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Standardizing the Reporting of Air Emissions to Ambient Air from Atlantic Canada Offshore Petroleum Activities

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Standardizing the Reporting of Emissions to Ambient Air From Atlantic Canadian Offshore Petroleum Activities
Final Report

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Submitted by:
Dillon Consulting Limited
In association with
BMT Cordah Limited

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Standardizing the Reporting of Emissions to Ambient Air From Atlantic Canadian Offshore Petroleum Activities

Dillon Consulting Limited is pleased to submit our final report on the standardizing of air emissions reporting from Atlantic Canadian Offshore Petroleum Activities.

The report summarizes our findings on current air emissions reporting requirements for the offshore from North America, the North Sea and Australia. We provide recommendations for the Boards' consideration on a reporting framework for Atlantic Canada, based on our findings.

Yours truly,

DILLON CONSULTING LIMITED

Robert Young, M.Sc.
Project Manager

RBY:emc
Our File: 02-0744-0100

Executive Summary

The Environmental Studies Research Fund (ESRF) commissioned a study to investigate existing requirements for the reporting of air emissions to ambient air from offshore upstream oil and gas (UOG) operations and to provide recommendations on a standardized reporting framework for the offshore UOG operators in Atlantic Canada. The objectives of the study were to:

- provide a qualitative understanding of air emissions from offshore UOG activities;
- benchmark existing reporting practices in Canada and other offshore areas; and
- provide recommendations for standardized reporting of emissions to ambient air from offshore UOG operations related to: cumulative regional impacts; global impacts from greenhouse gases; and national and international pollutant inventories.

Existing reporting requirements in North American offshore jurisdictions, including the proposed changes to the National Pollutant Release Inventory (NPRI) requirements, the United Kingdom and Norwegian sections of the North Sea, and Australia were reviewed.

Available air emissions inventory data and studies conducted in the United Kingdom, Canada, and the United States demonstrate that the bulk of air emissions from offshore UOG result from power generation and flaring. Based on this data, the primary pollutants of concern generated by the industry are CO_2, VOCs, CH_4, and NO_x.

The study determined that air emission reporting varies significantly by jurisdiction, ranging from no reporting in the Gulf of Mexico Outer Continental Shelf to annual reporting of emissions in the UK section of the North Sea. Work is, however, underway by the International Association of Oil and Gas Producers towards standardizing emissions reporting. In Canada, non-regulatory reporting structures are already in place for greenhouse gases (GHG) through the Voluntary Challenge Registry (VCR), and for benzene emissions from glycol dehydrators. In addition, beginning in the 2003 reporting year, the offshore UOG industry is required to report air emissions as part of NPRI for those facilities or activities that are currently exempt.

Based on the findings and ongoing developments related to the recently ratified Kyoto Protocol, consideration should be given to the: continuation of the current offshore UOG industry practice of reporting GHGs via the VCR program; reporting of benzene emissions from glycol dehydrators following CAPP's Best Management Practices (2000); and reporting NPRI substances, as required, following the NPRI format for applicable facilities until such time as international protocols are developed (e.g., GHG accounting for emissions trading purposes) or international industry lead frameworks are finalized. In the case of facilities that are required to report under NPRI, VOCs should be reported to the Boards following NPRI recognized protocols. It is suggested that the operator's environmental plans, submitted in compliance with the Petroleum Production and Conservation Regulations, contain a commitment to provide the reports to the Board.

Abbreviations and Acronyms

APCD	Air pollution control district
CAC	Criteria air contaminants
CH_4	Methane
CLRTAP	Convention on Long Range Transboundary Air Pollution
CNOPB	Canada-Newfoundland Offshore Petroleum Board
CNSOPB	Canada-Nova Scotia Offshore Petroleum Board
CO	Carbon monoxide
ESRF	Environmental Studies Research Fund
GHG	Greenhouse gases
HAP	Hazardous air pollutants
MMS	United States Department of the Interior Minerals Management Service
N_2O	Nitrous oxide
NAAQS	National Ambient Air Quality Standards
NEB	National Energy Board
NH_3	Ammonia
NM VOC	Non-methane Volatile Organic Compounds
NO_2	Nitrogen dioxide
NO_X	Nitrogen oxides
NPRI	National Pollutant Release Inventory
OSPAR	Convention for Protection of the Marine Environment of the Northeast Atlantic
OWTG	Offshore Waste Treatment Guidelines
PM_{10}	10-micron particulate matter
POP	Persistent organic pollutants
SO_2	Sulphur dioxide
UKOOA EMS	United Kingdom Offshore Operators Association Environmental Emissions Monitoring System
UKOOA	United Kingdom Offshore Operators Association
UOG	Upstream oil and gas
VCR	Voluntary Challenge Registry
VOC	Volatile organic compounds

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1.0 Introduction

It is the current government position that air emissions from offshore oil and gas activities in Atlantic Canada are not likely to cause significant impacts on a project-by-project basis, but may contribute to cumulative effects or affect national commitments on matters such as greenhouse gas (GHG) emissions reductions (NEB/CNOPB/CNSOPB, 2002).

There is currently no evidence that air emissions related to the upstream oil and gas (UOG) industry in Atlantic Canada are adversely impacting the offshore environment; nor is there data comparing contributions of UOG emissions with regional sources of pollutants, such as shipping, and emissions originating in the United States.

Considerable research has been conducted to support policy and regulatory development regarding air emissions from the UOG industry in onshore settings in Canada as well as onshore and offshore settings elsewhere. The development of reporting requirements has been given much attention through the revision of the Offshore Waste Treatment Guidelines (OWTG) and through the National Pollutant Release Inventory (NPRI) Upstream Oil and Gas Work Group. The recently revised OWTG (NEB/CNOPB/CNSOPB, 2002) recommend that new developments estimate the annual quantities of GHG emissions as part of the development application. In addition, the OWTG recommend that each operator, whether drilling or production, determine the type and significance of volatile organic compound (VOC) emissions, and provide a report of the emissions following existing best management practices for oil and gas operations in Canada. However, the findings, policies and regulations for Canadian onshore and international offshore UOG activities cannot be assumed to apply to offshore Atlantic Canada.

Furthermore, Environment Canada has expanded the NPRI reporting criteria, requiring the offshore UOG industry to report air emissions to NPRI for the 2003 reporting year and beyond.

As a result of these developments, there is a desire by the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB), the Canada-Newfoundland Offshore Petroleum Board (CNOPB), and Environment Canada (EC) to more fully address air quality in the offshore environment of

Atlantic Canada. In order to better understand offshore air quality on the Scotian shelf, the Environmental Studies Research Fund, CNSOPB, and EC are in the process of establishing an air quality monitoring station on Sable Island.

Furthermore, ESRF identified a need to develop standardized reporting criteria for air emissions that may be associated with:

- cumulative regional impacts;
- global impacts from greenhouse gases; and
- national and international pollutant inventory of criteria air contaminants.
- providing a qualitative understanding of air emissions from offshore UOG activities.

This is organized as follows:

Section 2 provides: a general overview of the types of offshore UOG activities related to exploration, production and transportation; a general description of the processes and equipment involved with these activities, that generate emissions to ambient air; and emission inventory data summarizing sources and typical composition.

Section 3 provides a discussion and summary matrix that assess the identified emissions in terms of potential for impact on local/regional marine environments and contribution to global impacts, as well as the relevance to existing and expected reporting requirements for onshore UOG in Canada and offshore UOG operations in other parts of the world.

Section 4 summaries the findings of this study and provides a suggested framework for standardized reporting criteria for air emissions that may be associated with local/regional impact and global impact, and that will be relevant to national and international reporting criteria.

2.0 Sources of Offshore UOG Emissions to Ambient Air

2.1 Offshore UOG Activities

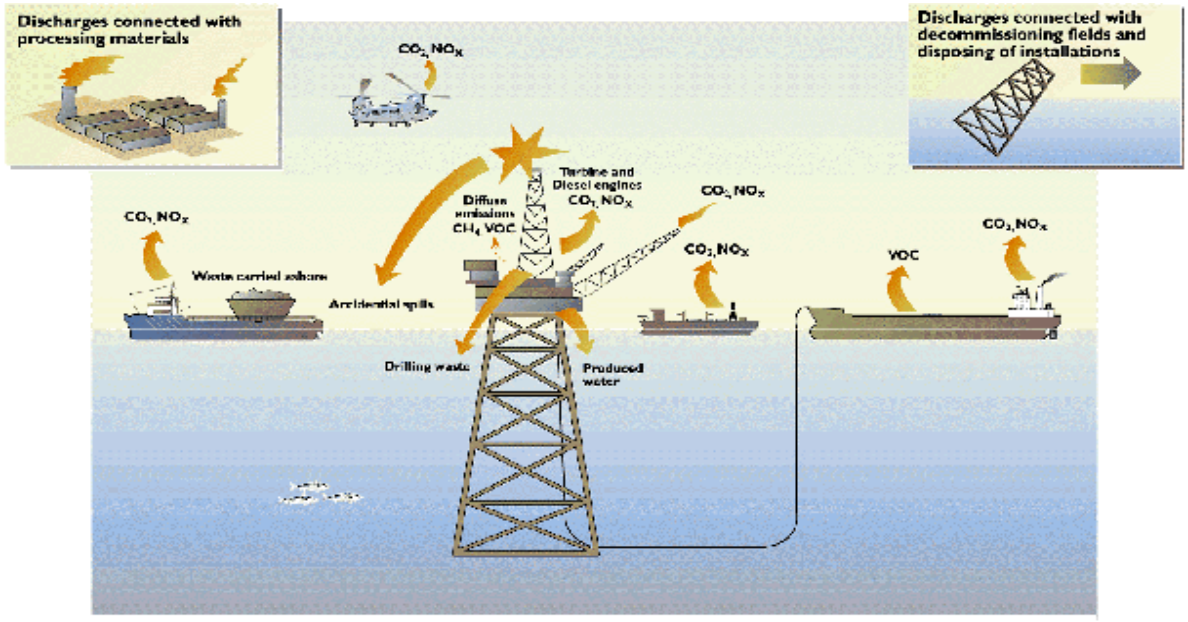
Offshore UOG operations involve a number of activities that bring a project from potential to production and through to decommissioning and abandonment. Every facet of UOG operations involve, activities that generate emissions to air.

Principal offshore oil and gas operations contributing to atmospheric emissions include the following:

- Exploration and production (E&P) activities such as vessel operations and drilling;
- Combustion of raw hydrocarbon materials during E&P and processing activities (e.g., from generators and
- Storage and transport of materials and waste.

Overall, atmospheric emissions can result from a number of sources associated with an offshore installation, which include: flare systems, vents, diesel engine and gas turbine exhausts, and leakage of gases from tanks, pipe-work and refrigeration systems from sources such as supply boats. Emissions to atmosphere can be broadly categorised as fugitive, accidental or controlled. Figure 2-1 shows the principal sources of air pollution from offshore installations.

Figure 2-1: Sources of Atmospheric Emissions



World-wide data on the contribution of these emissions to the total anthropogenic contribution is limited and location specific; however, based on the limited data set, the contribution of air emissions from the offshore UOG industry within a regional context is considered minor. The United Kingdom Offshore Operators Association (UKOOA) estimates that a relatively small amount, approximately 4%, of the annual loading of man-made atmospheric emissions in the UK are produced as a result of offshore production of oil and gas (UKOOA, 1998). The United States Department of the Interior Minerals Management Service (MMS) concluded that existing (2001) concentrations of nitrogen dioxide (NO_2), sulphur dioxide (SO_2), 10-micron particulate matter (PM_{10}), and carbon monoxide (CO) in the Gulf of Mexico Outer Continental Shelf region were well within the National Ambient Air Quality Standards (NAAQS) and would remain within NAAQS, given the projected increase in emissions from 2002-2007 associated with 770-1836 exploration and delineation wells and 1410-2637 development and production wells (MMS, 2001).

2.2 Categories of Emissions

2.2.1 Process Emissions

Process releases can include normal or abnormal emissions. Normal emissions arise from a process running under normal operating conditions. Abnormal releases are emissions that may occur during operation of a process under upset conditions that are likely to exceed normal emission release rates for a short time (e.g., discharges from safety control devices, such as emergency release valves) or other infrequent releases such as process start-up and shutdown and routine maintenance.

2.2.2 Fugitive Emissions

Fugitive releases are mainly associated with losses of gases or vapours to ambient air from joints and valves installed in pipes handling volatile substances under pressure. Breathing losses from storage tanks are also classified as fugitive emissions. While each point source may be a minute release, a complex industrial source may have hundreds of such sources, resulting in significant emissions when the process is operating normally.

2.2.3 Accidental Emissions

Accidental releases are leaks or spills that may escape in uncontrolled ways into the environment. Accidental emissions usually result from incidents such as equipment failure or operating errors. Fugitive and accidental emissions are the most difficult to quantify.

2.2.4 Mobile Emissions

Mobile emissions are emissions from transport equipment including supply vessels and helicopters.

2.3 Types of Emission Sources (Morphology)

2.3.1 Line

Line source emissions are releases arising from transport-related activities taking place along lines of a route, such as shipping lanes to offshore installations.

2.3.2 Point

Point source emissions are emissions arising from activities at a fixed location, such as flaring.

2.3.3 Area

Area source emissions are releases arising from small-scale diffuse activities, for which data is usually only available on a small area, as opposed to a site-specific or fixed point, basis. An example of an offshore area source would be accommodation areas. In practical terms, it is not possible to measure emissions from all sources associated with these areas.

Typical sources of air emissions, morphology and primary pollutants of concern are summarized in Tables A-1, A-2 and A-3 (Appendix A).

2.4 Quantification of Emissions for the Sector

Government and industry inventories of offshore air emissions data vary in detail and categorization from jurisdiction to jurisdiction; however, one of the more comprehensive data sources detailing current emissions has been assembled by UKOOA.

The UKOOA database provides figures for the emissions of principal pollutants from offshore (and mobile offshore) activities from 1996 to 2000 (Table 2-1).

Table 2-1: Offshore Atmospheric Emissions Inventory

Pollutant	Emissions per Year (Tonnes)				
	1996	1997	1998	1999	2000
Carbon dioxide	19,262,283	19,520,860	20,892,189	19,757,969	18,760,416
Nitrogen oxides	55,243	58,509	66,739	55,805	52,487
Nitrous oxide	0	0	0	1,351	1,289
Sulphur dioxide	10,330	13,947	11,643	9,661	6,776
Carbon monoxide	38,766	37,197	39,398	31,408	29,894
Methane	74,133	74,536	71,515	64,490	57,728
Volatile hydrocarbons	95,540	102,960	80,058	74,706	73,997

Source: UKOOA, Atmospheric Emissions Inventory Reports, 2000.

Emissions from fuelling, loading and ballasting operations are generally suspected within the industry to be significant, in particular with regard to VOC emissions. Having noted this, as most of these emissions are fugitive in nature, they are difficult to measure and are likely underreported or not reported at all. Nonetheless, oil loading and fugitive emissions are two of the sources of emissions reported via the UKOOA mechanism; however, it is unlikely that these figures accurately capture the emissions associated with all loading, transfer or ballasting activities.

In Canada, Environment Canada assembled an inventory of air emissions from the UOG industry as part of the preparatory work in support of the proposed expansion of NPRI to the UOG industry and to help facilitate the development of a practical reporting framework (Picard et al., 2002). The data used to develop the inventory were drawn from a number of sources including:

- *A Detailed Inventory of CH_4 and VOC Emissions from Upstream Oil and Gas Operations – Development of the Upstream Emissions Inventory* and the detailed database used to compile that inventory prepared by CAPP;

- emissions from off-shore operations were estimated by assuming that the amount of emissions per unit of production are comparable to those for on-shore production;

- published emissions factors (e.g., USEPA, CAPP, GRI Canada, and Picard et al.[1987]); and

- Alberta Energy and Utilities Board reports and Statistics Canada information.

Based on the available data, the key sources of CO_2 and N_2O in the Canadian UOG industry are:

- Fuel combustion by gas gathering systems;
- Field fuel combustion by conventional oil production facilities;
- Aggregate emissions at processing plants; and
- Fuel combustion by gas transmission compressor stations.

Collectively, these four sources contribute approximately 87 percent of total CO_2 emissions by the industry, 92 percent of N_2O emissions but only 15 percent of CH_4 emissions.

The Canadian UOG industry was defined by Picard et al as extending from the wellhead through to the refinery gate for oil and to the start of distribution systems for natural gas.

For the purposes of this study, UOG is defined to extend to the tailgate of the offshore gas processing facility, eliminating the contribution of fuel combustion associated with gas transmission compressor stations. The three primary sources considered in this study account for 92 percent of total CO_2 emissions by the industry, 93 percent of N_2O emissions, and 12.6 percent of CH_4 emissions (Table A-4 in Appendix A).

Table A-5 summarizes the total mass distribution of NPRI criteria air contaminants (CACs) by type of facility or major activity based on the 1995 CAPP inventory, with values listed for TPM, PM_{10} and $PM_{2.5}$. These values were inferred by the authors to be the ratio of the emission factors for these pollutants to the corresponding source-specific emission factors for NO_x. That is, for a given source, if the PM_{10} emission factor was 10 percent of the corresponding NO_x emission factor, it was assumed that total PM_{10} emissions from that source would be 10 percent of the estimated amount of NO_x emissions for that source.

Emission factors for particulate matter were only available for reciprocating engines (i.e., engine-driven oil and water pumps at oil production facilities, gas gathering systems, and gas processing plants). Heaters, boilers and gas turbine engines were not identified as sources of particulate emissions; however, fuel oil fired heaters and boilers were not addressed. The authors also acknowledged that "some aerosol emissions are known to occur from heavy oil production tanks because of the high temperatures they are operated at (i.e., 70 to 80ºC), which results in volatilization of some condensable hydrocarbons. Limited unpublished test data, however, indicates only a small fraction of these aerosol emissions persist beyond the site boundary, the rest either deposits on the ground or evaporates."

The data show that facilities with significant fuel consumption by reciprocating engines are the dominant sources of NO_x, CO, TPM, PM_{10} and $PM_{2.5}$ in the industry (Picard et al, 2002).

In addition to GHGs and CACs, the authors examined the emissions of NPRI-listed substances associated with the UOG industry (Table A-6). Emissions of cyclohexane and 1,2,4-trimethylbenzene (1,2,4-TMB) were attributed to process and fugitive sources only, while emissions of formaldehyde and phenol were attributed to fuel combustion activities only. All the other listed pollutants were deemed to be emitted by both types of sources.

Process and fugitive based contributions of the listed substances were inferred from the VOC estimates[1].

Combustion based contributions of the listed substances were inferred from combustion-related CO_2 emission estimates from the 1995 CAPP inventory, based on the ratio-of-emission-factors approach.

[1] The contribution was estimated by assuming that the percentage contribution of each pollutant to total VOC emissions could be represented by a single value for certain types of emission streams. From a review of detailed gas analyses available for wet gas samples from 9 different gas processing plants, the authors identified variances in these percentage contributions by pollutant of typically less than 100 percent. For oil and condensate vapours, analyses for 6 different samples, including both heavy oil and conventional oil facilities, showed variances of typically 25 to 80 percent. Only one detailed analysis was available for dehydrator reboiler vent emissions; however, for BTEX components only (i.e., benzene, toluene, ethyl benzene and xylene), it showed similar relative contributions as BTEX-only analyses for other dehydrator reboiler vent gas streams. All of the above variances were deemed reasonable for the purposes of determining the percentage contribution of emissions by facility type, and are expected to yield fair estimates of the total amount of these emissions (Picard et. al., 2002).

Strosher (1996) identified PAHS as a component of unburned hydrocarbon in field testing of sweet battery flaring; however, Picard et al concluded that it was not possible to evaluate PAH emissions due to the lack of analyses for this substance category for typical natural gas and vapour mixtures. Based on Australia's National Pollutant Inventory (NPI) 2002 data total, PAHs make up only 0.04% of compounds reported by the oil and gas exploration and production industry as a whole (92 facilities).

The data show that field glycol dehydrators are the main source of BTEX and, 1,2,4-trimethyl benzene emissions, accounting for 80 to 95 percent of the totals for these pollutants. Field dehydrators are also a major source of n-hexane and cyclohexane.

Formaldehyde, naphthalene and phenol emissions are primarily from fuel use by engines.

In total, based on the mass emissions estimated by Environment Canada, CO_2 represents 94% of emissions; CH_4, 3.6%; VOCs, 1.5%; and NO_x, 0.4% of emissions.

Although inventory data from the recently completed GOADS program are not available, MMS has estimated that total additional pollutant load, based on its proposed 2002-2007 leasing program, similarly shows CO_2 as the most significant pollutant but estimates a larger portion of bulk emissions to VOCs, NO_x and SO_2 than determined in the UK or Canada (Table 2-2). This may be partly explained by the fact that the MMS estimates include estimates of emissions from supply vessels, pipelay vessels, helicopters and platform construction.

Table 2-2: Estimated Pollutant Emissions From Proposed Gulf of Mexico Outer Continental Shelf 2002-2007 Program Activities (MMS, 2001)

Pollutant	Emissions Per Year (tonnes)			
	Minimum	Maximum	Minimum	Maximum
NO_x	16705	31699	11.02%	11.70%
SO_2	2504	4767	1.65%	1.76%
PM_{10}	443	834	0.29%	0.31%
CO	4004	7619	2.64%	2.81%
VOC	8867	17066	5.85%	6.30%
CH_4 (carbon equiv.)	29000	48000	19.14%	17.71%
CO_2 (carbon equiv.)	90000	161000	59.40%	59.41%
Totals	151524.1	270985.2	100.00%	100.00%

Emissions source data provided by NPRI and the UKOOA (Table 2-3) shows that power generation (fuel gas and diesel) is the principal source of both mass emissions and CO_2.

Table 2-3: Sources of Mass and CO_2 Emissions 2000, Offshore and Mobile Operations, North Sea UK Section

Source	Combined mass emissions (tonnes)	Percentage (%)	CO_2 (tonnes)	Percentage (%)
Fuel gas consumption	13,218,216	69.63	13,158,594	70.10
Flaring	4,093,004	21.56	4,050,028	21.60
Diesel consumption	1,406,605	7.41	1,384,686	7.40
Venting gas	37,550	0.20	3,276	0.03
Well testing	141,047	0.74	138,010	0.70
Other (sour flare)	26,559	0.14	25,823	0.20

Source: As reported to UKOOA, 2000 figures, derived via EEMS R039

3.0 Emissions Scenarios and Potential Impacts

As shown in the preceding sections, there is generally good understanding of the emissions of pollutants and the predominant sources based on available inventory data and industry and regulator knowledge. This data can be further evaluated by comparing the relative significance of emission scenarios (those processes or events that produce emissions to air) in terms of the impact to local/regional environmental (e.g., local marine environment), global environment (e.g., GHG contribution), and relevance to existing or anticipated reporting requirements.

3.1 Local/Regional Impacts

Local/regional environmental impacts for the purposes of this study relate to potential receptors within the immediate vicinity of the facility or the regional setting of the facility (e.g., Scotia Shelf).

The impacts in this category are generally a factor of proximity of receptors and intensity of development in a region. At present, in both producing offshore regions in Canada, Scotia Shelf and the Grand Banks, receptors are not generally present with the exception of Sable Island, and the intensity of development is low. Table 3-1 provides a summary of the scenarios that have the potential for local and/or regional impacts. Emissions of CH_4, VOC and H_2S are common to almost all scenarios but, as demonstrated in Section 2, the bulk emissions of these pollutants make up only a small fraction of the total emissions from the industry. On a scenario basis, there are a number of scenarios that emit all of the primary local/regional pollutants, including power generation, well testing, well clean-up, flaring, cold venting and vessel/helicopter exhaust.

The relative impact of the scenarios, that is, whether it is significant or not, will depend on local receptors and on the intensity of development. For example, the local/regional impacts of flaring may have measurable effects on a receptor such as Sable Island; in contrast, the local/regional impact of flaring at Hibernia is likely low. A better understanding of the local impact from UOG emissions should result from the proposed Sable Island ambient air monitoring station due to be operational in the summer of 2003.

Table 3-1: Emissions Scenarios and Potential Impacts

Primary Areas of Impact	**Primary Air Pollutants**									
L = Local **R = Regional** **G = Global** **nd = No Data**	**CO_2, CO**	**CH_4**	**SO_X**	**NO_X, N_20**	**VOC**	**H_2S**	**PM**	**Halons**	**PFC**	**SF_6**
SCENARIO										
Gas power generation	LRG	RG	LRG	RG	LRG	LRG	L			
Diesel power generation	LRG	RG	LRG	RG	LRG	LRG	L			
Well testing	LRG	RG		RG	LRG	LRG	L			
Well clean-up	LRG	RG	LRG	RG	LRG	LRG	L			
Flaring of gas	LRG	RG	LRG	RG	LRG	LRG	L			
Cold venting of gas	LRG	RG	LRG	RG	LRG	LRG	L			
Produced water discharge	L	L			L	L				
Fuel spills	L	L			L	L				
Maintenance activities (pipes, tanks)	L	L			L	L		G	G	G
Glycol regeneration					LRG					
Vessel / helicopter exhausts	LRG	RG	LRG	RG	LRG	LRG	LRG			
Loading – Crude oil to tanker		RG			LRG	LRG				
Loading –Diesel Fuel loading		RG			LRG	LRG				
Loading – Drilling muds		RG			LRG					
Blow-out		RG			LRG	LRG	L			
Tank breathing		RG			LRG	LRG				
Fugitive (valves, flanges, surfaces etc.)		RG			LRG	LRG		G	G	G
Mixing muds and cements					LRG		L			
Accidental fuel releases		RG			LRG	LRG				
Degassing muds and cuttings		RG			LRG	LRG				
Pigging		RG			LRG	LRG				
Laboratory chemicals					L					

3.2 Global Impacts

Table 3-1 also summarizes the scenarios and pollutants that contribute to global impacts. The majority of operational scenarios generate pollutants that contribute to regional and global air pollutant concerns such as GHG and acid deposition. As demonstrated in Section 2, the largest contribution to the global impacts is from CO_2 and CH_4 emissions from power generation (both diesel and gas) and flaring, with other inputs, such as VOCs, significantly less. There are little data on emissions of halons, PFC and SF_6 from the industry; however, the global contribution from the UOG industry is minor, based on data reported to UKOOA.

3.3 Emissions Reporting

3.3.1 Overview

Of particular relevance in this study is a review of emissions scenarios and emitted pollutants in light of existing and anticipated reporting requirements.

The principal purpose of atmospheric emission reporting inventory is often, but not necessarily, regulatory based. Emission regulations or statutes can require operators to determine the amount of pollutants released to the atmosphere. Data provided by the oil and gas industry, both onshore and offshore, are used by Governments to monitor compliance with air quality regulations and to meet national and international reporting requirements and commitments where applicable. The level of reporting varies from jurisdiction to jurisdiction. This ranges from the UK, which has a variety of requirements for reporting of emissions, to the Gulf of Mexico where there is no requirement for annual reporting, except for periodic emissions surveys, such as the recently completed Gulf wide Offshore Activities Data System (GOADS) program. With the inclusion of offshore UOG in the NPRI 2003 reporting year; other jurisdictions such as California, Norway, Australia, and Canada also require annual reporting, but the type of reporting and parameters reported varies.

In practice, it is not possible to measure emissions from all of the individual sources or, in the short-term, from all the different source types. In most reporting frameworks, atmospheric emissions are estimated on the basis of measurements made at selected or representative samples of the (primary) sources and source types. Others may be estimated using emissions factors, equipment run times and fuel usage. Although emission inventories may contain data on the three principal types of sources described earlier, the data may be reported on a site specific (e.g. drilling unit) or an area basis (e.g., E&P production field).

Those databases of emissions that do exist, generally do not report on pollutants to the level of detail of individual processes or sources, as discussed earlier, with the exception of flaring and oil loading. Rather, they report on aggregated emissions associated with larger scale activities such as gas, diesel and fuel oil consumption, venting, and fugitive emissions. Or, in the case of pollutant inventories in Canada and Australia, reported on total facility emissions of specific parameters.

The majority of oil and gas industry emissions to atmosphere are estimated from the knowledge of the process that forms them, as opposed to site specific monitoring of emissions. Certain Air Pollution Control Districts in California are the exception to this. For some of the pollutants this is relatively straightforward because emissions are largely dependent on fuel composition (e.g., the sulphur content of the fuel). For other pollutants (e.g., NO_x) emissions depend upon combustion conditions, such as temperature and pressure, and, therefore, are more difficult to quantify and may, therefore, be less accurate. Emission estimates from point or area sources generally tend to be better defined than from mobile sources (e.g., ships, etc.) as more factors affect the type and quantity of the pollutant emitted.

Reporting emissions requires data to produce pollution emission factors and loads. The emission factor is the amount of a pollutant or a combination of pollutants released by a source (directly or indirectly) per unit of production or per unit of raw material consumed, depending upon the type of industry or method of calculation of the pollution emission factor. Pollution loadings are the total amount of a pollutant or a combination of pollutants released (directly or indirectly) by a source in a given period of time. Emission estimates are collected together into inventories or databases that usually also contain supporting data. This includes: the locations of the sources of

emissions; emission measurements where available; pollution emission factors; capacity, production or activity rates in the various source sectors; operating conditions; and methods of measurement or estimation. Such supporting data are available from various sources including:

- CORINAIR and the Selected Nomenclature for Air Pollution (SNAP)
- UKOOA Environmental Emissions Monitoring System (UKOOA EEMS)
- US EPA AP 42
- American Petroleum Institute
- CAPP CH_4 and VOC Emissions from the Canadian Upstream Oil and Gas Industry.
- EMEP (Co-operative Programme of the Long Range Transmission of Air Pollutants in Europe)
- National Atmospheric Emissions Inventory (UK)

The following sections summarize the reporting requirements of selected offshore jurisdictions.

3.3.2 Current Canadian Reporting

In Canada, there are currently no regulatory requirements to report air emissions from offshore UOG activities; however, several companies voluntarily report emissions of GHGs from their activities through the Voluntary Challenge Registry (VCR). Where applicable, benzene emissions from glycol dehydrators following *CAPP's Best Management Practices for the Control of Benzene Emissions* from glycol dehydrators. As noted previously, NPRI will require the UOG industry to report emissions starting in the 2003 reporting year. The VCR program and proposed NPRI reporting requirements are discussed in the following sections.

3.3.2.1 Voluntary Challenge Registry

The VCR is a non-regulatory reporting program that is designed to account for both direct and indirect emissions associated with the industry, such as the supply of energy or services. The intent of the registry is not to develop a detailed inventory of GHG emissions, but to demonstrate the actions being taken by industry towards GHG reduction.

Companies submit annual reports that summarize GHG reduction progress, emissions of GHGs, and projections and actions for future GHG reductions. Mass emissions reported are obtained

either through direct measurement, where available, or through the use of emissions factors, or a combination of these methods. To ensure consistency in reporting of emissions, the VCR provides companies with guidelines for direct measurement as well as emission factors. In the Nova Scotia offshore, VCR reporting is completed using emissions factors based on energy used to extract the resource with no direct measurement.

3.3.2.2 Reporting of Benzene Emissions from Glycol Dehydrators

The UOG industry participates in a voluntary program to reduce benzene emissions from glycol dehydrators. The program's objective is to attain 90% reduction from the 1995 benzene emissions baseline by January 1, 2005. To demonstrate industry progress in reducing emissions, companies operating glycol dehydrators submit an inventory of their glycol dehydrators and corresponding benzene emissions. Emissions are estimated using the Gas Research Institute's GlyCalc Model or equivalent methods.

3.3.2.3 Proposed NPRI Reporting

Expansion of the scope of UOG industry NPRI reporting was considered appropriate following the addition of CACs (oxides of nitrogen, SO_2, CO, VOC and particulate matter) to NPRI. The UOG industry is considered a major source of these pollutants, but the industry is underreported due to the existing NPRI exemption for drilling and operating gas wells and the 20,000 employee-hour threshold (Aird, 2002).

To better capture UOG industry emissions both onshore and offshore, EC has proposed the following rule changes (only the changes effective for 2003 are listed):

- operating and injection wells will no longer be exempt from reporting if they meet the reporting criteria;
- offshore platforms, infrastructure and vessels (e.g., FPSOs) will be required to report if the facilities meet the criteria;
- all Schedule 1 pollutants to be reported at current thresholds;
- CACs related to stationary combustion and flares are to be reported, regardless of employee threshold; and

- selective changes to be made to reporting of benzene emissions specific to glycol dehydrators.

As with VCR, emissions are calculated using NPRI accepted protocols. No direct measurement is required.

3.3.3 International Reporting

In the North Sea, International protocols and conventions necessitate the need for national emission inventories. The reporting of emission inventory data to the Convention on Long-range Trans-boundary Air Pollution (CLRTAP) is required in order to fulfill obligations regarding strategies and policies in compliance with the implementation of protocols under the Convention. These protocols include, for example, the Helsinki Sulphur Protocol (1985); the Sofia NO_x Protocol (1988); the Geneva VOC Protocol (1991); the Oslo Sulphur Protocol (1994); and the Aarthus Protocols on Heavy Metals and on Persistent Organic Pollutants (POPs).

3.3.3.1 EU Member States

EU Member States are required to submit annual national emissions for NO_x, SO_2, Non-methane volatile organic compounds (nmVOC), CH_4, CO, NH_3, and various heavy metals and persistent organic pollutants (POPs) for 11 main source categories. Member States are also invited to report emissions of more detailed source sub-sectors. In addition, they are required to provide the European Monitoring and Evaluation Programme (EMEP) periodically with emission data within grid elements of 50 km x 50 km. Member States are required to use the draft reporting procedures (EB.AIR/GE.1/1997/5) when compiling their inventories. Member States are also required to report to the Commission their anthropogenic CO_2 emissions and removal sinks, as well as their national inventory data on emissions/removal for the six Kyoto greenhouse gases (CO_2, CH_4, N_2O, PFCs, HFCs and SF_6) on an annual basis.

Recently, a committee has been formed, in accordance with the EC Directive Integrated Pollution Prevention Control (IPPC) to establish the format and particulars of the 'inventory of principal emissions and sources responsible' (the proposed Polluting Emissions Register ([PER]). The inventory will be based on data supplied by Member States to Directorate-General

XI (DGXI), who are then required to report this inventory on a 3 yearly basis to Council and Parliament. The first inventory is expected to be reported some time in 2002.

Under Article 12 of the United Nations Framework Convention on Climate Change (UNFCCC) all parties (EU Member States) are required to develop, periodically update, publish and make available to the Conference of Parties national inventories of anthropogenic emissions by sources and removals by sinks of all greenhouse gases not controlled by the Montreal Protocol.

A summary of current reporting protocols in the United Kingdom and Norway is provided in the following sections.

3.3.3.2 United Kingdom

The adoption of the IPPC Directive (96/61/EC) by the Department of Trade and Industry (DTI) Oil and Gas office has placed a requirement on installation over 50 MW (thermal) to apply for an operating permit. Detail on the application of IPPC to the offshore industry is covered in Statutory Instrument (SI) 2001 No 1091. This permit details how an installation will operate its operational combustion equipment (e.g., gas turbines and diesels) to minimize atmospheric discharges; in particular, discharges of NO_x, SO_x, CO and unburnt hydrocarbons. Combustion equipment accounts for approximately three quarters of the total offshore emissions. Control of discharge of these gases is to be achieved by efficient use of all plant covered by the SI and adoption of Best Available Techniques (BAT). The SI does not cover atmospheric discharges from operational or emergency flaring.

Details required by the DTI prior to the granting of a permit include the quantity of these gases, in dry metric tonnes, that will be emitted annually during the lifetime of the field. Guidance on acceptable methodologies for the assessment of emissions is available in the DTI's '*Guidance notes on the offshore combustion installations (Prevention and Control of Pollution) Regulations 2001*' and in a companion report prepared by AEA Technology for the DTI '*Background Paper on Offshore Emission Monitoring'.*

To comply with the IPPC Directive (96/61/EC), operators are required to file an annual report with the DTI that includes the operator's assessment of the annual atmospheric discharges for

NO_x, SO_x, CO and unburned hydrocarbons. The assessment of the quantity of each discharge can be based upon a very limited measurement regime or spot measurement, provided that reference can be made to algorithmic or graphical methods for assessment of discharges at all other operating points.

The principal UK reporting system that provides emission data for the offshore UOG is the United Kingdom Offshore Operators Association Environmental Emissions Monitoring System (UKOOA EEMS) - specifically EEMS/R039 – Atmospheric Emissions Inventory Emissions by Source, and EEMS/R035 - Atmospheric Emissions Inventory Emissions by Species (an example of this inventory and data entry form is provided in Appendix B).

UK operators report on source emissions via the UKOOA system and these are recorded on EEMS R039. However, as indicated earlier, the level of detail is limited and source data consists of emissions from gas and diesel consumption, well testing, flaring, venting, oil loading and estimates of fugitive emissions.

In addition to the UKOOA EEMS database for offshore emissions, offshore oil and gas operating companies are also 'encouraged' to have their own inventories, although they are not legally obligated to do so.

3.3.3.3 Norway

In Norway all emissions are regulated under the Pollution Control Act. The Norwegian Pollution Control Authority issues discharge permits and has the authority to require monitoring of the environment and phase out the use of hazardous chemicals. The environmental authorities can also set targets for acceptable environmental impacts. The zero-discharge strategy for new petroleum installations, which states that all discharges of possibly harmful chemicals to the sea should be avoided, was first introduced in Report No. 58 (1996-1997) to the Norwegian parliament.

Norway plays an active role in much of the international work in this field. Some of the most important areas in this connection are the work of the Convention for Protection of the Marine Environment of the North-East Atlantic (OSPAR). This involves efforts to reduce emissions of

greenhouse gases within the framework of the Kyoto Protocol, and the new Protocol under the Convention on Long-range Transboundary Air Pollution, the Gothenburg Protocol to Abate Acidification, Eutrophication and Ground-level Ozone.

Under OSPAR, the main sources of air emissions and aqueous discharges can be categorized as follows:

- Spills and flaring;
- Cuttings and organic phase-based drilling muds;
- Displacement/drainage water;
- Production (and displacement) water; and
- Accidental spills.

The OSPAR Commission met in 1999 and developed a strategy on Environmental Goals and Management Mechanisms for Offshore Activities.

The Commission's action plan had various facets but Section 5C and D pertained to air emissions (OSPAR 99/15/1-E, Annex 10) as follows:

C. Emissions of substances which are likely to pollute the air, to the extent that they are not regulated by other international agreements.

D. Flaring, to the extent that emissions from flaring are not regulated by other international agreements.

As a result, a template was developed by the operating committee to allow data collection on discharges, waste handling and air emissions from offshore installations by country and by source.

In addition to the parameters above the following are to be reported:

- the number of installations with discharges to water or emissions to the air,
- the number of installations without discharges or emissions; and

- total number of installations, and volumes of water discharged, flaring operation spills, smaller spillages of oil, and number of wells drilled with oil based muds.

The reporting template, which is included in Appendix C, provides a mechanism by which the participant countries can report emissions. The template provides data on the following pollutants:

- CO_2
- NO_x
- VOC
- CH_4
- SO_2

3.3.3.4 Gulf of Mexico

The MMS has jurisdiction over federal waters off Louisiana, Texas, Alabama and Mississippi. Federal regulations 30 CFR 250 s. 303 and 304 serve as the basis for air emissions requirements in the Gulf of Mexico. At present, operators must file projected emissions data (based on API emissions factors and equipment run times) for approval prior to commencement of an activity or when equipment is replaced. However, following approval no additional monitoring or reporting of emissions is required (pers. comm., L. Puhler). A requirement from MMS to report equipment run time as a proxy for emissions is anticipated by industry within the next two years (pers. comm., N. Foreward).

3.3.3.5 California

In California, the requirements for addressing offshore air quality issues are overseen by individual county-based air pollution control districts (APCD). Based on the recommendation of the local MMS air quality specialist, Dillon reviewed the reporting requirements of the Ventura County APCD.

As a minimum standard, projects are required to meet the APCD's emissions standards by applying Best Available Control Technology. Permits are renewed annually and projects are

inspected by an Air Pollution Control Officer (APCO) to determine compliance with the issued permit.

Operators are required to keep records of fuel consumption and equipment inspections. While the records must be available for APCO review, formal reports are not required for these elements. Operators must also conduct annual source testing for stationary equipment such as engines. For smaller engines (<50 horsepower) the operator must test for NO_x. For engines over 50 horsepower, operators must test annually for NO_x, CO and reactive organic compounds (ROC). These are reported annually through the submission of an Emissions Statement to the APCO.

3.3.3.6 Australia

In Australia, reporting of air emissions by the UOG industry is through the National Pollutant Inventory (NPI). The NPI was established as a database to provide community, industry and government with information on the types and amounts of selected pollutants emitted to air, land or water. Similar to Canada's NPRI, there is a suite of triggers for reporting; however, there is no employee-hours threshold in NPI. All triggers are based on either use of the pollutant (Categories 1, 1a, 3) or energy use (Categories 2a, 2b). Reporting is done on a facility basis, broken down by major source/types. A list of substances and corresponding triggers, as well as examples of calculation worksheets, are provided in Appendix D.

3.4 Summary of Reporting Requirements

This report demonstrates that globally there is a wide variety of reporting regimes applicable to the offshore; however, the majority of the reporting covers the predominant emissions and sources. Table 3-2 provides a summary of those pollutants currently reported or proposed to be reported by the offshore UOG industry in the jurisdictions surveyed.

Table 3-2 Summary of Pollutants Reported by Industry From Jurisdiction Surveyed

Pollutant	Jurisdiction				
	Canada	**VCAPCD***	**North Sea-UK**	**Australia**	**Norway**
CO_2, CO	√[2,3]	√	√	√[4]	√
CH_4	√[2]		√	√	√
SO_x	√[3]		√		√
NO_x, N_2O	√[2,3]	√	√	√	√
VOC	√[3]		√	√	√
H_2S	√[3]		√	√	
PM	√[3]		√		
CFC	√[2]		√		
HCFC	√[2]		√		
Halons			√	√	
PFC	√[2]		√	√	
SF_6	√[2]		√	√	
Other Substances	√[3]	√[1]		√[5]	

1 Reactive Organic Compounds only.
2 As part of VCR program
3 Proposed for 2003 NPRI reporting year provided substance-specific reporting threshold met
4 CO Only
5 See Appendix D for complete list of substances

* Ventura County Air Pollution Control District

The UK section of the North Sea, through the UKOOA EMS, currently requires the most complete reporting in terms of parameters of significance and reportable activities. In Australia and Canada, through the VCR program and the proposed changes to the NPRI reporting requirements the industry, is or will be reporting a broader suite of pollutants. In contrast to the UK, Canadian reporting is, with the proposed exception of CACs, triggered by substance-specific and employee-hours thresholds. As well, exploration drilling (which is not currently being considered for the 2003 NPRI, but included as part of VCR reporting) is included in the UK emissions reporting. Similarly, Australia's reporting requirements are triggered by substance use or energy consumption. The triggers are set so that applicable facilities include not only processing but exploration and development.

In Ventura County, offshore reporting requirements are tied to onshore air quality objectives in which the reduction of smog is the primary impetus. Conversely, the Gulf of Mexico operators have no air emissions reporting requirements.

These differences are largely due to the differences in the jurisdiction's regulatory needs or international commitments. In Canada reporting is driven by both voluntary initiative(e.g., VCR program) and by federally legislated requirements (e.g. the *Canadian Environmental Protection Act* requirement for a national inventory of released pollutants). In the UK, the need for reporting is partially required by international treaties. In California, reporting is driven by the state's objective to reduce smog in onshore areas.

Similarly, there is no consistency on what aspects of the operations are included in the report. For example, Canada has set substance-specific and employee thresholds for reporting, whereas the UK and Australia do not. Furthermore, only the UK categorizes emissions by source type (i.e. fuel consumption flaring).

When comparing emission inventory data sets from different jurisdictions, it is important to take into account factors such as: the regulatory environment, the geographical location, climatic conditions, size and density of industrial operations and methods of estimating emissions.

Emission inventory studies have shown, particularly studies assessing Gross Energy Requirements, inherent uncertainty factors of 30-40% in predicted emissions (Ogilvie, 1992; Philipp et al., 1995; USEPA, 1995 in Cordah, 1998). With this level of uncertainty, is important to acknowledge the key influencing factors that may cause variations from one jurisdiction to another. For example, a rise in exploration and production emissions from one year to the next may be due, in part, to better data collection procedures, an improved understanding of the chemical composition of gaseous emissions, and new reservoirs coming on stream. Other reasons for variability to occur in emission inventories include:

- accuracy of monitoring and detection techniques;
- accuracy of emission sources characteristics (e.g., gas composition, volumetric flow rate);
- access to emissions sources; and

- misinterpretation or inaccuracies of recorded emissions.

These discrepancies are recognized internationally and, to that end, the International Association of Oil and Gas Producers has undertaken the task of gathering environmental data on a consistent basis so that comparisons can be made between jurisdictions. This work and the development of a framework for reporting is ongoing.

4.0 Recommendations

When contemplating the standardization of a reporting system, the objective of the reporting must be well defined and consistent with current regulatory requirements and international obligations. During the course of this study, two developments have arisen that impact on a proposed reporting framework.

First, EC has outlined its NPRI reporting proposal for the 2003 reporting year, which will encompass the onshore and offshore UOG industry. This proposal includes: the requirement for reporting on operating, injection wells, offshore platforms, infrastructure and vessels (e.g., FPSOs) if the facilities meet the criteria; the reporting of all Schedule 1 pollutants at current thresholds; the reporting of CACs related to stationary combustion and flares; and selective changes to the reporting of benzene emissions specific to glycol dehydrators.

Second, the Government of Canada ratified the Kyoto Protocol on December 17, 2002. Although a detailed implementation plan has not been defined, it is expected that internationally developed reporting will be required to demonstrate compliance with the Protocol or to facilitate emissions trading.

Given these developments and the industry's familiarity with and acceptance of the current VCR program for reporting GHG, NPRI reporting and, where applicable, benzene emission reporting, consideration should be given to maintaining the status quo and to continuing to require the offshore UOG industry in Atlantic Canada to report emissions through these programs as well as providing the reports to the Boards until such time that internationally agreed upon reporting mechanisms are in place. As demonstrated in the report, these reporting mechanisms provide substantial air emissions data on a facility basis. The reporting of GHG in accordance with VCR is consistent with the OWTG. To address OWTG requirements to report VOCs from drilling and production installations, it is suggested that the industry report VOCs to the Boards using protocols recommended by NPRI and CAPP (2001), regardless of NPRI (without applying the reporting threshold). Provision can be made in the operators' environmental plan (required by the Petroleum Production and Conservation Regulations) for a commitment to provide the reports to the Boards.

5.0 References

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Appendix A
Emissions Data Tables

Table A-1: Sources of Gaseous Emissions

Source	Category	Morphology	Pollutants
Exploration and Production (E&P)			
Generators to provide power (turbines/engines) gas powered (production platforms)	Process	Point or area	CO_2, CH_4 SO_x, NO_x, PM if unrefined
Generators to provide power (turbines/engines and thrusters on drill rigs) - diesel powered (production platforms and drilling rigs)	Controlled	Point or area	CO_2, CH_4, NO_x, SO_x, Project Manager
Generators to power compressors to export product	Controlled	Point or area	CO_2, CH_4, NO_x, SO_x
Combustion exhausts from plant and machinery (e.g. cranes, lifting gear)	Controlled	Point or area	CO_2, CH_4, NO_x, SO_x, PM, VOCs
Combustion exhausts to drive the drill string (if independently powered)	Controlled	Point or area	CO_2, CH_4, NO_x, PM, VOCs
Well testing	Controlled	Point or area	CO_2, SO_x, NO_x, VOC, CH_4, uncombusted HCs, HAP
Well clean-up	Controlled	Point or area	CO_2, SO_x, NO_x, VOCs, CH_4, HAP
Flaring	Controlled	Point	CO_2, SO_x, NO_x, VOCs, CH_4, uncombusted HCs, H_2S, PM, HAP
Venting	Controlled/ Accidental	Point	CO_2, SO_x, NO_x, VOCs, CH_4, H_2S, HAP
Cold venting, i.e., purging to gain + ve pressure in the lines (being phased out in UK)	Controlled	Point or area	CH_4, CO_2
Produced water discharge	Controlled	Point or area	VOCs
Fuel spills (e.g., taking diesel on board the rig)	Accidental	Area	CO_2, VOCs, SO_x, NO_x
Maintenance activities on pipes and tanks under + ve pressure	Controlled	Point or area	CO_2, NO_x, VOCs, H_2S, CH_4
Glycol regeneration	Controlled	Point or area	VOCs
Transportation			
Exhaust emissions from vessels	Mobile	Line	CO_2, NO_x, VOC, SO_x, Project Manager
Helicopter exhausts	Mobile	Line	CO_2, NO_x, VOC, SO_x, Project Manager
Collision (fuel release)	Accidental	Area/Line	VOCs
General Activities			
Loading oil tanks, tankers (e.g. from FPSOs)	Fugitive	Area	VOCs, CH_4

Source	Category	Morphology	Pollutants
Blowout	Fugitive	Area	VOCs, CH_4, CO_2, H_2S, HAP
Tank breathing	Fugitive	Area	CO_2, NO_x, CH_4, VOCs
Bunkering (e.g., taking diesel or drilling mud on board the rig)	Fugitive	Area	CO_2, NO_x, CH_4, VOCs
Emissions from valves, flanges, seals, bunds, drip trays, drains, decks, machinery spaces and other surfaces	Fugitive	Area	CO_2, NO_x, SO_x, VOCs
Mixing of muds and cements	Fugitive	Area	VOCs, PM
Spillages from localised refuelling	Fugitive	Area	VOCs
Gas activated pumps & pressure/level controllers	Fugitive	Area	VOC, HAP, CH_4
Degassing muds and cuttings (especially oil based muds)	Fugitive	Point or area	CH_4, VOCs, HAP (H_2S)
Pigging	Fugitive	Point or area	CH_4, VOC, HAP
HVAC and refrigerant systems (maintenance and accidental release)	Fugitive/ Accidental	Point or area	R23 (freon) or substitute, (halogenated hydrocarbons)
Fire fighting equipment (fixed or portable)	Fugitive	Point or area	Halon 1301 or CO_2 based systems, CFCs, (halogenated hydrocarbons)
Use of laboratory chemicals for routine testing	Fugitive	Point or area	Arklone (being withdrawn), perklone (halogenated hydrocarbons)

Table A-2: Main Pollutants Generated by Offshore Activities

Pollutant	Possible Source		Principal Environmental Impact
CO_2	Generators Combustion exhausts Well testing Well clean up Flaring Venting Fuel spills Blowout	Maintenance activities (pipes, tanks) Vessel/helicopter exhausts Tank breathing Bunkering Fugitive Fire fighting equipment	Climate change
CH_4	Generators Combustion exhausts Well testing Well clean up Flaring Venting Maintenance activities (pipes, tanks)	Loading tankers Blowout Tank breathing Bunkering Pumps & pressure level controllers Degassing muds & cuttings Pigging	Climate change
Nitrogen Oxides (NO_x)	Generators Combustion exhausts Well testing Well clean-up Flaring Venting Fuel spills	Maintenance activities (pipes, tanks) Vessel/helicopter exhausts Tank breathing Bunkering Fugitive emissions	Acid deposition Climate change
Oxides of Sulphur	Generators Combustion exhausts Well testing Well clean-up	Flaring Venting Fuel spills Vessel/helicopter exhausts	Acid deposition
VOCs	Combustion exhausts Well testing Well clean-up Flaring Venting Produced water discharge Fuel spills/collision Maintenance activities (pipes, tanks) Glycol regeneration	Vessel/helicopter exhausts Loading tankers Blowout Tank breathing Bunkering Fugitive emissions Mixing muds and cements Gas activated pumps etc Degassing muds & cuttings Pigging	Climate change
H_2S	Flaring Maintenance activities (pipes, tanks) Blowout	Degassing muds and cuttings Venting	Acid deposition
Halogenated HCs	HVAC Refrigeration systems	Laboratory chemicals	Climate change Ozone depletion
CFCs	Fire fighting equipment	Refrigeration	Climate change Ozone depletion

Pollutant	Possible Source		Principal Environmental Impact
HAP	Well testing Flaring Venting Blowout	Gas activated pumps, etc. Degassing muds Pigging	
Uncombusted HCs	Well testing	Flaring	
Particulate matter	Generators Combustion exhausts Flaring	Vessel/helicopter exhausts Mixing muds and cements	Deposition

Table A-3: NPRI Listed Substances from the UOG Industry

Pollutant	Possible Source	Principal Environmental Impact
Benzene	Process Fluids	Pollutant
1,3-Butadiene	Process Fluids	Pollutant
Carbon disulphide	Process Fluids	Pollutant
Cyclohexane	Process Fluids	Pollutant
Diethanolamine	Chemical	Pollutant
Ethylbenzene	Process Fluids	Pollutant
Ethylene glycol	Chemical	Pollutant
Formaldehyde	Combustion Product	Pollutant
n-Hexane	Process Fluids	Pollutant
Hydrogen sulphide	Process Fluids	Acid Deposition
Isopropyl Alcohol	Chemical	Pollutant
Methanol	Chemical	Pollutant
Naphthalene	Process Fluids	Pollutant
Phenol	Combustion Product	Pollutant
Propylene	Process Fluids	Pollutant
Toluene	Process Fluids	Pollutant
1,2,4-Trimethylbenzene	Process Fluids	Pollutant
Xylene	Process Fluids	Pollutant
PAHs	Process Fluids and Combustion Products	Pollutant

Table A-4 Estimated Mass Distribution of Atmospheric Emissions of GHGs by Source Type for the UOG Industry

Industry Subsector	Emission Source Category	Emission Source Subcategory	Prorated Emissions		
			CO_2 (kt)	CH_4 (kt)	N_2O (kt)
Drilling	Drill Stem Tests	All	63.6	3.0	0.0
	Drilling Fluids	All	0.0	0.0	0.0
	Drilling Rigs	All	748.1	0.0	0.1
Well Servicing and Testing	Venting Activities	All	0.1	8.5	0.0
	Service Rigs	All	99.9	0.0	0.0
	Pumping Units	All	93.4	0.0	0.0
	Wireline Units	All	0.0	0.0	0.0
Gas Production	Wells	All	1.8	94.0	0.0
	Gathering Systems	Low-Pressure	0.0	0.1	0.0
		Dehydrated	10.5	128.4	0.0
		Heated	0.1	3.1	0.0
		Fuel Combustion	6992.6	45.8	0.6
	Well Tie-ins	All	0.0	0.0	0.0
	Field Facilities	Compressor Stations	1.4	64.2	0.0
		Injection Plants	0.1	2.9	0.0
		Meter Stations	0.5	19.3	0.0
		Meter/Regulator Stations	0.1	8.0	0.0
		Regulator Stations	0.1	6.4	0.0
	Gas Batteries	Single-Well	1.2	56.8	0.0
		Group	2.6	124.3	0.0
Conventional Crude Oil Production	Wells	All	0.0	0.3	0.0
	Flow Lines	All	0.1	0.7	0.0
	Field Fuel Combustion	All	7739.3	33.7	0.2
	Single-Well Batteries	Sweet	11.1	59.3	0.0
		Sour	0.9	4.6	0.0
	Satellite Batteries	Sweet	1.4	7.4	0.0

Industry Subsector	Emission Source Category	Emission Source Subcategory	Prorated Emissions		
			CO_2 (kt)	CH_4 (kt)	N_2O (kt)
Conventional Crude Oil Production		Sour	0.2	1.1	0.0
	Central Batteries	Sweet	1.9	14.8	0.0
		Sour	0.1	0.3	0.0
Heavy Oil Production	Wells	Primary/Secondary	0.0	4.4	0.0
		Thermal	0.0	0.0	0.0
		Casing Gas	1.0	432.7	0.0
	Single-well Batteries	All	0.1	25.5	0.0
	Satellite Batteries	All	0.0	0.0	0.0
	Cleaning Plants	All	0.0	0.4	0.0
	Fuel Combustion	All	1696.4	4.2	0.0
Gas Processing	Sweet Gas Processing Plants	All	3019.4	54.2	0.2
	Sour Gas (Flaring) Plants	All	3043.5	15.6	0.1
	Sour Gas (Extraction) Plants	All	11422.1	18.0	0.2
Accidents and Equipment Failures	Sweet Oil Spills	All	0.0	0.1	0.0
	Sour Oil Spills	All	0.0	0.0	0.0
	C5+ Spills	All	0.0	0.0	0.0
	Sweet Gas Venting	All	0.1	2.9	0.0
	Sour Gas Venting	All	0.0	0.2	0.0
	Gas Vent Blows	All	1.5	79.0	0.0
	Gas Migration to the Surface	All	0.0	1.3	0.0
		Total Annual Emissions:	34955.2	1325.5	1.4

Table A-5 Estimated Mass Distribution of Atmospheric Emissions of CACs by Source Type for the UOG Industry

Industry Subsector	Emission Source Category	Emission Source Subcategory	Source Population	Sources Reportable		Proration of Emissions by Source for Each Target Pollutant					
				NPRI Rules	US EPA Rules	NOx (kt)	VOC (kt)	CO (kt)	TPM (kt)	PM_{10} (kt)	$PM_{2.5}$ (kt)
Drilling	Drill Stem Tests	All	12043			0.0	0.5	0.0	0.0	0.0	0.0
	Drilling Fluids	All	NA			0.0	0.0	0.0	0.0	0.0	0.0
	Drilling Rigs	All	NA			8.8	0.3	2.3	0.3	0.1	0.1
Well Servicing and Testing	Venting Activities	All	NA			0.0	0.1	0.0	0.0	0.0	0.0
	Service Rigs	All	NA			1.2	0.0	0.3	0.0	0.0	0.0
	Pumping Units	All	NA			1.7	0.1	0.5	0.1	0.0	0.0
	Wireline Units	All	NA			0.0	0.0	0.0	0.0	0.0	0.0
Gas Production	Wells	All	64754			0.0	14.8	0.0	0.0	0.0	0.0
	Gathering Systems	Low-Pressure	20975			0.0	0.0	0.0	0.0	0.0	0.0
		Dehydrated	2873			0.0	43.4	0.0	0.0	0.0	0.0
		Heated				0.0	0.5	0.0	0.0	0.0	0.0
		Fuel Combustion	NA			113.1	4.9	16.2	2.6	2.5	2.5
	Well Tie-ins	All	1178			0.0	0.0	0.0	0.0	0.0	0.0
	Field Facilities	Compressor Stations	2754			0.0	10.2	0.0	0.0	0.0	0.0
		Injection Plants	123			0.0	0.5	0.0	0.0	0.0	0.0
		Meter Stations	1835			0.0	3.0	0.0	0.0	0.0	0.0
		Meter/Regulator Stations	551			0.0	1.3	0.0	0.0	0.0	0.0
		Regulator Stations	1748			0.0	1.0	0.0	0.0	0.0	0.0
	Gas Batteries	Single-Well	1158			0.0	9.5	0.0	0.0	0.0	0.0
		Group	2196			0.0	20.6	0.0	0.0	0.0	0.0
Conventional Crude Oil Production	Wells	All	45819			0.0	16.3	0.0	0.0	0.0	0.0
	Flow Lines	All	39969			0.0	0.5	0.0	0.0	0.0	0.0
	Field Fuel Combustion	All	NA			39.5	15.3	4.7	1.8	1.8	1.8
	Single-Well Batteries	Sweet	6994			0.0	174.8	0.0	0.0	0.0	0.0
		Sour	832			0.0	4.1	0.0	0.0	0.0	0.0

Industry Subsector	Emission Source Category	Emission Source Subcategory	Source Population	Sources Reportable		Proration of Emissions by Source for Each Target Pollutant					
				NPRI Rules	US EPA Rules	NOx (kt)	VOC (kt)	CO (kt)	TPM (kt)	PM_{10} (kt)	$PM_{2.5}$ (kt)
Conventional Crude Oil Production	Satellite Batteries	Sweet	2070			0.0	7.6	0.0	0.0	0.0	0.0
		Sour	332			0.0	1.2	0.0	0.0	0.0	0.0
	Central Batteries	Sweet	303			0.0	232.2	0.0	0.0	0.0	0.0
		Sour	49			0.0	0.3	0.0	0.0	0.0	0.0
Heavy Oil Production	Wells	Primary/Secondary	18956			0.0	1.3	0.0	0.0	0.0	0.0
		Thermal	385			0.0	0.0	0.0	0.0	0.0	0.0
		Casing Gas	NA			0.0	27.1	0.0	0.0	0.0	0.0
	Single-well Batteries	All	19341			0.0	16.6	0.0	0.0	0.0	0.0
	Satellite Batteries	All	55			0.0	0.0	0.0	0.0	0.0	0.0
	Cleaning Plants	All	72			0.0	0.2	0.0	0.0	0.0	0.0
	Fuel Combustion	All	NA			1.0	2.9	0.1	0.1	0.1	0.1
Gas Processing	Sweet Gas Processing Plants	All	394			45.0	11.9	7.0	0.6	0.5	0.5
	Sour Gas (Flaring) Plants	All	197			9.6	5.5	1.6	0.5	0.5	0.5
	Sour Gas (Extraction) Plants	All	58			24.2	7.2	4.2	1.6	1.6	1.6
Accidents and Equipment Failures	Sweet Oil Spills	All	NA			0.0	3.1	0.0	0.0	0.0	0.0
	Sour Oil Spills	All	NA			0.0	0.0	0.0	0.0	0.0	0.0
	C5+ Spills	All	NA			0.0	0.0	0.0	0.0	0.0	0.0
	Sweet Gas Venting	All	NA			0.0	0.5	0.0	0.0	0.0	0.0
	Sour Gas Venting	All	NA			0.0	0.0	0.0	0.0	0.0	0.0
	Gas Vent Blows	All	NA			0.0	12.6	0.0	0.0	0.0	0.0
	Sour Gas Venting	All	NA			0.0	0.1	0.0	0.0	0.0	0.0
Total Annual Emissions:						164.3	564.3	24	4.8	4.4	4.4

Table A-6 Estimated Mass Distribution of Atmospheric Emissions of NPRI-Listed Substances by Source Type for the UOG Industry

Industry Subsector	Emission Source Category	Emission Source Subcategory	Source Population	Sources Reportable		Prorated Emissions									
				NPRI Rules	US EPA Rules	Benzene (kt)	Cyclo-Hexane (kt)	Ethyl Benzene (kt)	Formaldehyde (kt)	n-Hexane (kt)	Naphtha-lene (kt)	Phenol (kt)	Toluene (kt)	1,2,4-TMB (kt)	Xylene (kt)
Drilling	Drill Stem Tests	All	12043			0.0	0.0	0.00	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Drilling Fluids	All	NA			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Drilling Rigs	All	NA			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
Well Servicing and Testing	Venting Activities	All	NA			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Service Rigs	All	NA			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Pumping Units	All	NA			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Wireline Units	All	NA			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
Gas Production	Wells	All	64754			0.0	0.0	0.0	0.0	0.2	0.000	0.000	0.0	0.0	0.0
	Gathering Systems	Low-Pressure	20975			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
		Dehydrated	2873			11.4	4.8	0.7	0.0	12.0	0.000	0.000	10.9	0.3	3.4
		Heated				0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
		Fuel Combustion	NA			0.0	0.0	0.0	1.0	0.6	0.002	0.001	0.0	0.0	0.0
	Well Tie-ins	All	1178			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Field Facilities	Compressor Stations	2754			0.0	0.0	0.0	0.0	0.2	0.000	0.000	0.0	0.0	0.0
		Injection Plants	123			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
		Meter Stations	1835			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
		Meter/Regulator Stations	551			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0

Industry Subsector	Emission Source Category	Emission Source Subcategory	Source Population	Sources Reportable		Prorated Emissions									
				NPRI Rules	US EPA Rules	Benzene (kt)	Cyclo-Hexane (kt)	Ethyl Benzene (kt)	Formaldehyde (kt)	n-Hexane (kt)	Naphtha-lene (kt)	Phenol (kt)	Toluene (kt)	1,2,4-TMB (kt)	Xylene (kt)
Gas Production		Regulator Stations	1748			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Gas Batteries	Single-Well	1158			0.0	0.0	0.0	0.0	0.2	0.000	0.000	0.0	0.0	0.0
		Group	2196			0.1	0.1	0.0	0.0	0.3	0.000	0.000	0.1	0.0	0.0
Conventional Crude Oil Production	Wells	All	45819			0.0	0.0	0.0	0.0	0.3	0.000	0.000	0.0	0.0	0.0
	Flow Lines	All	39969			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Field Fuel Combustion	All	NA			0.0	0.0	0.0	0.2	0.4	0.000	0.000	0.0	0.0	0.0
	Single-Well Batteries	Sweet	6994			0.5	0.5	0.0	0.0	2.9	0.000	0.000	0.4	0.0	0.2
		Sour	832			0.0	0.0	0.0	0.0	0.1	0.000	0.000	0.0	0.0	0.0
	Satellite Batteries	Sweet	2070			0.0	0.0	0.0	0.0	0.1	0.000	0.000	0.0	0.0	0.0
		Sour	332			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Central Batteries	Sweet	303			0.6	0.7	0.0	0.0	3.8	0.000	0.000	0.6	0.0	0.2
		Sour	49			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
Heavy Oil Production	Wells	Primary/Secondary	18956			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
		Thermal	385			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
		Casing Gas	NA			0.1	0.1	0.0	0.0	0.4	0.000	0.000	0.1	0.0	0.0
	Single-well Batteries	All	19341			0.2	0.2	0.0	0.0	0.4	0.000	0.000	0.3	0.0	0.1
	Satellite Batteries	All	55			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Cleaning Plants	All	72			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Fuel Combustion	All	NA			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
Gas Processing	Sweet Gas Processing Plants	All	394			0.0	0.0	0.0	0.3	0.7	0.000	0.000	0.0	0.0	0.0

Industry Subsector	Emission Source Category	Emission Source Subcategory	Source Population	Sources Reportable		Prorated Emissions									
				NPRI Rules	US EPA Rules	Benzene (kt)	Cyclo-Hexane (kt)	Ethyl Benzene (kt)	Formaldehyde (kt)	n-Hexane (kt)	Naphtha-lene (kt)	Phenol (kt)	Toluene (kt)	1,2,4-TMB (kt)	Xylene (kt)
Gas Production	Sour Gas (Flaring) Plants	All	197			0.0	0.0	0.0	0.1	0.2	0.000	0.000	0.0	0.0	0.0
	Sour Gas (Extraction) Plants	All	58			0.0	0.0	0.0	0.1	0.2	0.000	0.000	0.0	0.0	0.0
Accidents and Equipment Failures	Sweet Oil Spills	All	NA			0.0	0.0	0.0	0.0	0.1	0.000	0.000	0.1	0.0	0.0
	Sour Oil Spills	All	NA			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	C5+ Spills	All	NA			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Sweet Gas Venting	All	NA			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Sour Gas Venting	All	NA			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
	Gas Vent Blows	All	NA			0.0	0.0	0.0	0.0	0.2	0.000	0.000	0.0	0.0	0.0
	Sour Gas Venting	All	NA			0.0	0.0	0.0	0.0	0.0	0.000	0.000	0.0	0.0	0.0
Total Emissions:						12.9	6.4	0.7	1.7	23.3	0.002	0.001	12.5	0.3	3.9

Appendix B

UKOOA Environmental Database for Emissions and Discharges from Offshore Installations; Atmospheric Emissions Inventory Summary Reports 2000

- UKOOA Reporting Template

Appendix C
OSPAR Emissions Reporting Template

Appendix D

National Pollutant Inventory Substance List

- Report Forms