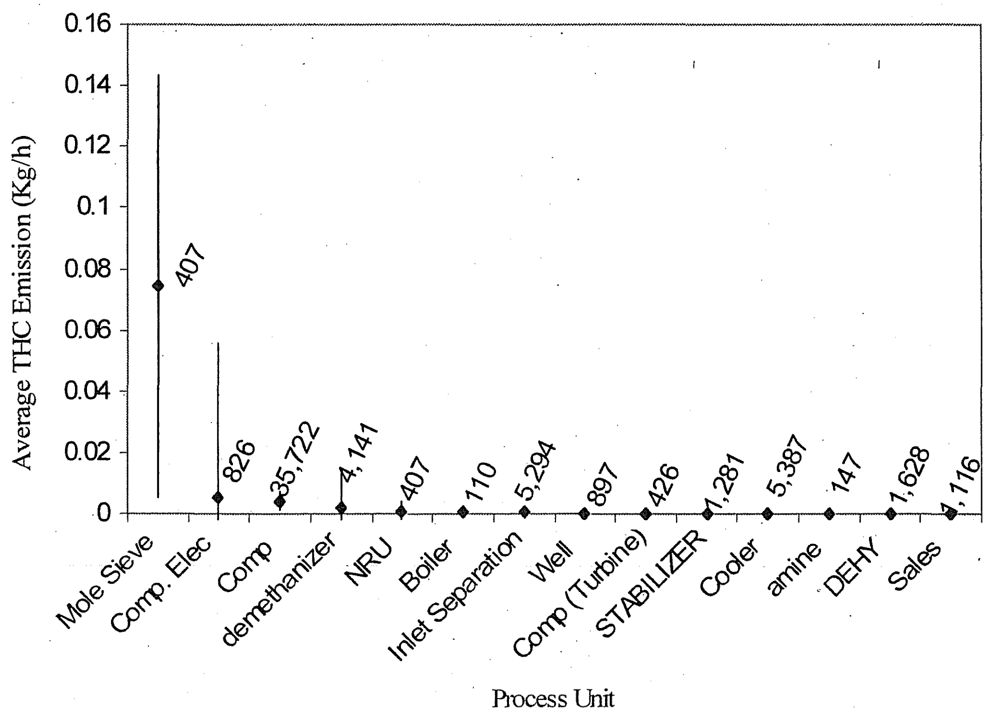


Figure 19 Average THC Emissions for Open-Ended Line By Process Unit

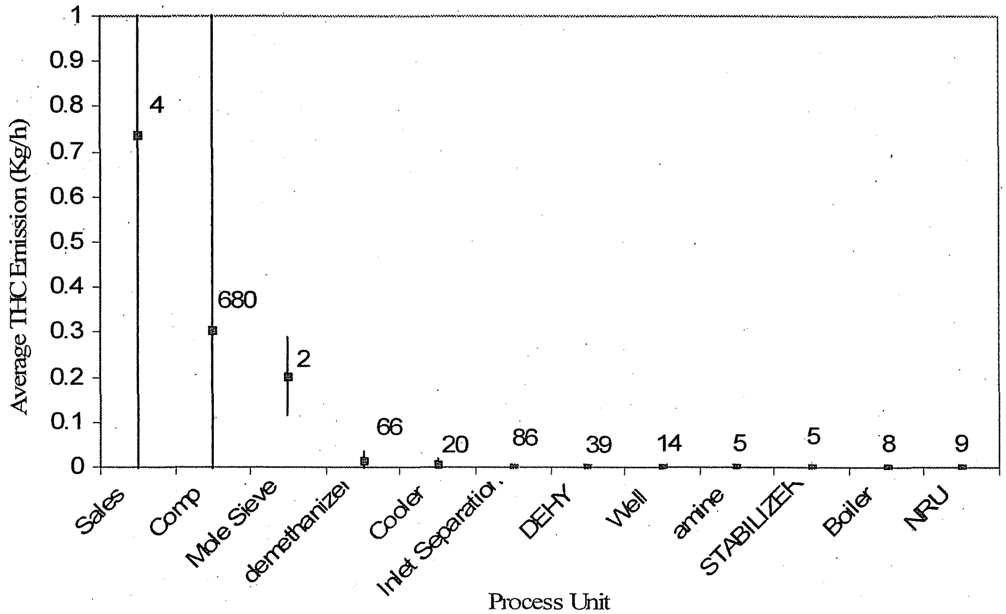
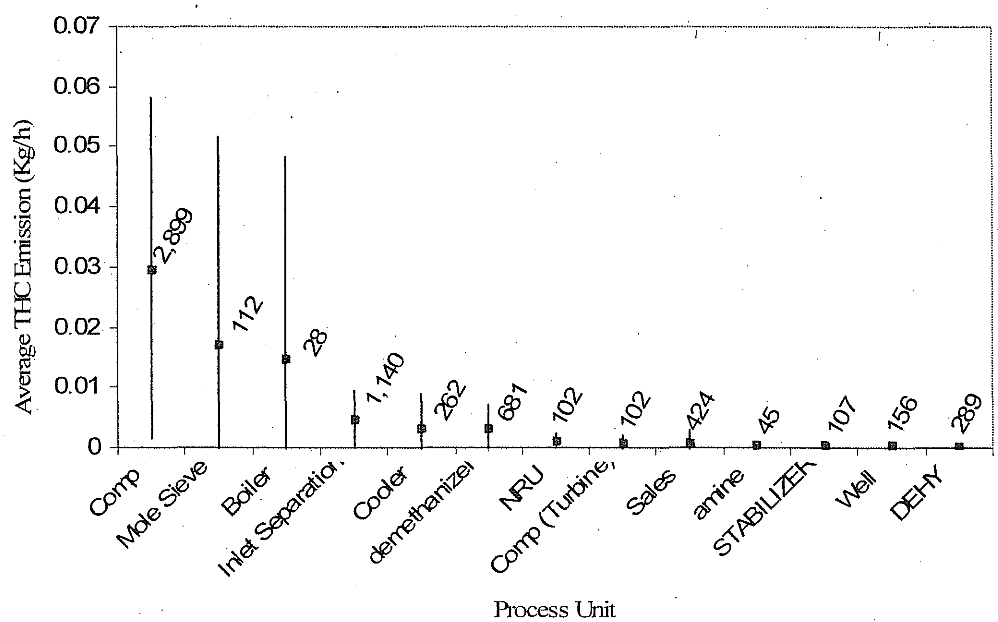


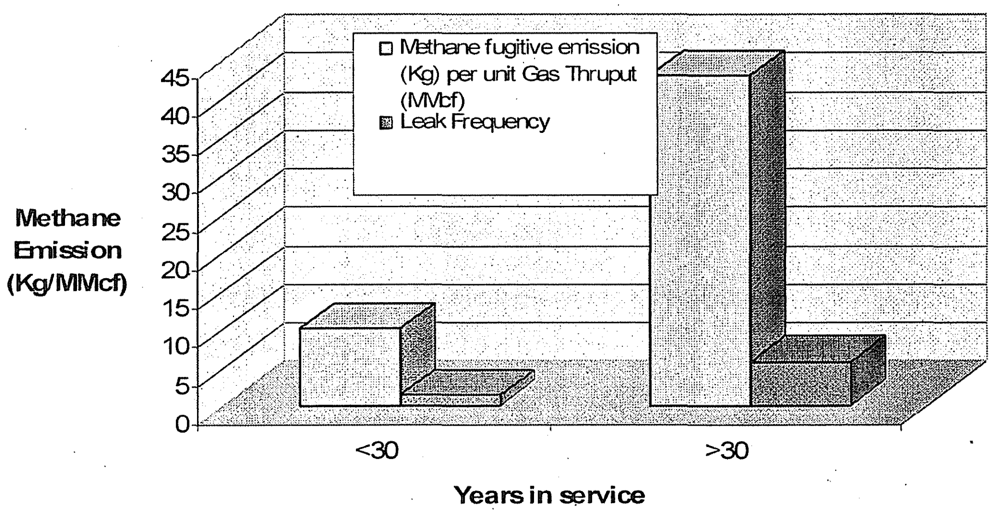
Figure 20 Average THC Emissions for Block Valves By Process Unit



Additional trends on the age of a facility, sweet/sour raw gas stream, and the potential of implementing a process-unit-targeted DI&M program are illustrated in the figures that follow.

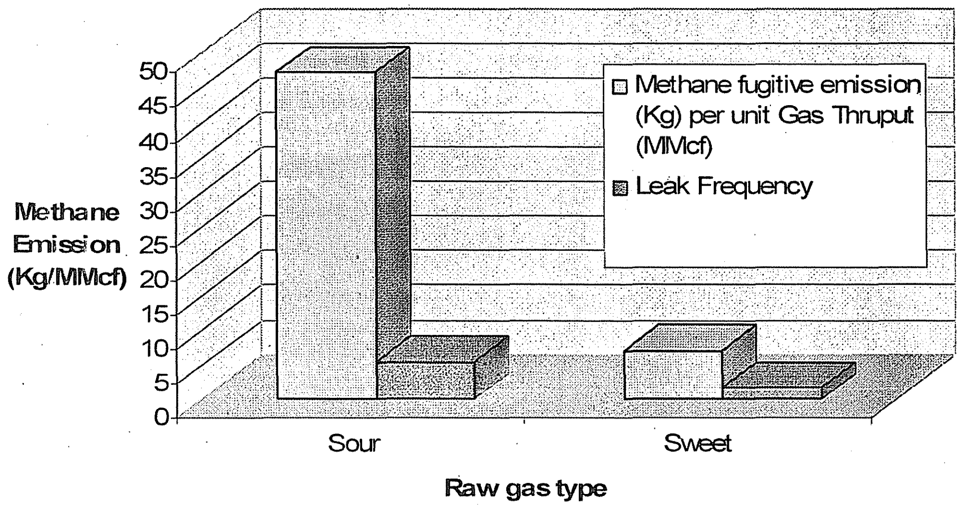
In Figure 19, the methane fugitive emission per unit gas throughput (kg / MMcf) and the leak frequency (%) are shown against years of service for the surveyed facilities. Facilities with longer than 30 years of service have higher methane fugitive emission per unit throughput and higher leak frequencies than those with less than 30 years of service. However, due to the limited number of surveyed facilities (3 with less than 30 years of service and 2 with longer than 30 years of service), it can not be concluded with statistical significance.

Figure 21 Methane Emissions Per Unit Gas Throughput For Plants With Different Service Duration



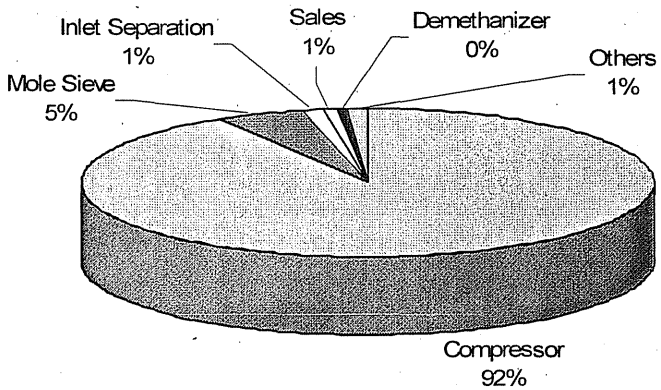
In Figure 20, the methane fugitive emission per unit gas throughput (kg / MMcf) and leak frequency are shown against raw gas type. Facilities with sour raw gas have significantly higher methane emission per unit gas throughput and higher leak frequency as well when compared with facilities with sweet raw gas input. As mentioned earlier, due to the limited number of surveyed facilities (3 with sweet and 2 with sour raw gas), the significance of sour versus sweet process plants can not be concluded with statistical significance.

Figure 22 Figure F Methane Emissions Per Unit Gas Throughput For Plants With Different Raw Gas Type



In Figure 21, fugitive methane emissions are shown against the process units. Compressor related components contributed the majority of methane fugitive emissions at 92% with the mole sieve being a distant second in methane emission contribution at 5%. These results validated the components under vibration (compressor units) and heat-cycle (mole sieve units) services are a lot more prone to leaks. The overwhelming percentage of methane emissions contributed by these two processes and related components warrants instituting a targeted DI&M program.

Figure 23 Methane Emissions Percentage by Process Units



4.3.3 Leak Frequencies

Fugitive equipment leaks are generally considered to be well controlled when the leak frequency for each component type (except connectors, compressor and pump seals) is 2% or less. For connectors, the allowable percentage of leaking components is 0.5%, and for compressor and pump seals the allowable percentage is 10%. Based on these guidelines, none of the categories for the combined plants would be considered adequately controlled (see Table 5). However, some categories at individual plants would have passed (i.e., connectors and block valves at Site 2). Table 5 below summarizes the most leak prone components. Compressor seals, orifice meters, control valves, and open ended lines constitute greater than 70% of the leak frequency. Figure 23 further illustrates the contribution of each component type to total THC emissions.

Table 5 Number of Components And Leak Frequency At Each Of The Five Gas Plants.

		Connectors	Block Valves	Control Valves	Pressure Relief Valves	Regulators	Orifice Meters	Crank Case Vents	Open-Ended Lines	Compressor Seals	Total
Site 1	Total Count	20,045	1,581	91	43	63	8	-	332	127	22,290
	Number of Leaker	273	84	6	0	2	1	-	31	71	468
	Leak Frequency %	1.36	5.31	6.59	0.00	3.17	12.50	-	9.34	55.91	2.10
Site 2	Total Count	10,705	1,392	82	-	69	25	-	57	-	12,330
	Number of Leaker	48	22	7	-	4	1	-	9	-	91
	Leak Frequency %	0.45	1.58	8.54	-	5.80	4.00	-	15.79	-	0.74
Site 3	Total Count	15,552	2,225	108	59	46	10	3	291	59	18,353
	Number of Leaker	193	133	14	0	3	4	0	25	30	402
	Leak Frequency %	1.24	5.98	12.96	0.00	6.52	40.00	0.00	8.59	50.85	2.19
Site 4	Total Count	14,509	1,657	158	21	131	11	23	160	17	16,687
	Number of Leaker	120	36	19	0	9	0	1	28	10	223
	Leak Frequency %	0.83	2.17	12.03	0.00	6.87	0.00	4.35	17.50	58.82	1.34
Site 5	Total Count	3,558	837	56	1	11	3	1	215	96	4,778
	Number of Leaker	282	131	5	0	1	0	1	14	11	445
	Leak Frequency %	7.93	15.65	8.93	0.00	9.09	0.00	100.00	6.51	11.46	9.31
Total	Total Count	64,369	7,692	495	124	320	57	27	1,055	299	74,438
	Number of Leaker	916	406	51	0	19	6	2	107	122	1,629
	Leak Frequency %	1.42	5.28	10.30	0.00	5.94	10.53	7.41	10.14	40.80	2.19

4.4 Tank Emissions

Of the five sites surveyed, three contains leaky tanks that were measured during the site surveys. Thief hatches were found to be leaking and subsequently the volume flow was measured. The average value of gas loss is $906,296 per year per site (see Table 6).

Table 6 Losses From Storage Tanks

Facility	THC Emissions (MMcf/year)	Methane Emissions (MMcf/year)	GHG Emissions (tonnes CO2E/year)	Value of Lost Product ($/Year)
Gas Plant 1	158.8	93.6	37,801	2,670,645
Gas Plant 2	0.46	0.42	183	3,429
Gas Plant 3	3.50	2.86	1,320	44,813
Gas Plant 4	NA	NA	NA	NA
Gas Plant 5	NA	NA	NA	NA
Total	162.7	96.9	39,304	2,718,887
Average	54.2	32.3	13,101	906,296

4.5 Results for Retested Site

One of the four surveyed sites from Phase I was retested in Phase II to investigate changes in its fugitive leak characteristics. Some of the process units from Phase I were decommissioned and replaced with new process units. Component count from the decommissioned process units (5,590 components) is about 30% of the total plant count from Phase I (18,390 components). The following sections discuss the process units that were replaced and the changes in fugitive emissions between the Phase I and Phase II plant surveys.

4.5.1 Overall Plant

Figure 22 shows the overall THC emissions between Phase I and II for the retest site. Component level emissions for each Phase were also demonstrated. The THC emissions increased about 50% from Phase I to Phase II. While the major THC contributors are the same between Phase I and II programs, the percentage contributions from each source following changes at the site were very different. The changes in the average THC emission rate for each component type are contrasted in Figure 23.

Figure 24 Total THC Emissions Between Phases

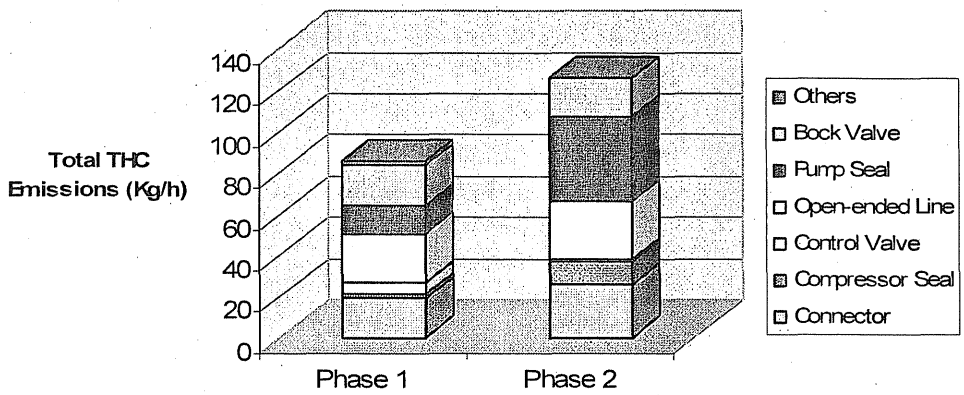
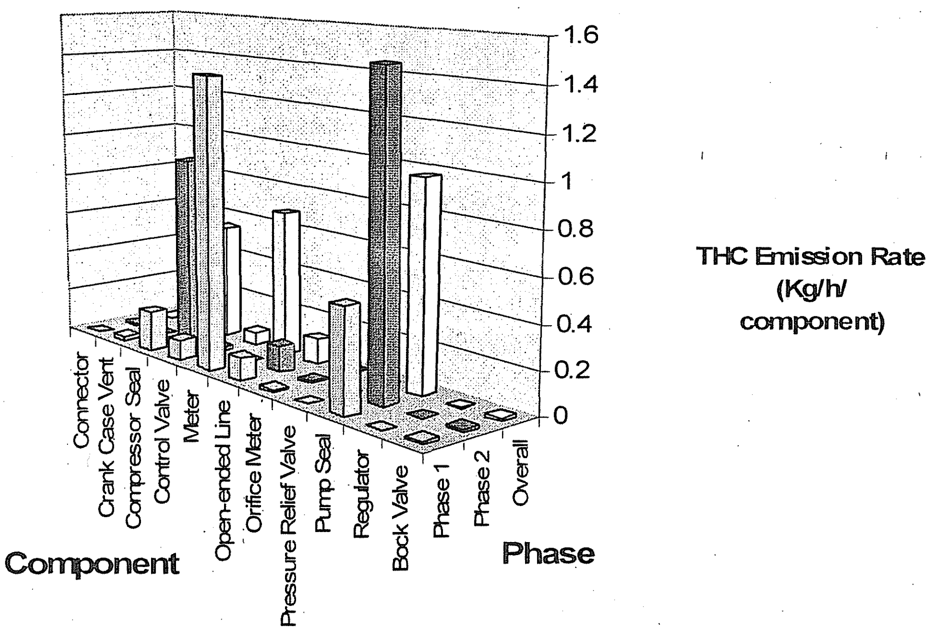


Figure 25 Component Emission Rate Between Phases



4.5.2 Replaced Process Units

About 30% of the original component count from Phase I was not active during the Phase II survey due to decommissioning and replacing equipment. These decommissioned process units were replaced with new process units and their associated fugitive equipment emissions were compared with those from the decommissioned process units in Phase I. In Figure 24, the total THC emissions for these two sets of process units were compared. The THC emissions reduced by an estimate of 80% from Phase I (decommissioned units) to Phase II (new units). The average emission rates per component between Phase I and II are compared and are shown in Figure 25. With open-ended lines being the exception, all other components have significantly lower average emission rates in the newly added process units.

Figure 26 Total THC Emissions Between Phases

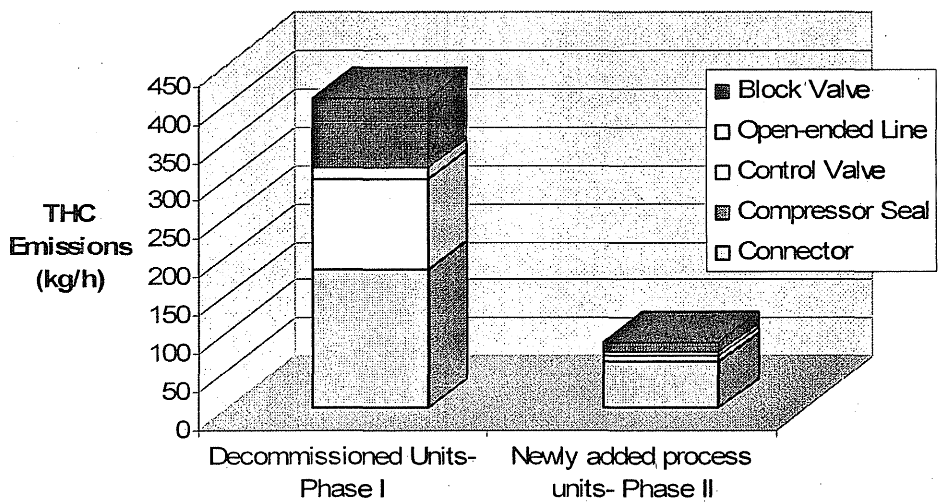
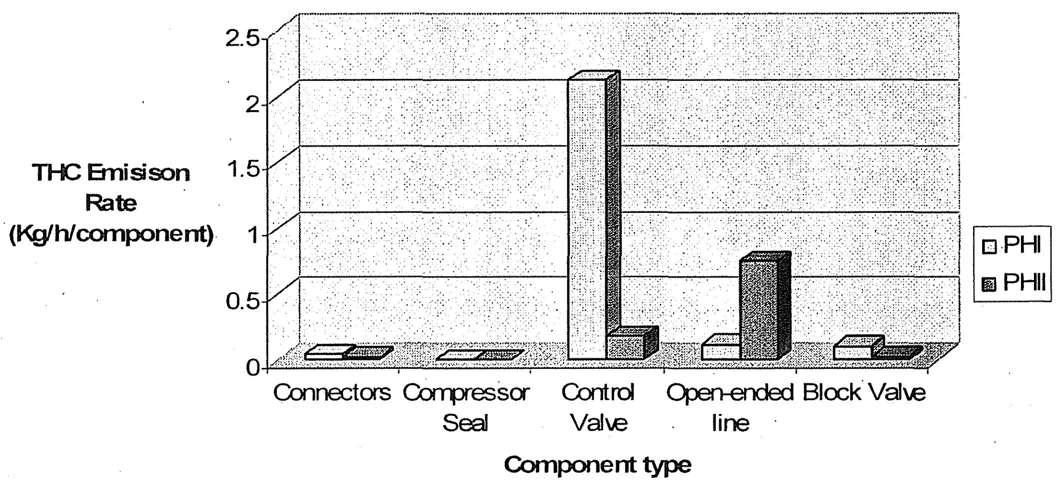


Figure 27 Component Emission Rate Between Phases



The results of this comparison tend to suggest that the DI&M program conducted at this facility has been ineffective at controlling emissions from fugitive equipment leaks. This apparent inability to control fugitive emissions using a

DI&M program may be attributed to a number of factors including: excessive duration between surveys, inadequate follow up to maintenance recommendations and insufficient documentation of maintenance activities. The 5 year time frame between these two surveys exceeds the estimated mean repair life for most components. This makes it difficult to assess the effectiveness of any repairs made in response to the Phase I survey because the leaks are likely to have reoccurred. Increasing the frequency of leak surveys to annually or bi-annually would allow for a better assessment of the effectiveness of maintenance activities and enable new leaks to be identified and repaired sooner. It is unclear what maintenance activities were undertaken in response to the Phase I survey. For example, a substantial leak from a weld failure identified during the Phase I survey was also found to be leaking during the Phase II survey. In order for the program to be effective, all cost-effective control opportunities should be acted on by either repairing the leak or reevaluating the economics to justify no action. Any maintenance performed in response to the survey should be adequately documented so the success of the repair can be addressed during subsequent site surveys. Accurate maintenance records will facilitate in tracking the true economics of the repair, and ultimately assist in establishing future control opportunities.

4.6 Control Opportunities

Practicable opportunities for reducing the identified natural gas losses were identified and assessed on a source-by-source basis. Overall, it is estimated that up to 96.6% of total fugitive natural gas losses could be avoided if all control opportunities with positive net cost or a positive payback are implemented (see Figure 26). This would result in corresponding reductions of 97% in fugitive methane emissions, 97% in fugitive GHG emissions, and 98% in fugitive NMHC emissions in the first year alone. Moreover, many of the control options have multi-year life expectancies resulting in significant emission reductions in subsequent years as well.

4.6.1 Cost Curve for Reduction of GHG Emissions

To further evaluate the control of natural gas losses as a means of reducing GHG emissions, it is useful to express the results in terms of a cost curve. Figure 27 presents the net annualized cost curve for implementation of the various opportunities identified at the five gas plants. The net cost of each target control opportunity is calculated as the equalized annual implementation cost over the life of the project (i.e., the net present cost of the opportunity expressed as an equivalent series of equal annual payments over the life of the project) divided by the resulting average annual CO_2-equivalent emission reduction.

Figure 27 shows that the incremental cost per tonne of CO_2E GHG emission reduction resulting from implementation of the available control opportunities in ranked order from most to least cost effective (i.e., see Table II-1 in Appendix II). The point at which the curve crosses over the abscissa axis (i.e., the axis of cumulative CO_2E GHG emission reduction) is the amount of CO_2E emission reduction that could be achieved if only opportunities with a zero cost or a positive payback are implemented (i.e., 103,363 tonnes CO_2E reduction per year). This reduction amounts to 17% of total estimated GHG emissions from the five gas plants.

If a value is assigned to GHG emission reduction credits, then companies may choose to pursue opportunities even further out on the cost curve. The shape of the cost curve shows that there are a few very attractive control opportunities, a large number of moderate control opportunities, and eventually a point of diminishing returns.

Figure 1 Emissions From Economically Repairable Sources

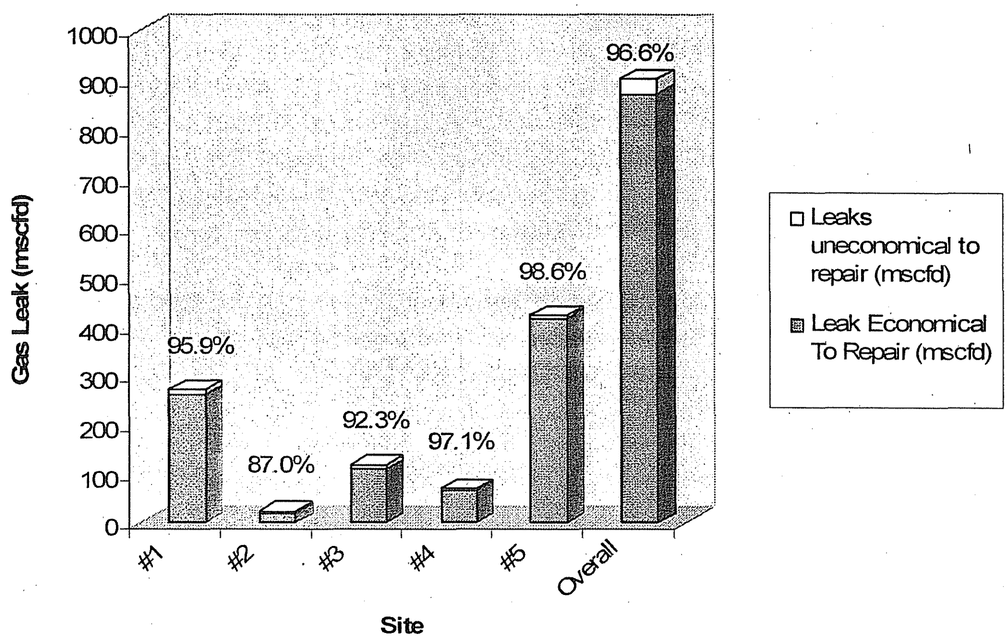
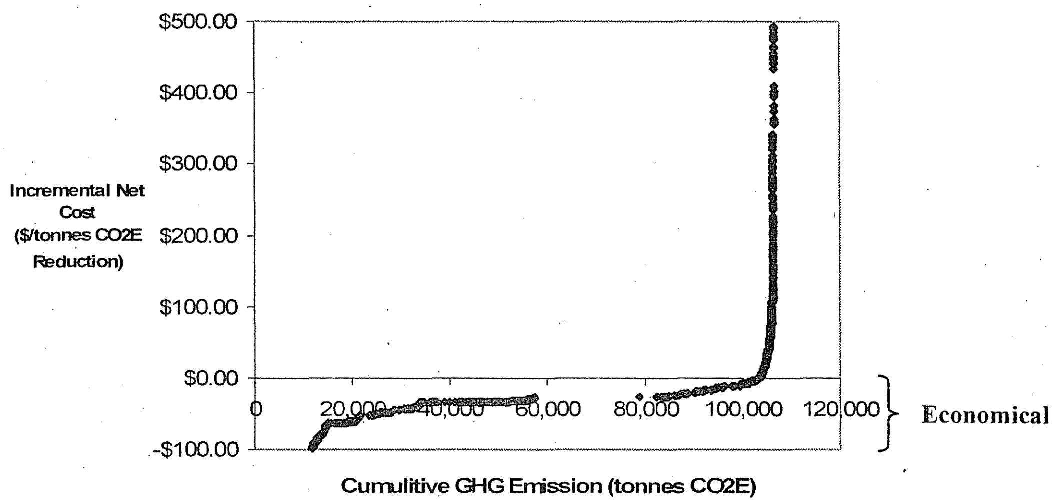


Figure 2 Incremental Net Cost Curve For Cumulative CO_2E Emission Reductions At Surveyed Gas Plants



4.6.2 Control Opportunities With a Payback of 1 Year or Less

On a purely financial basis, opportunities to reduce natural gas losses must compete against other investment opportunities to receive funding. A common parameter used to evaluate opportunities is either the effective rate of return on the investment or the payback period. To justify equipment upgrades or process enhancements, companies often look for a payback period of 1 year or less. Accordingly, it is useful to consider only opportunities to reduce natural gas losses that have a payback period of 1 year or less.

If only these control opportunities are implemented, it is estimated that total natural gas losses, including unnecessary fuel consumption, would be reduced by 97%. Corresponding reductions in NMHC and GHG emissions would both amount to 97% as well.

The 10 greatest individual control opportunities in the 1-year payback category are listed in Table 7. Collectively, they account for 42% of total natural gas losses in this category.

Table 7. Summary of Top Ten Sources of Natural Gas Losses Identified

Tag ID	Site No.	Process Unit / Location	Component Type	Gas Leak Rate (Mscfd)	Value of Lost Gas ($/year)
5935	5	Compressor - 2" waterjacket connection	Open-Ended Line - 2"	194.25	$621,168
5488	4	LP FG Scrubber - corrosion hole in bottle below HLL alarm	Corrosion Hole	46.90	$102,893
6074	5	Flare fuel gas line -	Corrosion Hole	42.92	$111,631
6075	5	Compressor	Variable Volume Pocket	30.45	$97,380
5956	5	Compressor	Compressor Seal	16.27	$52,044
7355	1	Compressor- distance piece vent (leak overwhelmed hiflow)	Compressor Seal	11.27	$33,573
7010	1	Residue compressor (north caterpillar) - common packing case drain	Compressor Seal	9.75	$25,863
7168	1	Residue compressor (#2 ingersoll-rand) -	Valve Cap	9.34	$24,787
6708	3	Amine Tank	PRV	9.34	$24,559
7322	1	Compressor -reptured diaphram on 4 NPS control valve	Control Valve - 4"	8.25	$21,899
Total				378.75	$1,115,799

5 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The second Phase added five additional gas processing plants to the four plants surveyed in the first Phase. The plants chosen for this study varied in plant age, throughput, size, location and sweet and sour gas. The second Phase also included well sites and gathering compressor stations located upstream from the gas processing plants. The variation ensures that the data collected represents an average for the natural gas processing industry. A comparison was conducted between the traditional leak detection methods and an optical passive infrared camera was conducted at all sites.

The sources with the greatest natural gas losses were not necessarily the most economical to control. Actual cost-effective emissions reduction opportunities may vary greatly between sites and not all gas plants will necessarily offer sufficient opportunities to justify the associated identification and control costs. In addition, actual economic opportunities depend on the natural gas value, and will therefore vary with fluctuations in the natural gas market price. Nonetheless, it is clear from the available data that significant cost-effective emissions reduction opportunities do exist at all surveyed facilities and a rational approach to finding these opportunities at all gas plants may be economically attractive to industry.

While any economical-to-repair leaking components detected by such efforts should be repaired, average leak rates based on combined data from the five test sites suggest that the most cost-effective approach would be to generally focus on the following types of components:

- block and control valves,
- orifice meters,
- open ended lines,
- pressure relief valves,
- regulators,
- flange connections,
- crankcase vents,
- compressor seals, and
- compressor valve stems and valve caps.

Additionally, components operating in thermal cycling (mole sieve) and vibration (compressor) applications have higher leak rates than other components. The results show that components in these two applications contributed 97% of the fugitive leaks and suggest that process-unit-targeted DI&M programs would have tremendous cost-effective emissions reduction potential. A DI&M program focusing on equipment in vibration and/or thermal cycling operation would likely identify and repair nearly all the large leaks at a fraction of a full facility DI&M program cost.

5.2 Recommendations for Further Work

Specific recommendations are:

- The amount and composition of emissions from engine and compressor crankcase vents, and field practices for the vent systems design should be examined more closely. In particular, the potential for air-toxic emissions from crankcase vents, especially those on engines, should be determined. Moreover, the practice of some companies to exhaust crankcase vents into buildings and work areas, a practice manufacturers discourage, should be evaluated.

- There are a wide variety of available technologies, as well as design and operating practices that would help companies cost-effectively reduce natural gas losses; however, these technologies and practices are under-utilized. One such example is the application of flow sensors, which can be installed on compressor seal vents at a relatively low cost. Flow sensors provide real-time excessive leakage detection. They may also be applied to crankcase and other vents. Only one of the five sites had installed seal vent flow sensors, and the operators did not monitor the sensors readings. Additionally, emergency flare systems are not normally equipped with flow meters, so in-leakage and excessive purge gas consumption often go unnoticed until natural gas losses produce a noticeably larger flame. Historically, meters were not installed because conventional obstruction meters do not provide reliable readings over the wide flow ranges and cause excessive system backpressure; however, non-intrusive ultrasonic flow meters, which overcome these problems, are now available. Moreover, ultrasonic techniques are available for identifying and quantifying leakage past valve seats into flare and vent systems.

- It is recommended that a best practices document be developed to disseminate and encourage the compilation and use of cost-effective emissions reduction practices. The document should also provide information required by companies to develop site-specific programs for reducing their methane and non-methane hydrocarbon losses, and greenhouse gas emissions (e.g., delineate source categories and/or facility areas to focus efforts on for maximum benefit, generic cost data for evaluating control options, recommended monitoring frequencies, and typical repairs life expectance by source type and service category).

- Analysis of the Phase I and Phase II results to determine the relative cost-effectiveness of a facility wide DI&M program and a process-unit-targeted DI&M program focused on components in vibration (i.e. compressor) or heat-cycle (i.e. mole sieve) services

Further analysis combining the data from Phase I and Phase II to improve the results statistical significance. Analyses should include, at a minimum, the plant level trends identified in the Phase 2 report (i.e. impacts of facility age and sweet or sour gas on methane emissions). Potential benefits include an age-based and/or gas-type-based DI&M program that would also reduce the cost of DI&M program.

- Use of the combustion equipment and compressor performance tests (new tests implemented in Phase 2) in future surveys. These tests, when implemented in the surveyed facilities, contributed significantly to the methane and overall GHG emissions inventories.

- A follow up program to evaluate the impact of monitoring frequency on gas processing facilities DI&M programs cost effectiveness.

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