GOVERNMENT OF NEWFOUNDLAND AND LABRADOR
Office of Climate Change, Energy Efficiency, and Emissions Trading
(GNL - CCEEET)

OFFSHORE OIL & GAS – NEWFOUNDLAND AND LABRADOR GHG REDUCTION OPPORTUNITIES & COMPETITIVE IMPLICATIONS

FINAL REPORT
(Deliverable 4)

Submitted to:

GNL - CCEEET
P.O. Box 8700
St. John's, Newfoundland
A1B 4J6

PLEASE NOTE:

Portions of this report have redacted as per Section 27(1)(b) of the Access to Information and Protection of Privacy Act.





Submitted by:

AMEC Environment & Infrastructure
a Division of AMEC Americas Limited

160 Traders Blvd. E., Suite 110, Mississauga, Ontario
Tel: (905) 568-2929 / Fax: (905) 568-1686

Canada's Top 100 Employers 2013

GOVERNMENT OF NEWFOUNDLAND AND LABRADOR
Office of Climate Change, Energy Efficiency, and Emissions Trading
(GNL - CCEEET)

OFFSHORE OIL & GAS – NEWFOUNDLAND AND LABRADOR GHG REDUCTION OPPORTUNITIES & COMPETITIVE IMPLICATIONS

FINAL REPORT

Submitted to:

GNL - CCEEET
P.O. Box 8700
St. John's, Newfoundland
A1B 4J6

Submitted by:

AMEC Environmental & Infrastructure
a Division of AMEC Americas Limited
160 Traders Blvd., Suite 110
Mississauga, Ontario
L4Z 3K7

May 2013

TC121804

May 2nd 2013

TC121804

Office of Climate Change, Energy Efficiency & Emissions Trading
Executive Council
Government of Newfoundland and Labrador
P.O.Box 8700
St.John's, NL, A1B 4J6

Attention: Mr. Gerald Crane

Dear Mr. Crane:

Re: Offshore Oil & Gas – Newfoundland and Labrador, Greenhouse Gas Reduction – Final Report

AMEC Environment & Infrastructure, its associate company Performance Improvements Limited and its sub-contractor Navius Research Inc., have pleasure in providing you with this final report on the Offshore Oil & Gas GHG Reduction study in accordance with Schedule A of the contract and meets the timelines for submission as amended.

This final report is an update of the previous version dated April 12th 2013 and incorporates actions relating to the comments received from you on April 18th, April 26th and April 29th. The Addendum report (extended scope) is also being issued as a final version in parallel with this update.

Yours truly,
AMEC Environment & Infrastructure
a Division of AMEC Americas Limited

Stephen Lamming, Ph.D., EP
Project Manager
Direct Tel.: (905) 568-2929 X4159
Direct Fax: (905) 568-1686
E-mail: steve.lamming@amec.com

Canada's Top 100 Employers 2013

EXECUTIVE SUMMARY

The report is on a study conducted by AMEC and partner Navius to "Identify Greenhouse Gas (GHG) Reduction Opportunities and Competitiveness Implications for the Offshore Oil and Gas Industry in Newfoundland and Labrador". It has been commissioned by the Government of NL Office of Climate Change, Energy Efficiency, and Emissions Trading (CCEEET). It approaches the subject in the context of helping inform the objectives of the GNL 2011 Climate Change Action Plan, within which the GNL committed to develop, and publicly release, a detailed approach for reducing GHG emissions from the energy-intensive sectors of the province, including provincial targets for 2020. The offshore petroleum sector comprising three large oil production facilities and a fourth due before 2020 is the largest single sector contributor to provincial GHG emissions, comprising 35% of GHG emissions from the large industry sector.

All three existing facilities are beyond their peak oil production rates but continue to require high levels of energy use to maintain reservoir pressure. A unique aspect of offshore oil production (which is very distinct from oil sands production) is that the energy intensity and the GHG emissions intensity (per unit of oil production) will tend to rise as oil production declines over field life. This is because gas compression and water injection pumping, the most energy intensive users of power generated from fuel combustion, are designed to maximise oil production with no direct correlation to oil decline, and with limited turndown capability.

For existing facilities GHG abatement opportunities relating to flaring (non-fuel) reduction best practices (flare management) are likely to be more practical and cost-effective than abatement opportunities relating to fuel combustion reduction. A number of best practice flare management measures are already being followed, and have allowed flare rates at existing facilities to be brought down significantly since 2007 cutting the proportion of GHG attributed to flaring down from [redacted] For the sector as a whole there is some further reduction in flaring possible of the order of [redacted], although some facilities are closer to practical safe limits than others. For combustion plant (primarily gas turbines), the theoretical potential for increased waste heat recovery is not practical nor cost effective, as it is severely constrained by available useful process duties on the facilities. In the medium to long term, optimisation of the main energy users (compressors and pumps) at key stages in field like has the potential for [redacted] reduction of fuel emissions. Fuel substitution has little potential since diesel use is already minimised to periods of fuel gas unavailability. Variable speed drive (VSD) technology should be considered BAT on new projects (as it is on Hebron), and will help optimise motor energy use over field life.

The policy analysis shows that application of various performance standards could reduce sector emissions by between [redacted] and [redacted] from their business-as-usual trajectory by 2020. However, the choice of compliance options and benchmark has an important on compliance costs. The availability of a technology fund achieves greater reductions in emissions and reduces compliance costs in comparison to the availability of offsets Allowing facilities to comply with a policy by accessing a technology fund ensures that revenues collected are used to reduce GHG emissions in the sector and also reduce compliance costs. It is likely that greater

reductions could be achieved from the sector with greater constraints on offset availability and greater emphasis on a technology fund.

The choice of benchmark affects the portion of compliance achieved through direct reductions and the level of contributions to a technology fund or from accessing other flexibility mechanisms. On one end of the spectrum, calling for a reduction from the fuel benchmark approach used in the EU ETS would require fewer reductions, while on the other end a reduction in emissions intensity from a production-based benchmark would require significant actual reductions from the sector. In the latter policy, compliance with the policy would become increasingly difficult as each field matures. While this leads to greater contributions to the technology fund and greater reinvestment of the technology fund in low emissions options in the sector, it also substantially increases the cost of compliance.

Increasing the price for accessing the technology fund achieves greater reductions, but at a diminishing rate. The main opportunities for reducing emissions from NL's offshore oil industry identified in this analysis are from flaring via improved flare managements and critical rotating equipment reliability. These reductions have relatively low cost in comparison to most other fuel-based options. However, once these options have been undertaken, there are fewer opportunities to achieve significant reductions in GHG emissions.

The analysis explicitly shows that a policy design option based on an oil production benchmark would achieve GHG reductions at significantly greater cost in comparison to other options. A production-based benchmark is difficult for the offshore oil industry to achieve due to the independence of relatively fixed combustion plant energy requirements with falling oil production rates. A benchmark based on historic emissions intensity becomes increasingly difficult to achieve even with maximum abatement from the sector. The balance must be met with either contributions to a technology fund or some other flexibility mechanism, which impose a financial cost on the sector. If flexibility mechanisms are not available, this performance standard may not be achievable for some facilities, and they would either have to fall out of compliance or shut down. The findings of this study's analysis are in line with the independent third party findings for the European offshore petroleum sector under EU-ETS Phase III policy design, where production based benchmarks were deemed inappropriate to offshore facilities and a fuel (combustion) benchmark has been used instead.

.

TABLE OF CONTENTS

PAGE

1.0 INTRODUCTION 1
1.1 Purpose 1
1.2 Background 1
1.3 Scope & Methodology 2
2.0 NL GHG EMISSIONS 3
2.1 Overview – NL GHG emissions 3
2.2 NL Offshore Oil & Gas Sector GHG Emissions 5
2.2.1 Available formally reported GHG data: 5
2.2.2 Formally reported GHG Emissions data for 2011 9
2.3 NL Offshore Oil & Gas Sector Production Data 9
2.4 NL Offshore Oil & Gas Sector – Future New Entrants 10
2.5 References 11
3.0 OFFSHORE OIL & GAS INDUSTRY 12
3.1 Overview of Offshore Oil & Gas Production 12
3.2 Offshore O&G GHG Emissions Sources 14
3.2.1 Stationary Combustion Sources 15
3.2.2 Flares 17
3.3 Offshore O&G Main Energy Users 18
3.3.1 Gas Compression Systems 19
3.3.2 Water Injection Systems 21
3.3.3 Vessel (e.g. FPSO) Positioning 22
3.4 NL Sector GHG Data & Trends 22
3.4.1 Historic Production and GHG Data 23
3.4.2 Sources and Breakdown of CO_2 Emissions 23
3.4.3 Production and CO_2 Intensity – NL Sector 24
3.4.4 Production and CO_2 Intensity – Benchmarking 24
4.0 TECHNICAL & TECHNOLOGY REVIEW OF ABATEMENT OPTIONS 26
4.1 Energy Efficiency Programmes and Systems 26
4.2 Stationary Combustion Sources 27
4.2.1 Combustion Plant – Conventional Best Practices 27
4.2.2 Combustion Plant – Technology BAT 28
4.3 Flaring Systems 29
4.3.1 Flare Reduction – Conventional Best Practices 29
4.3.2 Flare Recovery Technology 30
4.3.3 Flaring – Infrastructure & Market Considerations 31
4.4 Gas Compression Systems 32
4.5 Water Injection Systems 33
4.6 Oil Separation and Stabilisation System 33

4.7 Oil Cargo Offloading System 33
4.8 Vessel Positioning System (on FPSO facilities) 34
4.9 Emerging Technologies / Other Systems 34
4.10 Summary Table for Evaluation (and Workshop) 34

5.0 REVIEW OF FLARING & VENTING 35

5.1 Background to GGFVRS 35
5.2 Key Elements of the Standard 35
5.2.1 The Focus Areas of the Standard 35
5.2.2 The Goals of the Standard 36
5.2.3 The Implementation of the Standard by GGFR Partners 36
5.3 GGFR Implementation Plan for Canadian Regulatory Authorities 37
5.4 NL Oil & Gas Industry – Implementation Status and Objectives 39
5.4.1 NL Offshore – The C-NLOPB status (2008) 39
5.4.2 NL Offshore – The C-NLOPB status (2012) 39
5.4.3 NL Onshore – The Department of Natural Resources 40
5.5 Alternative Options to Flaring 41
5.6 Flaring & Venting – Pollution Prevention & Control Best Practice Measures 43
5.6.1 Flaring – Best Practice Measures 43
5.6.2 Venting – Best Practice Measures 43
5.7 References 44

6.0 EVALUATION OF TECHNOLOGY OPTIONS 45

6.1 Technology Assessment Criteria 45
6.2 Opportunity Ranking 46
6.3 Workshop Discussion and Feedback 46

7.0 REGULATORY REVIEW 47

7.1 Background & Introduction 47
7.2 Canadian GHG Regulatory Perspective 47
7.2.1 Canadian Federal Policy 47
7.2.2 Regional Initiatives in North America (Canada & US) 48
7.2.3 Provincial Initiatives in Canada 49
7.2.4 Regional Greenhouse Gas Initiative (NE United States) 51
7.2.5 Canadian Air Quality Management Issues (AQMS and BLIERs) 52
7.3 Australia 53
7.4 EU Emissions Trading System (EU-ETS) 54
7.4.1 Offshore Oil & Gas Industry specifics 55
7.5 Other European Initiatives 59
7.5.1 Norway 59
7.5.2 Denmark 61
7.5.3 Netherlands 62
7.6 Related Measures 63

8.0 POLICY OPTIONS & CRITERIA 65

8.1 Summary of Policy Options 65
8.1.1 Performance Standards 65

8.1.2 Policy options evaluated in the analysis 68
8.2 Policy Assessment Criteria 70
8.2.1 Environmental Effectiveness 70
8.2.2 Compliance Costs 70
8.2.3 Acceptability 71
8.3 Analysis Framework 71
8.3.1 Principles of Energy-Economy Modelling 71
8.3.2 Production and Emissions Profiles 73
8.3.3 Abatement Opportunities for the Offshore Oil Sector 75
8.3.4 Historic GHG Intensity Characteristics for the Offshore Oil Sector 76
9.0 POLICY EVALUATION 81
9.1 Scenario Overview 81
9.2 How do the Policies Affect Greenhouse Gas Emissions? 82
9.3 What are the costs of compliance for the different policy options? 85
9.4 Do the policies affect levels of production from the offshore oil industry? 88
9.5 Summary of Policy Evaluation 88
10.0 ADDITIONAL COMMENTARY 90
10.1 Performance Guidelines (rather than Standards) 90
10.1.1 Organisational Effectiveness 90
10.1.2 Energy Surveys of existing facilities 90
10.1.3 Emissions Monitoring 91
10.1.4 Performance & Energy Efficiency Monitoring 91
10.1.5 New Developments 92
11.0 MAIN FINDINGS AND CONCLUSIONS 93
11.1 Offshore Sector Characteristics 93
11.2 Offshore Resource Management 94
11.3 Sources of GHG Emissions 95
11.4 Combustion Plant Characteristics 96
11.5 Main Energy Consumers 97
11.6 Production, Energy and GHG Intensity 97
11.7 GHG Abatement Opportunities – Best Practice and Best Available Technologies 98
11.8 GHG Abatement Opportunities – Emerging Technologies 101
11.9 GHG Policy Options and Criteria 101
11.10 GHG Policy Evaluation 102

LIST OF TABLES

Table 2.1a: NL Large Facility GHG Emitters >50 ktonnes CO_2e (2009 data) 3
Table 2.1b: NL Large Facility GHG Emitters >50 ktonnes CO_2e (2010 data) 4
Table 2.2: NL Large Facility GHG Emitters >50 ktonnes CO_2e (2011 data) 9
Table 3.1: The Main Operations on an Oil & Gas Installation 14
Table 3.1: The Main Operations on an Oil & Gas Installation 14
Table 3.2a: Hibernia Platform – Main Gas Turbine Plant and Duty 16
Table 3.2b: Terra Nova FPSO – Main Gas Turbine Plant and Duty 16
Table 3.2c: White Rose (Sea Rose FPSO) – Main Gas Turbine Plant and Duty 17
Table 3.2d: Hebron Platform – Main Gas Turbine Plant and Duty 17
Table 3.3: The Main Energy Users on a Typical Oil & Gas Facility 20
Table 7.1: Nova Scotia – Total Emission Caps 50
Table 7.2: NL LTA Results 63
Table 8.1: Performance Standards Examined in the Policy Analysis 70
Table 8.2: Representation of Oil Production by Facility in GEEM (thousand barrels per day) 73
Table 8.3: Representation of Greenhouse gas emissions by facility and source in GEEM (kt CO_2e) 75
Table 9.1: Performance Standards Examined in the Policy Analysis 82

LIST OF FIGURES

Figure 1.1: NL Offshore Sector – Location of Facilities 2
Figure 2.1: NL Offshore Sector – CO_2 Emissions 7
Figure 5.1: Canadian Regulatory Authorities endorsing the GGFR Standard 38
Figure 8.1: Comparison of GEEM and CCEEET (Crude Oil Production from Hibernia) 73
Figure 8.2: Comparison between GEEM and CCEEET (GHG emissions from Terra Nova) 74
Figure 8.3: Abatement Cost Curve in GEEM for Hibernia 76
Figure 8.4a: Hibernia – trend of CO_2 emissions intensity vs. Oil Production 78
Figure 8.4b: Hibernia – trend of CO_2 emissions intensity vs. CO_2 emissions 78
Figure 8.5a: Terra Nova – trend of CO_2 emissions intensity vs. Oil Production 79
Figure 8.5b: Terra Nova – trend of CO_2 emissions intensity vs. CO_2 emissions 79
Figure 8.6a: White Rose – trend of CO_2 emissions intensity vs. Oil Production 80
Figure 8.6b: White Rose – trend of CO_2 emissions intensity vs. CO_2 emissions 80
Figure 9.1: Greenhouse Gas Emissions from the Offshore Oil Industry 83
Figure 9.2: Greenhouse Gas Emissions from the Offshore Oil Industry 84
Figure 9.3: Compliance Costs from the Offshore Oil Industry 86
Figure 9.4: Greenhouse Gas Intensity of Terra Nova 87
Figure 9.5: Evaluation of Policy Options 89

LIST OF APPENDICES

Appendix A: NL Production & GHG Data
Appendix B: Technology Options and Evaluation
Appendix C: Regulatory Review
Appendix D: An Overview of GEEM Modeling Methodology

ABBREVIATIONS

ALARP	As Low As Reasonably Practicable
AMEC E&I	AMEC Environment & Infrastructure
AMLD	Anti-Money Laundering Directives
API	American Petroleum Institute
AQMS	Air Quality Management System
BAT	Best Available Techniques
BCF	Billion Cubic Feet
BCM	Billion Cubic Metres
BLIERs	Base Level Industrial Emissions Requirements
BP	Best Practice
CAAQS	Canadian Ambient Air Quality Standards
CAPP	Canadian Association of Petroleum Producers
CB	Covenant Benchmarking
CCEEET	Climate Change, Energy Efficiency, and Emissions Trading
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CDM	Clean Development Mechanism
CGE	Computable general equilibrium
CIM	Common Implementation Measures
CH_4	Methane
CIDA	Canadian International Development Agency
CITL	Community Independent Transaction Log
C-NLOPB	Canada Newfoundland and Labrador Offshore Petroleum Board
CO_2	Carbon Dioxide
CSR	Comprehensive Study Report
DEA	Danish Energy Agency
DECC	Department of Energy & Climate Change (in UK)
EC	European Commission
EIB	European Investment Bank
ERCB	Energy Resources Conservation Board
ERU	Emission Reduction Units
EU	European Union
EU ETS	European Union Emissions Trading System
EUTL	EU Transaction Log
EUR	Euro
FEED	Front End Engineering and Design
FPSO	Floating Production Storage and Offloading
FPV	Floating Production Vessels
GBS	Gravity Base Structure
GC	Gas Compressor
GDP	Gross Domestic Product
GGFR	Global Gas Flaring Reduction
GGFVRS	World Bank Global Gas Flaring & Venting Voluntary Reduction Standard
GHG	Greenhouse Gas
GNL	Provincial Government of Newfoundland and Labrador
GT	Gas Turbine
GWh	Gigawatt hour

HFCs	Hexafluorocarbons
HP	High Pressure
HPC	High Pressure Compression
H_2S	Hydrogen Sulphide
IFC	International Finance Corporation
IPPC	Integrated Pollution Prevention and Control
JI	Joint Implementation
kt	kilotonnes
LDC	Least Developed Countries
LHV	Lower Heating Value
LP	Low Pressure
LPC	Low Pressure Compression
LPG	Liquefied Petroleum Gas
LTA	Long Term Agreements
LTE	Energy Efficiency for ETS enterprises.
MAD	Market Abuse Directive
mboe	million barrels oil equivalent
mg/l	milligrams per litre
MiFID	Market in Financial Instruments Directive
MP	Medium Pressure
MPC	Medium Pressure Compression
MRG	Monitoring and Reporting Guidelines
MRP	Monitoring and Reporting Plan
MS	Member State
Mt	Million tonnes
MW	Megawatt
MW_{th}	Megawatt Thermal
NAP	National Allocation Plan
NER	New Entrants Reserve
NGL	Natural Gas Liquids
NL	Newfoundland and Labrador
NOK	Norwegian Kroner
NM^3	Normal Meter Cubed
N_2O	Nitrous Oxide
NS	Nova Scotia
O&G	Oil and Gas
OEM	Original Equipment Manufacturer
OWTG	Offshore Waste Treatment Guidelines
PFCs	Perfluorocarbons
PI	Performance Improvements Ltd
POB	Personnel on Board
PPC	Pollution Prevention and Control
PWRI	Produced Water Re-Injection
SF_6	Sulphur Hexafluoride
SO_x	Sulphur Dioxide
TEG	Tri-ethylene Glycol
TJ	Terajoule
UNFCC	United Nations Framework Convention on Climate Change
UK DECC	United Kingdom Department of Energy and Climate Change

VRU	Vapour Recovery Unit
WHRU	Waste Heat Recovery Unit
WCI	Western Climate Initiative
WI	Water Injection

1.0 INTRODUCTION

1.1 Purpose

This report meets the requirements of a contract commissioned by the Provincial Government of Newfoundland and Labrador (GNL), Office of Climate Change, Energy Efficiency, and Emissions Trading (CCEEET). The study objective is to "Identify Greenhouse Gas (GHG) Reduction Opportunities and Competitiveness Implications for the Offshore Oil and Gas Industry in Newfoundland and Labrador (NL)".

The study took place predominantly in 2012. This revision of the report is a significant update that supersedes the interim draft report submitted to CCEEET at end of March 2012. It incorporates CCEEET review comments, information from face-to-face discussions with key stakeholders in June 2012, and additional discussions with CCEEET in the latter part of 2012 and early 2013.

1.2 Background

In its 2011 Climate Change Action Plan, the GNL committed to develop, and publicly release in 2012, a detailed approach for reducing GHG emissions from the energy-intensive sector. This approach will include a GHG reduction target for the energy-intensive sector and will be guided by 11 core principles in line with economic, social, and environmental objectives [Ref 2.1]. This study / report seeks to identify an inventory of potential measures, initiatives and regulations which could be employed in the NL Offshore Oil and Gas industry. The study aims to extend beyond and refine the high level conclusions of a previous GNL study in 2010 into modeling the impacts of carbon pricing on each sector of the GNL economy [Ref 2.2].

Currently the Offshore Oil and Gas production industry in NL and the Offshore Gas production industry in Nova Scotia (NS) are unique within Canada; the rest of the oil and gas production industry across Canada being primarily Onshore (including significant contribution from Alberta, British Columbia, and Saskatchewan). The NL offshore sector is also unique from the perspective that current Offshore Oil production is from remote oil fields where the associated gas is currently 'stranded', i.e. lacking the infrastructure (such as pipelines) that would allow economic monetisation of gas reserves / production in onshore industry. Furthermore, the existing / planned offshore oil installations fundamentally differ from each other, in that two of the four projects (Hibernia and Hebron) use fixed platform concrete gravity based structures (GBS), whilst the other two projects (Terra Nova and White Rose) use floating production, storage, and offloading (FPSO) vessels. In common, all four facilities are located in remote and harsh environments exposed to cold weather and ice conditions, in the same geographical area of the Jean D'Arc basin east of St John's, NL, as shown in Figure 1.1. Oil export from all facilities is by oil shuttle tanker as opposed to by pipelines ashore.

In its 2011 Climate Change Action Plan, one of the key goals of the GNL, at a provincial economy level, is to pursue the GHG reduction targets of the Conference of New England Governors and Eastern Canadian Premiers on a provincial basis: 10 percent below 1990 levels

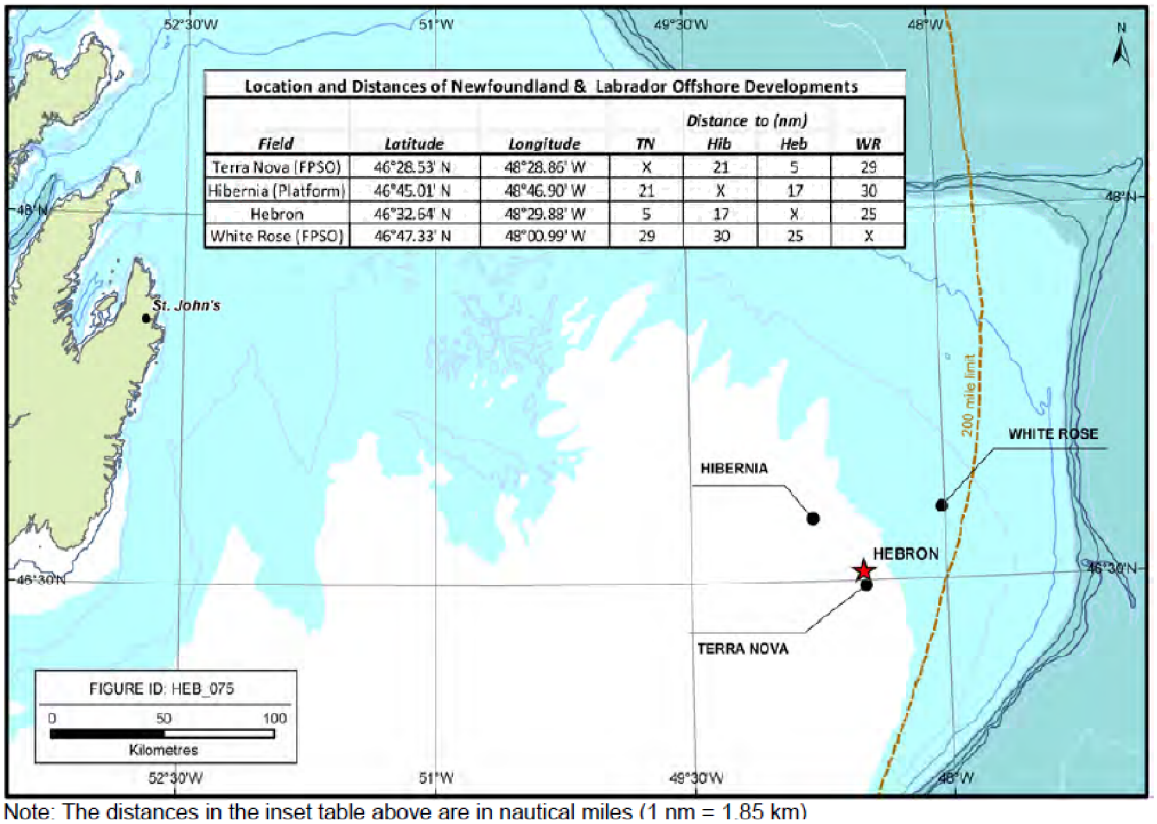
(8.4 MT) by 2020, and 75 – 85 percent below 2001 levels by 2050 [Ref 2.1]. With respect to NL provincial economy emissions relative to the 2020 target, it can be noted that provincial economy emission levels were around the same level in 2010 as they were in 1990, and therefore looking forwards beyond 2010, the target effectively corresponds to reducing the economy GHG emissions by approximately 10 percent between 2010 and 2020.

AMEC's approach to this study has therefore been to focus on reviewing best practices, technologies, and policy initiatives which could provide a contribution to GHG reduction in the NL offshore petroleum sector.

1.3 Scope & Methodology

AMEC Environment & Infrastructure (AMEC E&I) has coordinated this study supported by specialist teams from AMEC Performance Improvements (AMEC-PI) and Navius Research. The scope of work and methodology used are given in Ref 2.4.

Figure 1.1: NL Offshore Sector – Location of Facilities



Location and Distances of Newfoundland & Labrador Offshore Developments

Field	Latitude	Longitude	TN	Distance to (nm) Hib	Heb	WR
Terra Nova (FPSO)	46°28.53' N	48°28.86' W	X	21	5	29
Hibernia (Platform)	46°45.01' N	48°46.90' W	21	X	17	30
Hebron	46°32.64' N	48°29.88' W	5	17	X	25
White Rose (FPSO)	46°47.33' N	48°00.99' W	29	30	25	X

Note: The distances in the inset table above are in nautical miles (1 nm = 1.85 km)

Source: Hebron Comprehensive Study Report Executive Summary – September 2011

2.0 NL GHG EMISSIONS

2.1 Overview – NL GHG emissions

The GHG Emissions arising from energy intensive activities in large industry accounts for approximately 50% of NL GHG emissions. By comparison, large industry in the province also accounts for ~45% of energy consumed, ~30% of GDP, and ~5% of employment [Ref 2.1].

Within large industry, the main contributory sectors to NL GHG emissions are [Ref 2.1]:

i) Onshore Mining – including Iron Ore Company (Carol Project, Labrador City), Wabush Mines, and Voisey's Bay, with several new projects imminent from 2013 onwards.

ii) Offshore Petroleum – three existing offshore oil producing installations (Hibernia, Terra Nova, and White Rose, with a fourth Hebron due to come on-stream in 2017.

iii) Onshore Oil Refining – significantly the North Atlantic Refining Ltd, Come by Chance.

iv) Thermal Power Plant – significantly the Holyrood thermal generating station.

A relatively small number of individual large industry facilities in NL account for annual GHG emissions > 50 ktonnes, and by this definition these facilities are required to report into the Environment Canada database which has been the central federal mechanism for reporting of GHG emissions from large facilities since 2004.

The 2009 and 2010 GHG data for the NL large individual facilities (>50 ktonnes) is shown in Table 2.1a and 2.1b respectively, as recorded in the Environment Canada database of large emitters. It is worth noting, that from a national perspective, the Province's large emitters (8 in number) accounted for <2% of the inventory of GHG emissions from the total group of large emitters on the national database, numbering over 500 installations in total.

Table 2.1a: NL Large Facility GHG Emitters >50 ktonnes CO_2e (2009 data)

Facility	City	Greenhouse Gas (tonnes CO_2e)			
		CO_2	CH_4	N_2O	Total
Carol Project	Labrador City	792,711	390	3,723	796,824
Hibernia Platform	St. John's	516,771	33,456	4,507	554,734
Holyrood Thermal Generating Station	Holyrood	769,324	176	4,907	774,407
Mines Wabush - Scully	N/A	64,360	26	521	64,907
North Atlantic Refinery	Come by Chance	1,083,460			1,083,460
Sea Rose FPSO	St John's	442,995	23,616	8,274	474,885
Terra Nova	St. John's	534,997	22,518	11,032	568,547
Voisey's Bay Mine Site		58,455	63	2,046	60,564
Total (All 8 Large Facility Emitters)		**4,263,073**	**80,245**	**35,010**	**4,378,328**
Sub-Total (3 Offshore Petroleum Facilities)		**1,494,763**	**79,590**	**23,813**	**1,598,166**

Table 2.1b: NL Large Facility GHG Emitters >50 ktonnes CO_2e (2010 data)

Facility	City	Greenhouse Gas (tonnes CO_2e)			
		CO_2	CH_4	N_2O	Total
Carol Project	Labrador City	1,123,041	494	4,644	1,128,178
Hibernia Platform	St. John's	491,117	31,121	4,644	526,882
Holyrood Thermal Generating Station	Holyrood	667,728	155	4,311	672,195
Mines Wabush - Scully	N/A	95,254	40	765	96,058
North Atlantic Refinery	Come by Chance	1,019,300	-	-	1,019,300
Sea Rose FPSO	St John's	394,960	27,691	9,405	431,786
Terra Nova	St. John's	569,634	22,976	11,616	604,227
Voisey's Bay Mine Site		64,581	67	2,635	67,282
Total (All 8 Large Facility Emitters)		**4,425,615**	**82,544**	**38,020**	**4,545,908**
Sub-Total (3 Offshore Petroleum Facilities)		**1,455,711**	**81,788**	**25,665**	**1,562,895**

Some other statistics in relation to these eight NL large facilities (>50 ktonnes CO_2e) and the 2009 & 2010 data in the Environment Canada large facility GHG inventory database are:

i) The Carol Project Mines and North Atlantic Refining Ltd, are the largest individual NL emitters ranked 47th and 56th largest in the Environment Canada national database.

ii) The Terra Nova, Hibernia, and Sea Rose facilities, at 604 ktonnes CO_2e, 526 ktonnes CO_2e, and 431 ktonnes CO_2e respectively are ranked 90th, 105th, and 120th largest respectively in the 2010 database GHG inventory. The 2010 sub-total GHG emissions of 1,562 ktonnes CO_2e from the NL offshore petroleum sector facilities correspond to 34.4% of the 2010 GHG emissions emitted by the 8 NL large facilities reporting to the database. The corresponding proportion for the offshore sector in 2009 was 36.5%.

iii) The 2010 GHG emissions of 1,019 ktonnes CO_2e from the North Atlantic Refinery Limited (crude oil refining) corresponds to 22.4% of the 2010 GHG emissions from the total of 8 NL large facilities reporting to the database. The corresponding figures for 2009 were 1,083 ktonnes CO_2e and 24.7%.

iv) The 2010 sub-total GHG emissions of 1291 ktonnes CO_2e from the three NL mining sector facilities correspond to 28.4% of the 2010 GHG emissions from the 8 NL large facilities reporting to the database. The Carol Project (IOC) constitutes the bulk of this. The corresponding figures for 2009 were 922 ktonnes CO_2e and 21.1%.

v) The 2010 GHG emissions of 672 ktonnes CO_2e from the Holyrood thermal power plant (electricity grid generation) corresponds to 14.8% of the 2010 GHG emissions from the total of 8 NL large facilities reporting to the database. The corresponding figures for 2009 were 774 ktonnes CO_2e and 17.7%.

vi) The reported CO_2 emissions are approximately 93% - 94% of the total CO_2e emissions for each of the three facilities (Table 2.1 – CO_2 as a proportion of total GHG emissions).

The remaining 6% - 7% is attributed to CO_2 equivalent emissions primarily from methane (CH_4) emissions and also from some Nitrous Oxide (N_2O) emissions.

It can be seen therefore, that the Offshore Petroleum Sector, currently (based on 2009 and 2010 data published in 2011) contributes the biggest slice of GHG emissions of any one sector of large industry emitters (>50 ktonnes CO_2e) in NL. Although NL large facilities account for less than 2% of the GHG emissions from all large facilities in Canada, within the Provincial context the offshore petroleum sector is a major contributor to the GHG emissions inventory in NL. In addition, although the overall contribution from NL is a relatively small part of national emissions, it should be seen in the context that NL accounts for about 1.4% of national real Gross Domestic Product (GDP) and population, and NL accounts for a larger share of oil extraction, oil refining, and mining emissions. This study therefore focuses on the role that the offshore petroleum sector can play in Provincial GHG management strategies, within the context that the industry is forecast to expand as future offshore developments occur.

2.2 NL Offshore Oil & Gas Sector GHG Emissions

2.2.1 Available formally reported GHG data:

The reported GHG emissions for 2009 and 2010 calendar years, reported by the three existing offshore installations (Hibernia, Terra Nova FPSO, and White Rose / Sea Rose FPSO) are highlighted in Table 2.1a and Table 2.1b above.

The NL offshore sector has been formally reporting GHG emissions to the Environment Canada database since 2004. The data published in the Environment Canada inventory does distinguish between estimated GHG emissions from CO_2 (combustion processes), CH_4 (unburned methane release), and N_2O releases, as shown in Table 2.1a and Table 2.1b. This data has been used as the primary source of overall GHG emissions for this study. At the time of the main analysis in 2012 the reported data for calendar year 2011 had not yet been released.

However, the published Environment Canada GHG inventory does not provide the split in CO_2 combustion process emissions arising from energy used in fuel consumption (e.g. in stationary combustion plant) as distinct from those arising from energy wasted in flaring and venting.

AMEC considers from experience of the offshore petroleum industry in general, that it is fundamentally important for the purposes of this study that the CO_2 emissions from offshore facilities can be split between fuel emissions and non-fuel emissions, the latter being essentially, in most cases, flaring and venting. This is because the best practices and technology options to reduce fuel consumption are quite distinct from those options to reduce flaring or venting.

Therefore, for this report, data relating to natural gas consumption at the three facilities, split between natural gas flared and natural gas used for fuel consumption, was based on additional information by the Department of Natural Resources and by C-NLOPB [Ref 2.7]. This data was provided for the calendar years 2004 – 2009. In addition, similar information on fuel and flare volumes for each of the three facilities is available from the C-NLOPB annual reports for 2010

and 2011 [Ref. 2.7], but appears to be reported for the 12 months to the end of the fiscal year at March 31st 2010 and March 31st 2011 respectively.

In order to generate appropriate estimates for the GHG emissions from fuel and from flaring at each facility, to use in the study analysis, the following procedure has been used:

i) For each facility, for each calendar year 2004 - 2009, the ratio of fuel gas consumption to flare gas consumption has been used to pro-rata the total CO_2 emissions for the facility sourced from the Environment Canada database [Ref 2.5].

ii) For the calendar year 2010 the ratio of fuel gas consumption to flare gas consumption from the C-NLOPB annual reports [Ref 2.8] has been used in a similar manner and the fuel and flare data for March 31st 2010 to March 31st 2011 has been used as a surrogate for the 2010 calendar year.

The above approach is considered to provide a sufficient estimate of the split of GHG emissions from flaring vs. fuel consumption, to conduct the analysis, pending confirmation from the individual operators, providing that the following assumptions are valid:

i) For each installation, the CO_2 emission factor for the natural gas used in fuel consumption in stationary combustion plant is not radically different in value from the CO_2 emission factor for the natural gas flared. From AMEC experience this is likely to be a reasonable assumption; fuel gas is generally derived from the high pressure (HP) compression system, and flare gas will generally be a mixture of gas derived from both the low pressure (LP) and the HP systems, so may differ slightly in composition and emission factor, but such differences are unlikely to be significantly in the context of this study.

ii) For each installation, natural gas fuel is used in preference to diesel fuel in stationary combustion plant, and overall the use of diesel fuel is considered de-minimus compared to the use of natural gas for fuel. Diesel has a higher emission factor than natural gas.

At the beginning of March 2012, AMEC sent a request to the designated offshore facility Environmental representatives for them to verify several items of operating information, including this split. At the time of this final report, insufficient information had been received to fully verify the exact split for all three facilities, but the limited information received does support the method used by AMEC to estimate the split.

Figure 2.1 below shows the results of the calculation to estimate the split in CO_2 emissions for flaring and fuel gas for the period 2004 – 2010 for the NL offshore sector, based on the approach described above, with the results for each individual installation aggregated to provide the overall sector profile. More detailed information at an installation-specific level is discussed in Sections 3 through 5 based on information in Appendix A and Appendix B of this report.



By way of explanation of the trend shown in Table 2.1:

i) The data for 2004 represents data for Hibernia GBS and Terra Nova FPSO. The data for 2005 includes a small (insignificant) contribution from White Rose (Sea Rose FPSO) which began operation towards the end of 2005.

ii) The data for 2006 does not represent a typical year because firstly, Terra Nova FPSO was not producing for ~6 months of 2006, and secondly because 2006 marked the year when Sea Rose FPSO started production when gas flaring on Sea Rose was particularly high prior to completion of the commissioning of the gas re-injection compression systems. Incidentally, although the Environment Canada GHG inventory of standardized data only began in 2004, administrative data collected for Hibernia and Terra Nova for earlier years indicated that start-up flaring emissions were higher in each of these cases.

iii) Considering the standardized Environment Canada data since 2004, the reported GHG CO_2 emissions for the sector's three facilities peaked in 2007, the year after the Sea Rose FPSO was commissioned and oil production from this facility was at its peak.

iv) Since 2007, the CO_2 emissions from fuel consumption in the sector are estimated to have been fairly constant at just over [redacted] ktonnesCO_2 per annum. Since most of this will have constituted fuel gas used in combustion gas turbines used for power generation / gas compression (as detailed later in Section 3), this is likely to imply that there have been insignificant energy and GHG reduction measures implemented to these items of plant and /or that the corresponding energy consumers (process equipment loads) over

the period 2007 – 2010 have remained fairly steady. This is discussed in the context of best practice techniques and technology options in Sections 3, 4, and 6 of this report.

v) Since 2007, the CO_2 emissions from flaring in the sector are estimated to have reduced year on year to 2010, from being just under [redacted] ktonnesCO_2 per annum in 2007 to around [redacted] ktonnesCO_2 per annum in 2010. This is likely to imply that there have been some notable reduction measures implemented to reduce flaring volumes as operations at the installations have 'matured'. This is discussed in the context of best practice techniques and flaring reduction technology options in Sections 3, 5, and 6 of this report.

The fourth offshore installation considered in this study, Hebron, is currently in the design stage and is due to come on-stream in 2017. At the time of this study, the project is currently going from completed Front End Engineering Design (FEED) stage to Detailed Design (DD) stage. The data relating to Hebron for the analysis undertaken in this study and report has been taken from the Comprehensive Study Report (CSR) published by the Hebron project in September 2011 [Ref 2.9]. This includes data on GHG estimates and production estimates for the initial operation of the Hebron GBS and projections in the CSR covering the life of the field.

The Hebron project is due to come on-stream in 2017, which is some time prior to planned cessation of production of any of the existing three facilities. The GHG emissions from Hebron in its peak years of production are forecast in the CSR to be just shy of ~600 ktonnesCO_{2eq}/year. Relatively speaking, these are of a similar magnitude to the average GHG emissions from each of the three existing facilities. This implies that there is forecast to be a step increase in GHG emissions from the sector in 2017 before Terra Nova ceases economic production (forecast to be sometime around 2018 or potentially several years later). It is therefore important that for the offshore sector to play a part in meeting NL 2020 GHG reduction targets for the provincial economy, there would need to be a focus on GHG reduction initiatives.

In the context of reductions in GHG from the offshore petroleum sector, we suggest that a distinction should be made between the 'business as usual' (BAU) case represented by the three existing facilities, and that of any new entrants such as Hebron and others (such as Mizzen further into the future). Assuming that BAU GHG emissions from the three existing facilities remains relatively constant around 1.5MT – 1.6MT, and that further GHG emissions in the region of 0.5MT – 0.6MT are added from Hebron after 2017, the issue for the sector becomes one of limiting growth in GHG emissions before seeing actual reductions. Even with a reasonably stringent policy that might lead to reduction in GHG from the BAU case, it will be challenging for the four fields (including Hebron) to emit less than the current 1.5MT – 1.6MT prior to Terra Nova going offline. It may therefore be an issue of having policies which help reduce emissions from BAU activities as part of contributing towards limiting growth of GHG emissions in the sector between 2010 and 2020, rather than achieving actual reductions.

2.2.2 Formally reported GHG Emissions data for 2011

The GHG emissions for the 2011 calendar year were not yet formally available from the Environment Canada website during the duration of the study analysis in 2012. Therefore the analysis in this report was based on reported GHG emissions data up to 2010.

By the time of study conclusions and final report issue the 2011 facility level data had been released. For completeness this information is shown in Table 2.2 below and can be compared with Table 2.1a and Table 2.1b in the previous sub-section. Offshore GHG emissions have dipped below 1.5ktonnesCO_2e in 2011, primarily due to improvements in flare management.

It is also worth noting that Offshore sector emissions in 2012 will be impacted by the fact that both Sea Rose FPSO and Terra Nova FPSO had significant planned field-outages for off-station turnaround maintenance work to FPSO vessels and equipment during the 2012 calendar year.

Table 2.2: NL Large Facility GHG Emitters >50 ktonnes CO_2e (2011 data)

Facility	City	Greenhouse Gas (tonnes CO_2e)			
		CO_2	CH_4	N_2O	Total
Carol Project	Labrador City	945,491	357	3,100	948,948
Hibernia Platform	St. John's	466,324	29,523	4,597	500,444
Holyrood Thermal Generating Station	Holyrood	729,566	168	4,695	734,429
Mines Wabush - Scully	N/A	92,293	41	763	93,097
North Atlantic Refinery	Come by Chance	897,208	0	0	897,208
Sea Rose FPSO	St John's	361,367	18,588	11,383	391,338
Terra Nova	St. John's	567,650	22,538	11,379	601,567
Voisey's Bay Mine Site		84,673	95	3,379	88,147
Total (All 8 Large Facility Emitters)		**4,144,572**	**71,310**	**39,296**	**4,255,178**
Sub-Total (3 Offshore Petroleum Facilities)		**1,395,341**	**70,649**	**27,359**	**1,493,349**

2.3 NL Offshore Oil & Gas Sector Production Data

Production data for the three NL offshore facilities for the years 2004 – 2011 has been derived from the comprehensive monthly reports published on the C-NLOPB website [Ref. 2.9]. In particular annual (calendar year) information on the following production data was extracted from the C-NLOPB reports and used in this study:

i) Oil production data in mmbbls (million barrels) per year.

ii) Water production data in mmbbls (million barrels) per year.

iii) Associated gas production data in mmscf (million standard cubic feet) per year.

Based on the data for fuel gas consumption and flared gas, an estimate for the amount of gas re-injected was also derived by gas balance; by subtracting the fuel gas plus flared gas, from the gas produced, given that none of the installations export any gas. This estimate for gas re-injection would seem reasonable given that the Environment Canada database indicates that reported emissions from other activities are minimal in comparison with those from combustion (fuel and flare) activities.

The historical data on GHG emissions and Production data was combined for further analysis as part of this study. This information is tabulated and graphed in detail in Appendix A of this report. At the beginning of March 2012, AMEC sent a copy of this information to each of the offshore facility environmental representatives for a record of the basis of information being used in this study, in the event that they wished to comment on the data used. At the date of this report revision no comments had been received from Operators on the manner in which the data has been interpreted for use by AMEC in this the final report.

For Hebron, production estimates have been based on the information available in the Hebron project Comprehensive Study Report (CSR) [Ref. 2.8]. In fact the data used for future production forecasts for all four offshore installations is consistent with the data used in the Hebron CSR.

2.4 NL Offshore Oil & Gas Sector – Future New Entrants

The data in this study only considers the production and the associated emissions from the sector comprising the current four projects, in the timeline to 2025. The study is aware of other potential new entrants to the sector which are likely, if sanctioned, to start production after this timeframe. The most notable of these potential new entrants under currently project development is the Mizzen field.

In addition, whilst data relating to the White Rose extension is included in the forecast data used, the full ramifications of the potential impact on GHG emissions have not been considered in detail, pending detailed design information on that project.

2.5 References

The following references relate to the information provided in the Introductory Sections (Section 1 and Section 2) of this report.

2.1 'GNL Climate Change Action Plan 2011' CEEET Action Plan, prepared and published by CCEEET on behalf of the Governor of NL. Downloaded from the CCEEET website.

2.2 'A study to assess the impacts of Carbon pricing in Newfoundland and Labrador', Final report by MK Jackard and Associates Inc for GNL CCEEET, April 2010.

2.3 Scope of work and methodology contained in CCEEET contract.

2.4 Environment Canada GHG national Inventory http://www.ec.gc.ca/ges-ghg/default.asp?lang=En&n=83A34A7A-1 including large facilities dataset to 2009.

2.5 "Overview of Reported 2009 GHG Emissions" Environment Canada, December 2010

2.6 Data provided to AMEC by CCEEET in Feb 2012 in Excel worksheets. 'book4' & 'book 6'

2.7 C-NLOPB annual reports for 2010 and 2011.

2.8 Hebron Comprehensive Study Report, published September 2011.

2.9 C-NLOPB production reports from the board website http://www.cnlopb.nl.ca/

3.0 OFFSHORE OIL & GAS INDUSTRY

This section of the report mainly provides a generic description of the typical processes on board an offshore installation, especially those processes with energy intensive requirements and / or significant GHG emissions.

Whilst the description is generic, AMEC believes that it is reasonably accurate in the manner in which it relates to the permanent structures (e.g. Hibernia / Hebron) and to the FPSO (e.g. Terra Nova and Sea Rose) operating in the Offshore Oil & Gas Industry in NL. The main nuance for the NL offshore sector is that it currently only exports oil (by tanker) and has no gas export infrastructure for the associated gas.

This Section has been updated based on discussions with industry stakeholders in June 2012.

3.1 Overview of Offshore Oil & Gas Production

Offshore oil production consists of a number of process operations that allow for the safe and efficient production of hydrocarbons (oil, natural gas, and condensates) from the flowing wells that are connected to a facility. The key process operations that take place on an oil installation (whether it be a fixed platform such as a GBS, or a floating FPSO) are the following:

i) Separation of produced fluids (oil, natural gas, water).

ii) Associated gas processing including dehydration and gas compression.

iii) Well testing activities (periodic routine activities for production optimisation).

iv) Produced water treatment and where practicable re-injection.

v) Seawater lift for cooling duty and for water injection.

vi) Oil stabilisation and export (via pipeline or via shuttle tanker).

vii) Gas export of associated natural gas (via pipeline) if commercially viable.

viii) Liquified Petroleum Gas (LPG) separation and export of propane, butane, (e.g. via tanker) if commercially viable. Note this is not applicable to NL infrastructure.

ix) Safety flaring – including background flaring and additional upset / emergency flaring.

x) Utilities to support the above processes and to support on-board accommodation facilities. The most important utility is generally onboard main power generation and standby / emergency power generation facilities.

In addition to the above generic operations, the following operations are specific to fixed platforms or to FPSO installations, as indicated:

i) Drilling operations (periodic campaigns following initial production), for fixed platforms where wells are drilled directly from a drilling derrick on the platform structure. This does not apply directly to FPSO, where drilling is generally handled by separate drilling rigs.

ii) Subsea operations / wellheads where wells are not drilled directly from the installation. This applies to FPSO but can also apply to fixed platform tiebacks.

iii) Oil Storage in cargo tanks for FPSO operations and for fixed platforms where oil production is via shuttle tanker as opposed to via export pipeline.

iv) Vessel positioning operations for FPSO and other floating installations, including turret system for swiveling and vessel thrusters, heading, and anti-yaw / anti-roll.

Table 3.1 summarises the relevance of these offshore Oil & Gas operations to the NL offshore petroleum industry: the 3 existing installations (Hibernia GBS, Terra Nova FPSO, Sea Rose FPSO), plus the planned Hebron GBS installation which is past the front end engineering design (FEED) stage and entering detailed design stage. Future fields which may be developed offshore NL are not shown, but are likely to be similar; for example the Mizzen field is likely to be developed using an FPSO primarily due to the deep water location.

Table 3.1 shows that the NL offshore installations have most of the operations that would be found in an offshore petroleum producing environment. In addition to Table 3.1 the following comments provide some characteristics specific to the NL installations:

i) The three existing installations (Hibernia, Terra Nova, White Rose) are based on fields producing light crude oil specifications (they are typically in the oil gravity range 28 to 35 degrees API). The new Hebron development on the other hand will produce a heavier crude oil specification with API gravity of approximately 20 degrees. This primarily results in greater technological challenges with respect to hydrocarbon separation and produced water treatment, but does not necessarily imply significantly greater energy demand overall; with main energy users (compression and water injection) not impacted.

ii) Due to a combination of economics and the environmental location of all installations, in 'iceberg alley', the preferred methodology for oil export in the design of the installations is by shuttle tanker as opposed to pipeline infrastructure. So far this methodology has also precluded the construction of any gas export pipeline infrastructure. The preferred strategy / methodology for conservation of associated gas has been to re-inject as much of the gas that is not used locally as fuel (e.g. for power generation) back into the reservoir. This is a requirement under operating licences as part of energy conservation.

iii) All four NL offshore installations also employ water injection facilities for oil reservoir pressure maintenance; a common technique for optimising oil production rates in the offshore industry. Options for water injection include re-injection of treated produced water (PWRI) or injection of filtered seawater (WI). The second approach is more common, because although PWRI is more environmentally friendly, its technical feasibility is largely dependent on whether 'souring' of the oil reservoir based on total H_2S as a fraction of the water cut (water : oil ratio) is likely to be an operational issue for oil production from a field. None of the three existing installations use PWRI, nor does Hebron intend to use it initially, although according to the Hebron CSR, its potential use will be kept under review.

Table 3.1: The Main Operations on an Oil & Gas Installation

Operation	Hibernia (GBS Platform)	Terra Nova (FPSO)	White Rose (Sea Rose FPSO)	Hebron (GBS Platform)
Drilling operations	Intermittent	No (FPSO)	No (FPSO)	Intermittent
Subsea Operations	Yes	Yes	Yes	Yes
Hydrocarbons Separation (oil, gas, water, condensate)	Yes	Yes	Yes	Yes
Associated Gas processing (dehydration & compression)	Yes	Yes	Yes	Yes
Well testing activities	Yes	No (FPSO)	No (FPSO)	Yes
Produced water treatment	Yes	Yes	Yes	Yes
Seawater lift for cooling water and for injection water	Yes	Yes	Yes	Yes
Produced water reinjection (PWRI) or sea water injection (WI)	Yes (WI) (no PWRI)	Yes (WI) (no PWRI)	Yes (WI) (no PWRI)	Yes (WI)
Oil stabilisation and export (by pipeline or by shuttle tanker)	Yes (Tanker)	Yes (Tanker)	Yes (Tanker)	Yes (Tanker)
LPG separation and chilling (and export via shuttle tanker)	No	No	No	No
Natural Gas export (by pipeline)	No	No	No	No
Natural Gas re-injection (back to the reservoir)	Yes	Yes	Yes	Yes
Safety Flaring of associated gas	Yes	Yes	Yes	Yes
Power Generation Utilities (Main and standby / emergency)	Yes	Yes	Yes	Yes
Other Utilities	Yes	Yes	Yes	Yes
Oil Storage (in cargo tanks)	Yes	Yes	Yes	Yes
Vessel Positioning Systems	No (Platform)	Yes (FPSO)	Yes (FPSO)	No (Platform)
Ice Management	Yes	Yes	Yes	Yes
Accommodation	Yes	Yes	Yes	Yes

3.2 Offshore O&G GHG Emissions Sources

Conventionally the majority of all oil and gas installations in offshore producing regions worldwide, being located a significant distance from shore, need to generate their own electrical power for use as motive power on the installation, as well as their own heating systems. The NL offshore petroleum sector is no different. Even onshore, many large oil and gas producing

installations worldwide traditionally have their own captive power generation 'by choice' (rather than strictly 'by need'), so that they are not wholly reliant on electricity grid infrastructure. One strong rationale is that where there is natural gas being produced (as associated gas with the oil) then it is readily available to burn as a fuel in the local power plant.

As such, the main sources of GHG emissions on an offshore oil & gas installation fall into the following four broad categories:

i) Stationary Combustion Sources – where fuel is consumed (burnt in a combustion process) to generate electricity, produce direct motive power, or fired heating. Typical fuels are natural gas (preferentially) and marine diesel oil (when gas is not available).

ii) Flares – where waste gases from the process operations that cannot be readily captured are gathered in a flare header system and safely flared at the tip of a flare boom – it is common to have separate low pressure (LP) and high pressure (HP) flare systems.

iii) Venting from process equipment, including fugitive emissions from valves.

iv) Vapour release from Storage tanks and other vessels.

These typical sources of GHG emissions are described below in the context of the NL offshore sector.

3.2.1 Stationary Combustion Sources

These typically comprise any one or more of the following:

i) Gas turbines for main power generation (onboard electricity) requirements.

ii) Gas turbines for use as mechanical drivers for main items of process rotating machinery equipment (such as large centrifugal compressors or large pumps).

iii) Boilers used for steam generation for process heating requirements.

iv) Direct fired heaters used for process or utility heating duty.

v) Diesel engines used for standby or emergency power generation.

In common with most other offshore oil installations worldwide, industrial gas turbines are the main consumers of fuel flow on the NL installations and, aside from flaring, are the primary sources of GHG emissions in the sector. The following information is based on published information relating to each facility, and on discussion with Operator representatives during March 2012 – June 2012.

The main gas turbines installed on each of the installations are shown in Table 3.2.a (Hibernia), 3.2.b (Terra Nova), 3.2.c (Sea Rose) and 3.2.d (Hebron) below:

Table 3.2a: Hibernia Platform – Main Gas Turbine Plant and Duty

Gas Turbine Make & Model	Duty – Description	Rated Duty (ISO) MW	Normal Duty MW
GE LM2500 gas turbine generator (fitted with WHRU hot oil system)	Main Power generation	~25.0	[redacted]
GE LM2500 gas turbine generator (fitted with WHRU hot oil system)	Main Power generation	~25.0	[redacted]
GE LM2500 gas turbine generator	Mechanical Drive (MP & HP Compression)	~25.0	[redacted]
GE LM2500 gas turbine generator	Mechanical Drive (MP & HP Compression)	~25.0	[redacted]

The Hibernia main power generation turbines operate as [redacted] trains (both online), if one machine is down then some electrical loads, such as water injection, must be shed (taken offline). The mechanical drive turbines also operate as [redacted] gas re-injection compression trains. If one machine is down then additional gas must be flared or oil production cut back (wells closed in) to prevent excessive flaring. The power generation turbines are dual fuel (using natural gas or diesel) and normally run on natural gas. The mechanical drive (gas compression) turbines are natural gas fuel only, as they are only required when natural gas is available on the facility (i.e. they are not required when production operations are shut down).

Table 3.2b: Terra Nova FPSO – Main Gas Turbine Plant and Duty

Gas Turbine Make & Model	Duty – Description	Rated Duty (ISO) MW	Normal Duty MW
GE Frame 6B gas turbine generator (fitted with WHRU hot oil system)	Main Power generation	~39.0	[redacted]
GE Frame 6B gas turbine generator (fitted with WHRU hot oil system)	Main Power generation	~39.0	[redacted]

There are no direct mechanical drive gas turbines on Terra Nova. The gas re-injection compression trains are all electric motor driven, with electricity provided by the main power generation gas turbines. These are large heavy duty gas turbines (not commonly found offshore) and have dual fuel (natural gas or diesel) combustion systems and normally run on natural gas fuel. The two main power generation turbines operate as [redacted] trains (both online). The electrical power requirement for compression is roughly met by one of the two Frame 6B gas turbines, with the other turbine meeting the rest of the electrical load balance. If one machine is down then some electrical loads, such as water injection, must be shed (taken offline). The process plant including re-injection gas compression consists of a single train; this is an uncommon configuration / design since multiple trains are more usual in the sector.

Table 3.2c: White Rose (Sea Rose FPSO) – Main Gas Turbine Plant and Duty

Gas Turbine Make & Model	Duty - Description	Rated Duty (ISO) MW	Normal Duty MW
R-R RB211 gas turbine generator	Main Power generation	~27.6	[redacted]
R-R RB211 gas turbine generator	Main Power generation	~27.5	[redacted]
R-R RB211 gas turbine generator	Main Power generation	~27.5	[redacted]

There are no direct mechanical drive gas turbines on Sea Rose FPSO. The gas re-injection compression trains are all electric motor driven, with electricity provided by the main power generation gas turbines. These have dual fuel (natural gas or diesel) combustion systems and normally run on natural gas fuel.

The three main power generation turbines operate as [redacted] trains ([redacted] online and [redacted] standby).

There are also two Aalborg Mission OM model 3000 dual fuel boilers on board rated at 25 tonnes / hr at 700 kPag (7 barg).

Table 3.2d: Hebron Platform – Main Gas Turbine Plant and Duty

Gas Turbine Make & Model	Duty – Description	Rated Duty (ISO) MW	Normal Duty MW
Aeroderivative gas turbine (to be confirmed at detailed design)	Main Power generation	~30.0	[redacted]
Aeroderivative gas turbine (to be confirmed at detailed design)	Main Power generation	~30.0	[redacted]
Aeroderivative gas turbine (to be confirmed at detailed design)	Main Power generation	~30.0	[redacted]
Aeroderivative gas turbine (to be confirmed at detailed design)	Main Power generation	~30.0	[redacted]

The Hebron Comprehensive Study Report (CSR) indicates that ExxonMobil plans to install four turbine-driven main power generation units (at least two of which will have dual fuelled capability), and each capable of generating approximately 30 MW of power output. There will be separate emergency and essential diesel generators.

The three main power generation turbines will operate as [redacted] trains ([redacted] online and [redacted] standby).

3.2.2 Flares

The flare system on an offshore installation is primarily designed as a safety system for pressure relief to prevent over-pressurization of process equipment during process upset conditions. A flare header pipework system collects the gas from different parts of the plant. The

flare system typically disposes of any associated gas from the low pressure separator during periods when the LP compressor is down for maintenance. It also disposes of gas from the main MP / HP compression system during process upset periods, and in emergency during depressurization of other items of plant.

Flaring can be categorised as follows (These are North Sea definitions as used by Operators and the industry regulator DECC in the UK):

i) Category 1 – Base Load Flare, also commonly referred to as 'Background flaring'. This is the gas that is sent to flare for the safe and efficient operation of the process facility and flare system under normal operating conditions. It includes small amounts of fuel gas that are continuously used for the flare pilot and for purging the flare header system to prevent ingress of air. The flare purge flow rates may be manually set (hand valves) or may be automated. The flare pilot is normally lit and, and may also be either manual ignition (gun-pellet) or auto-ignition type. Note, on some systems the flare purge may use nitrogen, and the flare pilot may be lit when needed either manually or automatically.

ii) Category 2 – Flaring from operational or mode changes. This typically includes additional gas flaring due to controlled activities such as the start-up and planned shut-down of equipment during normal production. This category of flaring is generally minimised by operational best practice.

iii) Category 3 – Flaring from Emergency shutdown / Process Trip. This includes any gas flared during unplanned shutdown of plant (e.g. gas compressor trips) or that is sent to flare from other areas of the plant due to emergency trips. For oil production facilities the bulk of such flaring occurs as a result of MP / HP compressor trips when the volume of gas sent to flare can be high, or from high level emergency shutdowns.

Category 1 flaring constitutes background continuous flaring, and for a typical offshore installation with good design of the flare control system can be kept below 2 mmscfd. Category 2 and Category 3 flaring will lead to additional increases in flaring for limited periods of time. Depending on their frequency and duration these can contribute to significant increase in the average level of flaring several times above that of Category 1 flaring. The most significant factor in this respect is the uptime / reliability of the gas compression systems, since if they are down then either oil production must be shut in or produced gas that would otherwise be compressed and re-injected or exported must be flared for safe operation. For this reason flare volumes are often high at the start of field production when not only are associated gas rates high but compression systems are often still being commissioned or bedded in.

Systems operating at or near atmospheric pressure are often vented via an atmospheric vent header. Section 5 of this report discusses flaring and venting in more detail.

3.3 Offshore O&G Main Energy Users

The main energy users on an offshore Oil and Gas installation consist of process equipment that is generally being driven / powered by either:

i) Consumption of fuel gas or liquid fuel (e.g. diesel) in combustion gas turbines or engines to generate electricity to drive motors or generating power to directly driving process equipment such as pumps and compressors.

ii) Consumption of fuel gas or liquid fuel (e.g. diesel) directly in fired heaters / boilers as part of the process.

The main categories of energy intensive consumers offshore are shown in Table 3.3 and are described in generic terms in Appendix A. These are discussed below in the context of the NL offshore sector.

3.3.1 Gas Compression Systems

Natural gas compressor systems are critical to each installation's operation; whilst it is possible to sustain oil production without associated natural gas compression, it will normally mean a large amount of flaring off the separators when compression plant is not running for planned / unplanned reasons. To limit high flaring in such upset scenarios it is usually necessary to throttle back or close-in some of the producing wells to limit production rates. In this scenario there is a trade-off between oil production rates and minimising GHG emissions from flaring.

All four NL offshore installations in this study re-inject the vast majority of the associated gas volumes produced after separation from the oil production process, as illustrated in Appendix 3. As a consequence, gas compression is the single largest category of energy use on the installations, accounting for typically [redacted] of all fuel usage, and hence of GHG emissions from fuel. This is not uncommon in the worldwide offshore oil and gas industry. Gas compression duty will change over the life of the field as production profiles change. However, characteristically such changes are more prominent where natural gas is being exported (and hence field pressure is decaying more quickly) than where the majority of the natural gas is being re-injected to help maintain field pressure. In either situation the net product of flow and head duty is such that the power required for compression will remain fairly steady up to the point at which the production profiles have changed significantly to make it cost-effective to re-rate the compressor trains via a re-wheeling or a de-powering exercise. The implications of this with respect to fuel consumption and GHG emissions are discussed further in Chapter 6.

Table 3.3: The Main Energy Users on a Typical Oil & Gas Facility

Sub-Process contributing to GHG Emissions	Energy Intensity (High / Medium / Low)*	Typical Equipment	Relevant to NL Offshore Installations
Flaring and / or Venting of Associated Gas	Moderate to High (but BAT = Low / ALARP)	Flaring of 'Excess gas'	Yes, high, [redacted] of Sector CO2
Drilling	Moderate but only during a small part of the life of the well / field, or intermittently	Drilling rig (motor driven)	Yes
Artificial Lift (e.g. 'gas lift')	Moderate to High	Turbine or motor driven compressors	Yes (some)
Gas Compression for Export	High	Turbine or motor driven compressors	Not at present
Gas Compression for Re-injection into oil producing well	High	Turbine or motor driven compressors	Yes (the major element)
Water Injection Pumps	High	Turbine or motor driven pumps	Yes (a main element)
CO2 or steam injection / thermal EOR	Moderate to High	Motor driven pumps	No
Main Line Oil Pumps / Cargo Transfer Pumps	Low to Moderate. With cargo transfer to tanker is intermittent	Motor driven pumps	Yes
Gas De-hydration	Low - Moderate	Motor driven pumps	Yes
Water Treatment	Low to Moderate	Motor driven pumps	Yes
Condensate Separation	Low	Process Heating	No
NGL Separation from CH4	Moderate	Process Heating	No
NGL Fractionation	Moderate	Process Heating	No
Oil desalting	Low to Moderate	Process Heating	No
Oil Stabilisation and Sweetening	Low to Moderate	Process Heating	Yes
Vessel (e.g. FPSO) positioning	Low to Moderate, occasionally High for FPSO in bad weather	Thruster (motors)	Yes (Terra Nova only)
Accommodation / Hotel Load	Low to Moderate	Heating & Lighting etc	Yes

Key to Energy Intensity:
High [redacted] Moderate [redacted] Low [redacted]

The following base information was obtained in relation to re-injection gas compression systems on the three existing NL offshore installations, from discussions with representatives:



Overall it can be observed that the proportion of gas turbine fuel consumption that can be attributed to the gas re-injection compression systems is typically [redacted] on each of the installations and on-average for the sector as a whole. It is concluded therefore that the gas re-injection energy use is the single most energy intensive activity taking place on the installations.

With the exception of flaring, the energy efficiency of the power generation gas turbines and of the process gas compressors are therefore the most critical aspects in relation to GHG emissions in the sector. Any opportunities that can improve the efficiency of these sections of the plant will aid GHG minimisation. In addition improvements to the uptime of the plant will reduce the occurrence of compressor trips contributing to excessive flaring.

3.3.2 Water Injection Systems

All four NL offshore installations in this study operate water injection pump systems for reservoir pressure maintenance. After gas compression, water injection duty is the second largest category of energy use on the installations, accounting for typically [redacted] of all fuel usage,

and hence GHG emissions from fuel. This is not uncommon in the worldwide offshore oil and gas industry.

The following base information was obtained in relation to water injection pump systems on the three existing NL offshore installations, from discussions with representatives:

[redacted]

3.3.3 Vessel (e.g. FPSO) Positioning

The Terra Nova FPSO positioning system has five x 5 MW each azimuth thrusters, a significant load duty when in high demand (rough sea state and weather). They typically use [redacted] of the thrusters with a load just under [redacted] in summer and occasionally over [redacted] in winter. There are [redacted] essential service diesel generators as back-up to main power generation.
The Sea Rose FPSO does not operate with thrusters.

3.4 NL Sector GHG Data & Trends

Appendix A of this report contains the data and trends relating to GHG emissions from the NL Offshore petroleum sector relative to main sources and energy users. It also contains comparison of the NL sector installations with other installations within the AMEC-PI database of similar categories of offshore installations in the North Sea (Europe).

A detailed discussion is given in Appendix A, along with all related graphs.

The following is a summary of the main observations in relation to the NL offshore sector as a whole.

3.4.1 Historic Production and GHG Data

There following key observations are made with respect to data in Appendix A Section A1:

i) The majority of produced gas (~85% in 2007 and ~90% in 2010) is re-injected.

ii) Approximately 7% of produced gas is used as fuel gas on the installations, and the rest (~8% in 2007 and ~3% in 2010) is flared.

iii) This indicates that the sector is able to conserve (via gas re-injection) or utilize (as fuel gas in combustion plant) the bulk of the associated gas that is produced, with only a relatively small proportion being flared.

iv) This also implies that minimizing flaring activity whilst maximizing oil production will be sensitive to maximizing re-injection compressor reliability and performance, given that there is currently no gas export infrastructure in place. Similarly any potential savings in fuel gas (via efficiency improvement) or in flare management would have to be accommodated within gas re-injection capacity.

3.4.2 Sources and Breakdown of CO_2 Emissions

There following key observations are made with respect to data in Appendix A Section A2.

i) Since 2007 (after White Rose commissioning) the sub-total of CO_2 emissions from fuel gas consumption for the sector has remained fairly steady at just over [redacted] ktonnes CO_2 per annum, despite declines in oil production from the sector. This reflects the fact that the amount of gas re-injection duty has remained fairly steady at around [redacted] mmscf over this period, and it is reasonable to assume that the amount of water injection has also been fairly steady. These high energy intensive activities account for the bulk of fuel gas use, with compression estimated to account for [redacted] of fuel gas consumption and water injection for [redacted]

ii) In comparison, the sub-total of CO_2 emissions from flared gas has reduced from being just under [redacted] ktonnes in 2007 to around [redacted] ktonnes in 2010. This is understood to have been largely due to a combination of improvements in compression system reliability (uptime) and flare management procedures within the sector, at all three installations.

iii) As a result, between 2007 and 2010, total CO_2 emissions for the sector have reduced from 2,000 ktonnes to below 1,500 ktonnes due to reduction in flaring, and CO_2 emissions due to flaring have dropped from being [redacted] to being [redacted] of total CO_2 emissions over this period.

3.4.3 Production and CO_2 Intensity – NL Sector

There following key observations are made with respect to data in Appendix A Section A3.

i) The total sector GHG emission intensity factor (tCO2e/mboe) has been fairly steady since 2004, fluctuating around a value of 15 tCO2e/mboe. Whilst total oil production has been declining since 2007, flaring has also been coming down.

ii) Hibernia has, however, helped smooth the intensity factor profile; its intensity factor has been steady / declining, whilst that of Terra Nova and White Rose have been increasing. This is explained by the relative high oil production rates from Hibernia, that have not declined to the extent that they have from the two FPSO. The Hibernia CO_2 emissions intensity remains fairly low and this helps to pull down the sector average as well.

3.4.4 Production and CO_2 Intensity – Benchmarking

The following key observations are made with respect to data in Appendix A Section A4, in which the NL sector CO_2 emission intensity is benchmarked by AMEC against the AMEC database. Only oil producing installations are considered, and the data for FPSO have been considered separately to the data for fixed platforms.

i) The CO_2 emission intensity for Terra Nova and Sea Rose FPSO is slightly above average and higher compared to most of the North Sea FPSO facilities in the AMEC database. This is primarily due to the higher proportion of emissions from flaring in the NL FPSO. Essentially, the NL intensity from emissions due to fuel consumption is on par with other FPSO assets in the AMEC-PI database. The intensity from emissions due to flaring is lower than typical West African FPSO (high flaring) but higher than typical North Sea FPSO (lower flaring). The implication is that whilst flare management improvements have been made in NL sector, there should perhaps be a focus on potential for further reduction in flaring for NL FPSO facilities relative to improvements in fuel efficiency.

ii) An important underlying consideration, is that the installations in the NL sector do not have access to a gas export infrastructure (e.g. export pipelines), whereas the majority of installations in the AMEC-PI database do have such access.

iii) The Hibernia and Hebron facilities are large compared to the average fixed platform in the AMEC-PI database; they are large producers of both oil and GHG emissions. Overall, however, based on tCO2e/boe intensity factor they are well below the average of the North Sea oil production installations on the AMEC-PI database. This is a reflection of several factors. Firstly, both NL platforms are less mature than the North Sea database, and secondly, they are probably already implementing a fair number of best practices / BAT technologies. For Hibernia, the fact that it has reduced flaring by over [redacted] since 2005 has reduced its GHG intensity, against a background of fairly steady / only slightly declining oil production.

iv) For the FPSO facilities there does not appear to be any strong correlation between emissions intensity and years in production. This can be explained by the observation that for most FPSO, production tends to peak quickly within 1-3 years after field start-up.

v) For the fixed platform facilities there is good evidence of some correlation with the number of years in production, since oil platform production tends to decline more gradually over 10 – 30 years. However, there is little apparent evidence of any correlation with API gravity.

4.0 TECHNICAL & TECHNOLOGY REVIEW OF ABATEMENT OPTIONS

This section discusses some of the technical best practices for GHG management, and conducts a technology review of some of the main abatement options for implementation in the offshore oil and gas industry. It is divided into a number of sub-sections in line with the main sources of GHG emissions already discussed in Section 3, and in line with the profiles discussed in Appendix A.

Safety considerations are also of paramount importance in the context of technology implementation, and are dealt with in parallel in these discussions.

A slide deck presentation of the contents of this section of the report was sent to the representatives of the offshore installations in April 2012 and presented to them in June 2012. There has been limited feedback from Operators following that process. Therefore, this section is only able to breakdown the options into ones that are already in place, being considered, or have potential to be applied based on limited information / feedback provided to date.

4.1 Energy Efficiency Programmes and Systems

The following constitute some of the main types of programmes which are recommended for consideration as part of energy efficiency and GHG management at an installation. These generic programmes very much underpin the ability to implement specific technical best practice measures and BAT technology as detailed in later sub-sections.

i) Commission independent energy assessments of existing operations to establish energy baselines and review / repeat periodically to assess improvements.

ii) Include energy considerations in Maintenance schedules.

iii) Implement energy tracking software and generate and track Energy Key Performance Indices (KPI).

iv) Implement an energy management plan and benchmark energy management against industry.

v) For new installations conduct life of field options-appraisal of main energy users including power generation & mechanical drives.

vi) Conduct Best Available Techniques (BAT) Assessment and design-in best available technology / techniques.

This study assumes that the existing installations will already be carrying out some but not necessarily all of the above programmes. It is recommended that appropriate industry guidelines and / or regulatory policy should aim for existing installations to implement remaining programmes in a timely manner, and for all new installations to implement all programmes as part of (i.e. integral to) their initial design process and integral to their post-commissioning operation. This could be achieved by establishing or modifying guidelines for the offshore sector within existing regulatory frameworks and regulations, at provincial and/or national level.

4.2 Stationary Combustion Sources

Reduction of GHG from stationary combustion sources can be achieved by a combination of implementing energy efficiency best practices and by the design or retrofit of new technologies that improve the efficiency of energy supply (e.g. power generation).

4.2.1 Combustion Plant – Conventional Best Practices

The following are some of the main 'best practice' measures:

i) Optimise the spinning reserve and the number of power generation gas turbine units operating so that online units can run at higher thermal efficiency and overall fuel consumption can be minimised. This is often a tough balance between maximising the security of electricity supply and reducing fuel consumption. It is a common operational approach to maximise the security of electrical supply by operating N+1 power generation gas turbine units at partial load rather than operate N units closer to rated load (e.g. operating 2 units at 40% - 45% rated load rather than 1 unit at 80% - 90% rated load). This is normally done to provide adequate spinning reserve should one of the gas turbines trip offline, or should a major motor drive need to be started. The practicality of this measure to reduce spinning reserve is a function of amongst other things the critical loads, the power generation reliability, the load shedding strategy and the effect of trips on production operations. It is recommended that all installations should have operating procedures that seek to optimise spinning reserve against the constraints and priorities.

ii) Improve gas turbine fuel changeover reliability (gas to diesel), and prevent unnecessary shutdown trips.

iii) Fit High Efficiency Filters to gas turbine air intakes. Balance pros of better filtration vs. cons of higher pressure drop.

iv) Optimise inlet filter cleaning.

v) Conduct on-condition turbine axial compressor washing.

vi) Optimise gas turbine anti-icing system.

vii) Carry out Proactive Online Performance Monitoring.

viii) Lag turbine exhausts if close to air intakes.

ix) Install Oxygen analysers on heaters / boilers for optimum air to fuel ratio and efficiency.

x) Improve Insulation on Heating Medium systems.

xi) Maximise use of natural gas fuel in place of diesel.

xii) Install Individual fuel metering systems to sections of plant and to individual gas turbines in order to better identify differences in performance for appropriate corrective action.

4.2.2 Combustion Plant – Technology BAT

The following are some of the recommended approaches to consider for implementing Technology BAT on large combustion plant:

i) Use aero-derivative gas turbines instead of heavy frame gas turbines to improve fuel efficiency. This can typically lead to up to 20% reduction in fuel consumption due to better thermal efficiency. It is recognised that the main gas turbines on Hibernia and White Rose (Sea Rose FPSO) are aero-derivative units whereas those on Terra Nova are heavy frame machines. It is also understood from the Hebron CSR that the project plans to install up to date aero-derivative gas turbine technology. For the purpose of this study it is conservatively estimated that the use of the latest high efficiency aero-derivative gas turbines will lead to [redacted] savings in fuel consumption compared to alternative heavy frame turbines (e.g. based on 35% - 40% design efficiency as opposed to 30% - 35% design efficiency; [redacted] percentage points in 40% being greater than [redacted]).

ii) Install / Retrofit Waste Heat Recovery Unit (WHRU) in order to use waste heat from gas turbine exhaust to heat an oil system for process heating. This removes / minimises the need for the use of additional fired heaters or electric heaters on the plant and reduces overall fuel consumption. It is estimated that WHRU can achieve 5% - 15% of fuel requirements by elimination of additional fuel duty in this manner. For the purpose of this study an average estimate of [redacted] saving in total fuel consumption is used.

iii) Upgrade gas turbine engines / components to higher specification in line with original equipment manufacturer (OEM) technology developments. It is common for OEM to introduce gas turbines at a conservative 'introductory rating' and to provide operators with package upgrade opportunities based on latest technology developments when turbines reach their major overhaul milestones (typically after 20,000 to 40,000 run hours depending on turbine model). This is usually based on fleet wide experience of the OEM and on design and material improvements, particularly to turbine hot section components; allowing operating temperature limits to be raised for example. It is common for these upgrade packages to contain reliability, performance, and thermal efficiency improvements which if implemented on an installation during major turnaround can lead to operations and maintenance benefits as well as GHG reductions in the region of 1%-8%. For the purpose of this study it is estimated that OEM gas turbine technology upgrades could lead to [redacted] efficiency improvements. Where operators have a spare aero-derivative core engine in storage – as is often the case – the upgrades can be carried out away from the installation in a rolling manner during turbine engine outages for major overhaul. This eliminates the requirement for the technology retrofits to have to coincide with extended plant shutdown / turnaround periods. On the other hand for heavy frame gas turbines (e.g. Terra Nova) it is generally necessary to conduct the retrofits in-situ and there is greater dependence on outage periods.

4.3 Flaring Systems

Reduction of GHG from flaring activities can be achieved by a combination of implementing best practices and design or retrofit of new technologies.

4.3.1 Flare Reduction – Conventional Best Practices

The following are some of the main 'best practice' measures by which Category 1 continuous (background) flaring during normal operations, can be achieved:

i) Optimisation of the flare purge flow rates and the flare pilot. The traditional / common on some installations is for the flare purge flow rates and pilot fuel to be set at relatively high rates; often if the flow control is via manually controlled valves, then these valves are set conservatively 'open' to avoid the need for frequent adjustment. A more optimum approach is to set the flare purge and the pilot flow rates to be more optimal to site conditions. This does not normally require any significant capital expenditure as it can be implemented via operational trials.

ii) The replacement of manual purge control systems with an automatic purge control system. This will greatly reduce the manual intervention required to optimize purge flow rates, and will normally require only modest expenditure on automating pressure / flow control devices, or installation of suitable pressure control where this is not already fitted.

iii) The use of efficient flare tip design and optimum number of burner nozzles on the flare. This will allow the flare to operate optimally under a wider range of conditions / flows and will facilitate the above mentioned initiatives. It is important to try and select the most appropriate flare tip design from day one, since access restrictions make modifications / replacement of flare tips an expensive procedure post-commissioning, and one which must be scheduled to be done during a main shutdown / turnaround outage.

iv) As part of routine maintenance procedures it is important to repair any faulty components such as purge valves / gauges. Since such faults do not have a direct impact on operations but can lead to greater leakage to flare, they can often be overlooked if not part of formal maintenance.

v) Periodic non-intrusive ultrasonic valve leakage surveys should be carried out of all of the main valves on the flare header system, in order to identify any leaking valves which will be contributing to increased levels of continuous background flaring. Such surveys can be conducted in the lead-in to planned shutdown periods in order to identify valves needing corrective maintenance.

Implementing a combination of the above best practices can be expected to contribute to a reduction of background flaring by several percent. For the purposes of this study a reduction of [redacted] of Category 1 flaring volumes has been identified as a conservative potential outcome from a capital expenditure of around [redacted] million on improvements to the flare purge and pilot systems.

The following are some of the main 'best practice' measures by which reduction of Category 2 flaring (resulting from operational mode changes) and of Category 3 flaring (from emergency shutdown / trips) can be achieved.

i) Improvement in operating procedures to minimise the frequency and / or extent of operational mode changes, thereby minimising the volumes of gas constituting Category 2 flaring.

ii) Improvement in compression plant reliability / uptime. The largest cause of Category 3 flaring is generally the interruption of gas compression duty due to unplanned shutdown of compression plant (e.g. due to process trips). Even if oil production is restricted back or shut down in a control manner such upsets will lead to increased flaring of associated gas that cannot be compressed.

iii) Improvement in stable operation and control of the separation and gas processing equipment, including review of controller tuning parameters.

Implementation of the above best practice measures via continuous improvement can go a significant way in reducing the volume of flare from oil production activities, by reducing / optimizing Category 2 & category 3 flaring. However these will not address / eliminate Category 1 background flaring.

4.3.2 Flare Recovery Technology

The main technology that can result in significant decrease or near elimination of Category 1 (continuous background) flaring is the installation of a flash gas compression system, or ideally of a complete flare recovery system.

Many installations in the Norwegian offshore sector of the North Sea (particularly new installations as opposed to retrofits) have installed flare recovery systems as a result of the Norwegian CO_2 tax introduced from 1990, regulations described in detail in Section 7. The technology was developed and piloted by Statoil for the Gullfaks A and Gullfaks C platforms, which operated the first closed flare systems in 1994, and has since been field proven and rolled out to many more installations.

The technology consists of flare header isolation equipment, a gas recovery compression / ejector system, and a reliable flare ignition system. The flare recovery system is designed and sized to meet the normal background flaring volumes of the installation. The recovered gas can be re-injected or used as fuel gas or where viable exported. The system does away with a continuous flare purge and flare pilot. Instead, a fast-opening valve system and in-parallel protective bursting disk allows a direct route to flare in case of an emergency. In this instance the flare ignition system operates to instigate flaring during emergency upset conditions only. During the majority of normal operating periods there is zero flaring due to the isolation of the flare header and the capture and recovery of the gas collecting in the header system back into the normal compression system.

In the UK offshore oil & gas sector flare recovery installations are rare, and have been fitted to one or two new offshore installations only. In the UK flaring has contributed consistently to around 20% of offshore sector total GHG emissions over the last decade. In Norway, by contrast, where the government's carbon tax policy has incentivised the implementation of flare recovery systems, flaring accounted for around 10% of offshore sector total GHG emissions in 2003, down from around 20% in 1995. The Norwegian Petroleum Directorate (NPD) estimates that the installation of flare recovery systems to effect zero continuous flaring contributed the most to this reduction. These statistics are consistent with the estimate that a flare recovery system technology has the potential to reduce flaring on an installation by around 50% of typical annual flaring volumes, by largely eliminating Category 1 type flares. Combined with best practices to minimize Category 2 and Category 3 flaring this can lead to significant reduction in GHG emissions from flaring.

In theory such potential exists in the NL offshore sector, but in practice its viability must be considered hand in hand with certain infrastructure and market factors as well as a industry specific safety case.

4.3.3 Flaring – Infrastructure & Market Considerations

Whilst the technology to address the problem of gas flaring exists today, and the policy requirements to implement the technology are largely understood; in some regions of the world issues regarding barriers to infrastructure development and relating to market dynamics can affect the practical progress in achieving significant reductions in reduced flaring.

Offshore installations present specific issues relating to constraints for flare reduction technology, including associated safety considerations. In most circumstances the design priorities are to implement either gas re-injection for enhanced oil recovery, or NGL recovery for export via tanker, as well as using gas as fuel for captive power generation. NL industry currently uses 2 out of 3 of these approaches in minimizing the net gas that is safely flared.

In mature offshore oil and gas producing regions close to large industrial markets such as the European North Sea (UK, Norway, Netherlands), the infrastructure to export and monetise gas reserves has developed in parallel with oil production infrastructure, and the multitude of facilities (totaling over 100 large facilities in the European North Sea). In particular the offshore terrain and the proximity to onshore markets have made for viable economic development of both oil and gas pipelines in many areas. Oil producing installations with small amounts of surplus associated gas have been able to tie-into (export into) offshore gas export pipelines emanating from larger gas fields. Oil fields with a shortfall of associated gas for powering large combustion plant (e.g. power generation) are often able to import gas from other nearby platforms or a local gas pipeline network. Where the offshore terrain and proximity to shore are conducive to gas export but there is no large local market (e.g. northern Norway) it has been viable to develop pipelines ashore to serve onshore LNG liquefaction plant from which gas can be exported worldwide and monetized accordingly.

In other less mature areas and oil and gas producing regions not close to large industrial markets or with particular terrain challenges (e.g. in deepwater or in arctic conditions), the development of gas export infrastructure is more challenging. This applies to regions of the world such as offshore West Africa and Australia (deep water), and it also applies to a large extent to Newfoundland & Labrador (shallow water but extreme weather / iceberg hazards).

Overall, government policies and incentives, and market conditions that are conducive to developing gas export and gas inter-connectivity infrastructures will also be conducive to incentivising the implementation of zero-flaring and flare reduction technologies.

4.4 Gas Compression Systems

The following are some of the main 'best practice' measures for gas compression:

i) Optimise compressor anti-surge settings to minimise compressor recycle, and thereby minimise load / power and hence fuel consumption.

ii) Ensure process controllers are in auto-mode not manual-mode and are tuned appropriately to minimise plant instability or upsets.

iii) Install online performance monitoring system with the capability for local (offshore) and remote (onshore) monitoring by appropriate engineering disciplines.

iv) Optimise gas lift / gas injection pipe work and headers and operational procedures, to minimise energy wastage due to pipeline hydraulics, throttling to wells, etc.

v) Install wash system for gas compressors to prevent fouling (e.g. due to salt deposits). Excessive fouling can lead to degradation in performance throughput or to increased fuel consumption and / or increased flaring.

vi) Optimise compressor intercooler / after cooler operation / configuration.

The following are some of the main BAT technology measures:

i) Re-wheel / re-configure compressor systems at key stages within the field production decay profile in order to optimise the compressor envelope with changing production duty. This can have a significant impact on energy consumption; whilst being relatively capital intensive and potentially intrusive to operations (requiring to be done during a major outage period) it is one of the most effective ways of reducing energy consumption from fuel gas usage as oil and associated gas production rates drop over the life of a field. Compression being the biggest energy user, can be optimised via design configuration changes over the field life.

ii) Replace LP compressors with Eductor/Ejector technology driven by HP gas. This can be an effective strategy as LP compressor duty decreases over the life of a field, and will lead to fuel gas energy savings.

4.5 Water Injection Systems

The following are some of the main 'best practice' measures:

i) Optimise number of water injection pumps operating. Over the life of a field it can be common for design duties to become sub-optimal over time and to require periodic review in order to re-optimise oil production maintenance vs. energy intensity from water injection.

ii) Optimise Injection Header pressure levels in relation to injection well characteristics (e.g. to minimise choking of wells and reduce energy consumption of WIP).

iii) Install Variable Speed / Frequency Drives (VSD) to Pumps. It is understood from the Hebron CSR that this project will be the first NL offshore development that will implement VSD for major pumps instead of fixed motor drives. VSD have the potential to optimise the performance (energy demand) of driven equipment (pumps) over the field life as their operating duty requirements change with production profiles. In association with some of the other opportunities in this category they therefore have the potential for significant fuel reduction over field life.

Collectively, the above measures have been estimated to have the potential for energy savings of around 5% of Water Injection energy demand over time.

With respect to BAT technology for water injection, opportunities should be reviewed to change out water injection / seawater lift pump internal cartridges with high efficiency units to optimise water injection / sea water lift capacity. This has a similar capacity to reduce energy consumption by improving system efficiency, typically by up to 5%.

4.6 Oil Separation and Stabilisation System

Best practice technology measures include:

i) Optimise / Tune Separator Level Controls.

ii) Reduce / eliminate venting from tanks – see Section 5 for more detail.

4.7 Oil Cargo Offloading System

Best practice technology / BAT measures include:

i) Install a closed loop inert gas system. This will reduce fuel use in the inert gas generation (IGG).

ii) Convert Diesel IGG to fuel gas.

iii) Install / Retrofit Vapour Recovery Unit (VRU) to prevent venting of vapours.

4.8 Vessel Positioning System (on FPSO facilities)

Best practice technology / BAT measures include:

i) Optimise / Minimise the use of thruster systems via operational procedures.

ii) Install an Advanced Vessel Positioning System (e.g. non-linear predictive control of thrusters) or update existing systems with latest technology enhancements.

4.9 Emerging Technologies / Other Systems

The following are some categories of emerging technology that are worth consideration in parallel with consideration of long term infrastructure projects for monetisation of gas reserves:

i) Offshore floating LNG – this new technology is currently under development and implementation by Shell offshore Australia, and is due to come on-stream in 2013. Once field proven this has the potential to be used in other 'remote' regions of the world.

ii) Mini-scale LNG technology. This is a new technology licensed to and being developed by Hamworthy Gas Systems (Norway) based on patented technology developed by SINTEF the Scandinavian Foundation for Scientific and Industrial Research in association with NTHU the Norwegian University of Scienc and Technology. Mini-scale LNG is intended to address situations where gas volumes are too low for conventional commercial scale LNG. The technology was been piloted onshore in Norway in 2003 and put into full scale production in 2007. Although originally developed for hydrocarbon gas recovery and landfill gas / coal-bed methane, it has since been developed for onshore and offshore flare gas recovery.

iii) Smaller scale gas to liquid (GTL) technology.

iv) Offshore Combined Cycle Gas Turbine technology (CCGT) – commonly used onshore where space for steam utility systems is not a premium, this technology is also being considered for offshore operations.

4.10 Summary Table for Evaluation (and Workshop)

The above discussions on technology best practices and BAT were summarised into a series of tables for further evaluation with Operator representatives during bi-lateral discussions in St John's in June 2012. Following discussions in St John's there has been no additional feedback from operators on the generic opportunities discussed.

5.0 REVIEW OF FLARING & VENTING

This Section elaborates on the discussions made in Section 3 and 4 regarding flaring, with reference to the World Bank voluntary standard on flaring and venting reduction.

5.1 Background to GGFVRS

The Voluntary Standard for Global Gas Flaring and Venting Reduction (GGFVRS) [Ref 5.1] was published in 2004 in a report by the World Bank, as one of the outputs of the Global Initiative on Gas Flaring and Venting, led by the World Bank in collaboration with the government of Norway. The original initiative led to the Global Gas Flaring Reduction (GGFR) public-private partnership – 'the GGFR partnership' at the World Summit on Sustainable Development in Johannesburg in August 2002.

The principle aim of the initiative is to help overcome the worldwide barriers to reducing the flaring and venting of associated gas from oil producing installations, by sharing global best practices and by implementing country-specific programmes. The initiative was launched by a partnership of representative governments from oil-producing countries, major international oil companies, and donor countries.

The GGFR partnership supports national efforts to effectively use currently flared associated gas by promoting regulatory frameworks and addressing the constraints of gas utilisation such as inadequate gas export infrastructure. It arose in part to try and help address the access barriers to local and international markets, particularly from oil producing facilities in developing countries.

Current partners of GGFR include:

i) The World Bank.

ii) The governments of Angola, Chad, Canada, Ecuador, Equatorial Guinea, Indonesia, Nigeria, Norway and the United States.

iii) Main oil companies; Sonatrach of Algeria, SNH of Cameroon, BP, ChevronTexaco, Eni, ExxonMobil, NorskHydro, Royal Dutch Shell, Statoil, and TOTAL.

5.2 Key Elements of the Standard

5.2.1 The Focus Areas of the Standard

The specific focus areas of the Standard are [Ref 5.1]:

i) To eliminate routine sources of associated gas venting that can be captured and conserved or, if not conserved, routed to flare, thereby reducing the direct emissions of methane gas which has 21 times the global warming potential per unit of mass than CO_2 product of combustion (100 year basis). The rationale here is that it is better to conserve

gas, but if conservation is not possible, then it is better to flare the gas than to send it as raw gas to cold vent.

ii) To eliminate or reduce the large sources of associated gas flaring, especially / primarily the major sources of continuous production flaring, other than those aspects of flaring related to emergency, safety, and operational upsets. This is consistent with the objective of achieving significant reductions in gas flaring from oil production operations.

5.2.2 The Goals of the Standard

The goals can be summarised as an 'initial goal' and an 'ultimate goal' [Ref. 5.1].

i) The initial goal for flaring and venting is: ***'No continuous flaring and venting of associated gas, unless there are no feasible alternatives'***. For venting this would normally mean eliminating large sources of venting, or as a minimum routing them to an efficient flare, unless this is not feasible for technical, environmental, or safety reasons. For flaring it means targeting the identification and evaluation of alternative solutions for gas conservation and / or gas utilisation (as opposed to wastage via flare). For any remaining flaring, it is recommended that industry best practise be adopted to the design and operation of flare systems.

ii) To ultimate goal of the standard is to: ***'Minimize continuous and non-continuous production flaring and venting of associated gas.'*** This goal is to encourage continuing reductions in gas flaring and venting in the long term by prioritizing and addressing flaring and venting sources. The Standard outlines measuring, reporting, and verifying practices to provide a transparent mechanism for tracking performance towards achieving the Standard's goals, and documenting reductions in flaring & venting volumes and associated emissions including GHG emissions.

The Standard outlines recommended timeframes for implementation, and recognizes the distinction between new and existing projects in accommodating circumstances under which these timeframes may not be met.

.

5.2.3 The Implementation of the Standard by GGFR Partners

The voluntary actions required by GGFR partners can be summarised as follows:

i) Endorsement of the Standard's principles with intent to work with GGFR partners in the focus areas towards meeting initial and ultimate goals.

ii) Adoption of the Standard.

iii) Prepare 'Associated Gas Recovery Plans' aimed at identifying how the initial goal is to be met. This should concentrate on identifying feasible alternatives for flaring and venting, and how they are to be implemented.

iv) Implementation Plans by partner governments and associated regulatory bodies.

v) Implementation of the plans.

vi) Monitoring and Transparency, including estimation / metering, annual reporting by producers / operators, annual reporting by governments, and internal / external verification.

5.3 GGFR Implementation Plan for Canadian Regulatory Authorities

The Canadian Implementation Plan was developed on behalf of the Canadian Federal Government and the Canadian provincial regulatory authorities by the Canadian International Development Agency (CIDA) to the World Bank – Global Gas Flaring Initiative. It was published in June 2008 [Ref 5.2].

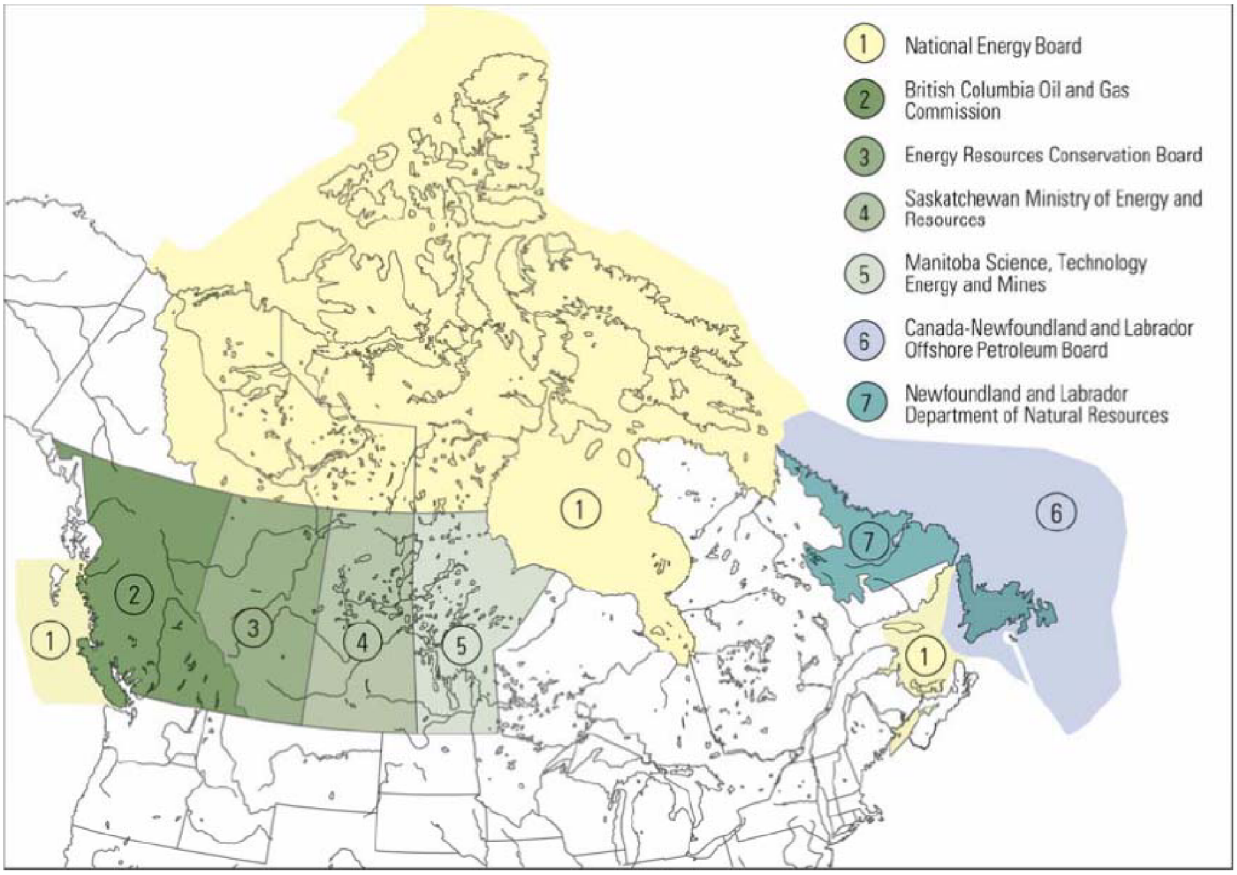
Canada played an important role at the launch of the GGFR, when the Energy Resources Conservation Board of Alberta (ERCB) took up the invitation from the World Bank to join the Global Steering Committee of the GGFR. Subsequently, CIDA agreed to financially support the GGFR initiative, and as a donor, also joined the Steering Committee. The committee was responsible for drafting the Global Gas Flaring Reduction Voluntary Standard, which was endorsed by the ERCB in 2004. Other Canadian regulatory authorities with an interest in endorsing the standard did so between 2004 and 2006.

In Canada, oil and gas activities are regulated by federal and provincial authorities. As of June 2008 the Canadian regulatory authorities responsible for regulating 99% of Canada's oil and associated gas production (as shown in Figure 5-1) had endorsed the Standard. This included the Canada - Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) and the Newfoundland and Labrador Department of Natural Resources.

Accordingly, the Implementation Plan for Canadian flaring reduction efforts is composed of a series of plans aligned with the respective legislative authorities listed in Figure 5-1.

British Columbia, Alberta, and Saskatchewan have developed provincial regulations, standards, or guidelines to realize the voluntary standard in each of those provinces. At a national level the Canadian Association of Petroleum Producers (CAPP) provides guidance in the subject of developing a Flare Reduction Plan in its "Facility Flare Reduction Best Management Practises Guidelines".

Figure 5.1: Canadian Regulatory Authorities endorsing the GGFR Standard [Source: Ref 5.2]



Source: GGFR Implementation Plan for Canadian Regulatory Authorities (June 2008) [Ref 5.2]

In 2007 the total oil production from the Canadian jurisdictions endorsing the standard (and representing 99% of Canadian oil and gas production) was 985.5 million barrels, and the total production of associated gas was 840.1 BCF (23.7 BCM). Of this the two largest contributory provinces by production of oil and associated gas were:

- Alberta – 672.0 million barrels oil and 568.4 BCF associated gas.
- NL – 134.5 million barrels oil and 157.6 BCF associated gas.

As a whole, in 2007, the average national utilisation rate of associated gas was 93.6%.

5.4 NL Oil & Gas Industry – Implementation Status and Objectives

5.4.1 NL Offshore – The C-NLOPB status (2008)

The following extracts from the June 2008 Canadian Implementation Plan highlight the status and objectives of the C-NLOPB as the regulatory body for offshore oil and gas in Newfoundland and Labrador [Ref 5.2].

As part of its mandate as a joint federal-provincial authority under the Canada – Newfoundland Atlantic Accord Implementation Acts, the C-NLOPB focuses on gas conservation for each offshore development plan, and expects operators to examine appropriate methods to conserve gas once an oilfield is placed on production. The C-NLOPB also approves and monitors gas flare volumes for the NL offshore area, including the three existing offshore production operations.

Since production first commenced (from Hibernia in 1997) the experience from the three existing projects has been the tendency for high flare gas volumes to exist during the early stages of oil production, prior to the commissioning and / or steady state operation of the gas compression facilities. This is a function of the fact that there is no export infrastructure in place for the associated gas, and gas re-injection along with local use of gas for fuel in gas turbines used to drive power generation and compression, are the viable alternatives. While the C-NLOPB does understand the issues related to establishing stable gas compression, and has granted some flexibility around gas flare volumes in the early stages of production, operators are expected to make every effort to establish gas compression as early as possible and to continuously strive to reduce flare gas volumes [Ref 5.2].

For projects where gas compression reliability has continued to be a problem, the C-NLOPB has imposed production rate restrictions and operators are expected to reduce production rates accordingly when the gas compression systems are out of service. As a result of the lessons learned related to gas compression system availability, the C-NLOPB also requires, where practical, that oil production installations be equipped with two gas compression trains.
The C-NLOPB expects all operators within the Newfoundland and Labrador offshore area to take steps to minimize flare gas volumes. Operators are also encouraged to develop flare management plans that strive for the reduction of gas flaring volumes down to background flare levels. While operators are given the flexibility to operate within set flare volume limits, the C-NLOPB also monitors flaring volumes and practices on a continuous basis to ensure that good flare management practices are in place at each of the producing fields. In the future, the C-NLOPB plans to meet with operators to examine best practices to further reduce gas flaring, including the potential to eliminate gas flaring from the pilot on the gas flare system.

5.4.2 NL Offshore – The C-NLOPB status (2012)

The following is as summary of discussions between AMEC, CCEEET and the C-NLOPB in June 2012 during stakeholder consultation discussions in St John's regarding flare management in the offshore oil and gas in Newfoundland and Labrador.

i) An offshore Operator is only allowed to flare or vent gas on a production test for 24 hours to relieve abnormal pressure, or because of an emergency, otherwise the Operator must obtain the Chief Conservation and Safety Officer's approval.

ii) Monthly production records are monitored to assess whether the volumes of gas and/or oil being flared, or oil being disposed of are within limits set out in the approval, and that requisite approval has been obtained.

iii) The annual production reports are similarly monitored and periodic assessments made, including the re-setting of annual flare limits in approvals.

iv) Gas flaring limits are applied on an annual basis for each installation on a case by case basis, based on historic profiles, expected production for the year ahead and related operation and maintenance activity. The limits are set in terms of volumes in million of m^3 per year. The annual periods are specific to each Operator and do not necessarily relate to a calendar year.

v) The flaring limit has so far been reduced year on year in line with discussions between the C-NLOPB and each Operator, from the original baseline in 2007. The reductions are non-uniform and are agreed annually.

vi) For the year to October 2011, the flaring for the Hibernia platform was approximately [redacted] m^3. This was [redacted] below the gas flaring allocation of [redacted] m^3 for the year to October 2011. The allocation for the year November 2011 to October 2012 was set at [redacted] million m^3, a reduction of [redacted].

vii) For the year to end December 2011, the flaring for the Terra Nova FPSO was approximately [redacted] m^3. This was [redacted] below the gas flaring allocation of [redacted] m^3 for the year to December 2011. The allocation for the 2012 year to December 2012 was set at [redacted] m^3, a reduction of [redacted] The Terra Nova will be on major turnaround outage for part of 2012.

viii) For the year to January 2012, the flaring for the White Rose field was approximately [redacted] m^3. This was [redacted] below the gas flaring allocation of [redacted] m^3 for the year. The [redacted] limit was itself a reduced by [redacted] from the previous year's limit of [redacted] m^3.

ix) The C-NLOPB receive a flare update report from each Operator each quarter. This provides information relating to flare volumes and flare contributors.

5.4.3 NL Onshore – The Department of Natural Resources

The following extracts from the June 2008 Canadian Implementation Plan highlight the status and objectives of the Department for Natural Resources as the regulatory body for the onshore oil and gas sector [Ref 5.2].

The Department of Natural Resources is responsible for the regulation of upstream onshore petroleum activities in the Province, including gas venting and flaring. All offshore upstream petroleum regulations are jointly created by the federal and provincial governments. The

province's Minister of Natural Resources is the minister responsible for approving these regulations and the federal Minister of Natural Resources is responsible for the corresponding federal regulations.

NB. It should be noted that the Newfoundland and Labrador onshore oil and gas production is currently insignificant relative to the offshore sector. However, there are future development plans for new onshore fields.

In general, existing practices within the province are consistent with the Global Gas Venting and Flaring Reduction (GGFR) Voluntary Standard and the Department of Natural Resources formally endorsed the GGFR principles in September 2007. The department will consider these principles when developing new regulations or revisions to existing regulations. The department's approach to guideline development will draw from both the work done by the GGFR and Alberta's Directive 60: Upstream Petroleum Industry Flaring, Incinerating, and Venting.

There are few Newfoundland and Labrador onshore operators (and mostly are in exploration stages). The Department of Natural Resources will work with emerging NL onshore operators to find feasible alternatives to flaring or venting associated gas at petroleum drilling and production sites. In addition, the department will report annual vented and flared volumes as well as associated gas volumes produced for all onshore upstream petroleum activities.

The department will also encourage C-NLOPB to continue in the pursuit of best practices for operators in NL offshore area [Ref 5.2].

5.5 Alternative Options to Flaring

In accordance with the goals of the Standard under the GGFR partnership the following are some of the key alternative options for flaring of associated gas at oil producing installations. This section covers the main options from a generic perspective. The application of these options to NL offshore installations is mentioned here, but the discussion of the application of specific best practices and of specific technology to the NL offshore petroleum sector is covered in more detail in Section 4 & 6.

i) **Gas utilisation as fuel for on-site energy**. For a typical oil and gas installation this equates to utilising associated gas as the primary fuel for stationary combustion plant on the installation. This plant is typically used to generate the motive power for the energy intensive processes needed for oil extraction, separation, processing and export, and consists of gas turbines, engines, heaters, and boilers. Section 3 describes these plant items in more detail. The use of associated gas (which is typically first cleaned and dried) in combustion plant is preferable compared to the use of diesel oil, for both environmental and economic reasons. In the NL offshore industry this option is used extensively at all three facilities, particularly as fuel gas in the combustion gas turbines

used for power generation (electricity supply) and mechanical drive (driving gas injection compressors in the case of Hibernia).

ii) **Export of gas to neighbouring facilities for use as fuel**. This option is advantageous where an installation with excess associated gas may be in relatively close proximity to another installation which is gas–deficient. The gas is typically compressed and piped from the first installation to the second rather than being flared at the first. This allows the gas-deficient installation to utilise gas fuel rather than diesel fuel and thereby equally enjoy the benefits of fuel substitution. This option is commonly used in mature oilfields including the North Sea (UK, Norway, Holland). It is not currently used in the NL offshore industry since none of the three existing facilities is in any way gas deficient (rather the opposite), and given that the majority of produced gas is re-injected (see below) then the option is also unlikely to be relevant to these facilities in the future.

iii) **Export of natural gas to the wider market**. This is an attractive option where the volumes of associated gas reserves and gas production rates are relatively high and the economics of establishing an export infrastructure are profitable (a viable return on investment). The traditional approach (where viable) is to compress the gas and send it ashore **via pipeline** to an onshore reception / processing terminal. From here the gas is either fed onto an **onshore gas grid** (transmission / distribution pipeline network), or is fed to an **onshore LNG** liquefaction plant for export worldwide via LNG tanker. Other offshore options / technologies exist and include; **offshore LPG / NGL recovery**, **floating LNG**, and **small scale LNG**. In addition there is the potential for onshore **'gas to wire'** options whereby associated gas is exported to a local onshore terminal where is utilised to **generate grid electricity** in a high efficiency combined cycle power station (e.g. using **CCGT technology**), and then exported further distances as high voltage (HV) electricity. Currently the offshore NL industry does not have any infrastructure in place for the export of associated gas to external markets. However, despite the technical challenges posed by the harsh cold weather environment, this option might be viable in future, particularly given the relatively high gas reserves in the White Rose field.

iv) **Gas re-injection for reservoir pressure maintenance / gas conservation**. In this option the majority of the produced gas is re-injected into the oil producing reservoir to maintain pressure as oil reserves are extracted. This requires expensive and energy intensive gas processing and gas compression facilities on the offshore installation, but in the absence of an export route option can allow the majority of associated gas to be conserved, and at the same time support oil production rates. This is the preferred option that has been designed into all three existing NL offshore petroleum facilities.

v) **Enhanced oil recovery using gas lift**. As opposed to being re-injected to maintain reservoir pressure, the gas is re-circulated in the oil producing wells to stimulate increased oil production rates. This only works with certain types of wells and can be employed in parallel with gas re-injection strategy, although the volumes are generally lower. There are a number of gas-lift wells at the three installations in the NL offshore sector.

All of the above options rely on critical gas handling equipment being operational during oil production operations to divert associated gas from otherwise being flared to alternative use / conservation. As a general principle, in order to minimize increased flaring events resulting from equipment breakdowns (unplanned outages) and plant upsets, plant availability should be high (typically >95%) and provision should be made for equipment sparing and for plant turndown protocols.

5.6 Flaring & Venting – Pollution Prevention & Control Best Practice Measures

The following pollution prevention and control best practice measures for flaring and venting are taken largely from the International Finance Corporation (IFC, part of the World Bank Group) guidelines for the offshore oil and gas industry development [Ref 5.3] supplemented by UK and European best practice guidelines [Ref 5.4].

5.6.1 Flaring – Best Practice Measures

If flaring is necessary then continuous improvement of flaring via the implementation of Best Practices and Best Available Techniques (BAT) should be adopted.

These include the following measures:

i) Reduction – implement source gas reduction measures to the maximum extent possible.

ii) Appropriate flare tip design – Use efficient flare tips and optimize the size and number of burner nozzles.

iii) Combustion efficiency – Maximize flare combustion efficiency to reduce the likelihood of unburned hydrocarbons including methane.

iv) Flare pilots and purge – Minimise flaring from purge and pilots, by using purge gas flow control and flow measurement devices, flare gas recovery units, or use of inert gas for purge.

v) Flare ignition – Use a reliable pilot ignition system.

vi) Pressure Integrity – Install high integrity pressure protection systems (HIPPS) in association with flare recovery systems.

vii) Gas Separation – Minimise liquid carry-over into the gas flare system by using appropriate liquid separators and associated control devices. Ensure control loops are well tuned.

5.6.2 Venting – Best Practice Measures

Appropriate best practice measures to reduce venting include the following measures:

i) Reduction – re-route vents to flare system of to vapour recovery unit (VRU).

ii) Centrifugal Compressor seals – replace wet seal technology with dry gas seals.

iii) Storage Tanks and cargo offloading – install VRU to tanks and tankers.

iv) Drilling mud degassing – route vents to VRU.

v) Glycol dehydration – route condenser vent to VRU.

vi) Pneumatic controls on pumps, pressure control, level controls, etc – replace with clean instrument air system.

vii) Fugitive leaks from valves, flanges, pumps, etc – implement regular direct inspection and maintenance regime to minimise fugitive emissions.

5.7 References

The following references relate to Section 5 of this report:

5.1 "Global Gas Flaring Reduction, A Public-Private Partnership – A Voluntary Standard for Global Gas Flaring and Venting Reduction" Report No. 4 May 2004, published by the World Bank Group.

5.2 "World Bank Global Gas Flaring Reduction - Public-Private Partnership Implementation Plan for Canadian Regulatory Authorities" June 2008.

5.3 "Environmental, Health, and Safety Guidelines for Offshore Oil and Gas Development". Published by the International Finance Corporation (IFC) World Bank Group, April 2008.

5.4 "Global Gas Flaring Reduction Partnership – Regulation of Associated gas Flaring and venting: A Global Overview and lessons learned" Report No. 3, published by the World Bank Group.

5.5 "Global Gas Flaring Reduction Partnership – Guidance on Upstream Flaring and Venting Policy and Regulation", Washington DC, March 2009.

5.6 "Technical Report – Guidelines on Flaring and Venting Measurement" prepared for the GGFR Partnership and World Bank by Clearstone Engineering, Ontario, Canada, September 2008.

6.0 EVALUATION OF TECHNOLOGY OPTIONS

The tables in Appendix B contain a summary of the evaluation of the technology options for best practice and BAT that were discussed in section 4 and 5 of this report. The following sub-sections describe the manner in which the tables in Appendix B should be interpreted for the interim report.

6.1 Technology Assessment Criteria

The following technology assessment criteria have been used in this study:

i) The **potential for GHG reduction or efficiency improvements** on an offshore oil and gas installation. For the purpose of the interim report the potential reduction of each technology has been expressed based on the percentage of annual GHG emissions that are estimated to be saved from either:

   a. flaring volumes; or
   b. fuel consumption

   The percentage estimates have been based on the AMEC-PI historical database of GHG reduction initiatives derived from over 100 energy assessments conducted worldwide since 2005, with emphasis on data collated for UK and North Sea offshore assets, with production processes similar to the NL offshore projects. Where the percentage benefits could potentially cover a range of values (e.g. 2% to 10%) a value close to the typical median value has generally been used (e.g. 5%) in this study pending further evaluation with specific reference to NL operations. It is anticipated that further refinements to make the percentage values more specific to NL operations are dependent on the extent of further successful stakeholder engagement.

ii) The **technical feasibility** of implementing each technology option. For the purpose of the interim report the feasibility of each technology has been expressed based on AMEC-PI experience of the difficulty or risk of implementing each option, as falling into one of three categories:

   a. Low difficulty or risk – a simple operation, procedure, or change. Easily planned and executed with no or minimum risk to safety and production. No shutdown or slowdown is required. Minimum of intrusive work. No risk of plant shutdown.
   b. Medium difficulty or risk – an operation, procedure, or change that requires significant effort or risk. A plant or unit shutdown or slowdown is likely to be required, or there is likely to be significant intrusive site work, or there is the risk of unit or plant shutdown.
   c. High difficulty or risk – a change requiring major effort in planning, engineering and execution or major risk to safety or production. Facility shutdown is required or high risk of plant shutdown. It is anticipated that the level of difficulty or risk specific to NL operations will be reviewed via stakeholder engagement.

iii) The **estimated economic costs** of implementing the best practice or technology on a typical installation. For the purpose of the interim report the cost of implementing each

technology option has been expressed based on AMEC-PI experience, and given a $ value for present 2012. The focus on the interim report has been on assigning relatively conservative dollar-values for capital cost, and operational costs have not been considered in any detail. It is anticipated that the level of CAPEX and OPEX costs relevant to NL operations will be reviewed via stakeholder engagement.

In addition, a reference installation case has been used in the interim report to set the typical reference level for absolute values of emissions. This has been defined as an installation with approximately 500 ktonnes / annum of CO_2 emissions, of which approximately [redacted] are due to fuel consumption and [redacted] are due to flaring. This based on being representative of the average emissions from the three NL offshore projects as of 2010 data. Variations specific to individual NL installations over time are addressed within the economic evaluation itself – as described in Section 9 of this report.

6.2 Opportunity Ranking

For the purpose of further economic analysis the individual best practice technologies and technology BAT have been grouped into related activities (based on area of plant and / or source of emissions), and given a collective cost and benefit. For example, best practices relating to flare and vent minimisation have been grouped together, and have been treated as a distinct sub-group from flare recovery BAT technology. This is so as to make the economic analysis model practicable (not too many individual technologies), but also to enable overlapping technologies to be treated more meaningfully in terms of their net benefits; i.e. benefits from implementing different technologies are often not cumulative, because implementing one option may often reduce the benefits of reducing a further option.

Sub-groups of best practices / technologies have therefore been assigned their own weighted benefits in terms of percentage GHG reduction benefits and implementation dollar costs. Once the technologies have been grouped in the above manner they have been ranked in terms of GHG abatement (tonnes CO_2) / dollar implementation cost.

6.3 Workshop Discussion and Feedback

The information on technology assessment criteria and opportunity ranking presented in Appendix B were issued to each Operator in April 2012 and were presented at a workshop in St John's in June 2012. The workshop was attended by representatives from each offshore Operator, plus from C-NLOPB and department of Natural Resources.

The information obtained from discussions in St Johns in June 2012 has been incorporated into the final analysis within this report.

7.0 REGULATORY REVIEW

7.1 Background & Introduction

Various policy instruments have been adopted in different countries to control greenhouse gas emissions (GHG). The general intent of these instruments is to reduce GHG emissions below a business as usual scenario in an economically efficient manner and with minimum impact on competiveness. Local circumstances influence the type of policy that is adopted and these include:

i) Voluntary systems

ii) Taxes on energy or CO_2

iii) Trading

The European Union Emissions Trading System (EU ETS) is the principal system adopted throughout the EU member states to mitigate GHG emissions and is a 'cap and trade' system. Countries outside the EU have variations of the EU ETS e.g. Norway has a quota system in which no free allowances are given and all quotas must be purchased at a combined cost of a tax plus quota cost. In Canada there are Federal and Provincial initiatives. The various systems are discussed in the following sub-sections.

7.2 Canadian GHG Regulatory Perspective

Canada has both national and provincial policies regarding GHG emissions and each policy will have different economic impacts. The current and proposed initiatives are described in the following sections.

7.2.1 Canadian Federal Policy

The Federal Government of Canada initiated the National Climate Change Process in the late 1990s and since then successive governments have produced various scenarios for the way forward. New carbon policy is emerging at the federal level together with policy mechanisms at the provincial level and there is a move to integrate the federal and provincial measures to produce equivalent outcomes.

In December 2009 the federal government committed to a national greenhouse reduction target of 17% below 2005 levels by 2020. The government plans to reduce greenhouse gas emissions on a sector by sector basis for all major emitters and have recently (August 2011) produced the draft *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations*.

The objective of this proposed Regulation (Ref. 7.1) is to promote a move away from high emitting coal fired generation of electricity to alternative technologies such as renewable energy, high efficiency natural gas or thermal power with carbon capture and storage (CCS). The Draft Regulations proposed an emission intensity standard of 375 tonnes of CO_2 per GWh coming

into effect on July 1 2015 to new units and old units reaching the end of their useful life. Units are required to begin reporting two years in advance of when they reach their end of useful life date or, in the case of new units (i.e. commencing operation in July 2015), in the first year of operation. The Final Regulations were approved in September 2012 and the emissions intensity standard was set at a value of 420 tonnes of CO_2 per GWh.

Some flexibility will be granted:

i) Temporary Exemption (System to be constructed) - New and old (retrofit) units would be able to apply for a temporary exemption until January 1, 2025, from the application of the performance standard if they incorporate technology for CCS and in so doing expect to be in compliance by January 1, 2025, in conjunction with other terms.

ii) 24 Month Exemption (Existing unit within system) – available to existing units that are retrofitted to employ CCS technology and that capture at least 30% of their CO_2 for a minimum period of 7 calendar years, in conjunction with other terms.

The Final Regulations were approved in September 2012 and the emissions intensity standard was raised from the propose level of 375 tonnes of CO_2 per GWh to a level of 420 tonnes of CO_2 per GWh. The Federal Government states that "This level more closely reflects the reasonably expected performance of a base-load natural gas combined cycle unit and responds directly to near-unanimous comments from industry, but is still within the range (360–420 tonnes of CO_2/GWh) that was announced in June of 2010". It is anticipated by the Federal Government (in Septemer 2012) that the proposed regulations will reduce GHG emissions over the period 2015-2035 by approximately 214 Mt CO_{2e}.

7.2.2 Regional Initiatives in North America (Canada & US)

Western Climate Initiative

As of mid-2012 the Western Climate Initiative (WCI) is a collective emissions trading system currently proposed between 7 US states and 4 Canadian provinces (British Columbia, Ontario, Quebec and Manitoba). The goal of WCI is to reduce GHG emission by 15% below 2005 levels by 2020 and the scheme will be phased in from 2012. Initially the cap and trade programme would apply to utilities and large industrial sectors but will expand to include other sectors in later years.

WCI will provide a broad framework for each partner to develop their own emission allowances and how these are distributed. This is similar to the process in EU ETS Phases I and II were each member state produced their National Allocation Plans (NAP). However, WCI allows for harmonisation across provinces to address competiveness issues. Also each province or jurisdiction will produce its own legal framework to implement the scheme. Trading with other provincial companies in the scheme and third parties across the WCI region will be allowed and offset credits are under review.

[2013 update: As of Q1 2013, Quebec and California have started up the program in 2013. WCI is all but disbanded as an emissions trading organization, deferring to a bilateral arrangement between two jurisdictions only. Currently, other states and provinces are not participating, although some still have policy commitments to enter the emissions trading system].

7.2.3 Provincial Initiatives in Canada

British Columbia (BC) has introduced a number of GHG reduction measures including a carbon tax as well as a carbon neutrality program for the public sector. The carbon tax applies to the purchase or use of fossil fuels within the province. The tax rates on July 1, 2011 are based on C$25 per tonne of CO_2 equivalent emissions, increasing by C$5 per tonne to $30 per tonne in 2012. The BC Greenhouse Gas Reduction (Cap and Trade) Act (2008 and amended 2010) provided the statutory basis for setting up a market-based cap and trade framework to reduce greenhouse gas emissions from large emitters operating in the province. As is the case in Ontario, the only provisions of the Act currently in force relate to GHG reporting for facilities meeting emission thresholds.

The Quebec cap-and-trade system was adopted in December 2011 and will include three compliance periods at first. These periods will be preceded by a one-year transition to enable emitters and other participants to familiarize themselves with the way the system works. During 2012, emitters and other participants will be able to register in the system, take part in pilot auctions and buy and sell emission allowances on the market. No GHG emission reductions or ceilings will be imposed during this transitional year.

Capping and reduction of Quebec greenhouse gas emissions began on January 1, 2013. Exceptionally, the initial compliance period will last two years, from January 1, 2013 to December 31, 2014. The duration of subsequent compliance periods will be three years. Starting in 2013, the operators of around 100, mainly industrial and electricity generation, sites, whose annual GHG emissions are equal to or greater than the annual threshold of 25 Kt of equivalent CO_2, will be subject to capping and reducing their GHG emissions.

The Ontario regulation, Ontario Regulation 452/09 Greenhouse Gas Emissions Reporting, applies to 26 source types emitting greater than 25,000 tonnes $CO_{2e.}$ It is important to note that this regulation is drafted in terms of CO_{2e} and therefore includes all greenhouse gases noted in the regulation converted to CO_{2e} based on global warming potential factors. The Province is currently reviewing it's policy structure with a view to moving towards a cap and trade system.

Around 70% of Alberta's industrial greenhouse gases arise from oil sands mines and coal fired power plants. From 2007 under the Specified Gas Emitters Regulation (Ref 7.2) all facilities emitting more than 100,000 tonnes of GHG per year must meet reduction targets based on their emissions intensity (emissions per unit of production). The target is 12 % reduction from their average intensities between 2003 and 2005. New facilities (i.e., those built after 2000) face a three year grace period, after which they must reduce their intensities by 2% annually until they achieve a 12% reduction.

Reduction targets may be achieved by implementing energy efficiency measures or alternatively as compliance options:

- Purchase offset credits from sectors not covered by the regulation (within Alberta).
- Buy allowances from companies that have over achieved on their reduction target.
- Purchase credits from the Climate Change and Emissions Management Fund (a technology fund) at C$15 per tonne CO_2e. These funds are invested in emissions reducing technologies throughout Alberta's economy.

Since there is no limit on paying into the technology fund this may be viewed as a carbon tax. The carbon price is effectively capped and this has implications for long term decisions in abatement technology.

The Nova Scotia Greenhouse Gas Regulations N.S.Reg 260/2009 applies to any facility located in the province that emits greater than 10,000 metric tonnes of carbon dioxide equivalent greenhouse gases in a calendar year. Table 7.1 shows the total cap of $CO_{2\,e}$ for all facilities to which the regulation applies together with the relevant time periods.

Table 7.1: Nova Scotia – Total Emission Caps

Compliance Period	Calendar Years	Emission Cap for all Facilities in the Province (million tonnes CO_{2e})
1	2010, 2011	19.22
2	2012, 2013	18.5
3	2014, 2015, 2016	26.32
4	2017, 2018, 2019	24.06
5	2020	7.5

The federal and provincial environment ministers are working together to clarify and eliminate overlap between the existing Nova Scotia regulation and proposed federal greenhouse gas regulation. The objective is to achieve the same reduction targets.

Nova Scotia is the first province to put in place hard caps on greenhouse gas emissions for electricity providers. This regulation requires a reduction of 25 per cent in greenhouse gas emissions in the electricity sector by 2020. The agreement will also require the province to create new targets which will extend to 2030 to match reductions that will be achieved under the proposed federal regulations.

In August 2011, the federal government proposed new regulations for the electricity sector that will apply a stringent performance standard to new coal-fired electricity generation units and those coal-fired units that have reached the end of their economic life. Final regulations were published in September 2012, from which any equivalency agreement can be finalized.

Saskatchewan has developed a climate change policy and introduced Bill 126: The Management and Reduction of Greenhouse Gases Act to reduce emissions by 20% from 2006 levels. Facilities emitting greater than 50,000 tonnes CO_{2e} in a year are subject to the legislation and must achieve a reduction target per year referenced to a baseline.

Regulated emitters will be able to purchase offset credits created from activities that have reduced and sequestered GHG in Saskatchewan and that occurred after January 1, 2006. In addition to offset credits, regulated emitters can make so-called "carbon compliance payments" to the Saskatchewan Technology Fund Corporation. Proceeds from this fund will be used to invest in GHG reduction initiatives and research.

7.2.4 Regional Greenhouse Gas Initiative (NE United States)

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort between nine Northeast and Mid-Atlantic states for a market-based regulatory program to cap and reduce CO_2 emissions from the power sector. The states include; Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. The Memorandum of Understanding (MOU) of the RGGI was entered into in December 2005. The state of New Jersey withdrew from the MOU in January 2012.

The program is designed around selling of emission allowances through auctions with the proceeds being invested back into clean energy technologies, including energy efficiency and renewable energy projects.

As called for in the original RGGI MOU, the Participating States conducted a program review of the CO_2 Budget Trading Programs. Proposed amendments to the RGGI program have been incorporated in an Updated Model Rule, released in February 2013, that will guide each state as it follows its own statutory and/or regulatory procedures to propose updates to its CO_2 Budget Trading Program regulations.

The recent program review revealed:

i) An excess supply of allowances relative to actual emission levels in the region.

ii) The current cost control measures in the program, which are based upon expansion of the percentage of offset allowances allowable for compliance, would likely be ineffective in controlling costs if the emissions cap is made binding.

Therefore in the Updated Model Rule a number of revisions have been proposed:

i) A Revised Regional Cap, lowered to re-align with current levels of actual emissions whilst accounting for excess allowances held by participants.

ii) A decline in the Regional Emissions Cap by 2.5% each year from 2015 to 2020.

iii) Periodic adjustments for banked allowances.

iv) A cost containment reserve of allowances to be used if defined allowance price triggers are exceeded.

7.2.5 Canadian Air Quality Management Issues (AQMS and BLIERs)

Whilst not being directly relevant to CO_2 emissions, the subject of air quality in relation to emissions of industrial pollutants (such as NOx, SO_2, and VOCs) from combustion processes is also topical for the NL industry and has been highlighted by CCEEET as being a tertiary area for discussion in this report.

In recent years the Canadian federal government has pursued efforts to control air emissions under the Canadian Environmental Protection Act 1999 (CEPA), and this has led to plans for Canada to adopt new air quality standards for industry and other emitters. The aim of the new Air Quality Management System (AQMS) – approved by the Canadian Council of Ministers of the Environment in October 2010 - is to set to provide consistent ambient air quality and industrial emission standards across the country, by building on existing federal and provincial air quality management, whilst at the same time providing flexibility to address regional differences in air quality issues.

The AQMS approach is outcome-based, by defining the desired ambient air quality in a particular air-zone, in relation to air-sheds across provinces and territories. AQMS is collaborative in that is requires federal and provincial governments and industry stakeholders to work together on developing standards and on continuous improvement. The three key components of AQMS are:

i) The development of Canadian Ambient Air Quality Standards (CAAQS), to drive air quality management in all jurisdictions.

ii) The adoption of 'place-based' air quality management in relation to six regional air sheds across Canada, and associated provincial air zones.

iii) The establishing of Base Level Industrial Emissions Requirements (BLIERs) in major industrial sectors, for specific pollutants such as NOx, SO_2, and total particulates.

In the context of this study and report, the NL government and the NL offshore petroleum sector are keen that the adoption of these AQMS components is undertaken in a manner that builds in flexibility in relation to the unique circumstances of the offshore petroleum sector.

The notes from a CAPP air issues forum in Calgary (held on Sept. 26 2011) indicate that work is ongoing on 17+ committees with CAPP represented on several BLIERs working groups including combustion turbines, boilers and heaters, VOCs from fugitive emissions, and reciprocating engines. Implementation is expected in the 2013 – 2015 time frame, however there will be a phasing in process for different sectors, and for existing facilities within a sector.

7.3 Australia

Australia has introduced a Clean Energy Future Package which puts a price on carbon to incentivize a reduction in pollution and investment in clean energy. The primary Act is the Clean Energy Act 2011, No. 131, 2011 establishing the scheme and comes into effect from 1 July 2012. Further Acts will set out:

i) The overall design and administration of the Scheme;

ii) Targets to reduce GHG emissions;

iii) The issuance of carbon units that allow liable entities to pollute;

iv) Rules regarding the trading in carbon units both domestically and internationally;

v) The application of an equivalent carbon price to fuel use not covered by the Scheme;

vi) New taxation measures;

vii) The provision of assistance to businesses affected by the Scheme; and

viii) The operation of the Australian National Registry of Emissions

It will apply to entities that exceed an emissions threshold of 25,000 tonnes of CO_{2e} and those entities will have to purchase and surrender carbon units for each tonne of CO_{2e} that they emit. The scheme will only apply to four greenhouse gas emissions:

i) Carbon Dioxide;

ii) Methane;

iii) Nitrous Oxide; and

iv) Perfluorocarbons.

The Carbon Price Mechanism (CPM) introduced by the scheme is a hybrid model in that the price of carbon will be fixed for the first three years (effectively a tax) followed by transition to a flexible cap and trade and emissions trading scheme including the use of some international trading credits. Under CPM the price is fixed at A$ 23 per tonne of CO_{2e} (approx. C$24, April 2012) from 1 July 2012 to 31 June 2013 and then rises by 2.5 per cent (to account for inflation) in each of the next two years. This creates price certainty for three years and gives business opportunity to assess their cost of carbon emissions and the impact on their business. While the scheme will operate as a carbon tax for the first three years at heart it is a cap and trade scheme.

The Government will cap the level of emissions and this cap will reduce in line with the Government's target to achieve an emissions reduction target of 5% below 2000 levels by 2020. It is intended to set the cap for five years in advance. The cap will be an overall cap from all sources but no limit will be placed on individual sectors, entities or facilities. A fixed number of

carbon units will be issued by the Government each year. Carbon units can be obtained from a number of sources including:

i) Government auctions;

ii) Domestic offset initiatives;

iii) Eligible international credits; and

iv) Free allocations.

Failure to surrender sufficient units to cover emissions will result in a "unit shortfall charge" amounting to 130% of the carbon price during the fixed price period and 200% of the average annual auction price for a carbon unit during the compliance year.

The main sectors affected by the scheme are:

i) Electricity generation;

ii) Mining;

iii) Industrial processes;

iv) Manufacturing;

v) Waste;

vi) Transport (with certain exclusions) including aviation; and

vii) Construction.

Some sectors of the economy will be heavily affected by the scheme and may be compensated by the Government through assisted packages. An Emissions Intensity and Trade Exposure (EITE) test will be applied to determine the level of assistance. Assistance will be given in the form of free permits.

7.4 EU Emissions Trading System (EU-ETS)

The European Union Emissions Trading System (EU ETS) is the key policy instrument established by the EU Emissions Trading Directive 2003/87/EC (Ref 7.5) to achieve the European Community's response to climate change. It is the world's largest and by far the most well developed trading scheme currently operating in 30 countries (the 27 EU Member States plus Iceland, Liechtenstein and Norway). It came into force in October 2003 with implementation in three phases:

Phase I from 2005-2007 was very much a trial phase laying the groundwork for the next phase. **Phase II** running from 1 January 2008 to 31 December 2012. This phase coincides with the first Kyoto commitment period of five years during which the EU and its member states must comply with their emission targets.

Phase III will run for eight years from 1 January 2013 to 31 December 2020. This phase will have significant changes compared with the earlier phases.

Since EU ETS is a large-scale GHG trading programme and has been running for almost seven years it offers an opportunity to critically assess its implementation and effectiveness to date. Key lessons will give an insight into the cost of emissions, impact on reduction of emissions, cost effectiveness, wider economic issues, new technologies and efficiency opportunities.

A detailed review of the EU-ETS is given in Appendix B.

Greenhouse gases within the context of the Directive refer to:

- Carbon Dioxide (CO_2);
- Methane (CH_4);
- Nitrous Oxide (N_2O;
- Hexafluorocarbons (HFCs);
- Perfluorocarbons (PFCs); and
- Sulphur Hexafluoride (SF_6).

As noted above **Phase I** was very much a trial period so that the infrastructure could be put in place to gain experience. **Phase II** introduced a significant change for the offshore oil and gas industry in that CO_2 emissions attributed to flaring were included in the system. Phase II will close at 31 December 2012 and **Phase III** will run from 1 January 2013 to 31 December 2020 and introduce further significant changes to the system. For the offshore oil and gas industry ***the most important of these is that in Phase III no free allowances will be given for electricity generation. (Ref 7.6). This is discussed further below.***

7.4.1 Offshore Oil & Gas Industry specifics

It is important to recognize that from the list of greenhouse gases above only CO_2 emissions from combustion activities and flaring on offshore installations are currently included in Phase II EU ETS and similarly for Phase III. The offshore oil and gas industry falls within “Energy” activities under the sub-activity 1.1 Table 7.1:

The scope of EU ETS for offshore oil and gas changed from Phase I to Phase II in that flaring was included in Phase II and will also be included in Phase III. Additional free allowances are given for flaring. Phase III introduces a significant change for the offshore sector in that no free allowances will be given for emissions from electricity generation. In Phases I and II allowances were given for fuel use regardless of whether or not it was for electricity generation. This means that there will be no free allowances for gas turbines or diesel generators which are used to produce electrical power. Combustion units that are used to produce mechanical energy e.g. a gas turbine directly driving a compressor will be given allowances. Consequently for Phase III

operators will have to purchase credits to cover the CO_2 emissions derived from electricity generation. Therefore operators will incur a significant increase in operating costs.

In Phases I and II the number of allowances was decided by each member state but in Phase III the EU will decide the allocation based on harmonised rules across the EU and using benchmarks. In the context of EU ETS a benchmark is a threshold for the level of free allowances for an installation. Free allowances were given for Phases I and II on the principle of "grandfathering" and benchmarking was largely only used in the offshore sector for new entrants. With the advent of Phase III a harmonized approach will be taken for the allocation of allowances and benchmarking is the norm for existing installations and new entrants.

A product benchmark is defined as the average of the 10% most greenhouse gas efficient installations, in terms of metric tonnes of CO_2 emitted per tonne of product produced at European level in the years 2007-2008. Each of the above benchmarks are referred to as sub-installations where a sub-installation means all inputs, outputs and corresponding emissions related to a specific allocation regime. One or a number of these sub-installation benchmarks can be applied to an installation to determine the free allowances but it must be done in the order 1 through 4 above.

However, energy intensity benchmarks related to product are not feasible in all cases and this has been clearly demonstrated for the offshore oil and gas sector. An exercise was undertaken to collect benchmarking data for the offshore oil and gas industry (Ref 7.10) but it was soon realized that product benchmarking could not easily be applied to offshore. Various factors contribute to the difficulties faced when trying to set a benchmark for offshore including:

a) Decreasing production;

b) Increasing emissions intensity;

c) Characteristics of reservoirs; and

d) Transportation to the market place.

As fields become more mature and production falls, relatively more energy is required to maintain production due to higher rates of re-injection for oil production and reducing pressure in gas reservoirs. Another important factor for offshore production is power supply. Due to their location offshore installations are generally designed to be self sufficient in power supply to drive all of the process facilities. Gas turbines are the main source of electrical power generation and there are a wide variety of turbine types with a range of output and efficiencies. The preferred fuel for these turbines is gas but many are dual fuelled and can run on diesel.

Where natural gas pipelines do not exist, as is the case in Newfoundland and Labrador, substantial amounts of gas are re-injected or flared. Thus fuel derived from the production process is "wasted" rather than being a useful product and a source of revenue.

All of the above make it difficult to rationalize an applicable benchmark related to unit output.

The upstream oil and gas production process can be sub-divided into a number of sub-processes and unit operations producing a number of products including:

- Live crude oil;
- Stabilised crude oil;
- Gas for export;
- Sales quality gas;
- Produced water; and
- Non-gaseous liquids.

It would only be possible to derive a product benchmark if the energy input to each of the sub-processes or unit operations could be measured with some degree of accuracy with a strong correlation to CO_2 emissions.

An Entec study undertaken for the Department of Energy and Climate Change (DECC), ranked in order of increasing CO_2 emissions. It showed that there is no apparent relationship between emissions and the energy content of different products and by-products, or the ratios between these products.

A study undertaken by Genesis concluded that a production benchmark based on total material flows which included hydrocarbons and produced water as boe was not feasible. This is shown in the wide spread of results and poor correlation between mass of product and CO_2 emitted.

In determining the rules for harmonized free allocation of emissions for Phase III the EC decided that in cases where it was not possible to elaborate a product benchmark (as is the case for the offshore sector) a fall back approach using a heat, fuel or process benchmark is applied. This approach was taken by the offshore oil and gas industry in applying for the Phase III allocation and the heat and fuel benchmarks were applied.

The EU produced a series of guidance documents for collecting the relevant information and data that would be required to determine the free allowances. Operators were given the option of submitting data for the periods 2005-8 or 2009-10 whichever was the most advantageous.

Heat benchmarking is much less significant in the offshore industry compared to fuel mix benchmarking as it generally only applies to waste heat recovery units. Nevertheless operators made every effort to claim as many allowances as possible and submitted data for the heat benchmark where applicable. Since no free allowances will be given for electricity generation in Phase III the fuel mix benchmark only applies to direct driven combustion equipment e.g. a gas turbine directly driving a compressor.

In order to determine the Phase III allocation for the offshore sector fuel consumption data (excluding fuel used for electricity generation) was collected in the standardized form of TJ and

this was converted to tonnes of CO_2 using the standard benchmark of 56.1 tonnesCO_2/TJ of fuel or flare. It should be noted that the 56.1 tonnes CO_2 /TJ is not a benchmark in the sense that operators must achieve this figure. This CO_2 emissions factor is for natural gas and was used as a standard factor by all operators applying for allowances. This would be impossible given the variation of fuel gas quality from different fields. It has been used as a standard by all operators to set the level of allowances that they will receive. This was necessary to account for the variation in fuel gas quality across installations. Allocating fuel consumption between electricity generation and direct driven equipment was not straightforward as the level of metering on many installations was not per individual piece of combustion equipment. A single meter may be used to measure the fuel gas consumption to a number of gas turbines, some of which are dedicated to electricity generation and some as direct drivers. In such cases the metered fuel had to be split across the consumers. Generally this was done using running hours and MW output for the combustion equipment

Similarly the data for flared gas was collected as TJ and the same benchmark standard of 56.1 tonnes CO_2/TJ flared gas was applied.

All data supplied to the regulatory body had to be externally verified. Benchmarking is complex and requires significant data to ensure transparency for the final allocation of allowances.

The allocation of free allowances for Phase III to each offshore installation will be determined by the EC using the data submitted by the operators.

Auctioning

From 2013 the basic method for allocating allowances will be auctioning and any sector not given free allowances will have to buy their credits under auctioning (Ref 7.14). The electricity sector will not be given free allowances and will have to purchase all of their credits. There will be a gradual transition towards full auctioning for other sectors and those sectors that are not subject to carbon leakage will have to purchase 20% of their allowances in 2013 rising to 70% in 2020 and 100% in 2027.

Carbon Leakage

Carbon leakage refers to production and/or investment relocating, as a result of EU ETS-related carbon costs, to countries without similar carbon constraints. This would undermine the environmental integrity of the system and lead to an overall increase in global emissions. Sectors at significant risk of carbon leakage will receive 100% of free allowances while those not at significant risk will receive 80% in 2013 declining to 30% in 2020 and 0% in 2027.
The offshore oil and gas sector will receive 100% of allowances for 2013 and 2014. Note that this excludes allowances for electricity generation. The EU Commission will review the carbon leakage sectors in 2014 which may result in some changes from 2015 onwards. The list of sectors currently subject to risk of carbon leakage is published in Commission Decision of 24 December 2009 determining, pursuant to Directive 2003/87/EC of the European Parliament and

of the Council, a list of sectors and subsectors which are deemed to be exposed to a significant risk of carbon leakage.

7.5 Other European Initiatives

7.5.1 Norway

Norway is a major oil and gas producer and, while oil production from the Norwegian Shelf has declined, gas has increased to the extent that Norway is the world's second largest gas exporter. Policies based on the principles of effectiveness and cost effectiveness have been introduced to enable Norway to meet its Kyoto commitment i.e. that the country's average emissions of greenhouse gases for the years 2008–2012 shall not increase more than one per cent compared with the emissions level in 1990.

In 1991 a carbon tax was introduced that applied to around 60% of all CO_2 emissions and included mineral products and the offshore industry. Gas, oil and diesel used for offshore production are taxed and the rate at 2011 is NOK 0.48 (C$0.08) per litre of oil or Sm^3 (scm) gas. Norway merged its CO_2 trading scheme with the EU ETS from 1 January 2008 which allowed businesses to trade within the EU system and introduced a quota system. Offshore oil and gas are not allocated free quotas and emission quotas must be purchased. Prior to EU ETS the carbon tax amounted to around NOK 350 (C$60) per tonne of CO_2. After the introduction of the quota system the total CO_2 cost (tax + quota cost) was maintained at the NOK 350 level by adjusting the carbon tax. The total cost now varies in relation to the quota price in line with the offshore sector in the EU. The quota will continue to be a key policy instrument for reducing CO_2 emissions. (Ref 7.22). Norway applies differentiated carbon tax rates across the various sectors to which the tax applies with the petroleum sector traditionally the highest.

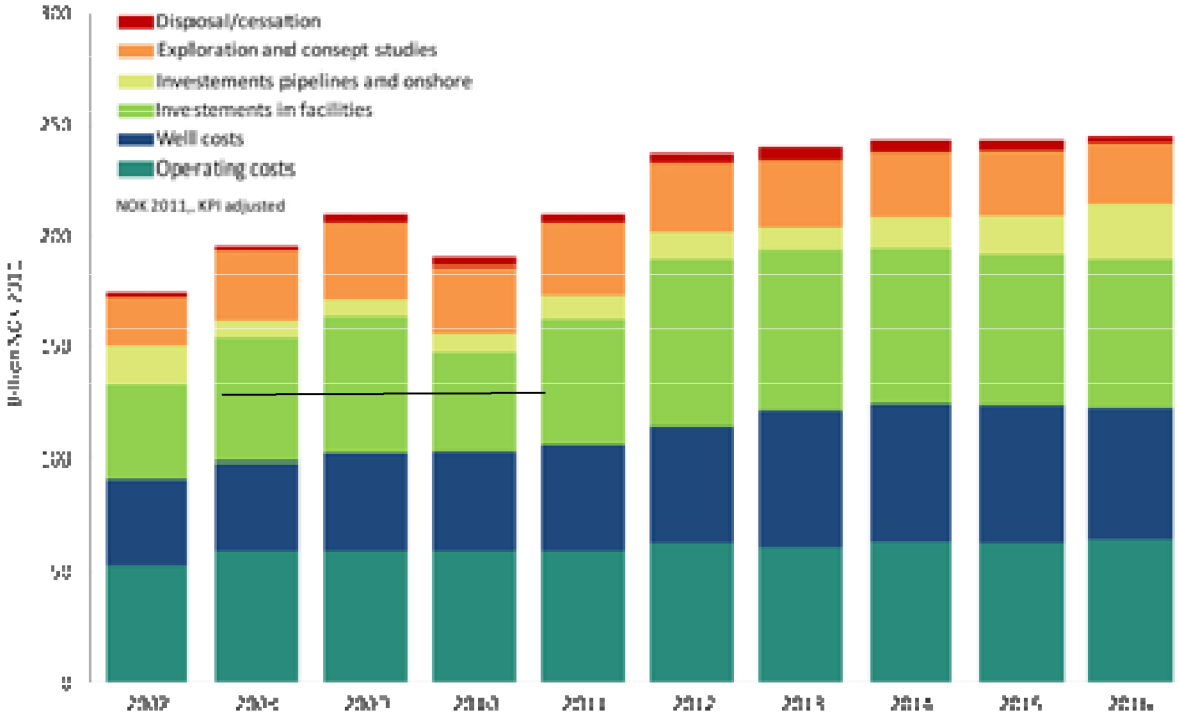
For 2010, an average opex/production cost is 6 USD/boe. Tariffs and environmental cost are not included in the opex.

We have used 5,73 NOK/USD.

Statoil accounts for 2010 indicate a production cost of NOK 42.8 (C$7.3 at April 2011 exchange rates) per boe.

UK Oil and Gas report for 2010 a unit production cost of US$12.5 (C$13.5) per boe.

In 2011 production amounted to 1380 million boe at a production cost of approximately NOK 58 billion which equates to NOK 42 per boe.



Source : An industry for the future Norway´s petroleum activities Meld.

A feature of this high taxation is that it has driven measures to reduce emissions through energy saving and technology opportunities. It is estimated that these measures have reduced emissions by 40 million tonnes since 1991. It was estimated that in 2009 the petroleum sector accounted for 27% of CO_2 emissions and almost 80% of these were from gas turbines and approximately 11% from flaring. The offshore sector has improved energy efficiency through the use of more efficient gas turbines, installing heat recovery systems and reducing flaring. ConocoPhillips are reputed to have avoided more than 1 million tonnes of CO_2 by upgrading turbines at the Ekofisk II development in 1998.

It is difficult to definitively attribute the implementation of measures to the introduction of the carbon tax but nevertheless it is reported that emissions increased by only 2.5% from 1990 to 1993 even though petroleum production increase by 24% in the same period.(Ref 7.23). There is a limit to measures that can be implemented on maturing installations at a cost that is reasonable and additional high cost measures are generally not cost effective. New production facilities and expansions to existing facilities are required to consider BAT to reduce emissions and the cost of providing energy from onshore compared to using gas turbines for electricity must be evaluated.

Around NOK 25 (C$4.25) million has been earmarked for research into reducing greenhouse gas emission from offshore oil and gas. The research will focus on issues such as flaring, optimizing processes, energy efficiency and heat recovery.

Emissions from petroleum activities are regulated by a number of Acts including:

- The CO_2 Tax Act;
- The Sales Tax Act;
- The Petroleum Act; and
- Act of 17 December 2004 No. 99 Relating to Greenhouse Gas Emission Allowance Trading and the Duty to Surrender Emission Allowances (revised 2007 and 2009).

Offshore gas production is more energy intensive than oil production and it is no surprise that Norway's greenhouse gas emission has increased as gas production has increased. Thus there is a dichotomy between increased production policy and climate change policy with the ramifications for the impact on taxation.

There is some suggestion that Norway may seek to offset its obligation to reduce emissions through increased trading or offsetting through investing in emissions reduction projects abroad. (Ref 7.24).

Norway also has a tax on nitrogen oxide emissions which primarily was directed towards onshore activities but also applies to the offshore combustion units and flaring. The tax in 2011 was set at NOK 16.43 (C$ 2.8) per kg NO_x. The Norwegian State has an agreement with industry organisations whereby the organisations have established a NO_x fund. Organisation that have signed up to the agreement pay into the fund at a reduced rate per kg NO_x and the funds are distributed to finance NO_x reducing measures. The level of the fees is determined by the NO_x Fund and not the State. Around 618 enterprises have endorsed the agreement (September 2010) and includes most of the oil and gas industry's activities.

A similar model for a CO_2 climate fund may be worthy of consideration as an alternative to a trading system.

7.5.2 Denmark

Denmark committed to reducing GHG emissions under the Kyoto Protocol and introduced an emissions trading scheme for the period 2000-2003. It set quotas for CO_2 emissions from electricity producers as part of a total electricity reform package. The quota was set at 23 million tonnes in 2000 reducing by 1 million tonnes each year to 2003. Allowances were issued per company and not plant and represented 76% of 1994-1998 emissions. Trading allowances was operated under bilateral agreements and not in an independent market place. Unused allowances could be banked and used in subsequent years of the scheme. If a producer exceeded the quota they had to pay a penalty to the Government of DKK 40 (7.2 Canadian dollars) per tonne of CO_2.

Denmark ratified the 2003 EU Directive on GHG emission trading and introduced the EU trading scheme from 2005 in line with EU ETS Phase II (Ref 7.25). Around 380 production units were

captured by the scheme with the majority being electricity producers. Offshore oil and gas producers were included and required to monitor, measure and report CO_2 emissions since 2005. Each installation requires a permit in conjunction with an approved monitoring and reporting plan similar to other European countries.

Free allowances were allocated based on average historical emissions for the period 1998 – 2002 or an amount equal to emissions in 2002 if this was higher. The 2002 figure was higher at 2.1 million tonnes CO_2 and free allowances averaging 2.2 million tonnes per year were allocated for the period 2005- 2007. Actual verified data for 2005 – 2007 were:

2005 2.206 million tonnes CO_2
2006 2.144 million tonnes CO_2
2007 2.139 million tonnes CO_2

As of 1 January 2009 seven installations in the offshore sector are included in the scheme. An installation in this case is defined as “all energy producing facilities on all platforms in a field” and currently there are more than 50 platforms. An average allowance of 2.281 million tonnes CO_2 per year for the period 2008 – 2012 has been allocated to the offshore sector.

The scheme is managed by the Danish Energy Agency (DEA) under the Danish Consolidated Act on CO_2 Allowances and the Agency maintains the Allowances Register.

Around 85% of the total gas consumption offshore was used as fuel gas and the remaining 15% was flared. Fuel gas consumption steadily rose until 2007 reflecting increased production and ageing fields but has shown a decrease since 2008. This has been attributed to energy efficiency measures by the operators. The operators along with the DEA reviewed the energy consumption associated with oil and gas production and agreed an action plan for energy management.

Also flared gas has decreased substantially from 2006 – 2010 with the exception of the Siri Field which had particular technical difficulties. This reduction has been attributed to energy efficiency, operational changes and more stable operating conditions (Ref 7.26).

7.5.3 Netherlands

The Netherlands signed the Kyoto Protocol in 1998 and following this the Dutch government launched the Climate Policy Implementation Plan (CPIP) in two parts:

- Part I related to domestic measures to mitigate greenhouse gas emissions; and
- Part II Using Kyoto external mechanisms (CDM, JI and trading).

EU ETS has been adopted by the Netherlands and the system operates as in other MS and applies to the relevant sectors in EU ETS. In addition there are two measures, Covenant Benchmarking (CB) and Long term Agreements (LTA) applicable generally to sectors not

included in EU ETS (Ref 7.27). These are voluntary agreements and the CB has been replaced by the Long Term Agreement on Energy Efficiency for ETS enterprises. (LTE). LTA 3 is aimed at medium to small sized enterprises which are outside the ETS. Over 1000 companies in 40 sectors have signed up to long term agreements.

These schemes have produced modest gains (Table 7.2):

Table 7.2: NL LTA Results

	Energy consumption 2010	**Improvement In Energy Efficiency***
	PJ	%
LEE	626	1.1
LTA3	219	2.3
Joint Result	845	1.4

*Savings resulting from measures in the production process and production chain within the Netherlands
Source: Covenants Results Brochure 2010

In 2009 five refineries signed up to LEE and are reported to have saved 745 TJ through process efficiency measures.

http://iepd.iipnetwork.org/policy/benchmarking%C2%A0-covenant-energy-efficiency

7.6 Related Measures

The EU ETS does not sit in isolation in the drive to address climate change and in Europe Integrated Pollution Prevention and Control (IPPC) legislation is a key measure which contributes to reducing CO_2 emissions. Two of the major requirements of the IPPC Directive are prudent management of natural resources and the efficient use of energy. Burning fossil fuel results in the release of large quantities of CO_2 and emissions of CO_2 can be used as an indicator of the efficiency with which the energy is generated. Optimising energy utilisation and the generating process will reduce the emission of CO_2 per unit of energy generated.

IPPC is designed to achieve a high level of environmental protection for the whole environment. Installations subject to Directive have to obtain a permit which takes account of the whole environmental performance of the installation and covers emissions to all media, waste production and minimisation, resource utilisation, energy efficiency, control over noise, prevention of accidents and restoration of the site upon closure. The controls provided by the permit must be based on Best Available Techniques (BAT).

- **Best**…the most effective in achieving a high level of protection of the environment.
- **Available**…those that can be implemented, balancing the costs of their implementation against benefits to the environment.
- **Technique**…both the way the technology is used and the way the installation is designed, built, maintained and operated.

The UK implemented this Directive in slightly different way for the offshore oil and gas sector compared to onshore facilities. The Offshore Combustion Installations (Prevention and Control of Pollution) Regulations 2001 (Ref 7.29) apply to combustion installations which are defined as: "any technical apparatus in which fuels are oxidised to use the heat thus generated and includes gas turbines and diesel and petrol-fired engines and any equipment on a platform connected to such apparatus which could have an effect on emissions from that apparatus or could otherwise give rise to pollution but does not include any apparatus the main use of which is the disposal of gas by flaring or incineration." The Regulations apply to combustion installations where the aggregated rated thermal input of the combustion equipment exceeds a threshold of 50 MW thermal (MW_{th}). If the aggregated thermal input is 50 MW_{th} or less then a permit is not required.

Installations subject to the Regulations must obtain a permit and these generally include conditions:

- The combustion installation shall be so operated, so far as is practicable, to maximize pollution and to maximize the efficiency with which energy is generated.
- Carry out an independent energy assessment of the installation.

While the Combustion Regulations do not directly refer to CO_2 emissions they indirectly, through the requirements to implement BAT and maximize the efficiency with which energy is generated, contribute to mitigating emissions. This type of regulation supports trading policies as it regulates non-greenhouse gases but also influences the implementation of energy efficiency measures to reduce GHG emissions.

The difference between this type of regulation and other complementary measures is that it directly applies at installation level whereas other measures are in the broader context of introducing renewables, research and development etc.

8.0 POLICY OPTIONS & CRITERIA

Policies implemented to reduce greenhouse gas emissions from the offshore oil and gas sector may have a variety of impacts on the sector as well as the wider economy. The direct objective of a climate policy targeting the offshore oil sector is to reduce emissions, but requiring the sector to comply with policies also has important implications for other government interests such as levels of economic activity, employment or the fiscal revenues to fund public services (e.g., education and health care). The following two sections of the report provide an evaluation of policies to reduce emissions from offshore oil. The objective of the analysis is to provide insight into the impact of these policies, and specifically to identify tradeoffs between different policy options.

This section begins by introducing the policies examined in the policy analysis, and identifies the criteria against which the policies are evaluated. The section then provides a high-level overview of the modeling tool used to evaluate the policies, with a focus on how the modeling analysis can be most helpful to policy makers. A detailed description of the modeling tool is provided as an appendix to the report.

8.1 Summary of Policy Options

Section 7 of this report provides a comprehensive review of policy instruments available to reduce greenhouse gas emission from the offshore oil sector. Sections 8 and 9 of the report examine how the design of specific policies affects the levels of greenhouse gas emissions and the cost of compliance for the offshore oil industry.

8.1.1 Performance Standards

Policy makers have several options for reducing emissions from the offshore oil industry; however this analysis focuses on performance standards. Several performance standards have been proposed at a federal level in Canada – the Regulatory Framework for Industrial Air Emissions (Ref 8.1) was a "tradable" performance standard, while the current regulations proposed for coal-fired electricity generation are a facility-based performance standard. The federal government has not yet announced their latest vision for regulations on the oil and gas sector, however most indications suggest they will use a performance standard.

A performance standard requires a sector or facility to reduce its emissions intensity below a benchmark. However, policy makers have to make several important considerations when establishing a performance standard for the offshore oil industry (or any other industry):

1. *Selection of benchmark* – government needs to decide how to measure the emissions intensity of the industry. The most common benchmark employed at the federal level is a production-based benchmark. The *Regulatory Framework* envisioned a production-based benchmark, while the current proposed regulations for coal-fired electricity generation call for a reduction in the emissions produced per unit of electricity generation (i.e., 375 kg of CO_2e per GWh of electricity generation). Such a benchmark applied

directly to the offshore oil industry would require a reduction in the emissions per unit of oil production (i.e., tonnes of CO_2e per barrel of oil). For this sector, CO_2 emissions are directly related to the energy input per barrel of oil equivalent which has been demonstrated to be highly variable across the offshore sector due to reservoir properties, production level and distance from shore etc. Therefore, a production-based benchmark is likely to be poorly suited for the province's offshore oil industry.

However, several other benchmarks are available to government. The EU ETS found that using a production-based benchmark poses a challenge for the offshore oil industry as production typically declines over the lifespan of a project while emissions remain fairly stable. As an alternative, they introduced a fuel based benchmark as described in Section 7.3.3 to be used in Phase III of the EU-ETS. The benchmark is based on the median total fuel consumption over a defined period (either 2005-2008 or 2009-2010) multiplied by 56.1 tonnes of CO_2e per TJ of fuel. For example, if a facility consumed a median of 10,000 TJ of fuel in the defined period (say 2009-2010), the allowed greenhouse gas emissions would be 561 kt CO_2e.

An issue with a fuel mix benchmark is that each facility has different emissions intensities per TJ of fuel consumed by virtue of the differences in fuel gas composition and diesel consumption. For example, Hibernia's emissions intensity is estimated at about [redacted] tonnes CO_2e per TJ of fuel, while Terra Nova and White Rose are close to [redacted] and [redacted] tonnes per TJ, respectively. The differences between the offshore platforms are mostly due to differences in gas composition (e.g., the amount of condensate in the raw natural gas). [redacted]

An alternative to a production or fuel mix benchmark is to establish a benchmark based on historic GHG emissions. In this case, the benchmark would require a percent reduction in emissions from a historic period (e.g., 2011 level of emissions) by a specific date (e.g., 2020). A key complication of using a benchmark based on historic activity (e.g., fuel consumed in 2009 or 2010) is the treatment of new entrants into the policy. This is particularly relevant because Hebron is not scheduled to begin operation until 2016, and therefore it is impossible to benchmark their emissions based on fuel consumed in 2009 or 2010. To overcome this challenge, it is possible to determine a benchmark based on projected emissions in the absence of policy. We use a benchmark based on Hebron's projected levels of GHG emissions in 2017.

In addition to the benchmarks identified above, many other benchmarks could be used, such as one based on the density of oil. Furthermore, benchmarks can be developed that use multiple criteria and weigh these criteria in different ways.

In the analysis, we examine the implications of historic, fuel mix and production-based benchmarks.

2. *Level of emissions reductions* – Once the benchmark has been selected, government must determine the reductions in emissions intensity required below the benchmark. These reductions can be based on a) the level of emissions reduction desired from the

entire economy of Newfoundland and Labrador (NL) or Canada, and b) the contribution desired from the oil sector.

Although it is not possible to know the level of reduction that will be required by the forthcoming federal oil and gas regulations, in this analysis, we have selected a 20% reduction for most analyses. In other words, the offshore oil industry is required to reduce their emissions intensity (based on a benchmark) by 20% below 2011 levels by 2020. For one benchmarking option, this target was not achievable and was reduced to 12.5%.

Although the 20% reduction target used in this analysis may not ultimately align with the federal policy, it is useful to hold the target fixed as it allows for a comparison among alternative policy design options. Therefore, the target itself is not a criterion we use to evaluate policy options in this analysis.

3. *Facility or fleet-wide application* – Performance standards can be applied to individual facilities or to a fleet of facilities. In the former, each facility receives a benchmark based on its unique GHG profile, while in the latter a group of facilities must collectively reach a benchmark.

4. *Flexibility mechanisms* – In addition to decisions related to the selection of benchmark and level of reduction, policy makers must decide whether flexibility mechanisms are available to participants in the system. If flexibility mechanisms are not available, each facility is required to reduce its emissions to achieve the benchmark. According to CCEEET, the federal government has indicated that flexibility mechanisms would be available, so all policies examined in this analysis allow for flexibility. However, each scenario is designed to illustrate tradeoffs between different options for flexibility. Options for flexibility include:

    a. *Trading of emissions performance credits* – in lieu of direct reductions in emissions to achieve a benchmark, facilities can purchase credits from any facility that has reduced its emissions below the benchmark. This option is included in all scenarios.

    b. *Access to a technology fund* – some designs for a performance standard, most notably Alberta's Specified Gas Emitters Regulation, allow firms to contribute to a technology fund in lieu of direct reductions. A technology fund is also significant because revenues are reinvested into abatement technologies. In other words, the policy could achieve reductions that exceed those achieved by an equivalent policy without a technology fund. This option is examined in several scenarios.

    An important consideration when designing a technology fund, is determining which abatement opportunities are eligible for reinvestment. Opportunities could be limited to sectors that contribute to the fund, or opportunities throughout the economy could be eligible. This analysis examines a technology fund that is reinvested in the offshore oil industry. However, if abatement opportunities in other sectors of the economy are eligible for reinvestment of the fund, the policy

would increasingly mimic the results shown for the availability of offsets (see below).

c. *Offsets availability* – As opposed to achieving emissions reductions directly, one option is for the offshore oil sector to purchase offsets representing emissions reductions elsewhere in the economy. These may be generated from sectors not included in the system (e.g., landfills, forestry or agriculture) and may be purchased from sectors outside of NL. This analysis compares the effect of the availability of offsets to the availability of a technology fund. The final design for any climate policy may employ both flexibility options, but by simulating each option separately, the analysis can highlight the key differences between the two approaches.

d. *Banking permits* – Banking allows facilities to exceed the benchmark in one year if they surpass the benchmark by an equal amount in an earlier or later year, therefore offering facilities more flexibility in complying with the policy. This option for NL's offshore oil industry may be particularly important because emissions fluctuate from year to year. This analysis does not examine such an option because it aims to capture long-term trends in emissions rather than annual fluctuations.

5. *Monitoring* – To ensure compliance has occurred, government needs to establish a method of monitoring greenhouse gas emissions from the industry. Success of any compliance system relies on effective monitoring, reporting and verification. Government may need to establish a department or agency that is responsible for overseeing compliance. External verification by accredited verifiers is widely practised and gives a greater degree of confidence in the system.

8.1.2 Policy options evaluated in the analysis

As discussed above, the policy options evaluated in this analysis are designed to draw insight into the impact of alternative policy designs. Therefore, the policies shown here do not necessarily correspond to a policy that is likely to be implemented by the government of NL, but rather show complementarities and/or tradeoffs between different designs.

In total the analysis explores five scenarios that examine the effects of specific policy considerations (Table 8.1) shows the characteristics of each policy scenario). The "Base" scenario is the base to which all other policies are compared. It features the following characteristics:

- Trading of Emissions Performance Credits (EPCs);
- Access to a technology fund at $40 per tonne of CO_2e;
- No access to offsets;
- A benchmark based on historic 2011 levels of emissions; and

- A 20% reduction in emissions from 2011 levels of emissions by 2020.

In some instances, the policy design choices are based on assumptions, as it is unclear at this time how the federal government will ultimately design its oil and gas regulations. However, many of the policy design options are based on policies under consideration in Canada. Alberta has proposed a 40/40 plan that calls for a 40% in the emissions intensity of industrial facilities and would establish a technology fund that could be accessed at $40 per tonne CO_2e.[1] In the assessment of abatement options for the offshore oil sector, achieving a 40% reduction in emissions intensity may not be possible, so this was judgmentally lowered to 20%. Please note that as this target is mostly held constant throughout the sectors, the evaluation mainly compares other design consideration.

Each additional scenario varies a single policy design element, which are highlighted in Table 8.1. The objective for varying one policy consideration at a time is that it enables a direct comparison with the base scenario. In other words, a change in the level of emissions or compliance costs can be directly attributed to the single change in policy design.

S2-OFF examines a scenario in which facilities in NL's offshore oil industry do not have access to a technology fund, but have access to offsets and inter-firm trading of EPCs. This scenario serves to highlight the effect of offsets in the system, as their effect is very different from access to a technology fund.

S3-EUETS evaluates a scenario that varies the choice of benchmark. Emissions intensity can be measured in many different ways, of which one option is to use the benchmark employed in the EU ETS. The EU ETS uses a fuel-based benchmark that allows for 56.1 tonnes of CO2e per TJ of fuel consumed from the reference year.

S4-PB examines the effect of a production-based benchmark. Most performance standards considered in Canada to date employ a production-based benchmark. This benchmark is calculated as the level of emissions per unit of physical production (e.g., kg CO_2e per barrel of oil produced). Alberta's Specified Gas Emitters Regulation uses a production-based benchmark (Reference), and although the federal oil and gas regulations have not been released, it is quite possible these regulations will also employ a production-based benchmark.[2] The objective of evaluating this design option is to highlight the significant challenges of using a production-based benchmark for NL's offshore oil industry. This analysis shows that this design option would achieve reductions at greater cost in comparison to other options. To further highlight the challenges with this option for benchmark, the reduction target had to be reduced to 12.5% from 20% used for the other policy scenarios. Complying with a 20% reduction from a production based benchmark, even with the availability of a technology fund that is reinvested in abatement opportunities in the sector, would prove difficult for the sector.

[1] Globe and Mail, 2013, "Alberta's bold plant to cut emissions stuns Ottawa and oil industry", available from www.theglobeandmail.com.; accessed April 2013.
[2] Alberta Environment, 2007, *Technical guidance document for baseline emissions intensity applications*, available from www.environment.gov.ab.ca.

S5-TF80 examines a scenario in which the price of accessing the technology fund is raised from $40 per tonne to $80 per tonne. The purpose of this scenario is to capture some of the uncertainty around the future price for the technology fund in any forthcoming oil and gas regulations, as this policy has not yet been announced.

Table 8.1: Performance Standards Examined in the Policy Analysis

	Flexibility Mechanisms				Benchmark	
	Trading EPCs	**Technology Fund**	**Offsets**	**Price ($ per tonne)**	**Type**	**Reduction**
S1-BASE	Yes	Yes	No	$40	Historic 2011 GHG	20%
S2-OFF	Yes	**No**	**Yes**	$40	Historic 2011 GHG	20%
S3-EUETS	Yes	Yes	No	$40	**Used by EU-ETS**	20%
S4-PB	Yes	Yes	No	$40	**Production-based in 2011**	**12.5%**
S5-TF80	Yes	Yes	No	**$80**	Historic 2011 GHG	20%

8.2 Policy Assessment Criteria

As discussed above, government has multiple objectives related to implementing policy on the offshore oil industry. The analysis evaluates each policy based on their environmental effectiveness and compliance costs. However, additional considerations could include political acceptability, but are beyond the scope of the modeling exercise.

8.2.1 Environmental Effectiveness

Environmental effectiveness is defined as a policy's ability to reduce greenhouse gas emissions from the offshore oil industry. Greenhouse gas emissions are measured as cumulative emissions from 2013 to 2020, as well as annual emissions in 2020.

8.2.2 Compliance Costs

There are two sources for compliance costs under a policy. First, achieving an environmental objective requires the offshore oil industry to adopt technologies and/or practices that would not have been adopted in the absence of the policy. These technologies/practices often impose costs on the industry, which has ramifications for either profits from oil extraction or the receipt of royalties for the provincial government, or both.

The second source of compliance costs is the financial transfer due to any carbon pricing policy. If an offshore oil facility has access to offsets, purchasing those offsets leads to a financial cost to the industry. Access to a technology fund may also lead financial costs, although in this analysis we assume that the technology fund is exclusively reinvested in abatement in the offshore oil industry. Therefore, no net transfer occurs from the offshore oil industry to other sectors in the economy or to other provinces.

8.2.3 Acceptability

Two key factors are:

- Ideally, the policy will have the support of the offshore oil sector.
- It should be easily implemented.

Gaining support from the sector will likely require industry consultations and perhaps negotiations. Regarding implementation it will also depend whether it can be harmonized with Federal and other complementary policies or if it is standalone in the province. Administrative systems will also have to be put in place.

8.3 Analysis Framework

To complete the analysis, Navius Research Inc employed a computable general equilibrium model called GEEM. This section provides a high level overview of how the model operates and the dynamics introduced to represent NL's offshore oil industry. A more detailed description of the model is presented as an appendix to the report.

Computable general equilibrium (CGE) models are designed to simulate how climate policies affect the competitiveness and greenhouse gas emissions from sectors of the economy. These models are particularly useful in showing how multiple policies interact. For example, the selection of policy design can lead to significantly different outcomes for both the level of GHG reductions and the cost of compliance. The GEEM CGE model provides an integrated framework in which to evaluate the effect of these policies.

This section begins with a discussion of the usefulness of models, and is followed with a discussion on how the model was parameterized to capture the unique nature of NL's offshore oil industry.

8.3.1 Principles of Energy-Economy Modelling

Energy-economy models can generate quantitative forecasts of future conditions under different assumptions. When used wisely, they can generate insight and improve policy decisions. To set the stage for the analysis, it's therefore useful to provide a brief overview of the utility (and possible pitfalls) of economic modelling.

Models are based on economic theory and empirical data

First, it's important to note that modelling is rooted in economic theory, which provides a tested and proven framework for thinking about the economy. This analysis generates forecasts of key future trends like GHG emissions and production from NL's offshore oil industry. Further, we can support this framework by basing key assumptions — for example, abatement options available to the offshore oil industry — on empirical estimates. Our model is parameterized based on the best available literature and analysis, and is constantly being updated based on new studies.

Models are a framework for understanding complex systems

The system that results from the many interactions between firms, households, and government through different markets — including investment markets, labour markets, and various commodity markets, both domestic and international — are incredibly complex. This complexity means that responses to policy are not necessarily simple to understand; sometimes impacts are counter-intuitive. A model provides an internally consistent framework for exploring these interactions and effects. As a result, we can learn from models about the dynamics within this complex system. These insights are particularly important when seeking to achieve multiple policy objectives (such as driving GHG emission reductions while minimizing economic costs of doing so).

All models are wrong, but some are useful

All model forecasts are inherently uncertain and should not be considered precise predictors of the future. NL's offshore oil industry and its interaction with other markets is complex, as are the effects of policy on this system. To simulate this system, the analysis depends on assumptions about technological and economic development, global energy markets, and firm behaviour. The model uses the latest research and data to guide these inputs, but no amount of research allows perfect foresight into the future of the economy.

Yet uncertainty in the forecasts does not preclude the usefulness of models. Forecasts can provide a directional indication of the likely impacts of policy and can be very useful in comparing relative impacts of different policy tools. The end-goal of economic modelling is not to produce a forecast for its own sake, but to draw insight and learning from forecasts and scenarios. This is the approach we take for this analysis of potential climate policy options for NL's offshore oil industry.

Clearly communicating assumptions ensures transparency in forecasts

To ensure the analysis is as useful as possible, we must be transparent about the assumptions and limitations about the analysis. This report includes extensive details on the assumptions embedded in our modelling analysis, both in terms of the modelling framework itself and in terms of how specific policies were represented in the model to develop each scenario.

8.3.2 Production and Emissions Profiles

The offshore oil industry in NL has been disaggregated into four facilities representing the Hibernia, Terra Nova, White Rose and Hebron platforms. Each facility is characterized by a unique production and emissions profile. The production profile for Hibernia is illustrated as an example in Figure 8.1, and the other facilities show similar comparisons to the production profiles received from CCEEET. The GEEM model represents the trend in oil production over time, but does not simulate the annual fluctuations in production that result from facility closures, refurbishments, etc. The projection from GEEM for the remaining facilities is illustrated in Table 8.3.

We have conducted a comparison between the Hebron Public Review and information received from CCEEET, and production profiles are reasonably similar. The key difference is the Hebron Public Review shows the development of several satellite fields from White Rose, leading to greater oil production. Our current forecast does not include these fields.





While production gradually declines over the lifespan of a platform, greenhouse gas emissions do not follow a similar trend. Emissions from fuel use are assumed to remain fixed over the lifespan of a project, while emissions from flaring peak in the early years of production and

decline before levelling out thereafter. The projection of greenhouse gas emissions have been calibrated to information received from CCEEET (see the emissions projection for Terra Nova in Figure 8.2 and emissions by source from all facilities in Table 8.3).

Again the projection of emissions from GEEM does not include the annual fluctuations due to facility closures, refurbishments, etc, as representing these fluctuations would not improve the model's ability to evaluate the majority of policy design considerations. The one exception is that the fluctuations point very strongly to the need for banking and borrowing permits.





8.3.3 Abatement Opportunities for the Offshore Oil Sector

Abatement opportunities have been informed by the technology review described in Section 4. These abatement opportunities are divided into fuel (combustion) and non-fuel (flaring and venting) abatement opportunities**.** The technology review identified several opportunities for abating emissions from fuel combustion and flaring/venting (see Section 4 for more details on the technologies that underpin the abatement cost curve in this analysis). Distinguishing between these sources of emissions is important because each of the facilities has different levels of emissions from fuel and non-fuel sources. Therefore, investment in these technologies or processes achieves different levels of reductions on each facility and therefore results in different costs of abatement.

In the analysis, abatement cost curves are characterized by each facility, and the curves differ based on levels of fuel, non-fuel emissions and the opportunity to reduce emissions using a specific technology. Figure 8.3 shows the abatement cost curve used in GEEM for Hibernia as an example. The figure also compares the specification of abatement technology in GEEM to the technologies identified in Section 4. As illustrated, the characterization of technology in GEEM matches the technologies in Section 4 reasonably closely.





8.3.4 Historic GHG Intensity Characteristics for the Offshore Oil Sector

It is informative to consider what the historic GHG intensity characteristic for the three existing NL offshore facilities has been in terms of the annual CO_2e emissions per unit of oil production.

This metric has been calculated for the period 2004 – 2011 using the oil production data (source: C-NLOPB public website) and the GHG emissions data from the Large Facility Emitters (LFE) database (source: Environment Canada website). Details of input and output data are given in Appendix A and the main characteristics are highlighted in this section.

Figure 8.4.a and Figure 8.4b show the trend in CO_2 emissions intensity for Hibernia. This has been reasonably steady between 9.0 and 12.0 $kgCO_2$/boe in the period 2004 to 2011, largely because, whilst oil production has decreased slightly from peak, GHG emissions have also decreased slightly, largely due to the flare volumes coming down. Currently oil production is being maintained at a fairly steady level via new developments in the Hibernia field, including new producing wells from the Hibernia South Extension (HSE).

Figure 8.5a and Figure 8.5b show the trend in CO_2 emissions intensity for Terra Nova FPSO. The 2006 data is atypical due to a 6-month outage. The Terra Nova emission intensity has been at typically twice the level of Hibernia in the period 2004 to 2011, largely because, oil production rates have been lower than Hibernia whilst the fuel and flare emissions have been at a similar level. Fuel emissions are relatively high because similar energy intensive processes are required for gas re-injection and water injection for reservoir pressure maintenance. Since 2007

the data shows an upwards trend in emission intensity due to the fact that the decline in oil production has been faster than the decline in GHG emissions (control of flaring). In addition to natural oil production decline, the 2011 data was also affected by the requirement to shut-in some production wells to allow for maintenance work to proceed on sour gas wells, leading to deferred production from these wells.

Figure 8.6a and Figure 8.6b show the trend in CO_2 emissions intensity for White Rose (Sea Rose FPSO). The emission intensity was very high initially in the period 2005 – 2007 in the period oil production was coming on-stream, due primarily to high flaring rates early on before gas re-injection compression duty was fully commissioned. As oil production increased to peak and flaring was reduced, by 2007 the emission intensity was at similar levels to Terra Nova, though still being twice the level of Hibernia. Since 2007 the intensity has remained relatively steady as flared volumes have reduced in parallel with natural decline oil production and associated gas production. Produced gas is re-injected into the 'North Pool' for conservation, as opposed to being used for enhanced oil recovery. With oil production in natural decline, an increase in emissions intensity is likely unless the flaring or fuel use can be reduced further.

Intensity for Terra Nova and Sea Rose in 2012 will be impacted by extended FPSO planned outages which took place during 2012. A return to steady state production is expected in 2013. Forecast BAU emission intensity profiles for the period to 2025 are also given in Appendix A.

Figure 8.4a: Hibernia – trend of CO_2 emissions intensity vs. Oil Production

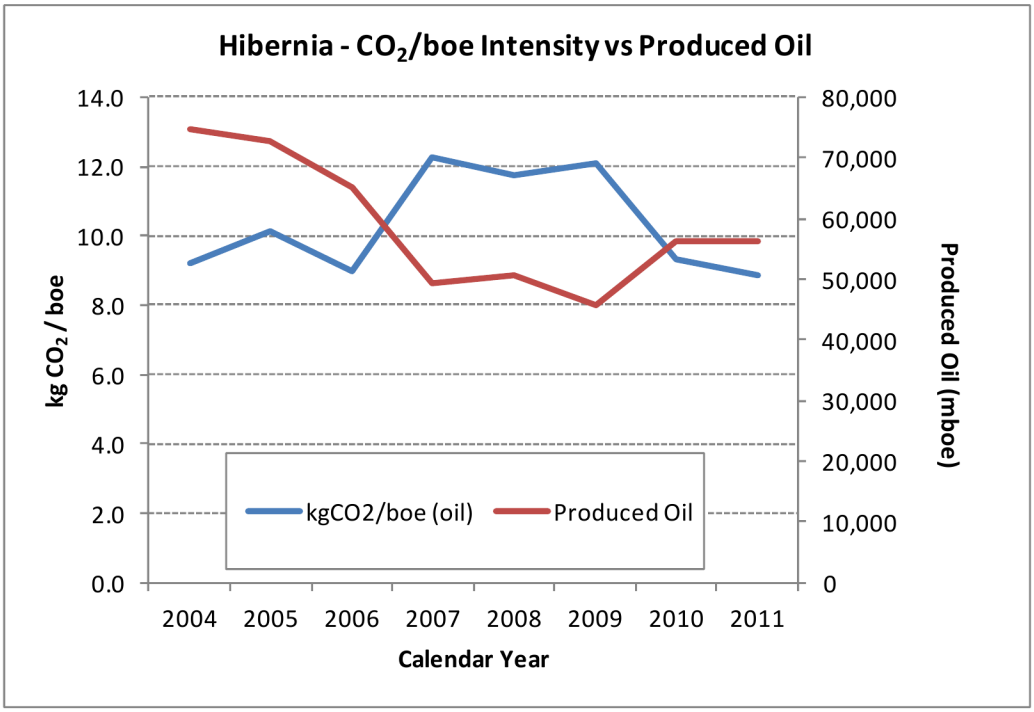


Figure 8.4b: Hibernia – trend of CO_2 emissions intensity vs. CO_2 emissions

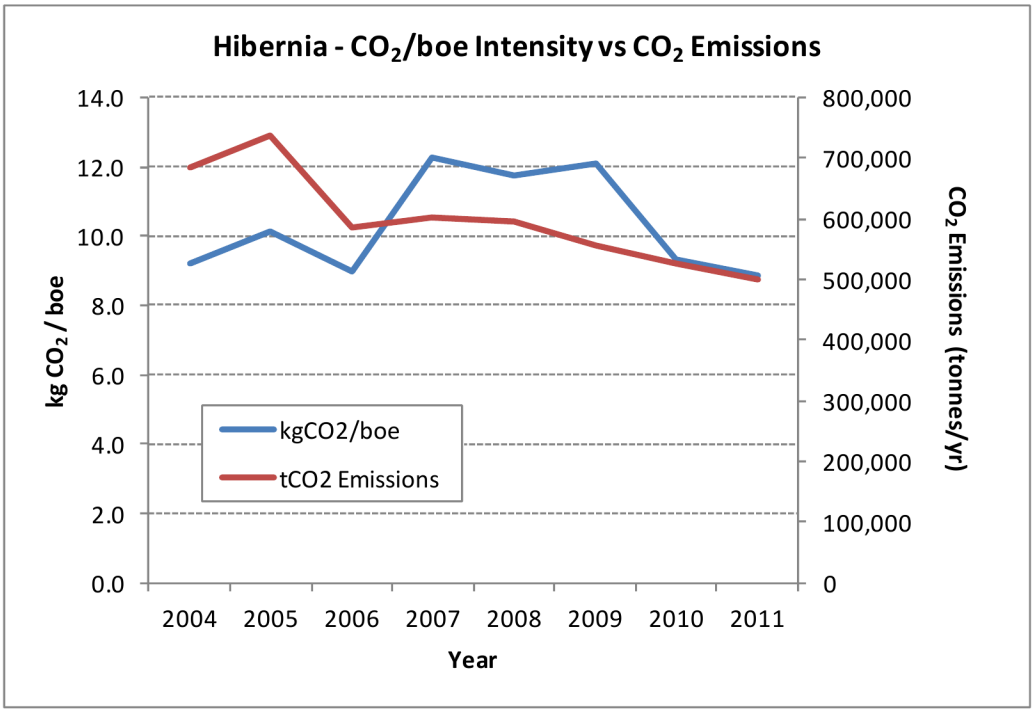


Figure 8.5a: Terra Nova – trend of CO_2 emissions intensity vs. Oil Production

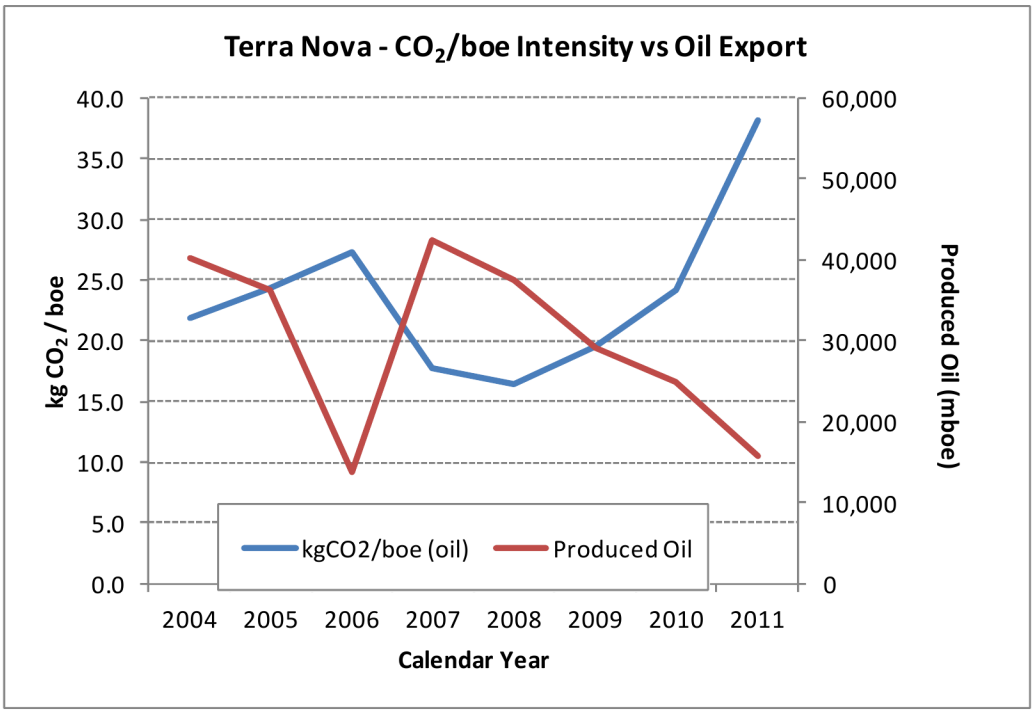


Figure 8.5b: Terra Nova – trend of CO_2 emissions intensity vs. CO_2 emissions

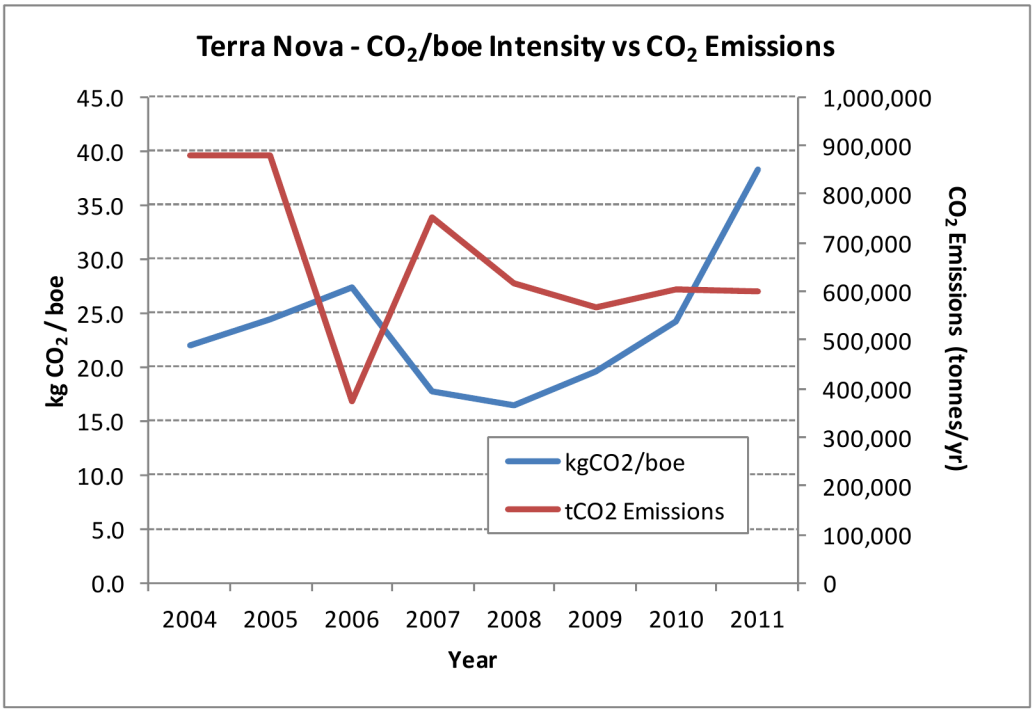


Figure 8.6a: White Rose – trend of CO_2 emissions intensity vs. Oil Production

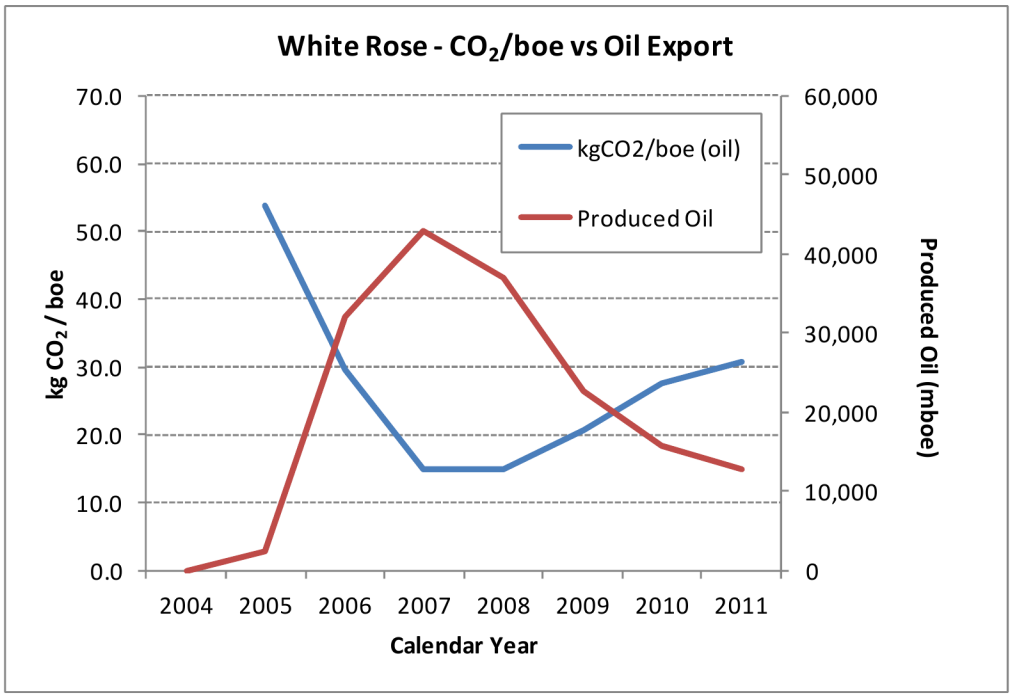
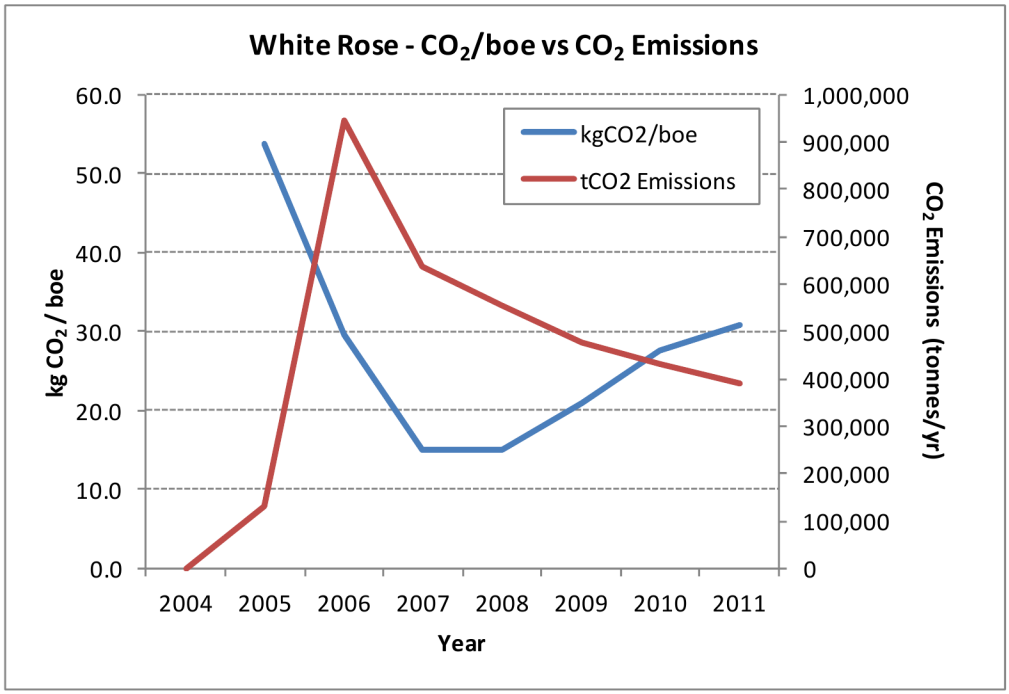


Figure 8.6b: White Rose – trend of CO_2 emissions intensity vs. CO_2 emissions



9.0 POLICY EVALUATION

As discussed in Section 8, policies implemented on NL's offshore oil sector are likely to have a variety of impacts on NL's economy. The primary objective of the policies examined in this analysis is to reduce greenhouse gas emissions, but policies have wider effects on competitiveness of the offshore oil industry, levels of economic activity and royalties received from the oil sector. This section evaluates how different policies impact greenhouse gas abatement and compliance costs (which in turn affect royalties and economic activity in the province).

9.1 Scenario Overview

As discussed in Section 8, the policy options evaluated in this analysis are designed to draw insight about the impact of alternative policy designs. Therefore, the policies shown here do not necessarily correspond to a policy that is likely to be implemented by the government of NL, but rather show tradeoffs between different designs.

This analysis examines five scenarios (Table 8.1) shows the characteristics of each policy scenario). The "Base" scenario is the base against which all other policies are compared. It features the following characteristics:

- Trading of Emissions Performance Credits (EPCs);
- Access to a technology fund at $40 per tonne of CO_2e, but not offsets;
- A benchmark based on historic 2011 levels of emissions; and
- A 20% reduction in emissions from 2011 levels of emissions by 2020.

Each additional scenario changes a single policy consideration, which are highlighted in Table 9.1. The objective for changing a single policy consideration is that it enables a direct comparison with the base scenario. In other words, a change in the level of emissions or compliance costs can be directly attributed to the single change in policy design.

S2-OFF examines a scenario in which facilities in NL's offshore oil industry do not have access to a technology fund, but have access to offsets and inter-firm trading of EPCs. This scenario serves to highlight the effect of offsets in the system, as their effect is very different from access to a technology fund.

S3-EUETS evaluates a scenario that varies the choice of benchmark. Emissions intensity can be measured in many different ways, of which one option is to use the benchmark employed in the EU ETS. The EU ETS uses a fuel-based benchmark that allows for 56.1 tonnes of CO2e per TJ of fuel consumed in 2011.

S4-PB examines the effect of a production-based benchmark. Most performance standards discussed in Canada to date employ a production-based benchmark. This benchmark is

calculated as the level of emissions per unit of physical production (e.g., kg CO2e per barrel of oil produced). Alberta's Specified Gas Emitters Regulation uses a production-based benchmark (Reference), and, although the federal oil and gas regulations have not been released, it is also possible these regulations will employ a production-based benchmark.[3] The objective of evaluating this design option is to highlight the significant challenges with using a production-based benchmark for NL's offshore oil industry. This analysis explicitly shows that this design option would achieve reductions at greater cost in comparison to other options.

S5-TF80 examines a scenario in which the price of accessing the technology fund is raised from $40 per tonne to $80 per tonne. Part of this is to highlight some of the uncertainty around the future price for the technology fund in any forthcoming oil and gas regulations.

Table 9.1: Performance Standards Examined in the Policy Analysis

	Flexibility Mechanisms				Benchmark	
	Trading EPCs	**Technology Fund**	**Offsets**	**Price ($ per tonne)**	**Type**	**Reduction**
S1-BASE	Yes	Yes	No	$40	Historic 2011 GHG	20%
S2-OFF	Yes	**No**	**Yes**	$40	Historic 2011 GHG	20%
S3-EUETS	Yes	Yes	No	$40	**Used by EU-ETS**	20%
S4-PB	Yes	Yes	No	$40	**Production-based in 2011**	**12.5%**
S5-TF80	Yes	Yes	No	**$80**	Historic 2011 GHG	20%

Note: Emissions prices in GEEM are specified in real dollars, and decline over time due to inflation.

9.2 How do the Policies Affect Greenhouse Gas Emissions?

Figure 9.1 shows a projection of greenhouse gas emissions from the offshore oil industry under the five policies examined in the analysis. It shows that in the absence of a policy, emissions rise from current levels to reach about [redacted] kt CO_2e by 2020. The various performance standards reduce emissions by between [redacted] and [redacted] from their business-as-usual trajectory. The following discussion explains the differences in environmental performance among each of the scenarios in order to draw insight into the effect of various policy design options.

[3] Alberta Environment, 2007, *Technical guidance document for baseline emissions intensity applications*, available from www.environment.gov.ab.ca.



The use of a technology fund leads to additional abatement than would occur relative other compliance mechanisms. Several policies options examined in this analysis employ a technology fund (i.e., all policies except S2-OFF).A review of S1-BASE and S2-OFF allows for a direct comparison between a scenario with a technology fund and the availability of offsets, as this is the only difference in policy design between the scenarios.

The policies represented in the S1-BASE scenario reduce emissions by [redacted] CO2e from the reference case in 2020, while the policies under the S2-OFF scenario reduce emissions by [redacted] CO_2e. The incremental [redacted] of reductions achieved by the S1-BASE scenario is the result of the inclusion of a technology fund. Under S1-BASE, if a facility's emissions exceed its allocation of emissions performance credits, it can contribute to a technology fund at a fixed price – in this case $40 per tonne. Similarly, under the S2-OFF scenario facilities can purchase offsets at $40 per tonne if they do not comply with the policy through direct reductions. In response to both policies, facilities undertake abatement activities up to $40 per tonne. However, reinvestment of the technology fund in abatement opportunities in the offshore oil sector reduces the cost of abatement in the sector, and therefore achieves a greater level of reduction.

The effect of the technology fund is shown graphically in Figure 9.2. This figure shows the abatement curve for Hibernia with and without the reinvestment of the technology fund in abatement opportunities. The curve representing abatement costs without the technology fund matches the abatement curve shown in Figure 8.3. When a technology fund is available, revenue from the fund would be used to offset a portion of the costs of abatement, and therefore lower the abatement cost curve. This means that facilities under the scenario will still undertake abatement until their abatement costs reach $40 per tonne, but greater abatement can be achieved at $40 per tonne.



If facilities do not have access to a technology fund (but have access to offsets), carbon revenue is not reinvested in abatement in the sector and less abatement is achieved by the offshore oil sector. However, the purchase of offsets may correspond to reductions elsewhere in the economy, in other sectors of the economy in NL or in other provinces.

As a final note, these scenarios represent archetypes of policy options, and the federal or provincial government could implement a policy that includes both a technology fund and offsets, or constrain the availability of one or both of these options. Additionally, we have examined scenarios in which the technology fund is exclusively reinvested in the offshore oil industry. In fact this is a political consideration, and abatement opportunities in other sectors of the economy could be eligible for reinvestment of the technology fund. While making other sectors eligible for reinvestment would achieve fewer reductions in the offshore oil industry, it may achieve greater total provincial reductions if opportunities in other sectors have lower cost than opportunities in the offshore oil industry. This analysis highlights that greater reductions can be achieved from the sector with constraints on offset availability and greater emphasis on a technology fund that is reinvested in the sector.

The choice of benchmark also has an impact on the level of GHG reduction. The scenario that employs a production-based benchmark (S4-PB) yields the greatest reduction of emissions, while the scenario that employs the benchmark used under the EU ETS (S3-EUETS) shows fewer reductions than the base scenario. The differences between the options for benchmark relate to how it interacts with the technology fund. All scenarios use the same price for accessing the technology fund – $40 per tonne. The difference results from the amount of revenue which is allocated to the technology fund.

As will be discussed later, it is more difficult for a facility to comply with a performance-based benchmark. The emissions intensity per unit of physical production from each facility increases as the facility field/facility matures. This is because of the natural decline in oil production over time and the fact that emissions over the lifespan of the facility are reasonably constant. As a result, a greater portion of compliance is achieved by accessing flexibility mechanisms – in this case a technology fund. As this revenue is reinvested in abatement, the policy achieves greater reductions.

Although not explicitly represented in this analysis, the combination of a production-based benchmark and the availability of offsets could have dramatically different results than S4-PB. Emissions reductions would approximately match the S2-OFF scenario, but compliance costs would be significantly greater.

Finally, the differences between using a benchmark based on historic 2011 emissions and the EU ETS are small.

Raising the price of accessing the technology fund contributes to greater reductions, but at a diminishing rate. The S5-TF80 employs a technology fund that can be accessed at $80 per tonne, while the S1-BASE scenario uses a $40 per tonne price. Doubling the emissions price achieves greater emissions, but only by [redacted] The limit on additional emissions reductions is primarily due to two dynamics:

1. Reinvestment of the technology fund achieves less abatement per dollar spent because it must target more costly abatement options at $80 per tonne. The biggest source of emissions reductions available at low cost is from reducing flaring emissions. However, most of these options are adopted at a $40 per tonne, and no longer available at the higher price. The abatement technologies above this option achieve fewer reductions at higher cost.
2. Greater abatement yields fewer contributions to the technology fund. Between 2017 and 2020, contributions to the technology fund with the lower price amount to [redacted] (2012$) (i.e., about [redacted] CO_2e at a $40 per tonne price), while contributions to the technology fund with the higher price amount to [redacted] (i.e., [redacted] CO_2e at an $80 per tonne price). Therefore, fewer funds are available for reinvestment in low emissions technologies in the oil sector.

9.3 What are the costs of compliance for the different policy options?

Complying with the policies under each scenario imposes costs upon the offshore oil industry. These costs can be divided into two categories:

1. Technology capital costs – as the offshore oil industry adopts technologies to reduce its GHG emissions, these costs impose costs on the sector.
2. Financial transfers due to accessing flexibility mechanisms – the facilities do not have to comply with the policy through direct reductions, but rather can access flexibility

mechanisms in lieu of direct abatement. Accessing these mechanisms can lead to financial transfers.

Figure 9.3 shows compliance costs imposed by each policy option from 2017 to 2020. The policies vary from imposing a [redacted] cost to a [redacted] cost (2012$). This discussion draws insight into how different policy options affect compliance costs for the sector.

[redacted]

Even though access to a technology fund achieves greater reductions than access to offsets, it imposes lower compliance costs on the sector. The scenario that employs a technology fund (S1-BASE) imposes a [redacted] cost on the sector, while access to offsets imposes a [redacted] cost (2012$). As discussed above, the only difference between the scenarios is access to a technology fund in one scenario, and access to offsets in the other.

Access to a technology fund actually reduces compliance costs because it achieves greater reductions. Payments to offsets represent a pure cost to the industry – they incur the cost from purchasing, but receive no direct benefit from offsets. The technology fund, on the other hand, is exclusively reinvested in the oil sector and is designed to reduce the costs of abatement.

The choice of benchmark can have a dramatic impact on compliance costs. The analysis examines three options for benchmarks used to allocate emissions performance credits: 1) based on historic 2011 emissions, 2) a production -based benchmark on 2011 level of emissions intensity and 3) a benchmark based on that used in the EU ETS. The compliance costs for these options range from [redacted] to [redacted] between 2017 and 2020.

A production-based benchmark is difficult for the offshore oil industry to achieve. As discussed above, the production profile for each facility is not fixed over its lifespan. Production gradually increases during the first years of production, and then naturally declines as the field matures. However, the energy and emissions profile from operating the facilities remains relatively constant in the absence of new actions to reduce emissions. This means that the emissions intensity per unit of barrel produced increases over time (see Figure 9.2).

A benchmark based on historic emissions intensity (e.g., 2011 level of emissions intensity as envisioned in S4-PB) becomes increasingly difficult to achieve even with maximum abatement from the sector. The balance must be met with either contributions to a technology fund or some other flexibility mechanism, which impose a financial transfer on the sector. If flexibility mechanisms are not available, the performance standard may not be achievable for some facilities, and it would either have to fall out of compliance or shut down.



The difference between a benchmark based on 2011 level of emissions (i.e., P1-BASE) and the benchmark used in the EU ETS is less pronounced – the EU ETS imposes [redacted] less costs on the sector. However, this difference is mostly attributed to greater emissions reductions.

A higher price for accessing the technology fund imposes greater compliance costs on the sector. Raising the price of accessing the technology fund from $40 per tonne to $80 per tonne (i.e., S1-BASE and S5-TF80, respectively) raises the cost of compliance by [redacted] As shown in Figure 9.4, the composition of these costs changes considerably from the scenario with lower prices. Under a $40 per tonne price, about [redacted] of compliance costs are from contributing to the technology fund (which is subsequently reinvested in abatement). Under an $80 per tonne price, about [redacted] of compliance costs are from contributing to the technology

fund. The higher price leads to more abatement, therefore reducing contributions to the technology fund. Furthermore, the remaining funds in the technology fund are used to invest in increasingly greater abatement from the sector.

9.4 Do the policies affect levels of production from the offshore oil industry?

None of the policies examined in this analysis affect the level of offshore oil production in Newfoundland and Labrador. First, Hibernia, Terra Nova and White Rose all have sunk capital costs, (i.e., the investment in the facility, pre-development drilling and infrastructure installation have already occurred). Terra Nova and White Rose, as Floating Production Storage and Offloading (FPSO) structures, also face an "opportunity cost" in that they can relocate to a different field once the profit earned from new field exceeds the profit earned in NL. The abatement costs from complying with the policies vary from about [redacted] per barrel (the variation is due to differences in abatement costs and levels of production from the facilities), and these additional costs do not push operating costs over the threshold that would lead to the closure or relocation of the facilities.[4] As a result, all facilities continue operating despite the additional costs. Second, the compliance costs for Hebron are not sufficient to discourage the project from moving forward.

However, it may be almost impossible for the facilities to comply with some designs for policy. Compliance was achievable in all options examined in the analysis, however a big concern for industry would be the use of a production-based benchmark with limited flexibility mechanisms. As discussed above, the emissions intensity of offshore facilities gradually increases over time as the field matures. Therefore, it becomes increasingly difficult for a facility to achieve compliance. In our assessment, this option for benchmarking the emissions from offshore oil should be avoided.

9.5 Summary of Policy Evaluation

To summarize the key findings, we rank each of the policies examined in the analysis. Figure 9.5 evaluates each of the performance standards as performing "better" to "worse" at achieving emissions reductions and minimizing compliance costs. Each marker corresponds to a single policy scenario. Policies located in the top right hand corner of the figure perform best on both emissions reductions and compliance costs, while policies that perform the worst would be located in the bottom left hand corner.

The key findings from the analysis are:

i) **The availability of a technology fund (S1-BASE) achieves greater reductions in emissions and reduces compliance costs in comparison to the availability of offsets (S2-OFF).** Allowing facilities to comply with a policy by accessing a technology

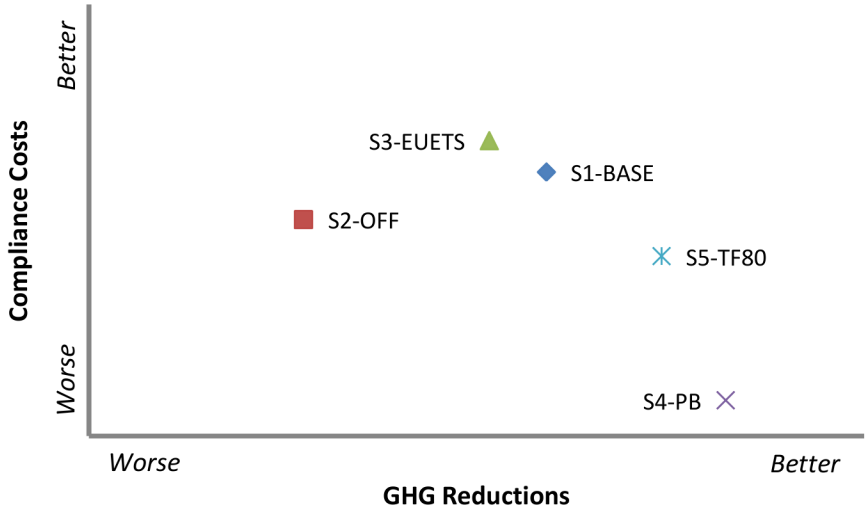
[4] The costs per barrel are measured as the total compliance costs between 2017-2020 divided by total production over the same period.

fund ensures that revenues collected are used to reduce GHG emissions and also reduce compliance costs.

ii) **The choice of benchmark affects the portion of compliance achieved through direct reductions and the level of contributions to a technology fund.** On one end of the spectrum, calling for a 20% reduction from the benchmark used in the EU ETS would require fewer reductions, while on the other end a 12.5% reduction in emissions intensity from a production-based 2011 benchmark would require significant reductions from the sector.[5] In the latter policy, compliance with the policy would become increasingly difficult as each field matures. While this leads to greater contributions to the technology fund and greater reinvestment of the technology fund in low emissions options in the sector, it also substantially increases the cost of compliance.

iii) **Increasing the price for accessing the technology fund achieves greater reductions, but at a diminishing rate.** The main opportunities for reducing emissions from NL's offshore oil industry identified in this analysis are from flaring. These reductions have relatively low cost in comparison to most other fuel-based options. However, once these options have been undertaken, there are relatively fewer opportunities to achieve significant reductions in GHG emissions.

Figure 9.5: Evaluation of Policy Options



[5] As discussed in Section 8, the reduction target had to be reduced to 12.5% from 20% used for the other policy scenarios. Complying with a 20% reduction from a production based benchmark, even with the availability of a technology fund that is reinvested in abatement opportunities in the sector, would prove difficult.

10.0 ADDITIONAL COMMENTARY

10.1 Performance Guidelines (rather than Standards)

Performance guidelines are an alternative to and in some cases complementary to prescriptive standards and have the advantage that operators are more likely to accept them but it requires external monitoring to ensure that the objectives of the guidelines are achieved.

The following sub-sections discuss a number of guideline approaches which could be used, based on AMEC's practical experience worldwide.

10.1.1 Organisational Effectiveness

GHG and Energy Management Plans can be an effective means of driving energy efficiency at an installation level. Essentially the plan brings together all of the elements contributing to energy use and the resulting emissions into a comprehensive document that is updated annually. The plan contains details of the overall policy, links to relevant management systems, details of the process, combustion equipment, fuel consumption and production. Baseline data is collected for a particular year and forecast for the following five years. A facility-specific energy efficiency study is allied to the plan and all energy and GHG reduction opportunities for improvement are captured and assessed for further study or implementation. The plan is reviewed and updated annually so that improvement can be tracked.

Essential elements of the plan are:

i) Develop a common data base of baseline information/data for all installations.

ii) Data/information
   - a) Overview of the operations in sufficient detail to give an understanding of the processes and operating scenarios that contributes to energy inputs/outputs.
   - b) Business organization and current management systems.
   - c) Location of the asset and interdependence on other assets, if applicable.

iii) Regulatory framework.

iv) Collate data on GHG emissions and energy use, flaring and venting at equipment level.

v) Develop GHG, energy and mass balances.

vi) Produce forecast data based on production forecasts etc.

vii) Identify and assess opportunities.

10.1.2 Energy Surveys of existing facilities

In the UK the offshore regulator requires operators of offshore installations to commission an independent energy survey.

The energy assessment incorporates three main elements:

i) Independent review of emissions of Greenhouse Gases (GHG) and other atmospheric pollutants and investigation and quantification of any potential opportunities to reduce emissions;

ii) Independent review of the energy usage on an asset, and investigation and quantification of any potential opportunities to avoid energy wastage; and

iii) Demonstration to the regulator's satisfaction that the whole plant is being operated in the most energy efficient manner that is financially viable.

Measurement of efficiency: The main objective is to identify opportunities which, if implemented, will lead to a reduction in emissions from the installation. The operator can further study the opportunities and develop them in to viable projects if cost effective. Energy efficiency is the primary focus but CO_2 emissions are used as a surrogate

10.1.3 Emissions Monitoring

The main reasons that air emission measurements are undertaken at onshore combustion plant are to demonstrate or, check compliance with, the regulatory emission limits laid down in the process permit. Compliance demonstration is the responsibility of the operators and is carried out by them or their emission monitoring contractors. The scope and frequency of compliance monitoring is specified by the Regulatory Authority in the process permit. Check monitoring is carried out from time to time by the regulators or their appointed contractors. The scope of such check monitoring often matches the operator's compliance monitoring programme.

Other reasons for monitoring could include process characterisation and optimisation or, for new installations, plant commissioning and acceptance tests that may be undertaken. In addition, emission monitoring could be carried out to gather input data for modeling the predicted contribution to ground level concentrations from the combustion process. This activity is normally undertaken to check that workers and the general public are not likely to be exposed to pollutant concentrations which might exceed the associated exposure limit value, (or the appropriate fraction of the exposure limit value or air quality limit value). Emission controls are applied for a variety of reasons. One reason is because of health effects associated with pollutants *(*many of which have associated exposure limits*)*. Other reasons include issues such as local amenity (for example due to dust deposition or plume colouration) and wider environmental damage (global warming, acidification). Much of the legislation regulating emissions in the UK has arisen from international protocols and agreements relating to environmental issues.

10.1.4 Performance & Energy Efficiency Monitoring

The Offshore Combustion Installations (Prevention and Control of Pollution) Regulations 2001, referred to as PPC Combustion Regulations are UK regulations directly applicable to the offshore sector. Offshore operators must obtain a permit to operate offshore combustion

equipment from the Regulator, in this case the Department of Energy and Climate Change (DECC).

While PPC Combustion Regulations and EU ETS are distinct pieces of legislation applicable to the offshore sector they are nevertheless complementary. PPC is directed at emissions to air other than CO_2 (e.g. NO_x, SO_2) but indirectly impacts on ETS. This occurs through the principals of BAT and energy efficiency enshrined in PPC.

Under PPC operators must demonstrate that they are applying Best Available Techniques (BAT) to their operations and are achieving a high level of energy efficiency.

Various tools have been developed to enable operators to monitor the energy efficiency of an offshore installation and help companies comply with new demands from environmental emissions regulations. The efficiency of offshore rotating and combustion equipment, monitoring energy usage and machine efficiency can be tracked. This helps to identify and reduce loss, ultimately reducing the amount of CO2 released into the atmosphere. Actual and avoidable CO2 emissions are calculated and displayed. Overall plant operation, individual train and machine performance graphs are displayed across a hierarchy of screens. In each case, the actual running conditions are shown compared to the "ideal" design operation. In addition, offline simulations can be carried out using the tool to provide users with the predicted costs of running different.

10.1.5 New Developments

i) BAT Reviews and Assessments are extremely useful when considering new developments. An analysis can be made of various equipment selection options such as number and type of compression and pump sets and the various drivers (e.g. direct drive, GT drive) and these are compared in terms of: Technical feasibility.

ii) Atmospheric emissions over plant operational lifetime (CO_2, NO_x and SO_x).

iii) Capital expenditure (Capex).

iv) Operating Expenditure (Opex).

v) Reliability.

A weighted system is then used to determine a ranking for the various options and the BAT then selected. Note that various sensitivities can be implemented such as ambient temperature, level of spinning reserve, extent of gas turbine degradation, different production throughputs etc. Such considerations have been found to be vital in providing the optimum configuration for life of field review to demonstrate BAT.

11.0 MAIN FINDINGS AND CONCLUSIONS

The following main findings and conclusions are made with respect to the characteristics of the offshore petroleum sector comprising the three existing facilities (Hibernia, Terra Nova, White Rose) and the planned Hibernia project. Where 'future facilities' are mentioned, no reference to any specific new facilities is intended, and the conclusions are aimed at 'new entrants' to the sector in a general sense.

11.1 Offshore Sector Characteristics

i) The NL offshore petroleum sector is unique to the rest of Canada's oil and gas production industry, the majority of which is located onshore. The remote offshore location poses **unique environmental as well as health and safety constraints**. This translates to higher capital costs for major technology projects compared to technology applied within an onshore context. This applies to GHG emission reduction projects just as much as it does to production-critical operations and maintenance activities (e.g. turnarounds) or infrastructure projects. This is reflected in the relative attributes of the provisional GHG marginal abatement cost information developed as part of this project; project costs are high, and there is no 'silver bullet'. Demonstrating Operations and Maintenance 'best practice' has a major role to play.

ii) The NL offshore petroleum sector has been developed for oil production monetisation not natural gas. Lacking export-to-shore pipeline infrastructure the **associated gas is 'stranded'** from economic monetisation; instead the majority is re-injected for pressure maintenance of enhance oil recovery and/or to preserve gas reserves for potential future monetisation. The large distance from shore and from sizeable natural gas markets, the unique environmental conditions of 'iceberg alley', and various inter-related factors are an **economic barrier to pipeline export**.

iii) The NL offshore petroleum sector has more **similarities with conventional offshore oil producing regions** worldwide than it has with onshore oil production elsewhere in Canada (especially oil sands). Similar offshore technology is employed in Europe's North Sea, the US Gulf of Mexico, offshore Brazil, offshore West Africa, and various regions of offshore Australasia. Appropriate technology and regulatory experiences from these regions have been used for comparative purpose within this study, in particular AMEC's extensive database and experience from the offshore European North Sea.

iv) The **NL facilities employ one of two types of construction, GBS or FPSO**. Whilst these are of quite different physical design, the main energy intensive process technology used on board the facilities for the produced oil, natural gas, and water processes is in general very similar. Being maritime vessels, however, the FPSO facilities are unique in requiring periodic 'off-station' maintenance, whereas maintenance turnarounds on the GBS are done 'in-field'. This impacts the implementation timescale for any major retrofit work which requires planning outside of production-critical operations.

v) The three most significant industry sector high level characteristics impacting GHG emissions and the potential for GHG emission reductions are; firstly the **lack of an electricity grid** infrastructure (requiring local power generation at facilities), secondly the **lack of a natural gas export pipeline** (requiring a prudent gas utilisation strategy), and thirdly the difficulty of integrating facility operations with other sectors of industry (e.g. via conventional CHP or CCGT technology). A major conclusion of this report is that **these factors play such a significant role in constraining the range of GHG reductions opportunities in the sector, that they warrant special consideration within GHG regulatory policy**, if the national and international market competiveness of NL offshore facilities is to be retained. An analogy in other regulatory jurisdictions is the way that the EU-ETS Phase III (from January 2013) has recognised the need to accommodate specific measures and allowances for sectors deemed most at risk to 'carbon leakage' with respect to economic disadvantage risk; Offshore Petroleum is one of these sectors.

11.2 Offshore Resource Management

i) The resource management of the associated gas has a direct relationship with sector GHG emissions and for the potential for GHG emission reductions at facilities. This is a common situation worldwide for offshore facilities processing significant amount of associated gas. It is particularly acute where, as in NL, there is no established natural gas export infrastructure. The NL offshore petroleum regulator **C-NLOPB has in place a comprehensive approach to monitoring gas utilisation** profiles.

ii) On each facility, the separation of produced oil from the associated natural gas and water uses similar processes. **Separating and offloading the crude oil to tanker is of itself a relatively low energy intensive process**. However, the majority of the produced gas is re-injected back into the field via a high pressure (high energy intensive) gas compression process. Depending on reservoir specifics this gas re-injection serves the dual purpose of preserving natural gas resources whilst also helping to maintain reservoir pressure to help prolong oil production flow rates and to optimise cumulative oil extraction volumes from available oilfield reserves.

iii) In addition to **gas re-injection**, reservoir pressure is maintained to enhance / prolong oil recovery via a high pressure process of sea **water injection** into the reservoir. After gas re-injection, water injection is the second most **energy intensive process duty** on all four NL offshore facilities. Critically, because relatively steady gas re-injection and water injection duties are required in the face of gradually falling oil production rates, in a BAU case offshore facilities (worldwide, not just in NL) are **characterised by rising energy intensity as oil production declines** from peak. The rate of production decline can be slowed by tying-back new discoveries to the facility, something which is generally slightly easier to do for GBS facilities than it is for FPSO. FPSO on the other hand have the potential to be re-fitted and re-deployed to new field locations once the production from a field reaches its economic end of field life (cessation of production).

iv) Because the gas is 'stranded', gas which is not re-injected or which cannot be used as fuel gas to generate power on the facilities for driving the energy-intensive processes is

flared locally to atmosphere at each facility. The amount of **flaring is sensitive to production process stability** and to the design capacities of process equipment items across the design life of each field. Process plant stability is highly sensitive to process **equipment reliability and performance**, which in turn is sensitive both to plant configuration and to plant **operations and maintenance best practices**. It is therefore considered that **Flare Management** has to be a core focus area for GHG abatement on all offshore facilities. **The C-NLOPB already addresses this focus area with facilities by agreeing facility-specific flare allowances and flaring procedures**.

v) Natural gas resource management is therefore one of the greatest challenges of the offshore sector and is a core focus area for both the C-NLOPB regulator and the facilities. Good gas resource management will also generally translate into good GHG management. For the sector as a whole (and ignoring facility commissioning periods when flaring is highest) **the proportion of produced gas volume being separated and conserved via gas re-injection has improved gradually over the past decade** from being marginally below [redacted] of total gas production in 2004 to being marginally above [redacted] today (2010 official data). However, there are significant variations between facilities. Data for 2011 indicates that the figure for Hibernia GBS is highest (around [redacted]), that of Sea Rose FPSO is lowest (slightly below [redacted]), whilst Terra Nova FPSO is in the middle (around [redacted]). This is largely due to the unique factors at each facility.

11.3 Sources of GHG Emissions

i) The vast majority [redacted] of GHG emissions on all existing offshore projects is the result of CO_2 emissions arising either from the **consumption of natural gas fuel** (a fraction of the associated gas) in simple-cycle combustion gas turbines used for power generation, or in the **safety flaring** of natural gas during both **normal and upset / emergency** process scenarios. Respectively, these are **'fuel' and 'non-fuel'** categories, and although formal reporting to the Environment Canada large facility emitter database does not explicitly require these to be disaggregated, this is useful in the current context.

ii) All NL facilities use **simple-cycle medium size gas turbines for power generation**, as electricity generators (for powering motors driving process and utility equipment) or alternatively for direct mechanical drive of the gas re-injection compressors. This is standard power generation equipment in the offshore petroleum industry, and is a direct consequence of a lack of economically-viable connection to onshore grids. Due to the remote location constraints, more thermally-efficient combined cycle gas and steam turbine **CCGT configurations or integrated CHP solutions are not as practical offshore**, compared to their use as BAT in onshore facilities close to industrial complexes. This is an inherent disadvantage of the offshore location.

iii) Natural gas **safety flaring comprises three generic elements**; firstly a **background flare** comprising pilot, purge, flash gas, and routine leaks to flare arising from normal stable operations, secondly additional **flaring arising from periodic controlled changes in process duty**, and thirdly **emergency flaring** arising from process upsets, major equipment trips, and production shutdowns / re-starts. Frequent or prolonged

flaring as a result of upset/emergency leads to a step-increase in GHG emissions from non-fuel use, and commonly results from unplanned trips of the gas compressors, whereby the large gas volume has to be relieved locally at flare to prevent unsafe gas pressure build-up on the facility. The **C-NLOPB issues strict procedures for the practice and reporting of emergency flaring** by facilities.



viii) The amount of GHG (CO_2e) emissions from other sources is relatively small in comparison with gas combustion and gas flaring and includes; diesel combustion for power generation (when oil and gas production is interrupted and natural gas is not available to burn), venting of methane rich natural gas and of volatile organic compounds from vessels, storage tanks and transfer equipment during crude oil unloading to tanker. The turbines for electricity generation are dual fuel, normally run on natural gas but are capable of being switched to diesel when gas plant is down. For all facilities, however, **operation on diesel is kept to a minimum**, and generally restricted to plant outages to supply accommodation and emergency loads only.

11.4 Combustion Plant Characteristics

i) The two FPSO facilities (Sea Rose and Terra Nova) are 'all-electric' facilities. They have combustion gas turbines used solely to generate electricity, and their main process equipment items including gas compressors and water injection pumps are all driven by electric motors. This is a common configuration on FPSO where space and weight are at a premium. Sea Rose has 3 x Rolls Royce RB211 gas turbines and normally runs ■

whilst Terra Nova has 2 x GE Frame 6 gas turbines and normally runs [redacted] **On Terra Nova the lack of a standby gas turbine combined with only a single process compressor train is a significant practical design constraint with respect to operations and maintenance strategy**.

ii) Hibernia and Hebron have a split configuration more commonly found in the design of fixed platform facilities worldwide. They have some **gas turbines for electricity generation and others for mechanical drive** of the large gas compressor trains. Hibernia has 4 x LM2500 gas turbines, with 2 generating electricity and 2 others directly driving the two [redacted] duty gas compressor trains. With respect to most aspects of operation and maintenance this is a more flexible configuration. However, it does not necessarily translate into reduced GHG emissions, although it has potential to do so indirectly via better plant stability and/or more controlled response to upsets.

iii) The Hibernia and Sea Rose facilities use **aero-derivative gas turbine technology** (as will Hebron). These are more efficient at rated duty than the heavy industrial gas turbines used on Terra Nova. On all four offshore projects the **typical thermal efficiency of the gas turbine units will be in the range 25% to 40%** at normal duties, without any heat recovery of hot exhaust gases, where the majority of the energy from combustion is wasted up the exhaust stack. Highest thermal efficiencies will occur when operating closest to rated design, [redacted]

iv) Additional combustion duty is attributable to gas fired process boilers used for process heat generation and the emergency diesel generators used in shutdowns.

11.5 Main Energy Consumers

i) On all four offshore projects **the main energy consumers (energy demand side) are the gas re-injection compressors and the water injection pumps**. Together they account for close to [redacted] of the emissions arising from gas fuel consumption in the main gas turbine power generation plant. These consumers are therefore the 'big ticket' items for meaningful short and long term reduction of GHG emissions on the 'demand side' of the fuel category.

ii) Both FPSO facilities being vessels require positioning capability via internal weather vaning turret or thrusters. The Sea Rose FPSO (weather-vaning FPSO) does not make use of thrusters, whereas the Terra Nova FPSO (modified tanker) has a system of 5 thrusters, a sub-set of which are used to maintain heading during crude offloading. The electric power duty of the **thrusters** is another significant but intermittent/variable load dependent on weather and sea state.

11.6 Production, Energy and GHG Intensity

i) **All three existing facilities are beyond their peak oil production rates but continue to require high levels of energy use**. By end of 2011, Hibernia (peak in 2004) was at ~75% of peak oil, Terra Nova (peak in 2003) was at ~33% and White Rose (peak in 2007) was at ~30%. Yet for all facilities the required energy from combustion fuel for

power generation was relatively steady. The more rapid natural decline of FPSO facility oil production is a characteristic of the worldwide offshore industry since FPSO are more commonly used on projects as a lower initial capital cost alternative to fixed platforms where field reserves are smaller or lie in deep water.

ii) **A unique aspect of offshore oil production is that the energy intensity and the GHG emissions intensity (per unit of oil production) will tend to rise as oil production declines.** Gas compression and water injection pumping are the most energy intensive users of power generated from fuel combustion, and are designed to maximise oil production, such that the overall energy requirement on the facilities does not decline at as fast a rate as their oil production; the two profiles are largely independent of each other since plant equipment is largely fixed by upfront design.

iii) The historical energy intensity from fuel combustion at all three installations has increased significantly over the period 2007 to 2011 in line with static fuel use and declining oil production. In terms of overall GHG intensity this has been offset slightly by reductions in 'non-fuel' flaring over this period, particularly at Terra Nova and Hibernia. At the end of 2010 the GHG emission intensity (relative to oil production) was Hibernia (12.1 $kgCO_2$/boe), Terra Nova (19.6 $kgCO_2$/boe), and White Rose (20.8 $kgCO_2$/boe). The straight average of the three facilities in 2010 was 17.5 $kgCO_2$/boe, and the weighted average of total sector emissions was 16.4 $kgCO_2$/boe.

iv) **A realistic target for average intensity for the two FPSO in the period to 2020 is in the range [redacted] $kgCO_2$/boe**. Relative to 'years in production', the 2010 emission intensities of the FPSO facilities are slightly above the average business as usual GHG intensity of FPSO facilities in the North Sea (for similar age).

v) **A realistic target for average intensity for Hibernia GBS in the period to 2020 is in the range [redacted] tCO_2/boe**. Relative to current years in production, the 2010 GHG emission intensity of Hibernia GBS is in line with the average GHG intensity of platform facilities in the North Sea. A realistic target for Hebron is [redacted] $kgCO_2$/boe.

11.7 GHG Abatement Opportunities – Best Practice and Best Available Technologies

i) The main abatement opportunities can be logically split into '**Best Practices**' (BP) and '**Best Available Technologies**' (BAT) for each of the main process areas and each facility. In general the implementation of BAT will require higher capital project budgets and in many cases will require planned shutdowns or off-station downtime. There is currently limited planned opportunity for this in the run-up to 2020.

ii) Discussions with the facilities and with C-NLOPB indicates that **a number of best practice flare management measures are already being followed, and have allowed flare rates at existing facilities to be brought down since 2007**. These include improvements to help minimise background emissions, and also improvements in the reliability of critical rotating machinery equipment items to reduce the frequency and duration of upset events which lead to spikes in flare rates.

iii) On the whole, and in the medium term (to 2020), **GHG abatement opportunities relating to flare (non-fuel) reduction best practices are likely to be more promising and cost-effective than abatement opportunities relating to fuel combustion reduction** at existing facilities.

iv) Flaring is currently attributable for [redacted] of GHG emissions for the sector. For the three existing NL facilities collectively, **improved flare management could amount to a further [redacted] reduction in GHG emissions for the sector from 2010 levels by 2020, with flaring dropping below [redacted] of total GHG emissions**. [redacted] One should also expect Hebron to quickly match low levels of flaring once it has completed commissioning, since it is likely to have many of the best practice measures built into the plant O&M philosophy. Experience from mature offshore sectors such as the North Sea indicates that it is possible for gradual improvement in implementing flaring best practices to allow the proportion of GHG emissions attributed to flaring to be reduced to a value in the range [redacted] of overall GHG emissions at oil facilities, without expensive technology. More rigorous use of BAT and investment as has occurred in Norway has resulted in levels in the range 10% - 15% at facilities.

v) **Flare gas recovery (FGR) technology recovers and recycles the background flare gas, and has the potential to reduce the sector GHG emissions from flaring further on top of standard best practice measures**. This could equate to a further reduction of [redacted] in overall emissions from 2010 levels by 2020. It would appear that a local robust 'safety case' review of FGR implementation has not yet been made by the industry and regulator C-NLOPB. It was considered for the Hebron project design but was rejected primarily for this reason. The technology has been field proven in the North Sea, has been widely deployed offshore in Norway (led fundamentally by offshore Operator Statoil) and on a handful of other projects worldwide. FGR is also currently being adopted as BAT for several deepwater FPSO facilities offshore Brazil, including by Statoil on the Peregrino FPSO. Statoil has a diverse exploration portfolio in Brazil in partnership with Petrobras, Repsol and others. In particular FGR has significant potential application for any new-entrant facilities to the NL petroleum sector. Given that Statoil have extensive experience of FGR in the North Sea and are deploying this elsewhere, it could be reasonable to anticipate that this technology might feature in the design appraisal of the future development of the Mizzen project in offshore NL.

vi) With respect to **stationary combustion plant, aero-derivative gas turbines are widely in use** (on all facilities except Terra Nova), and represent existing BAT for offshore facilities. Terra Nova's industrial frame gas turbines are not quite as efficient but it would be prohibitive in cost, downtime, and risk to justify replacement. However, for all gas turbines in use, incremental thermal efficiency improvements in the order of [redacted] might be achieved by implementing the turbine OEM's latest technology upgrades, including improved turbine hot section components. The best time to consider these upgrades is when each gas turbine reaches its next scheduled major-overhaul milestone. These occur infrequently (typically every 3-10 years) and as such this

constitutes a medium term as opposed to short term opportunity, and one which would have to be planned coincident with major turnaround/off-station outages.

vii) **Terra Nova is unique in that it operates without a stand-by gas turbine and compression train plant equipment, which leads to operational and maintenance constraints in relation to plant uptime**. The potential to install a third power generation gas turbine (possibly a smaller aero-derivative unit) on the facility would contribute to improved O&M flexibility and would also potentially generate GHG reductions of up to [redacted] below the facility's 2010 overall GHG footprint.

viii) **Theoretically, on all facilities the increased use of waste heat recovery (WHR) from the gas turbine exhaust stacks has the largest potential for GHG reductions from stationary combustion activities**. However, in practical terms this is severely constrained by the lack of adequate process duty to utilise the full WHR potential; there is no large process requirement. It is for this reason that the WHR units that are fitted to existing facilities are working significantly under-capacity. Realistically, abatement opportunity is likely to be [redacted] More beneficial design implementations of WHR should be considered in future new entrant projects.

ix) There has been insufficient information-response from facilities to quantify the degree to which **combustion plant standard best practices** are already in place. Collectively these are estimated to have a GHG abatement potential up [redacted] of combustion emissions, with a portion of this likely to have been already achieved by the facilities.

x) **The most productive abatement best practices relating to gas compression plant is to focus on areas which improve machine reliability and machine performance**. The former will reduce compression plant trips and hence help minimise emergency flaring, whilst the latter will help reduce power demand and hence reduce the fuel gas consumption in gas turbine units. There is insufficient information from operators to confirm to what extent standard best practices are being followed at facilities, but abatement opportunities (2010 to 2020) are likely to be in the range [redacted] of the sub-total of GHG from combustion activities.

xi) **Gas compressor re-wheeling (aerodynamic re-design of internal components) has abatement potential at key points in field life.** It helps re-optimise the compressor to changing production profiles over field life, but also provides a GHG abatement opportunity due to potentially lower energy duties. This is especially relevant to the situation where gas injection flow starts to reduce within the bounds of natural field decline, though the use of fixed speed motor drives can constrain re-wheel opportunities.

xii) **Variable Speed Drive (VSD) technology for large motor drives is regarded as energy efficient BAT since it has the capacity to better match motor power consumption with changing process duty across the field life.** The existing three facilities utilise large water injection pumps (WIP) with fixed speed motors. These will have been sized for peak duties and will have limited turndown capacity later on in field life. The Hebron project is adopting VSD on its WIP motor drives. In the long term life of field, reductions in WIP energy use and combustion GHG emissions of the order of [redacted] can be achieved using VSD technology. There may be potential to retrofit VSD to

existing installations during key turnarounds, although costs are likely to be higher than for new facility designs. VSD should be considered BAT on all new projects.

xiii) **Replacing WIP cartridge internals with latest high-efficiency designs may be another option for mature installations**, helping re-optimise pump 'sweet spots' with changes in process duty. This has more modest abatement potential in the order of [redacted] of WIP energy costs. Likewise WIP pipe work system pressures can be reconfigured throughout field life to generate similar levels of abatement opportunity.

xiv) Although not a high energy duty, crude oil stabilisation, storage, and offloading can be optimised using best practices and BAT to generate incremental savings. Use of closed loop inert gas systems and vapour recovery units can contribute to typically [redacted] reductions in overall GHG emissions. [redacted]

xv) The operation of weather-vaning positioning systems on FPSO facilities can reduce their electrical demands and contribute to modest improvements in energy efficiency. FPSO designs based on tanker conversions will likely require more energy for thrusters.

xvi) Fuel substitution is not regarded as having any significant potential offshore NL, since consumption of diesel fuel is already low and restricted to when gas plant is down. However, it does become a consideration for any new-entrants that might be gas-limited, and gas import pipeline infrastructure from surrounding facilities would be relevant.

11.8 GHG Abatement Opportunities – Emerging Technologies

i) Relevant emerging technologies should be considered for new projects post 2020. These include offshore mini-LNG, integrated CCGT systems, new motor technology, and power from shore options where distance is not a barrier. Experiences from other offshore regions (e.g. Europe, South America, Australia, West Africa) are relevant.

ii) Such emerging technologies could be ideal candidates for attracting investment from a Technology Fund, very much in line with how such funds are used for R&D in other jurisdictions. The Norwegian and the Brazilian offshore petroleum sectors are examples of where R&D investment into such technologies is currently underway, incentivised by access to funds generated via GHG regulation policy (Tech Funds or Carbon Taxes).

iii) Some emerging technologies could have important cross-sector benefits in addition to direct benefits within the NL offshore sector. For example, offshore technologies that enable the monetisation of NL offshore natural gas reserves (e.g. mini-LNG or pipeline) would potentially allow fuel substitution onshore in other industries; for example replacing fuel oil combustion with natural gas combustion in the NL onshore refinery sector. This would have economic and GHG benefits across multiple sectors.

11.9 GHG Policy Options and Criteria

i) The policy options evaluated in this study using the Navius GEEM model have been designed to draw insight about the impact of alternative policy designs. Given the level

of uncertainty regarding alignment with the likely federal policy preferences, the policies covered do not necessarily correspond to a policy that is likely to be implemented by the government of NL, but rather the analytical value is in showing tradeoffs between different policy designs. This should be informative to NL policy in relation to considering alternative mechanisms towards achieving equivalency.

ii) This analysis examines performance standards under five scenarios with the "Base" scenario being the base against which all other policies are compared. The base scenario features the following characteristics; trading of Emissions Performance Credits (EPCs), access to a technology fund at $40 per tonne of CO_2e, but not access to offsets, a benchmark based on historic 2011 levels of emissions, and a 20% reduction in emissions from 2011 levels of emissions by 2020. Each additional scenario changes a single policy characteristic for comparative purposes.

11.10 GHG Policy Evaluation

The key findings from the policy analysis are:

i) The various performance standards reduce emissions by between [redacted] from their business-as-usual trajectory between 2010 and 2020. However, the choice of benchmark can have a dramatic impact on compliance costs.

ii) **The availability of a technology fund (S1-BASE case analysis) achieves greater reductions in emissions and reduces compliance costs in comparison to the availability of offsets (S2-OFF case analysis).** Allowing facilities to comply with a policy by accessing a technology fund ensures that revenues collected are used to reduce GHG emissions in the sector and also reduce compliance costs. The analysis highlights that greater reductions can be achieved from the sector with greater constraints on offset availability and greater emphasis on a technology fund. However, the analysis also acknowledges that investment opportunities for the technology fund do not necessarily need to be limited to the offshore oil industry, and could include opportunities in other sectors of the economy. In fact this may be optimal from a provincial GHG perspective if opportunities in other sectors have lower costs. As the technology fund is reinvested in other sectors of the economy, a policy will increasingly mimic the effect of the availability of offsets as shown in this analysis. The use of a technology fund and offsets is already field trialed as part of Canadian provincial policy in other sectors of industry, and similarly as part of Norwegian offshore sector policy and EU-ETS Clean Development Mechanism (CDM). A technology fund is also at the heart of the Brazil's new offshore petroleum sector GHG policy; a growth petroleum region where significant numbers of FPSO projects are currently under approval.

iii) **The choice of benchmark affects the portion of compliance achieved through direct reductions and the level of contributions to a technology fund.** On one end of the spectrum, calling for a reduction from the benchmark approach used in the EU ETS would require fewer reductions, while on the other end a reduction in emissions intensity from a production-based 2011 benchmark would require significant reductions

from the sector. In the latter policy, compliance with the policy would become increasingly difficult as each field matures. While this leads to greater contributions to the technology fund and greater reinvestment of the technology fund in low emissions options in the sector, it also substantially increases the cost of compliance.

iv) **Increasing the price for accessing the technology fund achieves greater reductions, but at a diminishing rate.** The main opportunities for reducing emissions from NL's offshore oil industry identified in this analysis are from flaring. These reductions have relatively low cost in comparison to most other fuel-based options. However, once these options have been undertaken, there are relatively fewer opportunities to achieve significant reductions in GHG emissions.

v) **The analysis explicitly shows that a policy design option based on an oil production benchmark would achieve GHG reductions at significantly greater cost in comparison to other options**. A production-based benchmark is difficult for the offshore oil industry to achieve due to the independence of relatively fixed combustion plant energy requirements with falling oil production rates. A benchmark based on historic emissions intensity (e.g., 2011 level of emissions intensity as envisioned in case S4-PB) becomes increasingly difficult to achieve even with maximum abatement from the sector. The balance must be met with either contributions to a technology fund or some other flexibility mechanism, which impose a financial transfer on the sector. If flexibility mechanisms are not available, this performance standard may not be achievable for some facilities, and they would either have to fall out of compliance or shut down. The findings of this study's NL analysis are in line with the independent third party findings for the European offshore petroleum sector under EU-ETS Phase III policy design, where production based benchmarks were deemed inappropriate to offshore facilities and a fuel (combustion) benchmark was used instead.

Signed



Steve Lamming
Project Manager
AMEC Environment & Infrastructure



Sikobe Litaba
Energy & Emissions Specialist
AMEC Performance Improvements Ltd



Jotham Peters
Navius Research Inc.

APPENDIX A

NL PRODUCTION & GHG DATA

(Contained in separate document)

GOVERNMENT OF NEWFOUNDLAND AND LABRADOR
Office of Climate Change, Energy Efficiency, and Emissions Trading
(GNL - CCEEET)

OFFSHORE OIL & GAS – NEWFOUNDLAND AND LABRADOR
GHG REDUCTION OPPORTUNITIES & COMPETITIVE IMPLICATIONS

FINAL REPORT
(Deliverable 4)

APPENDIX A

NL PRODUCTION & GHG DATA

TC121804

TABLE OF CONTENTS

PAGE

A1. HISTORIC PRODUCTION & GHG DATA 1
A2. SOURCES AND BREAKDOWN OF CO_2 EMISSIONS 9
A3. PRODUCTION & GHG INTENSITY 12
A4. GHG INTENSITY BENCHMARKED AGAINST AMEC-PI DATABASE 17
A5. PRODUCTION AND GHG INTENSITY – USING CCEEET FORECAST DATA 22

LIST OF TABLES

Table A1: Hibernia Installation – Production & GHG Data(2002 - 2011) 2
Table A2: Terra Nova Installation – Production & GHG Data(2002 - 2011) 4
Table A3: Sea Rose Installation – Production & GHG Data(2005 - 2011) 6

LIST OF FIGURES

Figure A1.a: Hibernia Installation – Annual Fluids Production (2002 – 2011) 3
Figure A1.b: Hibernia Installation – Fuel, Flare, & GHG Emissions (2004 – 2011) 3
Figure A2.a: Terra Nova Installation – Annual Fluids Production (2002 – 2011) 5
Figure A2.b: Terra Nova Installation – Fuel, Flare, & GHG Emissions (2004 – 2011) 5
Figure A3.a: White Rose Installation – Annual Fluids Production (2005 – 2011) 7
Figure A3.b: White Rose Installation – Fuel, Flare, & GHG Emissions (2005 – 2011) 7
Figure A4.a: NL Offshore Sector – Fate of Produced Gas in mmscf (2004 – 2011) 8
Figure A4.b: NL Offshore Sector – Fate of Produced Gas by % (2004 – 2011) 8
Figure A5.a: NL Offshore Sector – Carbon Dioxide emissions by source (tonnes) 10
Figure A5.b: NL Offshore Sector – Carbon Dioxide emissions by source (%) 10
Figure A6.a: NL Offshore Sector – estimate of CO_2 emissions by duty (tonnes) 11
Figure A6.b: NL Offshore Sector – estimate of CO_2 emissions by duty (%) 11
Figure A7.a: Hibernia – trend of CO_2 emissions intensity vs. Oil Production 13
Figure A7.b: Hibernia – trend of CO_2 emissions intensity vs. CO_2 emissions 13
Figure A8.a: Terra Nova – trend of CO_2 emissions intensity vs. Oil Production 14
Figure A8.b: Terra Nova – trend of CO_2 emissions intensity vs. CO_2 emissions 14
Figure A9.a: White Rose – trend of CO_2 emissions intensity vs. Oil Production 15
Figure A9.b: White Rose – trend of CO_2 emissions intensity vs. CO_2 emissions 15
Figure A10a: NL Offshore Sector – trend of CO_2 emissions intensity 16
Figure A10.b: NL Offshore Sector – trend of CO_2 emissions intensity vs. Oil Production 16
Figure A11.a: NL Offshore FPSO – CO_2 emissions vs. AMEC-PI FPSO Database 18
Figure A11.b: NL Offshore FPSO – CO_2 emissions Intensity vs. AMEC-PI FPSO Database 18
Figure A12.a: NL Offshore GBS Platform – CO_2 emissions vs. AMEC-PI Platform Database 19
Figure A12.a: NL Offshore GBS – CO_2 emissions intensity vs. AMEC-PI Platform Database 19
Figure A13.a: NL Offshore FPSO – CO_2 emissions vs. years in production 20
Figure A13.a: NL Offshore FPSO – CO_2 emissions vs. API gravity 20
Figure A14.a: NL Offshore GBS Platforms – CO_2 emissions vs. years in production 21
Figure A14.b: NL Offshore GBS Platforms – CO_2 emissions vs. API gravity 21
Figure A15: Hibernia – production & CO_2 emissions intensity forecast 22
Figure A16: Terra Nova – production & CO_2 emissions intensity forecast 22
Figure A17: White Rose – production & CO_2 emissions intensity forecast 23
Figure A18: Hebron – production & CO_2 emissions intensity forecast 23

Appendix A provides a summary and commentary on the NL Offshore Petroleum Sector production and GHG data used in this study, including comparison with AMEC-PI experience.

The Appendix is split into the following sections:

i) Historic Production & GHG Data (2004 – 2011)
ii) Sources and breakdown of emissions
iii) Production and GHG intensity – historic
iv) Energy Intensity benchmarking (comparison with AMEC-PI database)
v) Production and GHG intensity – CCEEET forecast data

A1. HISTORIC PRODUCTION & GHG DATA

This section contains the data and trends relating to facility Production data and associated GHG emissions from the NL Offshore petroleum sector. The base data has been sourced from the C-NLOPB public record of statistics on the C-NLOPB website.

Table A1 and Figure A1.a and A1.b summarize the data for **Hibernia GBS facility**. Although oil production peaked in 2004 (6 years after startup), there has not yet been any significant decline in production rates and the gas to oil ratio and water cut rate have remained reasonably steady until 2011; oil production is still above 75% of its peak 2004 rate. This characteristic differs markedly from the other two facilities.

Table A2 and Figure A2.a and A2.b summarize the data for **Terra Nova FPSO facility**. After start-up in 2002 oil production peaked in 2003 (one year after startup). Since 2007 there has been a sharp decline in production rate and the water cut ratio has increased significantly; by 2011 oil production rate had declined to below 40% of its peak 2003 rate.

Table A3 and Figure A3.a and A3.b summarize the data for **Sea Rose FPSO facility**. After start-up in 2005 oil production peaked in 2007 (less than two years after start-up). Since 2007 there has been a sharp decline in oil production rate and the water cut ratio has increased significantly; by 2011 oil production rate had declined to below 40% of its peak 2007 rate.

A key item of data in relation to the source of GHG emissions from the sector is the fate of the produced gas. This is summarized for the offshore sector as a whole (the three installations) in Figure A4.a and A4.b. The figures show that the majority of produced gas (~85% in 2007 and ~90% in 2010) is re-injected. Approximately 7% of produced gas is used as fuel gas on the installations, and the rest (~8% in 2007 and ~3% in 2010) is flared. This highlights the fact that the sector is achieving its main high level target of conserving or using the bulk of the associated gas that is produced, with only a relatively small amount flared. It also implies that minimizing flaring activity whilst maximizing oil production is sensitive to maximizing re-injection compressor reliability and performance, given that there is currently no gas export infrastructure in place. Simply put, without such infrastructure, then GHG reductions due to reductions in fuel gas or flaring are reliant on being accommodated within re-injection compressor capacity.

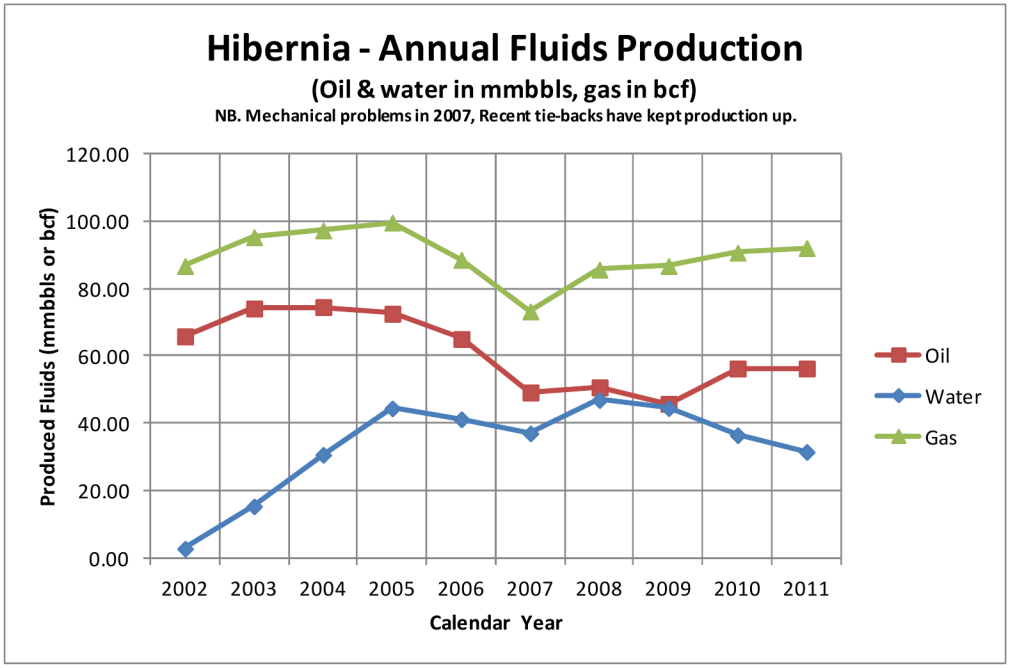


The information in Table A1 is a summary of the historical production data and GHG emission data for the **Hibernia** Installation used in this study.

Production data (shown in green) for the calendar years 2002 to 2011 has been sourced from the C-NLOPB website. Flared gas and Fuel gas volumes for the calendar years 2004 to 2009 (shown in yellow) were provided by CCEEET for this study based on information from the Department of Natural Resources. Total GHG emissions data for the calendar years 2004 to 2009 (shown in yellow) were also provided by CCEEET based on Environment Canada data, and have been checked against the Environment Canada database (via the website) by AMEC as part of this study. The very latest data has also been extracted from the C-NLOPB annual reports for 2010 and 2011 (shown in orange), but it should be noted that this covers data to the fiscal year end (31st March) and not calendar year like the other data. Additional calculations, conversions, and sense checks have been conducted by AMEC and are shown in purple.

Figure A1.a and A1.b summarize the key data for **Hibernia** in graphical format.

Figure A1.a: Hibernia Installation – Annual Fluids Production (2002 – 2011)



[redacted]

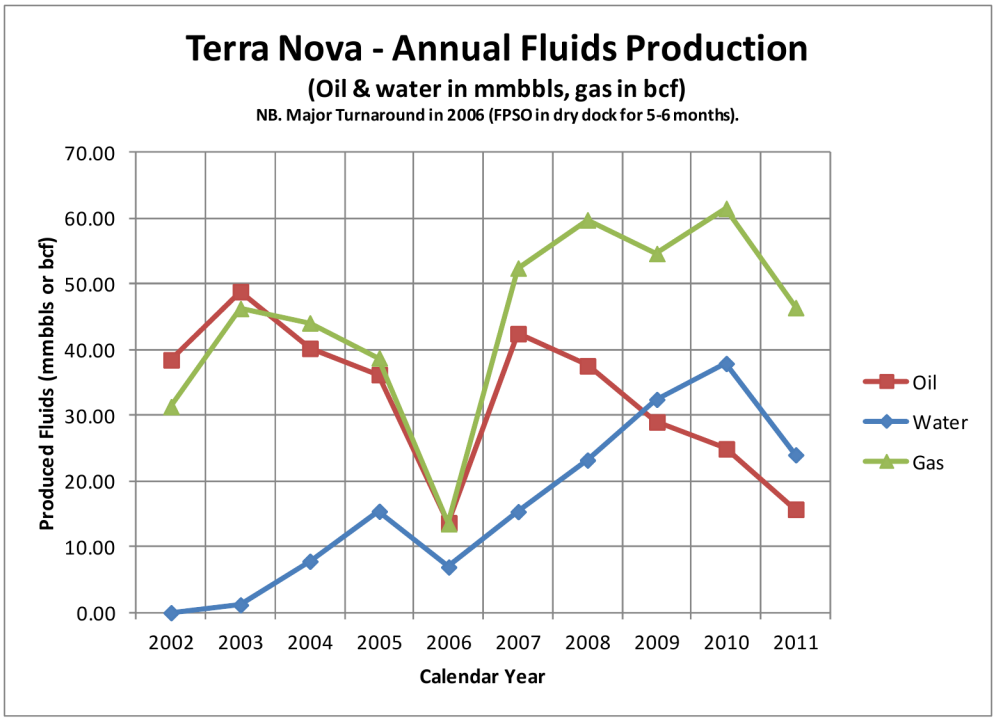


The information in Table A2 is a summary of the historical production data and GHG emission data for the **Terra Nova** Installation used in this study.

Production data (shown in green) for the calendar years 2002 to 2011 has been sourced from the C-NLOPB website. Flared gas and Fuel gas volumes for the calendar years 2004 to 2009 (shown in yellow) were provided by CCEEET for this study based on information from the Department of Natural Resources. Total GHG emissions data for the calendar years 2004 to 2009 (shown in yellow) were also provided by CCEEET based on Environment Canada data, and have been checked against the Environment Canada database (via the website) by AMEC as part of this study. The very latest data has also been extracted from the C-NLOPB annual reports for 2010 and 2011 (shown in orange), but it should be noted that this covers data to the fiscal year end (31st March) and not calendar year like the other data. Additional calculations / conversions / sense checks have been conducted by AMEC and are shown in purple.

Figure A2.a and A2.b summarize the key data for **Terra Nova** in graphical format. It should be noted that 2006 was an 'atypical year' due to the field being out of production with the FPSO being in dry dock for ~6 months.

Figure A2.a: Terra Nova Installation – Annual Fluids Production (2002 – 2011)



[redacted]

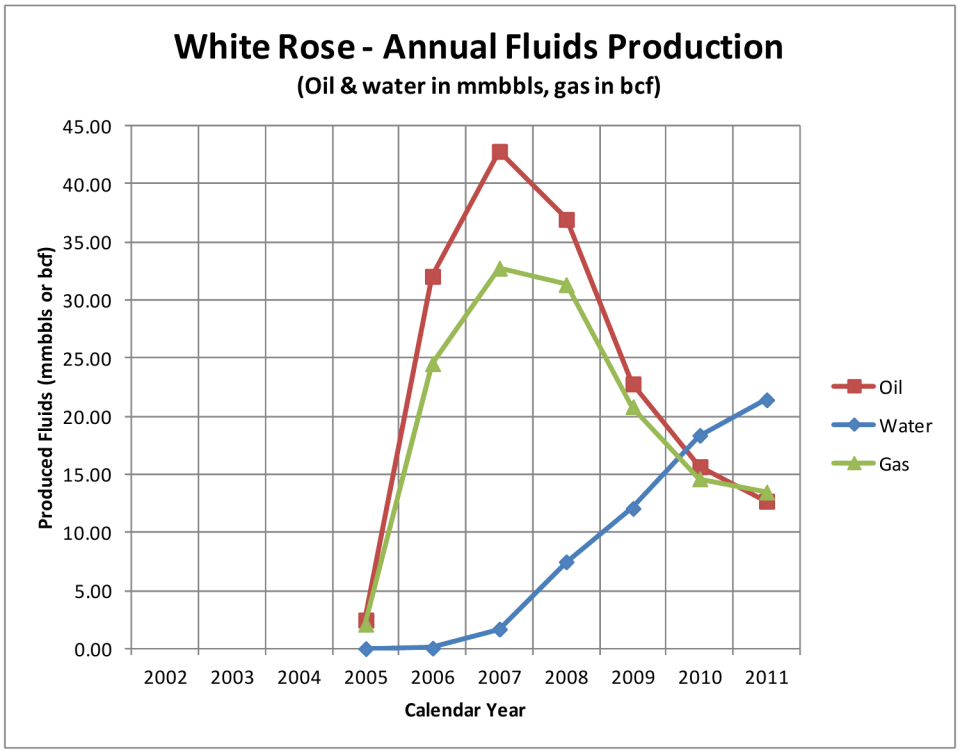


The information in Table A3 is a summary of the historical production data and GHG emission data for the **White Rose** Installation (**Sea Rose FPSO**) used in this study. The data covers the period since the field came on stream in 2005.

Production data (shown in green) for the calendar years 2005 to 2011 has been sourced from the C-NLOPB website. Flared gas and Fuel gas volumes for the calendar years 2005 to 2009 (shown in yellow) were provided by CCEEET for this study based on information from the Department of Natural Resources. Total GHG emissions data for the calendar years 2005 to 2009 (shown in yellow) were also provided by CCEEET based on Environment Canada data, and have been checked against the Environment Canada database (via the website) by AMEC as part of this study. The very latest data has also been extracted from the C-NLOPB annual reports for 2010 and 2011 (shown in orange), but it should be noted that this covers data to the fiscal year end (31st March) and not calendar year like the other data. Additional calculations / conversions / sense checks have been conducted by AMEC and are shown in purple.

Figure A3.a and A3.b summarize the key data for **White Rose** in graphical format. It should be noted that 2005 - 2006 corresponds to the initial period of commissioning. Gas from white rose is re-injected into the north pool for conservation as opposed for enhanced oil recovery.

Figure A3.a: White Rose Installation – Annual Fluids Production (2005 – 2011)



[redacted]





A2. SOURCES AND BREAKDOWN OF CO_2 EMISSIONS

This section contains the raw data, derived estimates, and trends relating to the breakdown of GHG emissions from the NL Offshore petroleum sector.

Figure A5.a and A5.b summarize CO_2 emissions for the sector as a split between the CO_2 emissions from flaring & venting (primarily flaring) and CO_2 emissions from fuel consumption. The split has been derived by AMEC based on the relative proportion of fuel gas and flare gas volumes, on the assumption that the corresponding gas compositions and hence emission factors are not significantly different; this is considered reasonable based on AMEC experience.

Figure A5.a shows that since 2007 (after White Rose came online as the third offshore installation) the sub-total CO_2 emissions from fuel gas consumption for the sector have remained fairly steady at just over [redacted] ktonnes CO_2, despite declines in production. In comparison the CO_2 emissions from flared gas wastage have reduced from being just under [redacted] ktonnes in 2007 to around [redacted] ktonnes in 2010. As a result, between 2007 and 2010, total CO_2 emissions for the sector have reduced from just below 2,000 ktonnes to below 1,500 ktonnes due to reduction in flaring, and CO_2 emissions due to flaring have dropped from [redacted] to [redacted] of total CO_2 emissions over this period.

Figure A6.a and A6.b breaks down the CO_2 emissions attributable to fuel gas consumption further, based on the observation that the vast majority of the fuel usage on all three of the installations is consumed in simple cycle gas turbines for power generation or direct mechanical drive. The following assumptions have been made based on typical modern industrial gas turbines with majority of duty being for gas re-injection compressors and for water injection / seawater lift duty:

i) The gas turbines will typically be operating below rated duty, perhaps between [redacted] and [redacted] load, and their thermal efficiency will correspondingly be slightly lower than it is at maximum rated duty. Thermal efficiency at maximum rated duty will be in the region of 35%, whereas at reduced duties the average thermal efficiency at the turbine is likely to be in the range [redacted]

ii) This means that it is estimated that a significant proportion of the energy from fuel gas consumed in the gas turbines is wasted in hot exhaust gases. For illustration 35% thermal efficiency is considered to be a conservative estimate of useful energy from fuel gas. No specific data is available for the amount of heat energy which is recovered via use of waste heat recovery units (WHRU), but process demand is likely to be low.

iii) The gas compression duty is estimated to account for [redacted] of the gas turbine overall generated output power, with water injection / seawater lift another [redacted] and the balance [redacted] attributable to other miscellaneous loads.

In summary, wastage due to flaring and thermal losses from turbine hot exhaust gases account for the majority of CO_2 emissions with only around [redacted] of emissions being from useful duty.









A3. PRODUCTION & GHG INTENSITY

This section contains trends relating to GHG intensity from the NL Offshore petroleum sector.

Figure A7.a and A7.b summarize the trend in CO_2 emissions intensity for Hibernia. This has been reasonably steady between 9.0 and 12.0 $kgCO_2$ / boe in the period 2004 to 2010, largely because, whilst oil production has decreased slightly, GHG emissions have also decreased slightly, largely due to the flare volumes coming down.

Figure A8.a and A8.b summarize the trend in CO_2 emissions intensity for Terra Nova. NB. The 2006 data is atypical due to the 6-month outage. The Terra Nova emission intensity has been at typically twice the level of Hibernia in the period 2004 to 2010, largely because, oil production rates have been lower than Hibernia whilst the fuel and flare emissions have been at a similar level. Fuel emissions are relatively high because similar energy intensive processes are required for gas re-injection and water injection for reservoir pressure maintenance. Since 2007 the data shows an upwards trend in emission intensity due to the fact that the decline in oil production has been faster than the decline in GHG emissions (control of flaring).

Figure A9.a and A9.b summarize the trend in CO_2 emissions intensity for White Rose. The emission intensity was very high initially in the period 2005 – 2007 in the period oil production was coming on-stream, due primarily to high flaring rates early on before gas re-injection compression duty was fully commissioned. As oil production increased to peak and flaring was reduced, by 2007 the emission intensity was at similar levels to Terra Nova, though still being twice the level of Hibernia. Since 2007 the intensity has remained relatively steady as flared volumes have reduced in parallel with declining oil production and associated gas production. Produced gas is re-injected into the 'North Pool' for conservation, as opposed to being used for enhanced oil recovery. With oil production in decline, an increase in emissions intensity is likely unless the flare volume and/or fuel consumption can be reduced further.

Figure A10.a and A10.b summarize the trend in CO_2 emissions intensity for the sector in addition to the individual facilities. Due to the relatively high oil production rates from Hibernia, that have not declined to the extent that they have from the two FPSO, the Hibernia intensity remains fairly low and this helps to pull down the sector average as well.

It is observed that the total sector GHG emission intensity factor (kgCO2e/boe) has been fairly steady since 2004. Whilst total production is declining since 2007, the flaring has been coming down with it. Hibernia has, however, helped smooth the intensity factor profile; its intensity factor has been steady / declining due to flare management, whilst that of Terra Nova and White Rose have been increasing since 2007 – 2008. Unless there are significant field tie-backs / extensions this increase in intensity will continue for the FPSO facilities.

Figure A7.a: Hibernia – trend of CO_2 emissions intensity vs. Oil Production

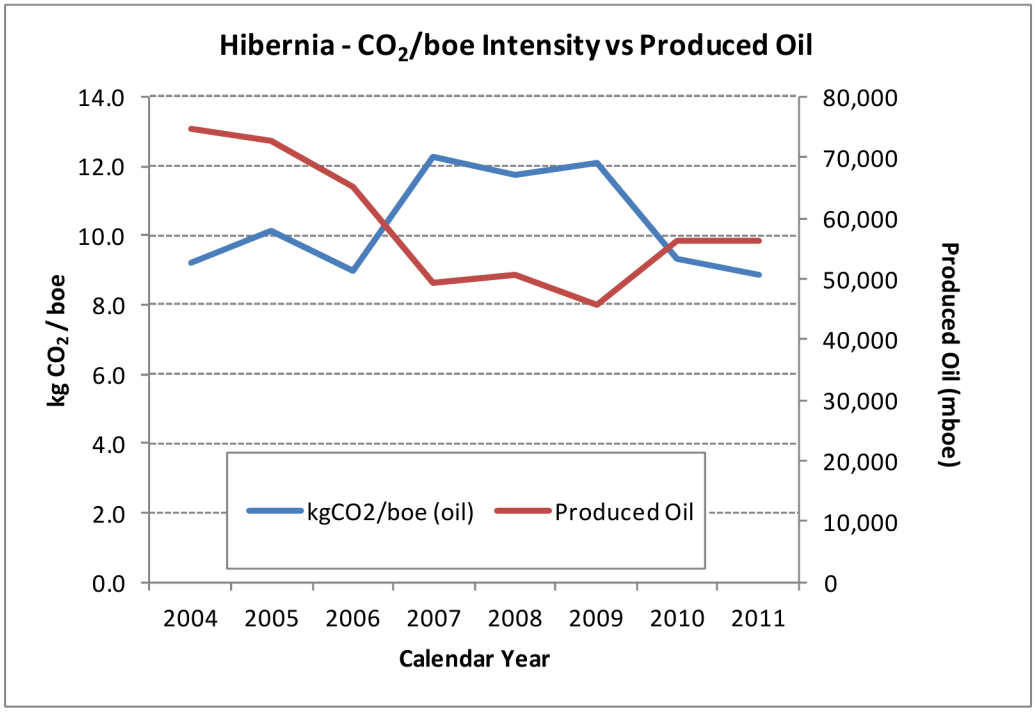


Figure A7.b: Hibernia – trend of CO_2 emissions intensity vs. CO_2 emissions

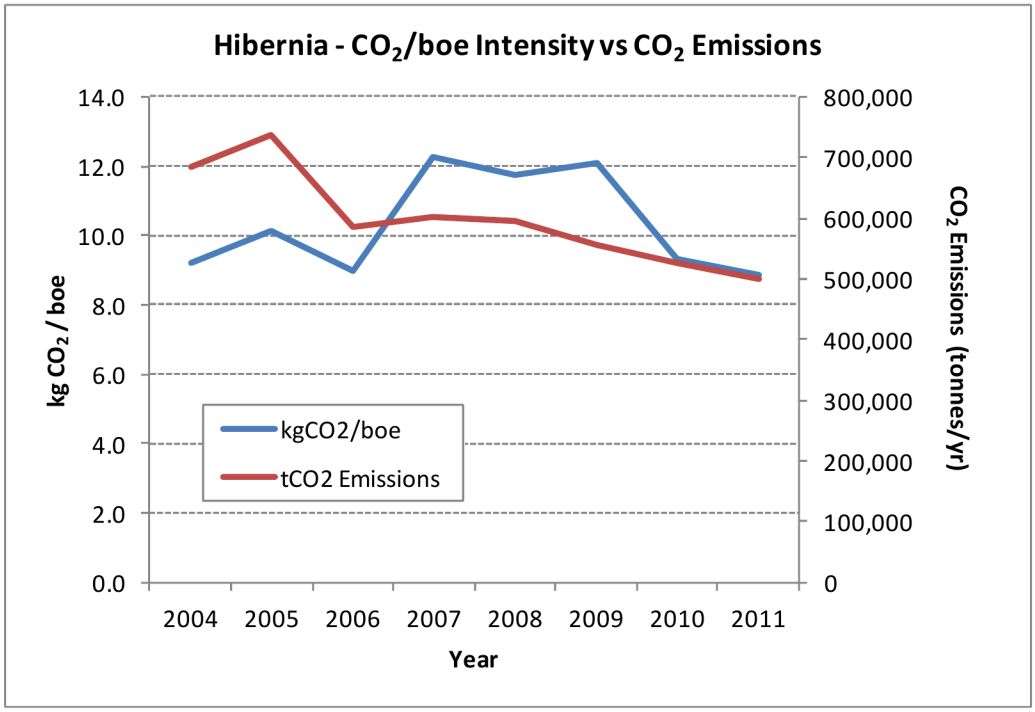


Figure A8.a: Terra Nova – trend of CO_2 emissions intensity vs. Oil Production

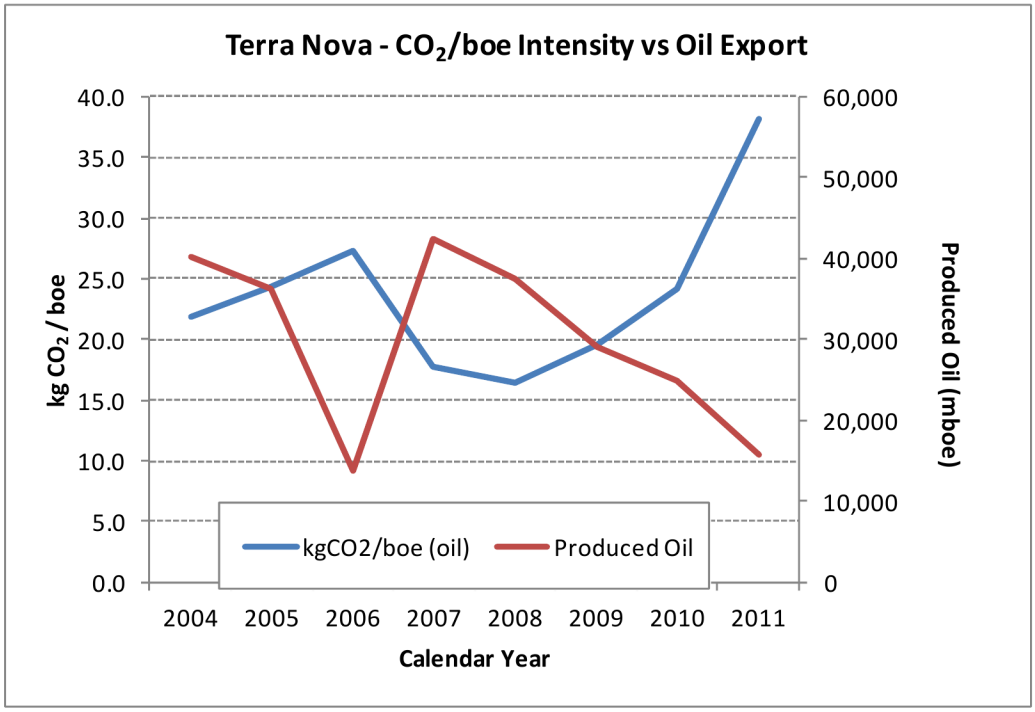


Figure A8.b: Terra Nova – trend of CO_2 emissions intensity vs. CO_2 emissions

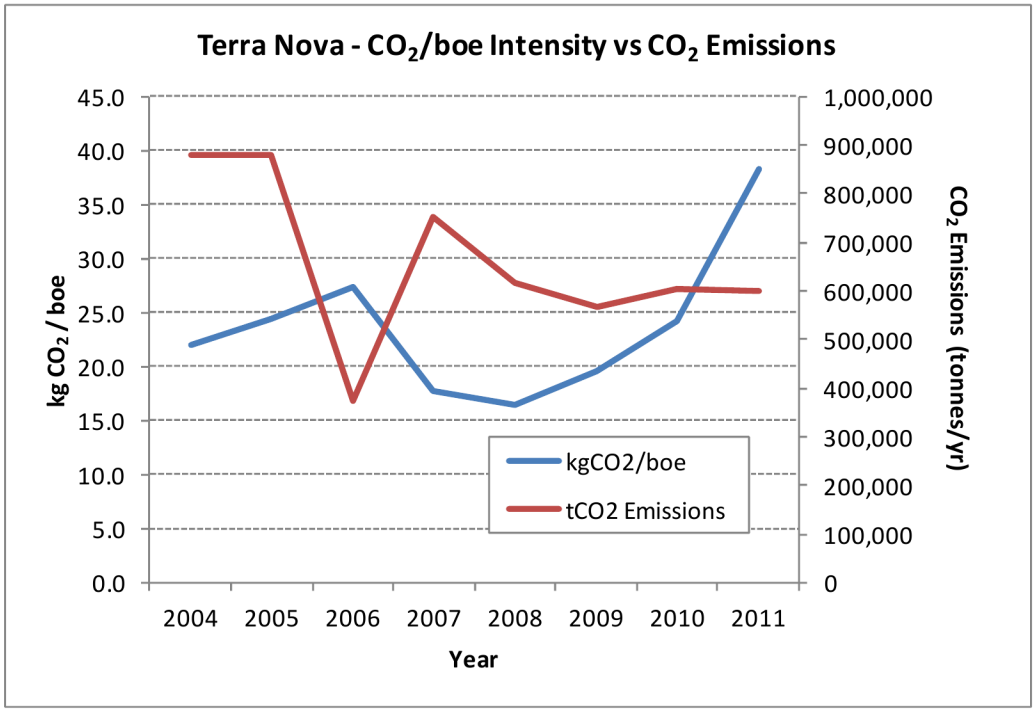


Figure A9.a: White Rose – trend of CO_2 emissions intensity vs. Oil Production

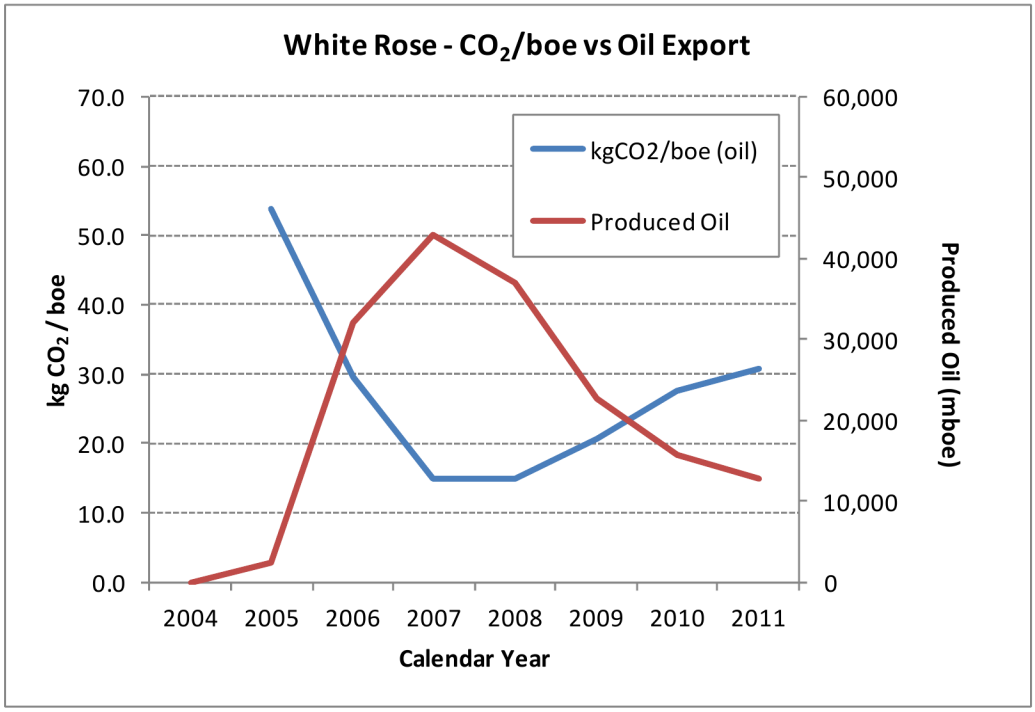


Figure A9.b: White Rose – trend of CO_2 emissions intensity vs. CO_2 emissions

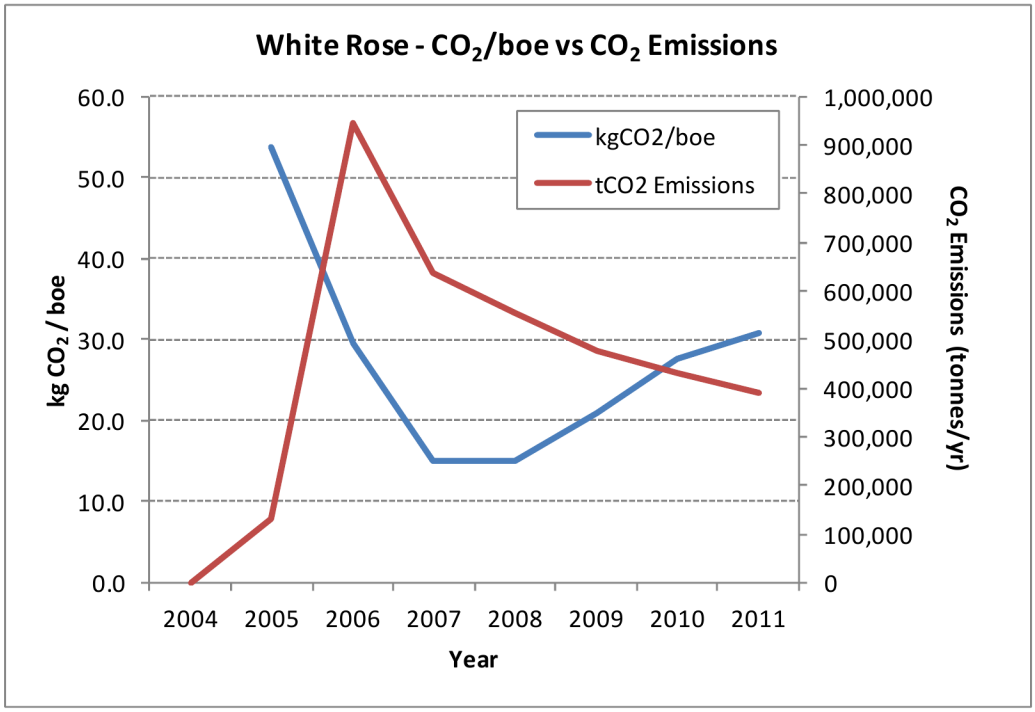


Figure A10a: NL Offshore Sector – trend of CO_2 emissions intensity

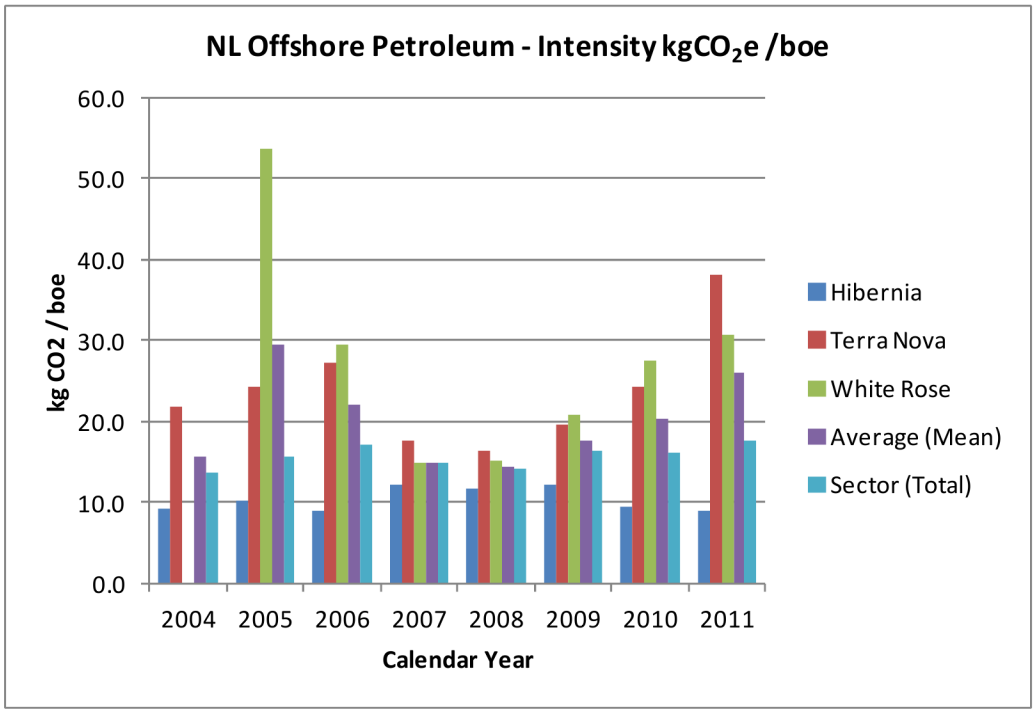
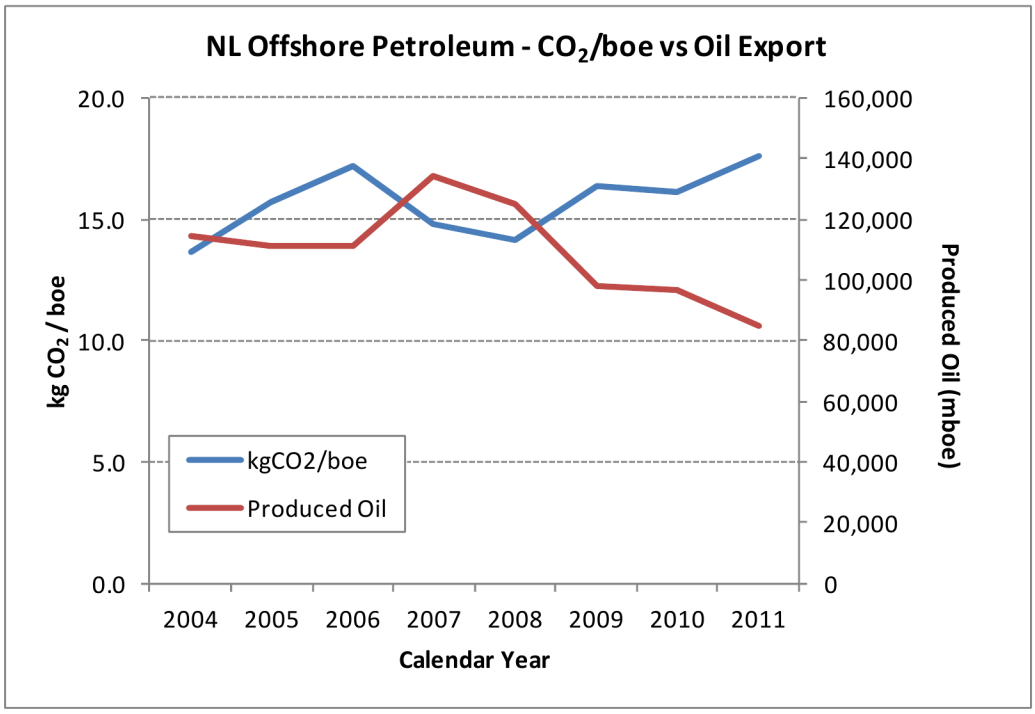


Figure A10.b: NL Offshore Sector – trend of CO_2 emissions intensity vs. Oil Production



A4. GHG INTENSITY BENCHMARKED AGAINST AMEC-PI DATABASE.

This section contains trends relating to GHG intensity from the NL Offshore petroleum sector, based on 2009 data for the NL sector, compared with the AMEC-PI database.

Figure A11.a and A11.b summarize the comparison of CO_2 emissions and CO_2 emissions intensity per unit of production for the two NL FPSO facilities (Terra Nova and Sea Rose) against the AMEC-PI energy assessment database for FPSO facilities. It can be observed that their intensity is slightly above average and higher than most North Sea FPSO facilities, and that this is primarily due to the higher proportion of emissions from flaring. Essentially, the NL intensity from emissions due to fuel consumption is on par with other FPSO assets in the AMEC-PI database. The intensity from emissions due to flaring is lower than typical West African FPSO (high flaring) but higher than typical North Sea FPSO (lower flaring).

The implication is that there should perhaps be more focus on (potential for) reduction in flaring for NL FPSO facilities than on fuel efficiency.

Figure A12.a and A12.b summarize the comparison of CO_2 emissions and CO_2 emissions intensity per unit of production for the two NL GBS facilities (Hibernia and Hebron) against the AMEC-PI energy assessment database for fixed oil platform facilities. It can be observed that the Hibernia and Hebron facilities are comparatively large; they are large producers of both oil and GHG emissions. Overall, however, based on kgCO2e/boe intensity factor they are well below the average of the North Sea oil production installations on the AMEC-PI database. This is a reflection of several factors. Firstly, both NL platforms are less mature than the North Sea database, and secondly, they are probably already implementing a fair number of best practices / BAT technologies. For Hibernia, the fact that it has reduced flaring by over [redacted] since 2005 has reduced its GHG intensity, against a background of only slightly declining oil production.

Because emissions intensity varies with age (years since first production) and oil field decline, it is useful to also compare NL sector with AMEC-PI database in this regard. It is also worthwhile considering if there is any relationship with oil API gravity. These comparisons are shown in Figure 13.a and 13.b for the FPSO facilities and in Figure 14.a and 14.b for the GBS facilities.

For the FPSO facilities there does not appear to be any strong correlation – mainly since FPSO production tends to peak very quickly in 1-3 years after commissioning.

For the fixed platform facilities there is good evidence of some correlation with the number of years in production, since oil platform production tends to decline more gradually over 10 – 30 years. However, there is apparently little evidence of any correlation with API gravity. This is to be expected because the energy intense processes are gas and water injection not for oil separation but for reservoir pressure maintenance.









GHG Intensity Benchmarking vs. years in production - FPSO Database
(NB. Terra Nova & White Rose are based on 2009 data)

Figure A13.a: NL Offshore FPSO – CO_2 emissions vs. years in production

(A comparison with AMC-PI FPSO database)

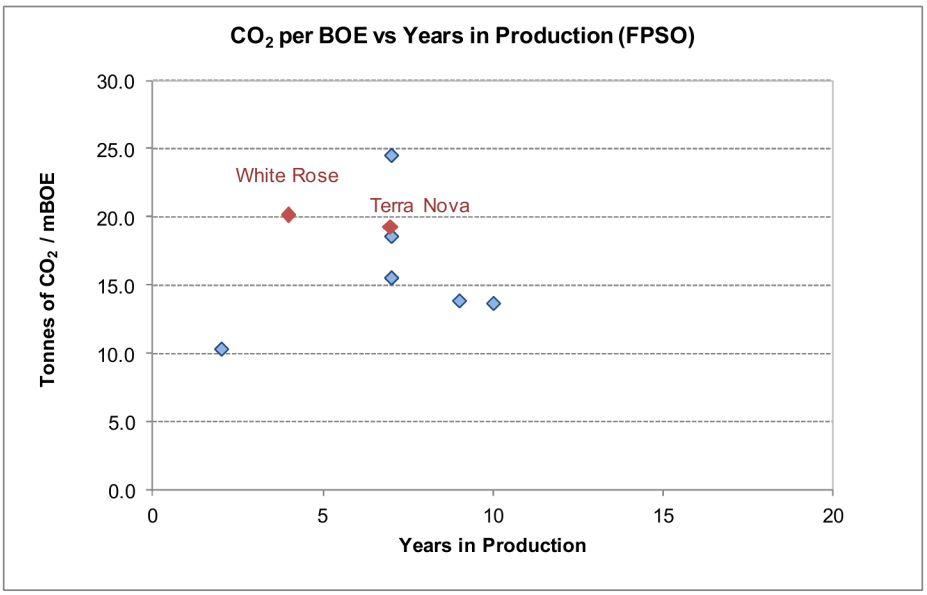


Figure A13.a: NL Offshore FPSO – CO_2 emissions vs. API gravity

(A comparison with AMC-PI FPSO database)

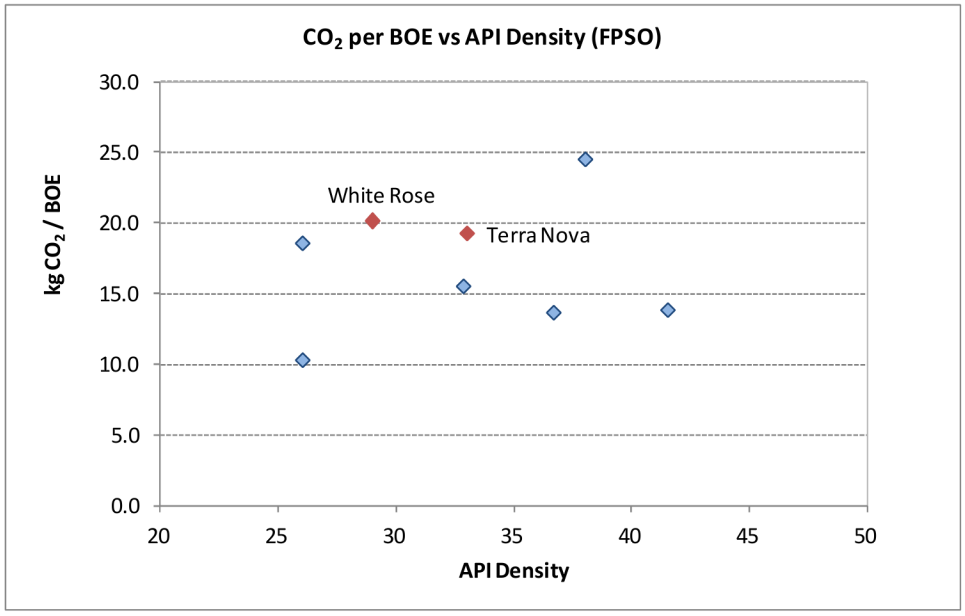


Figure A14.a: NL Offshore GBS Platforms – CO_2 emissions vs. years in production

(A comparison with AMC-PI fixed offshore oil platform database)

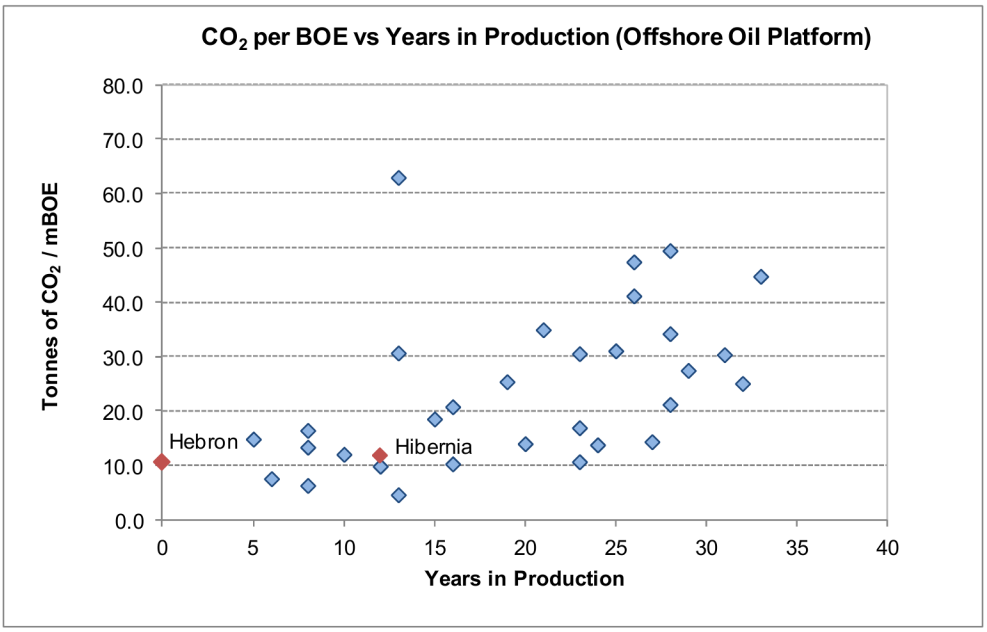
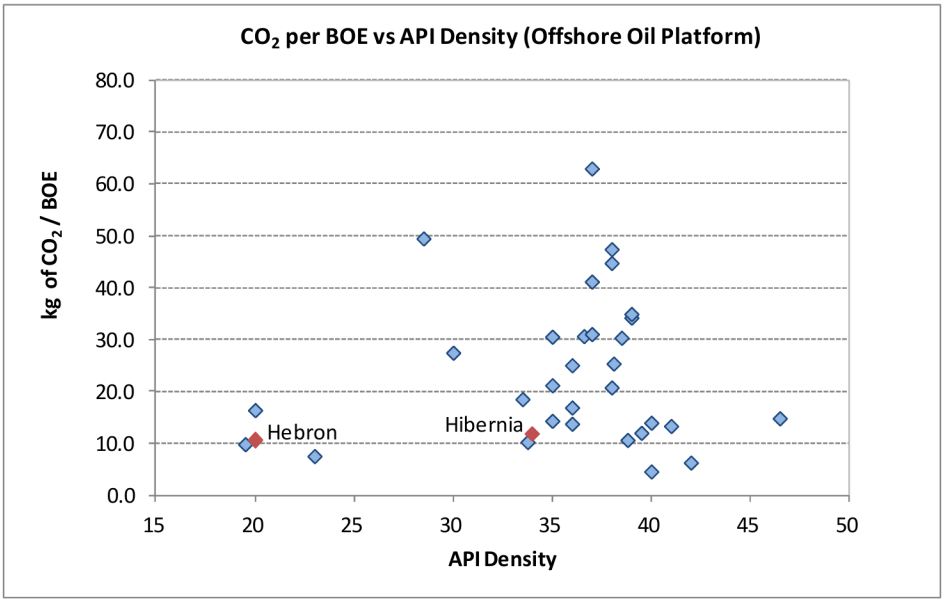


Figure A14.b: NL Offshore GBS Platforms – CO_2 emissions vs. API gravity

(A comparison with AMC-PI fixed offshore oil platform database)



A5. PRODUCTION AND GHG INTENSITY – USING CCEEET FORECAST DATA

This section contains trends relating to forecast production and GHG emissions intensity from the NL Offshore petroleum sector, based on data from CCEEET in Feb 2012. This essentially reflects declining oil production against the backdrop of BAU static emissions at 2010 levels.





Note: Above 2012 analysis does not incorporate the 2013 release of reserves re-estimate for Terra Nova.



Note: Above analysis does not incorporate the 2013 release of reserves re-estimate for White Rose in connection with the White Rose Extension Project and the potential new Wellhead Platform

.



APPENDIX B

TECHNOLOGY OPTIONS & EVALUATION

(Contained in separate document)

GOVERNMENT OF NEWFOUNDLAND AND LABRADOR
Office of Climate Change, Energy Efficiency, and Emissions Trading
(GNL - CCEEET)

OFFSHORE OIL & GAS – NEWFOUNDLAND AND LABRADOR
GHG REDUCTION OPPORTUNITIES & COMPETITIVE IMPLICATIONS

FINAL REPORT
(Deliverable 4)

APPENDIX B

GHG ABATEMENT OPPORTUNITIES
BEST PRACTISE MEASURES & BEST AVAILABLE TECHNOLOGIES

TC121804

LIST OF TABLES

Table B1: General Energy Efficiency Programmes and Best Practices 2
Table B2: NL Offshore Petroleum Sector – Stationary Combustion Plant 3
Table B3: Stationary Combustion Plant and Best Practices 3
Table B4: Stationary Combustion Plant – Best Available Technologies 4
Table B5: Categories of Safety Flaring 5
Table B6: Best Practices for Category 1 Flare Management 5
Table B7: Best Practices for Category 2 & Category 3 Flare Management 6
Table B8: Generic Alternative Strategic / Infrastructure Options to Flaring 7
Table B9: Flare Recovery Systems 7
Table B10: Gas Compression Systems – Best Practice Measures 8
Table B11: Gas Compression Plant – Technologies 8
Table B12: Water Injection Systems – Best Practice Measures 9
Table B13: Water Injection Systems - Technologies 9
Table B14: Oil Separation / Offloading Systems 9
Table B15: Emerging Technologies – for long term consideration 10
Table B16: Hebron Project relevant technology (Source Hebron CSR consultation 2010) 10

LIST OF FIGURES

Figure B1: Atlantic Canada – Gas Turbines (medium-large size) in operation 2
Figure B2: Gas Turbine OEM Upgrade paths – example of GE LM2500 (source GE GER4250) 4
Figure B3: Example of outcome to Flare Management Best Practices 6

This Appendix provides a summary of best practices and best available technologies of relevance to the offshore petroleum sector, and to the NL Offshore facilities.

These tables were provided to facility representatives in April 2012 as 'proformas' for them to review and comment on. They were presented at a workshop in St Johns in June 2012 at which relevant stakeholders attended. At the time of this final report only very limited response had been received from the facilities.

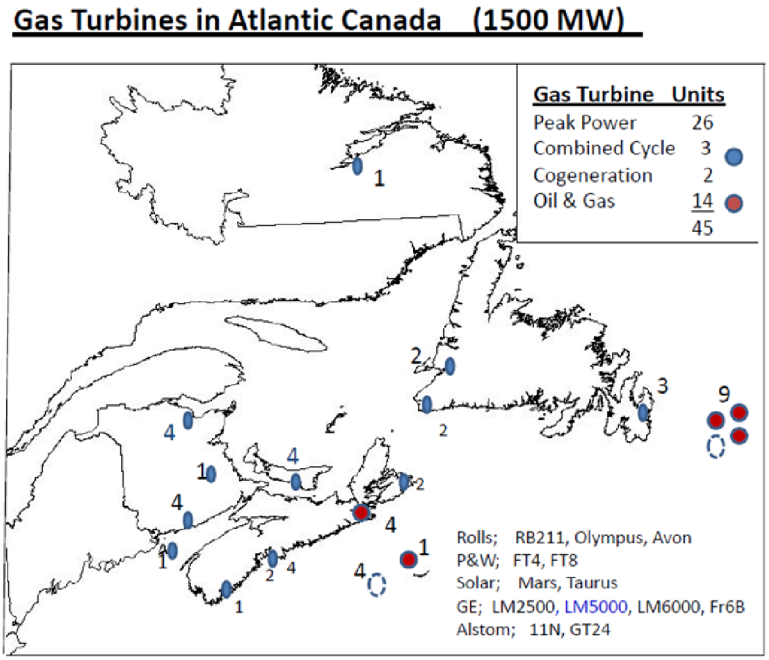
The Appendix contains potential abatement opportunities in the following areas:

i) General Efficiency Programmes
ii) Stationary Combustion Plant - Best Practices
iii) Stationary Combustion Plant - Technologies
iv) Flare Management - Best Practices
v) Flare Management - Technologies and Strategic Options
vi) Gas Compression Systems - Best Practices
vii) Gas Compressor Systems – Technologies
viii) Water Injection Systems - Best Practices
ix) Water Injection Systems – Technologies
x) Oil Separation & Offloading Systems
xi) Emerging Technologies for future consideration
xii) An overview of relevant technologies on the Hebron project

Table B1: General Energy Efficiency Programmes and Best Practices

ID	Best Practices – energy efficiency programs & systems	Relevance
i)	Commission independent Energy Assessments of existing operations to establish energy baselines, and review / repeat the process periodically to assess improvements	Yes
ii)	Include energy considerations in Operations procedures and Maintenance schedules, giving a value to CO_2 reduction	Yes
iii)	Implement energy tracking software and generate and track Energy Key Performance Indices (KPI).	Yes
iv)	Implement an Energy Management Plan and benchmark energy management against industry.	Yes
v)	For new installations conduct life of field options-appraisal of main energy users including power generation & driven loads	Yes
vi)	Conduct BAT Assessment and design-in BAT technologies	Yes

Figure B1: Atlantic Canada – Gas Turbines (medium-large size) in operation



Source: IAGT conference, Ottawa, Fall 2010

Table B2: NL Offshore Petroleum Sector – Stationary Combustion Plant

Facility	Duty	Equipment	Type / Model
Hibernia	Main Power Generation	Aero-derivative GT	2 x GE LM2500
	Mechanical Drive (GC)	Aero-derivative GT	2 x GE LM2500
Terra Nova	Main Power Generation	Heavy Frame GT	2 x GE Frame 6B
	Essential Power Generation	Diesel Engines	2 x CI engines
Sea Rose	Main Power Generation	Aero-derivative GT	3 x R-R RB211
	Essential Power Generation	Diesel Engines	2 x Wartsila
Hebron	Main Power Generation	Aero-derivative GT	Subject to design
	Mechanical Drive (GC)	Aero-derivative GT	Subject to design
All (x 4)	Process Heating Duty	Boilers	various

Table B3: Stationary Combustion Plant and Best Practices

ID	Best Practices – energy efficiency within O&M procedures	Relevance
i)	Optimize gas turbine spinning reserve / no. units operating	Yes
ii)	Improve fuel change-over (gas-diesel-gas) reliability	Yes
iii)	Fit high efficiency air intake filtration systems	Yes
iv)	Optimize inlet filter cleaning to enhance thermal efficiency	Yes
v)	Conduct on-condition gas turbine axial compressor cleaning	Yes
vi)	Optimize gas turbine anti-icing system operation	Yes
vii)	Carry out proactive online performance monitoring	Yes
viii)	Lag turbine exhausts if close to air intakes	Yes
ix)	Improve insulation on heating medium systems	Yes
x)	Maximise use of natural gas fuel in place of diesel	Yes
xi)	Install Individual fuel metering to main items of plant	Yes

Table B4: Stationary Combustion Plant – Best Available Technologies

ID	Technologies – energy efficiency within Plant design BAT	Relevance
i)	Use of efficient aero-derivative gas turbines - Simple cycle efficiency 35% - 40% compared with [redacted] - Will lead to [redacted] fuel savings compared to heavy frame	Yes
ii)	Install / retrofit Waste Heat Recovery Units (WHRU) - Use waste heat within process systems (e.g. hot oil heating) - Can typically replace [redacted] of fuel demand on an oil facility	Yes
iii)	Upgrade gas turbines to OEM high efficiency specifications - OEM upgrade packs can improve efficiency and rated output - Typical gains in the region of [redacted] efficiency improvement	Yes

Figure B2: Gas Turbine OEM Upgrade paths – example of GE LM2500 (source GE GER4250)



Figure 3. LM2500+G4 Gas Turbine Heritage

Table B5: Categories of Safety Flaring

Category 1 - Base Load Flare, also commonly referred to as 'Background flaring'. Small amounts of fuel gas that are continuously used for the flare pilot and for purging the flare header system to prevent ingress of air.

Category 2 - Flaring from operational or mode changes e.g.additional gas flaring due to controlled activities such as the start-up and planned shut-down of equipment during normal production.

Category 3 – Flaring from emergency shutdown / process trip, including unplanned shutdown of plant (e.g. gas compressor trips) or significant production well upsets

Table B6: Best Practices for Category 1 Flare Management

ID	Best Practices – minimize flaring within O&M procedures	Relevance
i)	Optimize flare pilot and flare purge settings on existing controls	
ii)	Replace manual purge control systems with automatic controls	
iii)	Use efficient flare tip design and optimum burner nozzles	
iv)	Repair faulty purge valves / instrumentation	
v)	Conduct periodic valve leakage surveys (e.g. Ultrasonic survey) to identify valves requiring maintenance during plant outages	

Table B7: Best Practices for Category 2 & Category 3 Flare Management

ID	Best Practices – minimize flaring within O&M procedures	Relevance
i)	Change operating procedures to minimize the frequency and/or the duration of operational mode changes	Yes
ii)	Improve compression plant reliability / uptime	Yes
iii)	Improve stable operation and control of fluid separation and gas processing equipment including controller tuning	Yes
iv)	Implement flare management procedures to turndown production activities during Cat. 2 changes / Cat. 3 upsets.	Yes

Figure B3: Example of outcome to Flare Management Best Practices



Table B8: Generic Alternative Strategic / Infrastructure Options to Flaring

ID	Alternative Options to Flaring in Upstream offshore Oil & Gas	Relevance
i)	Natural gas utilisation as fuel for on-site energy requirements	Yes
ii)	Export of gas short distances for use as fuel on nearby facility	Potential
iii)	Export of natural gas onshore to the wider energy market	Potential
iii)	Re-injection for pressure maintenance or conservation	Yes
iv)	Enhanced oil recovery using gas lift of production wells	Yes

Table B9: Flare Recovery Systems

ID	Technologies for flare reduction
i)	Flare Recovery Systems Have been operational offshore Norway since 1994, and have since been field proven and rolled out to many more installations in Norway and UK North Sea, and also to FPSO facilities. The technology consists of flare header isolation equipment, a gas recovery compression / ejector system, and a reliable flare ignition system. The flare recovery system is designed and sized to meet the normal background flaring volumes of the installation. The recovered gas can be re-injected or used as fuel gas or where viable exported. The system does away with a continuous flare purge and pilot, but maintains an emergency route to flare to ensure safe release during upsets.

Table B10: Gas Compression Systems – Best Practice Measures

ID	Best Practices – energy efficiency within O&M procedures	Relevance
i)	Optimise compressor anti-surge settings to minimise recycle	Yes
ii)	Ensure process controllers are in auto-mode not manual	Yes
iii)	Ensure adequate tuning of process control loops	Yes
iv)	Install online local & remote performance monitoring system	Yes
v)	Optimise gas lift / gas injection header pressures	Yes
vi)	Optimise compressor inter/after cooler operation	Yes
vii)	Install wash system for gas compressors to prevent fouling	Yes
viii)	Optimise compressor operations to minimise fuel & flaring	Yes

Table B11: Gas Compression Plant – Technologies

ID	Technologies – energy efficiency within Plant design BAT	Relevance
i)	Use of latest high efficiency gas compressor designs - Compressor Polytropic efficiency of >75% across wide range - Reduce electrical load and/or fuel consumption in GT drives	Yes
ii)	Re-wheel / re-configure compressor systems at key stages - Match compressor envelope with changing production duty - Thereby reduce energy use from fuel gas over life of field	Yes
iii)	Replace LP compressors with Educter/Ejector technology - Can be an effective strategy as LP compressor duty decreases - Will lead to savings in electricity and fuel gas consumption	Towards end of field life

Table B12: Water Injection Systems – Best Practice Measures

ID	Best Practices – energy efficiency within O&M procedures	Relevance
i)	Optimise number of Sea Water Lift Pumps (SWLP) operating	Yes
ii)	Optimise number of Water Injection Pumps (WIP) operating	Yes
iii)	Optimise Injection Header pressure levels vs. injection wells	Yes
iv)	Integrate condition monitoring with pump maintenance	Yes

Table B13: Water Injection Systems - Technologies

ID	Technologies – energy efficiency within Plant design BAT	Relevance
i)	Install Variable Speed Drive (VSD) Motors to main pumps	Yes
ii)	Replace WIP / SWLP cartridges with high efficiency models	Yes
iii)	Re-configure water injection system over life of field duties	Yes

Table B14: Oil Separation / Offloading Systems

ID	Oil Separation / Offloading - Best Practice & Technology BAT	Relevance
i)	Optimise and tune separator level controls	Yes
ii)	Reduce or eliminate venting from surge vessels & cargo tanks	Yes
iii)	Install closed loop inert gas system to (reduce fuel use)	Yes
iv)	Convert diesel inert gas generator systems to fuel gas	Yes
v)	Install / retrofit vapour recovery unit (VRU) technology	Yes

Table B15: Emerging Technologies – for long term consideration

ID	Emerging Technology	Relevance
i)	Offshore Floating LNG liquifaction and export - Currently under development by Shell offshore Australia - Has the potential to be considered for 'stranded gas' reserves	
ii)	Mini-scale LNG technology - New technology developed in Norway (Hamworthy / SINTEF) - Potential solution where volumes are < commercial LNG	
iii)	Small scale Gas-to-liquid (GTL) Technology	
iv)	Offshore combined cycle gas turbine (CCGT) technology	

Table B16: Hebron Project relevant technology (Source Hebron CSR consultation 2010)

ID	Best Practices – energy efficiency within new plant design
i)	Aeroderivative type gas turbines will be used for Power Gen.
ii)	Waste Heat Recovery (WHRU) will be installed on main GTs
iii)	Insulation will be applied to process piping to reduce losses
iv)	Cross-stream heat exchangers to be used on crude stab.n
v)	Mechanical Variable Speed Drive motors will be used on WIP
vi)	Flare system will be purged with Nitrogen preferentially
vii)	Leak detection to be used rigorously
viii)	Flange management system to be in place for fugitive leaks
ix)	Steady state flaring expected to be < existing facilities
x)	** Standard flare continuous pilot preferred – safety case
xi)	** Gas disposal via open flare with no recovery is preferred

APPENDIX C

REGULATORY REVIEW

(Contained in separate document)

GOVERNMENT OF NEWFOUNDLAND AND LABRADOR
Office of Climate Change, Energy Efficiency, and Emissions Trading
(GNL - CCEEET)

OFFSHORE OIL & GAS – NEWFOUNDLAND AND LABRADOR
GHG REDUCTION OPPORTUNITIES & COMPETITIVE IMPLICATIONS

FINAL REPORT
(Deliverable 4)

APPENDIX C

REGULATORY REVIEW OF EU-ETS

TC121804

TABLE OF CONTENTS

PAGE

1.0 EU-ETS 1

1.1 Overview of EU-ETS 1

1.1.1 Offshore Oil & Gas Industry Specifics 3
1.1.2 EU-ETS Successes & Failures 11
1.1.3 EU-ETS Impact on GHG Regulation in Europe 16

LIST OF TABLES

Table C1: EU ETS Activities 2
Table C2: EU ETS Benchmarks 5
Table C3: EU ETS Measurement Tiers 9
Table C4: Surplus of allocation over 2005 verified emissions by sector in five major European economies 12
Table C5: Overview of EU-ETS (Source OECD/IED 2010) 18

LIST OF FIGURES

Figure C1: Comparison of CO_2 Emissions and Production (toe) 7
Figure C2: Total and non-generation CO_2 per BOE produced by facility (2008) 8
Figure C3: EU Trading Allowances 2005-2008 13
Figure C4: EU-ETS Processes (Source OECD/IED 2010) 19

1.0 EU-ETS

This Appendix provides a regulatory review of the European Union Emissions Trading System (EU ETS). This is the principal system adopted throughout the EU member states to mitigate GHG emissions and is a 'cap and trade' system. Countries outside the EU have variations of the EU ETS e.g. Norway has a quota system in which no free allowances are given and all quotas must be purchased at a combined cost of a tax plus quota cost. In Canada there are Federal and Provincial initiatives. The various systems are discussed in the following sub-sections.

1.1 Overview of EU-ETS

The European Union Emissions Trading System (EU ETS) is the key policy instrument established by the EU Emissions Trading Directive 2003/87/EC (Ref 5) to achieve the European Community's response to climate change. It is the world's largest and by far the most well developed trading scheme currently operating in 30 countries (the 27 EU Member States plus Iceland, Liechtenstein, and Norway).

The scheme came into force in October 2003 with implementation in three phases:

Phase I from 2005-2007 was very much a trial phase laying the groundwork for the next phase.

Phase II running from 1 January 2008 to 31 December 2012. This phase coincides with the first Kyoto commitment period of five years during which the EU and its member states must comply with their emission targets.

Phase III will run for eight years from 1 January 2013 to 31 December 2020. This phase will have significant changes compared with the earlier phases.

Since EU ETS is a large-scale GHG trading programme and has been running for almost seven years, it offers an opportunity to critically assess its implementation and effectiveness to date. Key lessons will give an insight into the cost of emissions, impact on reduction of emissions, cost effectiveness, wider economic issues, new technologies and efficiency opportunities.

EU ETS applies to a range of activities specified in Annex I of the Directive as follows:

Table C1: EU ETS Activities

1. Combustion	
1.1 Activities of combustion installations with a rated thermal input exceeding 20 megawatts (excluding hazardous or municipal waste installations).	Carbon dioxide
1.2 Activities of mineral oil refineries.	Carbon dioxide
1.3 Activities of coke ovens.	Carbon dioxide
2. Production and processing of ferrous metals	
2.1 Activities of metal ore (including sulphide ore) roasting and sintering installations.	Carbon dioxide
2.2 Activities of installations for the production of pig iron or steel (primary or secondary fusion), including continuous casting, with a capacity of more than 2.5 tonnes per hour.	Carbon dioxide
3. Mineral Industries	
3.1 Activities of installations for the production of cement clinker in rotary kilns with a production capacity of more than 500 tonnes per day.	Carbon dioxide
3.2 Activities of installations for the production of lime in rotary kilns or other furnaces with a production capacity of more than 50 tonnes per day.	Carbon dioxide
3.3 Activities of installations for the manufacture of glass including glass fibre where the melting capacity of the plant is more than 20 tonnes per day.	Carbon dioxide
3.4 Activities of installations for the manufacture of ceramic products (including roofing tiles, bricks, refractory bricks, tiles, stoneware or porcelain) by firing in kilns where– (i) the kiln production capacity is more than 75 tonnes per day; and (ii) the kiln capacity is more than 4m^3 and the setting density is more than 300 kg/m^3.	Carbon dioxide
4. Other activities	
4.1 Activities of industrial plants for the production of pulp from timber or other fibrous materials.	Carbon dioxide
4.2 Activities of industrial plants for the production of paper and board with a production capacity of more than 20 tonnes per day.	Carbon dioxide

Greenhouse gases within the context of the Directive refer to:

- Carbon Dioxide (CO_2)
- Methane (CH_4)
- Nitrous Oxide (N_2O
- Hexafluorocarbons (HFCs)
- Perfluorocarbons (PFCs)
- Sulphur Hexafluoride (SF_6)

As noted above **Phase I** was very much a trial period so that the infrastructure could be put in place to gain experience. **Phase II** introduced a significant change for the offshore oil and gas industry in that CO_2 emissions attributed to flaring were included in the system. Phase II will close at 31 December 2012 and **Phase III** will run from 1 January 2013 to 31 December 2020

and introduce further significant changes to the system. For the offshore oil and gas industry ***the most important of these is that in Phase III no free allowances will be given for electricity generation. (Ref 6). This is discussed further below.***

1.1.1 Offshore Oil & Gas Industry Specifics

It is important to recognize that from the list of greenhouse gases above only CO_2 emissions from combustion activities and flaring on offshore installations are currently included in Phase II EU ETS and similarly for Phase III. The offshore oil and gas industry falls within "Energy" activities under the sub-activity 1.1 Table 7.1:

"Combustion installations with a rated thermal input exceeding 20 MW (except hazardous or municipal waste installations)."

The licensed operator of an installation where the aggregated thermal input of the combustion units is greater than 20 MW must apply to the Regulator for an Emissions Trading System (ETS) permit and it is a condition of the permit to submit a detailed plan setting out the proposed monitoring and reporting plans.

Guidance regarding the interpretation of an "installation," "stationary technical units" and "combustion" is given in a guidance note by the European Commission (EC) (Ref 7.7).

Calculation of CO_2 emissions are derived from fuel consumption, flaring rates and composition data.

For fuel gas and diesel the CO_2 emissions are calculated:

> **CO_2 emissions = fuel flow (tonne or Nm^3) * emissions factor (tonne CO_2/tonne or NM^3) * oxidation factor**

For flares the CO_2 emissions are calculated:

> **CO_2 emissions = flared gas (tonne or Nm^3) * emissions factor ((tonne CO_2/tonne (or Nm^3)* oxidation factor**

Fuel consumption and flaring are measured using meters with a specified uncertainty. The CO_2 emission factors (tonne CO_2/tonne or Nm^3 fuel) is obtained from compositional data.

Each offshore installation is given an annual allocation of free allowances (one allowance equals 1 tonne of CO_2) and aannual (calendar year) independently verified reports of CO_2 emissions must be submitted by 31 March each year to the Regulator. SSufficient allowances must be surrendered to meet the emissions at the end of each year. Installations can emit more than their annual free allowances but must buy allowances from the market to cover the excess above their free allowances. If they have surplus allowances i.e. emit less than their free allowances they can sell these on the market or bank them.

The scope of EU ETS for offshore oil and gas changed from Phase I to Phase II in that flaring was included in Phase II and will also be included in Phase III. Additional free allowances are given for flaring. Phase III introduces a significant change for the offshore sector in that no free allowances will be given for emissions from electricity generation. In Phases I and II allowances were given for fuel use regardless of whether or not it was for electricity generation. This means that there will be no free allowances for gas turbines or diesel generators which are used to produce electrical power. Combustion units that are used to produce mechanical energy e.g. a gas turbine directly driving a compressor will be given allowances. Consequently for Phase III operators will have to purchase credits to cover the CO_2 emissions derived from electricity generation. Therefore operators will incur a significant increase in operating costs.

In Phases I and II the number of allowances was decided by each member state but in Phase III the EU will decide the allocation based on harmonised rules across the EU and using benchmarks. In the context of EU ETS a benchmark is a threshold for the level of free allowances for an installation. Free allowances were given for Phases I and II on the principle of "grandfathering" and benchmarking was largely only used in the offshore sector for new entrants. With the advent of Phase III a harmonized approach will be taken for the allocation of allowances and benchmarking is the norm for existing installations and new entrants.

The EU ETS Directive 2009/29/EU states:

> **Article 10a (1)7:**
> ***For each sector and sub-sector, in principle, the benchmark shall be calculated for products rather than for inputs, in order to maximise greenhouse gas emissions reductions and energy efficiency savings throughout each production process of the sector or the sub-sector concerned.***
>
> **Article 10a (2):**
> ***In defining the principles for setting ex-ante benchmarks in individual sectors or sub-sectors, the starting point shall be the average performance of the 10% most efficient installations in a sector or sub-sector in the Community in the years 2007 – 2008.***

Note that "installations" in the context of Article 10a (2) refers to installations in all sectors including offshore.

Four allocation methodologies have been developed in order to calculate free allowances. A hierarchical approach has been adopted and each installation must adopt the strict order below to calculate free allowances. Table 7.2 shows the methodology and conditions under which each is applied.

Table C2: EU ETS Benchmarks

	Methodology	Value	Conditions	Emissions
1	Product benchmark	Depends on product	Product benchmark available	Emissions within system boundaries of product as referred to in Annex I of the Community Implementation Measures (CIMs)
2	Heat benchmark	62.3 tonnes CO_2/TJ	- No product benchmark Available - Heat is measurable	Emissions relating to production of the consumed measurable heat, not covered by a product benchmark
3	Fuel benchmark	56.1 tonnes CO_2/TJ	- No product benchmark available - Heat is not measurable - Fuel is combusted	Emissions originating from the combustion of fuels, not covered by product or heat production benchmark.
4	Process emission approach	97% of historical emissions tonnes CO_2	- No product benchmark available - Heat is not measurable - Emissions are not resulting from combustion of fuel - Emissions are “process emissions”	All emissions within installation not covered by previous approaches, but not including non-eligible emissions.

A product benchmark is defined as the average of the 10% most greenhouse gas efficient installations, in terms of metric tonnes of CO_2 emitted per tonne of product produced at European level in the years 2007-2008. Each of the above benchmarks are referred to as sub-installations where a sub-installation means all inputs, outputs and corresponding emissions related to a specific allocation regime. One or a number of these sub-installation benchmarks can be applied to an installation to determine the free allowances but it must be done in the order 1 through 4 above.

However, energy intensity benchmarks related to product are not feasible in all cases and this has been clearly demonstrated for the offshore oil and gas sector. An exercise was undertaken to collect benchmarking data for the offshore oil and gas industry (Ref 7.10) but it was soon realized that product benchmarking could not easily be applied to offshore. Various factors contribute to the difficulties faced when trying to set a benchmark for offshore including:

a) Decreasing production;
b) Increasing emissions intensity;
c) Characteristics of reservoirs; and
d) Transportation to the market place.

As fields become more mature and production falls, relatively more energy is required to maintain production due to higher rates of re-injection for oil production and reducing pressure in gas reservoirs. Another important factor for offshore production is power supply. Due to their location offshore installations are generally designed to be self sufficient in power supply to drive all of the process facilities. Gas turbines are the main source of electrical power generation and there are a wide variety of turbine types with a range of output and efficiencies. The preferred fuel for these turbines is gas but many are dual fuelled and can run on diesel.

Where natural gas pipelines do not exist, as is the case in Newfoundland and Labrador, substantial amounts of gas are re-injected or flared. Thus fuel derived from the production process is “wasted” rather than being a useful product and a source of revenue.

All of the above make it difficult to rationalize an applicable benchmark related to unit output.

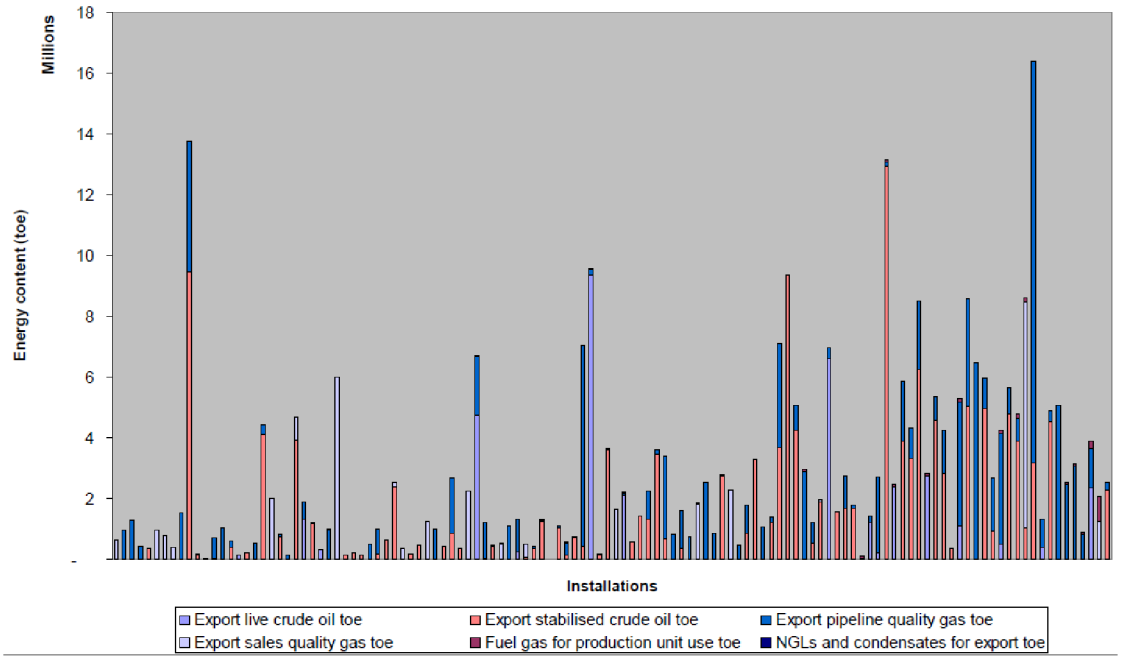
The upstream oil and gas production process can be sub-divided into a number of sub-processes and unit operations producing a number of products including:

- Live crude oil;
- Stabilised crude oil;
- Gas for export;
- Sales quality gas;
- Produced water; and
- Non-gaseous liquids.

It would only be possible to derive a product benchmark if the energy input to each of the sub-processes or unit operations could be measured with some degree of accuracy with a strong correlation to CO_2 emissions.

Figure 7.2 shows the output from an Entec study undertaken for the Department of Energy and Climate Change (DECC). Installations are ranked in order of increasing CO_2 emissions. It can be seen that there is no apparent relationship between emissions and the energy content of different products and by-products, or the ratios between these products.

Figure C1: Comparison of CO_2 Emissions and Production (toe)



Source: Entec February 2010

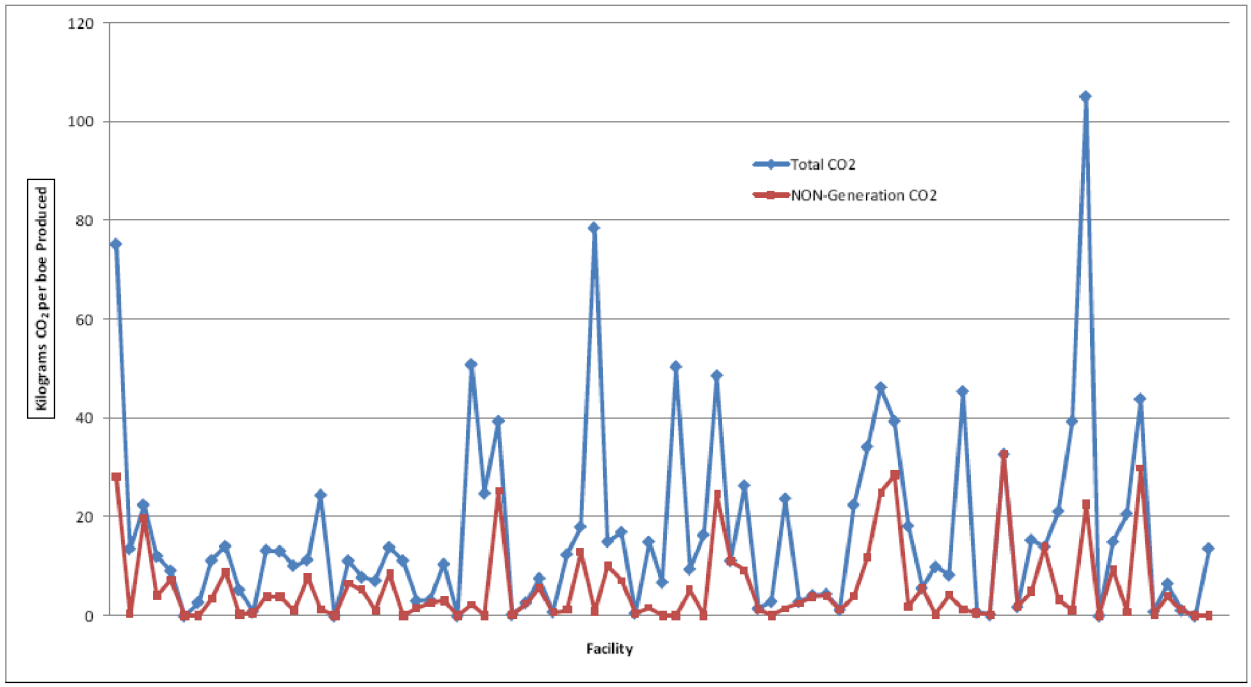
toe = tonnes oil equivalent

toe x 41.868 = GJ

Installations are ranked in order of increasing CO_2 emissions. It can be seen that there is no apparent relationship between emissions and the energy content of different products and by-products, or the ratios between these products.

A study undertaken by Genesis concluded that a production benchmark based on total material flows which included hydrocarbons and produced water as boe was not feasible. This is shown in the wide spread of results and poor correlation between mass of product and CO_2 emitted.

Figure C2: Total and non-generation CO_2 per BOE produced by facility (2008)



Source: Genesis (2009)

In determining the rules for harmonized free allocation of emissions for Phase III the EC decided that in cases where it was not possible to elaborate a product benchmark (as is the case for the offshore sector) a fall back approach using a heat, fuel or process benchmark is applied (Ref 7.11). This approach was taken by the offshore oil and gas industry in applying for the Phase III allocation and the heat and fuel benchmarks were applied.

The EU produced a series of guidance documents for collecting the relevant information and data that would be required to determine the free allowances. Operators were given the option of submitting data for the periods 2005-8 or 2009-10 whichever was the most advantageous.

Heat benchmarking is much less significant in the offshore industry compared to fuel mix benchmarking as it generally only applies to waste heat recovery units. Nevertheless operators made every effort to claim as many allowances as possible and submitted data for the heat benchmark where appicable. Since no free allowances will be given for electricity generation in Phase III the fuel mix benchmark only applies to direct driven combustion equipment e.g. a gas turbine directly driving a compressor.

In order to determine the Phase III allocation for the offshore sector fuel consumption data (excluding fuel used for electricity generation) was collected in the standardized form of TJ and

this was converted to tonnes of CO_2 using the standard benchmark of 56.1 tonnesCO_2/TJ of fuel or flare. It should be noted that the 56.1 tonnes CO_2 /TJ is not a benchmark in the sense that operators must achieve this figure. This CO_2 emissions factor is for natural gas and was used as a standard factor by all operators applying for allowances. This would be impossible given the variation of fuel gasquality from different fields. It has been used as a standard by all operators to set the level of allowances that they will receive This was necessary to account for the variation in fuel gas quality across installations. Allocating fuel consumption between electricity generation and direct driven equipment was not straightforward as the level of metering on many installations was not per individual piece of combustion equipment. A single meter may be used to measure the fuel gas consumption to a number of gas turbines, some of which are dedicated to electricity generation and some as direct drivers. In such cases the metered fuel had to be split across the consumers. Generally this was done using running hours and MW output for the combustion equipment

Similarly the data for flared gas was collected as TJ and the same benchmark standard of 56.1 tonnes CO_2/TJ flared gas was applied.

All data supplied to the regulatory body had to be externally verified. Benchmarking is complex and requires significant data to ensure transparency for the final allocation of allowances.

.As noted above CO_2 emissions from the offshore industry arise from combustion emissions associated with fuel consumption and flaring and are calculated as follows:

CO_2 emissions = fuel (flare) flow (tonnes or Nm^3) * emissions factor (tonnes CO_2/ tonne (or Nm^3) * oxidation factor

Each of the variables in the above equation can be measured with varying degrees of accuracy and the Monitoring and Reporting Guidance (MRG) specifies the levels of accuracy expressed in tiers from Tier 1 through Tier 4 with 4 being the highest.

Table C3: EU ETS Measurement Tiers

Activity / source stream type	Parameter to which the uncertainty is applied	Tier 1	Tier 2	Tier 3	Tier 4
Combustion of fuels and fuels used as process input					
Commercial standard fuels	Amount of fuel [tonne] or [Nm3]	± 7.5 %	± 5 %	± 2.5 %	± 1.5 %
Other gaseous and liquid fuels	Amount of fuel [tonne] or [Nm3]	± 7.5 %	± 5 %	± 2.5 %	± 1.5 %
Flaring	Amount of flare gas [tonne] or [Nm3]	± 17.5 %	± 12.5 %	± 7.5 %	

Fuel and flare gas flow can be effectively measured with various meters with related levels of uncertainty that define which tier is achieved. Representative analyses of the fuel for the reporting period provides the CO_2 emission factor applied to the total fuel consumed by all of the

relevant sources identified in the ETS Permit issued for the installation. The oxidation factor is defined in the MRG.

The same calculation applies to flaring and includes routine flaring and operational flaring (trips, start-up and shutdown as well as emergency relieves). In many cases the CO_2 emissions factor for flaring is the same as that used for fuel gas but it may also be obtained from modelling studies for the flare gas composition.

Operators are also required to submit an improvement plan annually to drive continuous improvement in reporting.

The allocation of free allowances for Phase III to each offshore installation will be determined by the EC using the data submitted by the operators.

Auctioning

From 2013 the basic method for allocating allowances will be auctioning and any sector not given free allowances will have to buy their credits under auctioning (Ref 7.14). The electricity sector will not be given free allowances and will have to purchase all of their credits. There will be a gradual transition towards full auctioning for other sectors and those sectors that are not subject to carbon leakage will have to purchase 20% of their allowances in 2013 rising to 70% in 2020 and 100% in 2027.

Carbon Leakage

Carbon leakage refers to production and/or investment relocating, as a result of EU ETS-related carbon costs, to countries without similar carbon constraints. This would undermine the environmental integrity of the system and lead to an overall increase in global emissions. Sectors at significant risk of carbon leakage will receive 100% of free allowances while those not at significant risk will receive 80% in 2013 declining to 30% in 2020 and 0% in 2027.

The offshore oil and gas sector will receive 100% of allowances for 2013 and 2014. Note that this excludes allowances for electricity generation. The EU Commission will review the carbon leakage sectors in 2014 which may result in some changes from 2015 onwards. The list of sectors currently subject to risk of carbon leakage is published in Commission Decision of 24 December 2009 determining, pursuant to Directive 2003/87/EC of the European Parliament and of the Council, a list of sectors and subsectors which are deemed to be exposed to a significant risk of carbon leakage.

1.1.2 EU-ETS Successes & Failures

Establishing a Market

The EC adopted a Communication on climate change in May 1999 that highlighted the need for a "sustained policy response" and this was followed by a Green Paper on greenhouse gas emission trading within the EU in March 2000 (Ref 7.17). This laid out the principles and design of a cap and trade system for which there was no experience in Europe. Introducing such a system across sovereign states was a challenge and not without its problems.

The Phase I trial period laid the groundwork for the regulatory framework and the supporting infrastructure regarding monitoring and reporting, registries and compliance. This is now well established and a market for carbon trading has been developed. Reaching this goal took time and was not without its difficulties and lessons have been learned.

Allowance Allocation

Phase I allocations were allocated free based on "grandfathering" i.e historical emissions. Quality baseline historical data were not available on actual emissions for each installation prior to the start of the system and Member States developed their allowances on business as usual baselines and estimated growth projections. This was not entirely satisfactory as projection models in existence at that time did not adequately capture data for the trading sectors within ETS (Ref 18). The result of this was over allocation shown in the examples Table 7.4 below which had an impact on the price of carbon.

Table C4: Surplus of allocation over 2005 verified emissions by sector in five major European economies

Sector	Country					Unweighted average
	UK	Netherlands	France	Germany	Austria	
Glass	11.4%	1.1%	11.3%	19.0%	0.1%	8.6%
Paper & Pulp	34.3%	10.5%	45.3%	37.1%	5.0%	26.4%
Cement & Lime	13.5%	n/a	0.7%	15.7%	4.3%	6.9%
Ceramic	23.5%	n/a	16.8%	40.7%	4.7%	17.2%
Refineries	7.6%	12.6%	12.8%	-0.4%	-3.6%	5.8%
Iron & Steel	6.1%	60.3%	7.5%	13.8%	3.7%	18.3%
Small combustion	10.8%	17.4%	29.0%	11.0%	15.7%	16.8%
Power stations	-22.5%	-5.3%	8.7%	-0.3%	-17.7%	-7.4%
TOTAL	-13.2%	7.6%	14.6%	4.4%	-2.9%	

Source: Derived from analysis carried out for the Carbon Trust by Entec, June 2006 (based on disclosure as of 19th May).

As allocation was decentralized there was no guarantee that installations operating in the same markets in different member states would receive the same allocation of allowances. This led to a perception of unfairness and competitive advantage. Allocations in Phase III will be determined centrally by the EC thus removing these factors under harmonized rules.

It was not known how restrictive the cap on allowances would be for Phase I and this uncertainty pushed up prices until the first report of verified emissions was available in April 2006. Prices rose from around €10 per tonne to €30 (C$13-39) in the first few months after the introduction of the scheme and remained between €20 - €30. per tonne (C$26-39) until the spring of 2006 when it fell.

Figure C3: EU Trading Allowances 2005-2008

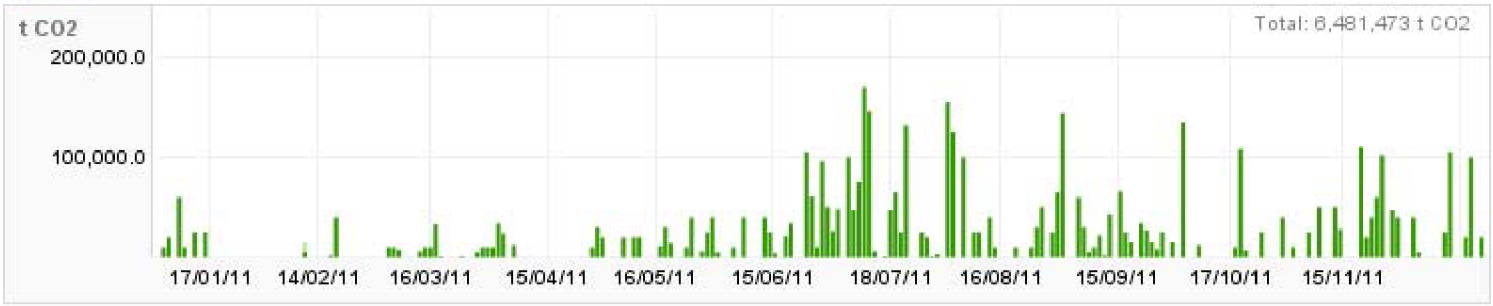


Source : CARBIX, http://www.eex.com
€/tCO_2 is euros/tonne CO_2

Price



Volume



Source : CARBIX, http://www.eex.com

Actual verified emissions were far less than the allowances and this contributed to the price fall as allowances were plentiful. This reinforces the need to set the cap tightly enough so that there is a demand for allowances and the price is established. This is an important lesson for any government body seeking to establish a greenhouse gas trading system and good emissions data at installation level is a pre-requisite.

Even though the Directive allowed for benchmarking as a means for setting allowances it was not widely used and "grandfathering" was the norm. This was particularly so in the offshore industry where benchmarking presents some difficulties as noted above. Allocation for similar industries across MS was not equally applied and producers in one member state complained if a producer in another member state received a more generous allowance. This led to calls for harmonization to remove competitive distortion.

The allocation process for Phase III relies on benchmarking and a central allocation of allowances by the EC.

The current economic recession may lead to a prolonged reduction in emissions such that there will be surplus allocations from Phase II which can be carried forward to Phase III and dilute the impact of Phase III. (Ref 7.19)

Abatement

No cap and trade system can guarantee a reduction in emissions by a set amount and it is difficult to be certain how much abatement is achieved within a particular sector. Nevertheless there is reasonable consensus that EU ETS produced modest abatement in the first phase. The CO_2 price was high during the first half of Phase I and businesses began to incorporate the cost of carbon into their investment decisions and to seek energy improvements. A reasonable estimate for reductions for the period 2005-2007 allowing for all factors is 3.5 ± 1.5%. (Ref 7.20)

Auctioning

The EU favoured auctioning as opposed to free allowances from the inception of ETS but this was not supported by industries in the member states and the final ruling was up to 5% auctioning in Phase I and 10% in Phase II but no compulsory auctioning. Giving free allowances gave the trading system a kick start but it is recognised that it has some downsides e.g the power sector had significant windfall profits from free allowances as they could pass costs on to the consumer. In Phase III initially around 50% of allowances will be auctioned with no free allowances to the power sector.

Auctioning is seen to be a more efficient method for allocating allowances from an environmental and economic perspective. It fits with:

- The "polluter pays" principle;
- Provides an incentive to move to technologies that minimise GHG emissions;

- Generates public revenue; and
- Removes problems regarding distribution of allowances across sectors.

The EU has proposed that at least 50% of the revenues derived from auctioning should be used for various schemes including:

- To reduce greenhouse gases;
- To develop renewable energies, and other technologies contributing to the transition to a low-carbon economy;
- Measures to avoid deforestation and increase afforestation and reforestation;
- Forestry sequestration;
- Capture and geological storage;
- A shift to low-emission and public forms of transport;
- Research in energy efficiency and clean technologies;
- Improvements in energy efficiency and insulation; and
- To cover administrative expenses of the management of the European scheme. (ref 7.21).

As noted earlier auctioning will be phased in and will become the norm by 2027 with no free allowances.

Project Based Credits

The EU ETS has access to a large pool of external credits from CO_2 reduction projects in developing countries through the CDM and JI under the Kyoto Protocol. This stimulated investment in projects and transfer of environmentally sound technology to third countries. In addition it increased the liquidity of the trading market and compliance options. These have been used to a limited extent but in Phase III will be restricted to 50% of the total EU wide emissions reduction. After 2012 CDM projects (i.e. projects in countries outside the EU) can only be undertaken in a defined list of least developed Countries (LDCs) excluding emerging economies such as India and China. Consequently a greater proportion of reductions will have to be achieved in the EU.

1.1.3 EU-ETS Impact on GHG Regulation in Europe

Ultimately the EU ETS will be judged on its long term target of reducing emissions by 80% by 2050. It has been successful in introducing a coherent system across all member ststes despite their national differences and introduced a price for carbon across Europe and achieved a reduction in GHG emissions. It has moved from a decentralised position of NAPs to a centralised allocation of allowances based on benchmarks. A centralised registry will be established with harmonised accounting, monitoring, reporting and verification. It is one of a range of policies e.g. energy efficiency and renewables to reduce GHG emissions and each member state has developed their own policies which sit alongside the EU ETS.

Trading carbon has become established and does work even though there has been price volatility. As EU ETS has developed and lessons have been learned, Phase III incorporates important changes that impact on regulation:

1. The cap will decrease steeply from 2013 – 2020 to reduce overall emissions levels by 30% below 1990 levels.
2. More consistent EU wide allocation rules that eliminate distortions across member states.
3. Power generators will have to buy all of their allowances by auction with a transition to full auctioning for sectors not subject to carbon leakage.

The longer term policy is clear for business and it provides a framework for decisions around investment related to reduction of GHG emissions. In the process of monitoring and reporting emissions companies have focused on energy efficiency gains in their day to day operations and consequently on reducing emissions.

Offshore

From our experience with North Sea operators it is evident that they are seriously considering the impact of Phase III on their operations and the additional cost burden resulting from loss of free allowances for electricity generation. PI has conducted a number of studies for operators to assess the impact of the reducing cap through to 2020 and particularly the cost implications.

Examples from these show the decrease in allowances and additional cost burden.

Current free allowances tonnes CO_2 (annual)	Proposed phase III allowances tonnes CO_2 (annual)	Additional cost at €20 per tonne CO_2 (annual)
278,000	61,000	€4.34 million (C$5.68 April 2011)
128,000	56,000	€1.44 million (C$1.89 April 2011)
109,000	55,000	€1.00 million C$1.31 April 2011)

While the above examples use a CO_2 price of €20 (C$26) per tonne CO_2 it could well be much higher during 2013-2020.

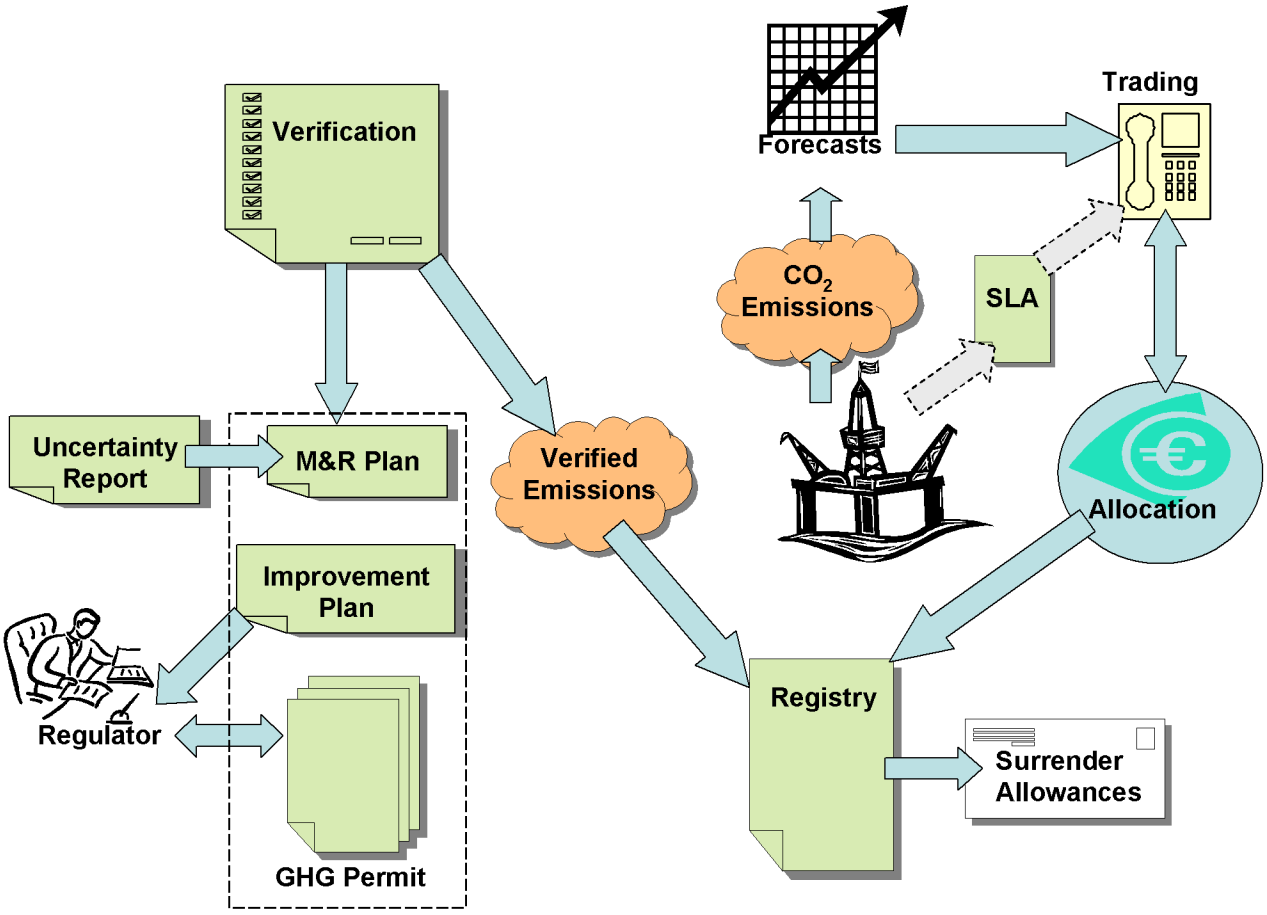
Table C5: Overview of EU-ETS (Source OECD/IED 2010)

European Union Emissions Trading System (EU ETS)

General scheme design
• Mandatory cap and trade scheme for large emitters in 30 countries (27 European Union countries plus Norway, Iceland and Liechtenstein under European Economic Area agreement). • Introductory Phase I (2005-07) completed, currently trading in Phase II (2008-12), Phase III rules have been set (2013-20).
Coverage
• CO_2 and from Phase III some industrial gases if resulting from processes that are otherwise covered (for example PFCs from aluminium, N_20 from nitric acid). In Phase II the Netherlands, Austria and Norway have unilaterally opted-in nitrous oxide from nitric acid production. • Includes installations undertaking combustion of fuels with total capacity 20MWth. For other industries there are specific production thresholds (for example 50t/day lime, 20t/day glass, 20t/day mineral wool insulation). • Currently covers approximately 11 500 installations in 30 countries, owned by 5 000 companies. The scheme covers 45% of European CO_2 emissions in 2010 (40% total European emissions). • Aviation emissions will be included from 2012 and the aluminium industry from 2013. From Phase III there is an option to exclude small facilities with emissions less than 25 000/tCO_2eq per year if they are covered by other policies.
Cap/target
• Phase I (2005-07): Cap was set below the full range of BAU estimates, with the objective of establishing the infrastructure for trading not to achieve significant reductions. The cap reflected a 4.3% reduction by the European Commission in the quantity of allowances that had been proposed by member states. • Phase II (2008-12): Annual cap 11.8% below the number of allowances in Phase I, 6.5% below 2005 verified emissions. The cap reflects a 10% reduction by the European Commission in the quantity of allowances that had been proposed by member states. • Phase III (2013-20): Cap to decline linearly to 21% below 2005 verified levels by 2020. This is intended to deliver a large part of Europe's targeted reduction of 20% on 1990 levels by 2020. If Europe adopts an overall 30% by 2020 target, the EU ETS cap will be reduced to 34% below 2005 levels by 2020.
Emissions reductions, allowance prices and economic impacts
• Phase I – Problems with poor initial data availability and a false assumption that energy efficiency trends had been exhausted meant that the cap was set too high. Following release of the first year's verified emissions, allowance prices crashed. Nonetheless, analysis has found that emissions were reduced by 2% to 5% in Phase I due to high initial allowance prices. • Phase II – Allowance prices traded around EUR 25/tCO_2eq for much of 2008, before tumbling as industrial production and electricity generation was curtailed with the recession. Since mid-2009, allowances have traded in a range between EUR 13/tCO_2eq and EUR 16/tCO_2eq. Emissions have reduced dramatically with the recession and are below the level of the cap. • Phase III - With a -21% EU ETS cap in 2020 (-20% economy-wide reduction target) the European Commission forecasts allowance prices will be EUR 16 in 2020 (or EUR 30 with a -34% cap [-30% economy-wide target]). This is lower than previously forecast, due to projections of slower emissions growth following the recession and the banking of excess units from Phase II. Private sector analysts expect higher Phase III allowance prices, in the range of EUR 30 to 40 (Reuters). • Cost EUR 48 billion for the current policy package (-21% ETS cap [-20% economy-wide target], 20% renewable energy and energy efficiency targets) and EUR 81 billion if a -34% ETS cap (-30% economy-wide target) is taken on. These correspond to reductions in GDP in 2020 of 0.32% and 0.54% in 2020 respectively, compared to 28% GDP growth to 2020.

Source: OECD/IEA 2010

Figure C4: EU-ETS Processes (Source OECD/IED 2010)



References

1. Environment Canada “Canada’s Emission Trends”. Report dated August 2012
2. Canada Gazette August 27 2011 Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations
3. Government of Alberta (2010), Alberta and Climate Change website, http://environment.alberta.ca/0918.html, accessed 20 August 2010.
4. UNFCC Climate Change
5. Connie HedegaardEuropean Commissioner for Climate Action EU Brussels, 14 July 2011
6. EC Directive 2003/87/EC
7. EC Directive 2009/29/EC Phase III Article 10a
8. EUROPEAN COMMISSION DIRECTORATE-GENERAL CLIMATE ACTION Directorate B - European & International Carbon Markets Guidance on Interpretation of Annex I of the EU ETS Directive (excl. aviation activities)
9. EC Climate Action 12 Jan 2012: 12 million NER 300 allowances sold by the European Investment Bank in December
10. European & International Carbon Markets. Guidance Document nos 1 & 2 on the harmonized free allocation methodology for the EU-ETS post 2012
11. ENTEC study
12. COMMISSION DECISION of 27 April 2011 determining transitional Union-wide rules for harmonised free allocation of emission allowances pursuant to Article 10a of Directive 2003/87/EC of the European Parliament and of the Council (notified under document C(2011) 2772) 2011/278/EU)
13. COMMISSION REGULATION (EU) No …/..of XXX on the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council
14. Symposium: The European Union Emissions Trading Scheme The European Union Emissions TradingScheme: Origins, Allocation, and Early Results A. Denny Ellerman and Barbara K. Buchner ,
15. COMMISSION REGULATION (EU) No 1031/2010 of 12 November 2010 on the timing, administration and other aspects of auctioning of greenhouse gas emission allowances pursuant to Directive 2003/87/EC of the European Parliament and of the Council establishing a scheme for greenhouse gas emission allowances trading within the Community
16. EUROPEAN COMMISSION DIRECTORATE-GENERAL CLIMATE ACTION Directorate B - European & International Carbon Markets. Guidance Document n°7 on the harmonized free allocation methodology for the EU-ETS post 2012
17. Directive 2004/101/EC of the European Parliament and of the Council of 27 October 2004 amending Directive 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community, in respect of the Kyoto Protocol's project mechanisms.
18. Green Paper Brussels, 8.3.2000 COM(2000) 87 final

19. The European Union Emissions Trading Scheme: Origins, Allocation, and Early Results A. Denny Ellerman and Barbara K. Buchner.

20. UK Environmental Audit Committee - Fourth Report The role of carbon markets in preventing dangerous climate change Jan 2010
21. Carbon Pricing Ellerman
22. http://europa.eu/legislation_summaries/energy/european_energy_policy/l28012_en.htm
23. An industry for the future Norway´s petroleum activities Meld. St. 28 (2010–2011) Report to the Storting (white paper)
24. Executive Summary of the National communication of Norway submitted under Articles 4 and 12 of the United Nations Framework Convention on Climate Change Oct. 1994
25. The Economist March 5 2012.
26. http://www.ens.dk/EN US/CLIMATEANDCO2/EMISSIONTRADINGSCHEME/Sider/Forside.aspx
27. Denmarks Oil and gas Production 2010.
28. NL Agency Ministry of Economic Affairs, Agriculture and Innovation LTA Long Term Agreements on Energy Efficiency in the Netherlands
29. Directive 2008/1/EC of the European Parliament and of the Council of 15 January 2008 concerning integrated pollution prevention and control.
30. The Offshore Combustion Installations (Prevention and Control of Pollution) Regulations 2001
31. IPPC Horizontal Guidance Note IPPC H2 Energy Efficiency

APPENDIX D

AN OVERVIEW OF GEEM MODELING METHODOLOGY

(Contained in separate document)

GOVERNMENT OF NEWFOUNDLAND AND LABRADOR
Office of Climate Change, Energy Efficiency, and Emissions Trading
(GNL - CCEEET)

OFFSHORE OIL & GAS – NEWFOUNDLAND AND LABRADOR
GHG REDUCTION OPPORTUNITIES & COMPETITIVE IMPLICATIONS

FINAL REPORT
(Deliverable 4)

APPENDIX D

NAVIUS GEEM MODEL - METHODOLOGY

TC121804

TABLE OF CONTENTS

PAGE

1.0 OVERVIEW OF GEEM MODELLING METHODOLOGY 1

1.1 Industry 2
1.2 Consumers 11
1.3 Trade 12
1.4 Selected References 13

LIST OF TABLES

Table 1: Industries in GEEM 2
Table 2: Elascticities for resource quality 6
Table 3: Elascticities of substitution by sector 8
Table 4: Elascticities of substitution for households 12
Table 5: Armington elasticities 12

LIST OF FIGURES

Figure 1. Overall Structure of the GEEM Model 1
Figure 2. Structure of inputs into industry (top level) 4
Figure 3. Structure of resource and quality bundle 5
Figure 4. Value-added bundle 6
Figure 5. Capital-energy bundle 7
Figure 6. Representation of carbon capture and storage to capture emissions from coal combustion 9
Figure 7. Abatement opportunities for Hibernia 9
Figure 8. Abatement opportunities for Terra Nova 10
Figure 9. Abatement opportunities for White Rose 10
Figure 10: Structure of household welfare 11
Figure 11: Structure of imports 12

This Appendix provides a summary of the GEEM model used in the analysis of competitiveness implications and GHG policy for the NL Offshore Petroleum Sector, incorporating the outputs from the technology and regulatory review.

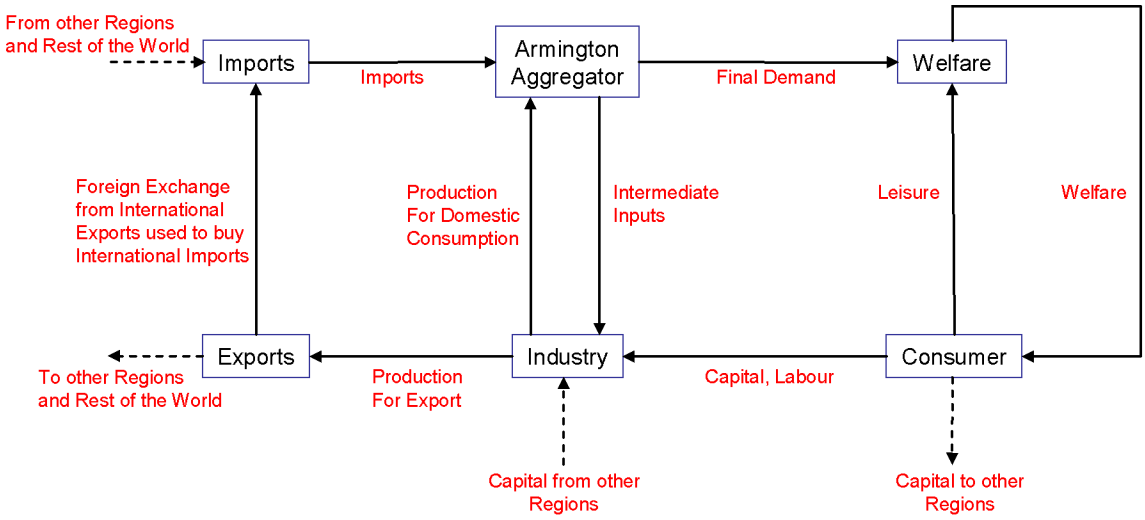
1.0 OVERVIEW OF GEEM MODELLING METHODOLOGY

To complete the analysis, Navius employed a computable general equilibrium (CGE) model called GEEM. GEEM is a macroeconomic model that ensures all markets within an economy are in balance by adjusting prices until equilibrium is achieved. The version of GEEM used for the analysis represents Newfoundland Labrador, the rest of Canada and the United States as separate regions, and each of these regions interact through the trade of commodities and services. Capital is assumed to be mobile among regions within North America, while labour is assumed to be mobile within provinces or states. In the model, a representative household in each region is the owner of primary factors (labour, capital and natural resources) which they rent to producers who combine them with intermediate inputs to create commodities. Commodities can be sold to other producers (as intermediate inputs), to final consumers, or to other regions and the rest of the world as exports. Commodities can also be imported from other regions or the rest of the world.

The key economic flows in GEEM are captured schematically in Figure 1.

.

Figure 1. Overall Structure of the GEEM Model



The current version of GEEM is dynamic and solves in single year increments from 2002 to 2020. One of the benefits of using a dynamic model is it can simulate policies that change over time as well as producing results for multiple years. For example, it can simulate carbon prices that rise over time, or regulatory policies (e.g., a renewable portfolio standard) implemented in a certain year. Furthermore, the model simulates the turnover of capital stocks and the addition of new capital to sectors over time and based on the rate of return to capital.

The data underlying the model is derived primarily from the Statistics Canada System of National Accounts. We use the S-Level Input, Output, and Final Demand tables to populate the model, and aggregate these somewhat to focus on sectors of primary interest. One of the challenges with the S-Level data is its lack of disaggregation for energy and emissions intensive sectors. We disaggregate these sectors using the M- and L-Level data from Statistics Canada, Statistics Canada's Report on Energy Supply and Demand, CAPP's production data for oil and gas production, Navius' CIMS energy economy model, among other sources.

The following sections describe our representation of industry, consumers and trade between provinces and countries.

1.1 Industry

The GEEM model represents over 30 industries in Newfoundland Labrador and North America (see Table 1). The table also shows the data from Statistics Canada's input-output tables on which the sectors are based.

Table 1: Industries in GEEM

GEEM Code	*GEEM Sector Description*	*Data Available for NB at the S-Level*
PEXT	Crop and animal production	Crop and animal production
	Fishing, hunting and trapping	Fishing, hunting and trapping
	Support activities for agriculture and forestry	Support activities for agriculture and forestry
FOREST	Forestry and logging	Forestry and logging
OSANDS	Oil sands extraction	Mining and oil and gas extraction
BITUP	Bitumen upgrading	
OCLM	Oil light medium	
OCHY	Oil heavy	
CNGAS	Conventional natural gas extraction	
UNGAS	Unconventional natural gas extraction	
COALMIN	Mineral mining	
MINING	Coal mining	
EOROIL	Enhanced oil recovery	
OGSER	Support activities for mining and oil and gas extraction	
CELEC	Conventional electric power generation	Utilities
HELEC	Hydroelectric, other renewable and nuclear electric power generation	
PAPER	Paper manufacturing	Manufacturing
REFINE	Petroleum and coal products manufacturing	
CHEM	Chemical manufacturing	

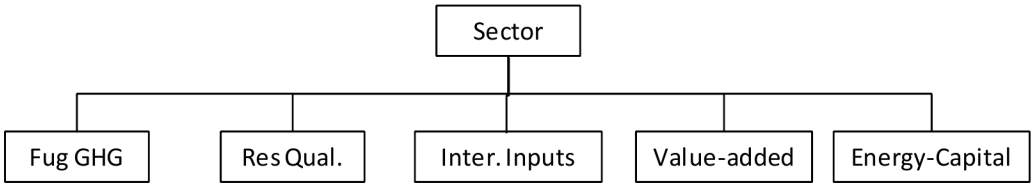
GEEM Code	*GEEM Sector Description*	*Data Available for NB at the S-Level*
BIOFUEL	Biofuel manufacturing	
CEMMAN	Cement manufacturing	
LIMMAN	Lime manufacturing	
ONMMAN	Other non-metallic mineral product manufacturing	
METAL	Primary metal manufacturing	
OMAN	Miscellaneous manufacturing	
TRANSIT	Transit and ground passenger transportation	Transportation and warehousing
TRANS	Other Transportation	
TRMARGIN	Transportation margins	Transportation margins
WRTD	Wholesale trade	Wholesale trade
	Retail trade	Retail trade
SERV	Natural gas distribution, water and other systems	Utilities
	Construction	Construction
	Information and cultural industries	Information and cultural industries
	Finance, insurance, real estate and rental and leasing	Finance, insurance, real estate and rental and leasing
	Professional, scientific and technical services	Professional, scientific and technical services
	Administrative and support services	Administrative and support services
	Educational services	Educational services
	Health care and social assistance	Health care and social assistance
	Arts, entertainment and recreation	Arts, entertainment and recreation
	Accommodation and food services	Accommodation and food services
	Other services (except public administration)	Other services (except public administration)
	Operating, office, cafeteria, and laboratory supplies	Operating, office, cafeteria, and laboratory supplies
	Travel and entertainment, advertising and promotion	Travel and entertainment, advertising and promotion
	Non-profit institutions serving households	Non-profit institutions serving households
WASTE	Waste management and remediation services	Waste management and remediation services
GOVT	Government sector	Government sector

The petroleum sector is further disaggregated by facility: Hibernia, Terra Nova, White Rose and (in 2017) Hebron. Each of these facilities is characterized by a unique production and emissions profile that matches data received from CCEEET.

Industrial sectors in the GEEM model are comprised of four complementary bundles of inputs (e.g., capital or cement) required to produce a good or service (e.g., pulp and paper) (see Figure 2). A sector requires each of these bundles in fixed proportions to produce output. In other words, substitution is not possible between the bundles, although substitution is possible within the bundles. The five complementary bundles are:

1. **Non-combustion emissions:** Some sectors produce non-combustion emissions that are directly linked to production. For example, lime manufacturing produces 750 g CO_2e per kg of lime produced. These emissions are produced in fixed proportions to output, unless an abatement opportunity is specified for these emissions (e.g., carbon capture and storage). Under a carbon price that affects non-combustion emissions, these emissions become a cost to the sector.
2. **Resource quality:** Resource industries are constrained by the availability of resource in a specific region. For example, New Brunswick cannot produce oil as these resources are not available. Similarly, the opportunity for expanding forest operations is constrained to the available resource. This bundle is explained in more detail below.
3. **Intermediate inputs:** Intermediate inputs unrelated to energy consumption are assumed to be required in fixed proportions to produce output. These include inputs such as cement or financial services. These inputs are required in fixed proportions; so for example, the refining sector cannot reduce its consumption of crude oil by increasing energy consumption.
4. **Value-added:** This bundle includes labor and capital requirements for a sector. The capital requirements are those unrelated to energy consumption or resource quality. This bundle is explained in more detail below.
5. **Capital-energy:** This is bundle determines levels of energy efficiency and the choice of fuel within each sector. This bundle is explained in more detail below.

Figure 2. Structure of inputs into industry (top level)

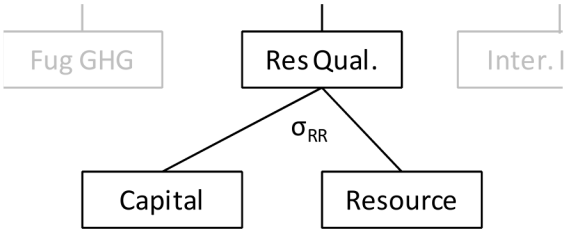


Although a sector cannot substitute between each of these bundles, substitution is possible within three bundles explained below. These bundles are represented by constant elasticity of substitution (CES) functions, which represent the technologies industry can use to produce goods and services. Central to this function are the “elasticity of substitution” parameters which represent how easily a sector can substitute between different inputs while maintaining a given level of production. A “low” elasticity value indicates it is difficult to substitute between inputs, while a “high” elasticity value indicates greater substitution potential.

Resource quality bundle

To model resource extraction sectors, we introduce the concept of "resource rent", which is profit earned by resource sectors that exceeds a normal rate of return on investment. Resource extraction sectors earn extra profits (some of which is collected by government in the form of royalties) because the resource they extract is scarce and resource plays have different costs of extraction. In other words, unlike manufactured commodities there is a finite amount resource to extract, such that buyers pay a premium that reflects the scarcity of the commodity. In addition, resource plays differ in their costs of extraction (quality), such that owners of easy to extract (high quality) resources earn additional profits relative to owners of resources that are more difficult to extract. For example, oil extraction from a conventional well would yield greater resource rent per unit of oil production than oil sands mining and upgrading (which has higher costs of extraction).

Figure 3. Structure of resource and quality bundle



We use the concept of resource rent to characterize the supply curve for resources. As illustrated in Figure 3, we simulate the ability of a resource sector to substitute between the amount of a fixed resource and other inputs into production, which is represented by the elasticity value σ_{RR}. If the price for the resource increases, the value of resource rent (extra profits) for a given level of production increases. Assuming the price for other inputs into production stays constant, the model will simulate an increase in production by shifting away from the fixed resource towards greater inputs. This reflects industry moving towards more marginal resources. In an alternative scenario where the costs of extraction increase (due to the adoption of carbon capture and storage for example), the cost of inputs becomes more costly in comparison to the resource and the model simulates that the marginal resources will not be developed.

The value of all elasticity values used to parameterize the model are illustrated in Table 2. The elasticity values for σ_{RR} are calibrated to ensure the long-run supply elasticity for natural resources sector (e.g., oil sand extraction or electric generation from renewable resources) is one. This means that a one percent increase in price leads to a one percent increase in production, all else equal.

Table 2: Elascticities for resource quality

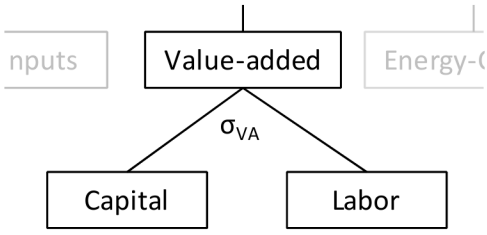
	σ_{RR}
PEXT	0.6
FOREST	0.6
OSANDS	1.2
OCLM	0.25 or 0[1]
OCHY	0.25
CNGAS	0.4
UNGAS	0.8
COALMIN	0.4
MINING	0.4
EOROIL	0.52

Source: Elasticities for oil and gas production are calibrated to NEB, 2011; forestry and agriculture sectors (PEXT) are from Paltsev et al, 2005; enhanced oil recovery (EOROIL) is calibrated to the Alberta Development Council (2009) and NETL (2011); coal mining and mining are assumptions that ensure the output can expand without significant increases in price.

Value-added bundle

The value-added bundle represents the potential tradeoff between capital and labor (see Figure 4). Therefore, if the labor wage rate increases relative to the capital rental rate, a sector has an incentive to increase capital consumption by reducing labor consumption. The elasticity between capital and labor is assumed to be 1.0, as specified in MIT-EPPA (Paltsev et al, 2005).

Figure 4. Value-added bundle



As capital can be specified in several bundles for a sector, capital in this bundle represents the residual after capital has been allocated to the capital-energy and resource quality bundles.

Capital-energy bundle

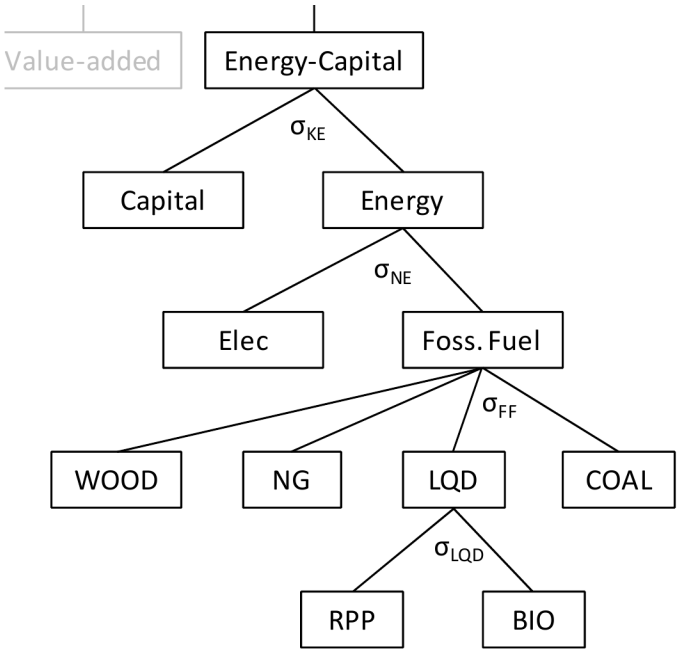
Finally, the capital-energy bundle represents the potential for energy efficiency as well as the fuel switching within a sector (see Figure 5). The top level represents the potential for changing

[1] For Newfoundland and Labrador's offshore oil industry, this elasticity is set to zero.

levels of energy efficiency through a capital-energy tradeoff. Therefore, if the price for energy increases relative to capital, a sector has an incentive to improve levels of energy efficiency.

Below the energy efficiency decision, a sector decides which fuels are consumed to produce output. The first level simulates a tradeoff between electricity and non-electric fuels; the second level simulates a tradeoff between wood, natural gas, coal and liquids; and the third level simulates a tradeoff between biofuels and refined petroleum products.

Figure 5. Capital-energy bundle



The portion of capital allocated to this bundle has been informed by Navius Research's technologically detailed CIMS model. Table 3 shows the elasticities used to parameterize this bundle.

Table 3: Elascticities of substitution by sector

	σ_{KE}	σ_{NE}	σ_{FF}	σ_{LQD}
PEXT	0.86			
FOREST	0.86			
OCHY	0.4			
OCLM	0.4			
OSAND	0.4			
BITUP	0.4			
CNGAS	0.4			
UNGAS	0.4			
EOROIL	0.4			
COALMIN	0.86			
MINING	0.86			
CELEC	0.5			
ELEDIS	0.4			
NGDIS	0.4	0.5	1	3
PAPER	1.00			
REFLOL	0.78			
BIOFUEL	0.78			
CEMMAN	0.46			
LIMMAN	0.46			
ONMMAN	0.46			
METAL	0.97			
OMAN	0.97			
WRTD	0.4			
SERV	0.4			
TRANS	0.86			
TRANSIT	0.86			
GOVT	0.4			

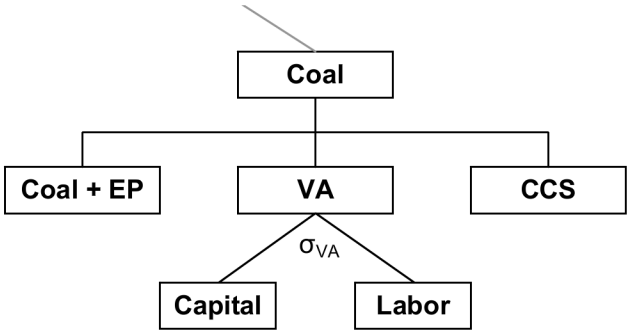
Sources: The inter-fuel elasticities are from Paltsev et al, 2005; the capital-energy elasticities for PAPER, REFLOL, LIMMAN, OMAN and TRANS were econometrically estimated from CIMS Atlantic model; the capital-energy elasticities for PEXT, FOREST, COALMINI, MINING and TRANSIT are based on the elasticity from TRANS; the capital-fuel elasticities for CEMMAN and ONMAN are based on the elasticity for LIMMAN; the capital-energy elasticity for BIOFUEL is based on the elasticity for REFLOL; the capital-energy elasticity for METAL is based on OMAN; the remaining capital-energy elasticities are from Paltsev et al (2005).

Alternative production methods included in GEEM

The GEEM model includes “alternative” methods of producing goods and services from sectors with specific abatement technologies (e.g., carbon capture and storage (CCS) and the reduction of landfill gas emission). These technologies are typically unprofitable in the absence of a policy but become active under certain economic or policy conditions (e.g., carbon pricing or high prices for oil that warrant the adoption of EOR). Figure 6 illustrates an example of how CCS is simulated for abate emissions from coal combustion (e.g., a coal-fired electricity plant). To

achieve the same level of service from coal as without CCS, the CCS technology requires 1) additional fuel consumption to reflect the energy required to operate CCS equipment ("COAL + EP" in Figure 6), 2) capital to build the CCS plant and labour to operate it ("VA"), and 3) a stream of emissions that are captured from the plan ("CCS"). The captured emissions can either be stored or transported to an EOR site at a premium.

Figure 6. Representation of carbon capture and storage to capture emissions from coal combustion



Alternative production methods are the main way in which the abatement opportunities identified by AMEC-PI are introduced into the analysis. Each offshore oil facility in NL includes 5 distinct levels of abatement, with increasing levels of cost. These are shown in Figure 7 through Figure 9. Note that while AMEC-PI characterizes technologies that have costs in excess of $250, only technologies up to a cost of $150 per tonne were characterized in GEEM. Furthermore, in most cases the technologies in GEEM are an aggregation of several technologies that have similar costs.







In the GEEM model, all industries maximize profits (i.e., revenue minus costs of production) subject to technology constraints through Lagrangian optimization.

1.2 Consumers

GEEM uses a representative agent framework, where all households are represented by a single representative agent. In this framework, the representative agent maximizes his/her welfare, where welfare is a function of consumption of various commodities, savings (i.e., future consumption) and leisure (see Figure 10 for the tree structure and Table 4 for the associated elasticity values). Note that the trees representing space heating, appliances and other goods is similar to the tree representing transportation, and therefore are not shown in. Most of the elasticity values have been econometrically estimated from Navius' CIMS energy-economy model, while the values representing the substitutability between an end-use and other goods (σ_{TST}) are from Paltsev (2005).

Figure 10: Structure of household welfare

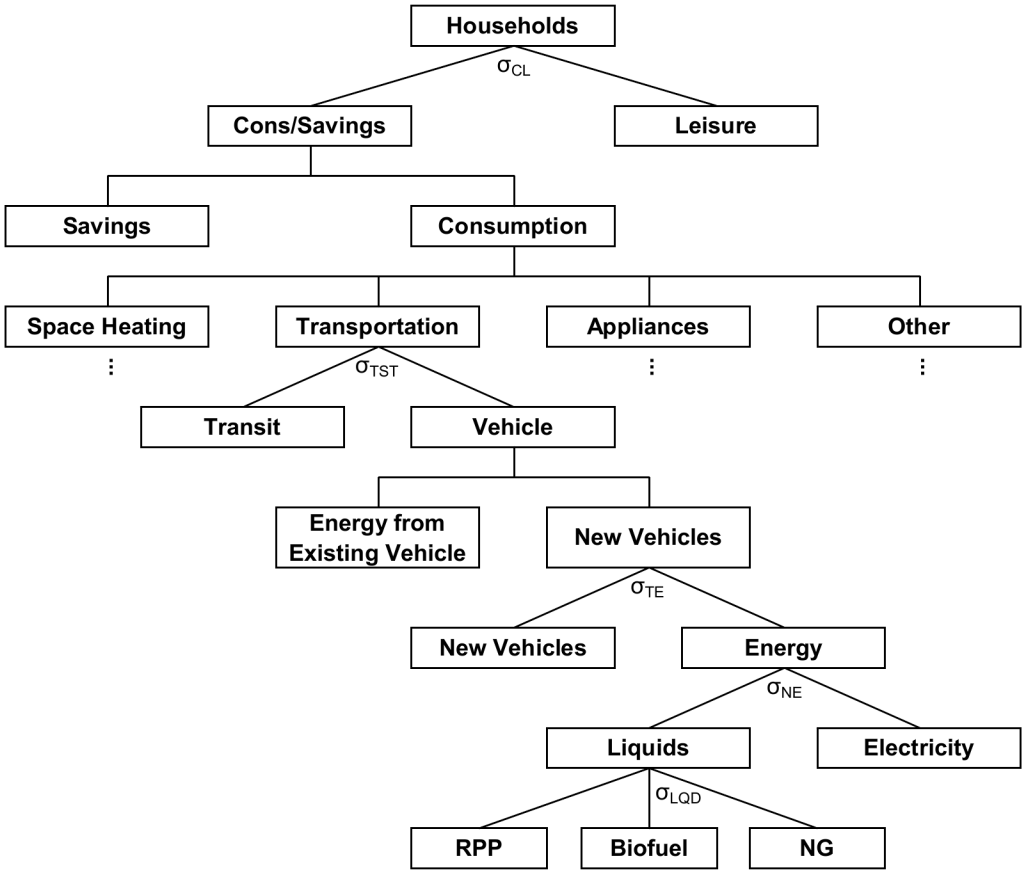


Table 4: Elascticities of substitution for households

	σ_{CL}	σ_{TST}	σ_{TE}	σ_{NE}	σ_{LQD}
Space Heating	0.6	0	0.25	4.0	0.4
Transportation		0.2	0.2	5	2
Appliances		0	1	0	0
Other Goods		0.25	0	0	0

Source: CIMS, 2009 and Paltsev, 2005

The representative agent in GEEM maximizes his/her welfare subject to available income through Lagrangian optimization.

1.3 Trade

The substitutability between domestically produced and imported goods are represented by an armington formulation (see Figure 11 for the structure of imports and Table 5 for the corresponding elasticity values). An elasticity of infinity indicates that a commodity is homogeneous and Alberta is price taker. This is important to represent crude oil which is priced in international markets and natural gas which is priced in North American markets.

Figure 11: Structure of imports

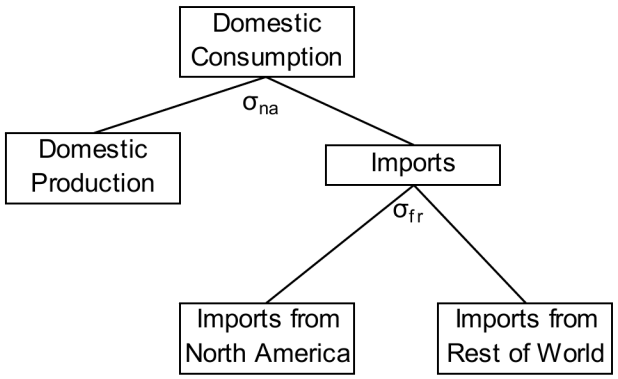


Table 5: Armington elasticities

	σ_{na}	σ_{fr}
Crude Oil	∞	∞
Natural Gas	∞	NA
Electricity	2.5	2.5
Refined Petroleum Products	∞	NA
Other Goods	2.5	2.5

Source: Bohringer and Rutherford (2002); and personal communication with NB Environment.

1.4 Selected References

Alberta Carbon Capture and Storage Development Council. (2009). *Accelerating Carbon Capture and Storage Implementation in Alberta*.

Babiker, M. H., Metcalf, G. E., & Reilly, J. (2003). Tax distortions and global climate policy. *Journal of Environmental Economics and Management, 46*(2), 269-287.

Bataille, C., Jaccard, M., Nyboer, J., & Rivers, N. (2006). Towards general equilibrium in a technology-rich model with empirically estimated behavioural parameters. *Energy Journal, 27*, 93-112.

Bohringer, C,. and Rutherford, T. (2002). Carbon abatement and international spillovers. *Environmental and Resource Economics*, Vol. 22.

Canadian Association of Petroleum Producers (2009). *Crude Oil Forecast.* Available from: www.capp.ca.

CIMS (2009). Navius' technologically detailed energy economy model.

Dissou, Y. (2005). Cost-effectiveness of the performance standard system to reduce CO2 emissions in Canada: a general equilibrium analysis. *Resource and Energy Economics* 27 (2005) 187–207.

Iowerth, A., P. Bagnoli, Y. Dissou, T. Peluso, and J. Rudin (2000). A Computable General Equilibrium Aalysis of Greenhouse Gas Reduction Paths and Scenarios. Economic Studies and Policy Analysis Division, Finance Canada.

Kallbekken, Steffen. (2004). *A description of the Dynamic analysis of Economics of Environmental Policy (DEEP) model*. CICERO Report 2004:01. Available from: http://www.cicero.uio.no/media/2719.pdf

McKibbin, W., and P. Wilcoxen (1999). The Theoretical and Empirical Structure of the G-Cubed Model. *Economic Modelling* (16): 123-48.

McKitrick, R. (1997). Double dividend environmental taxation and Canadian carbon emissions control. *Canadian Public Policy - Analyse de Politiques, XXIII*(4), 417-434.

National Energy Technology Laboratory. (2011). *Improving domestic energy security and lowering CO_2 emissions with "next generation" CO_2-Enhanced Oil Recovery (CO_2-EOR).*

Paltsev et al, (2005). *The MIT Emissions Prediction and Policy Analysis (EPPA) Model: Version 4*. Available from: http://globalchange.mit.edu/igsm/eppa.html.

Statistics Canada (2009). *The Input-Output Structure of the Canadian Economy*. Catalogue no. 15-201-X.

Statistics Canada (2009). *The Report on Energy Supply Demand*. Catalogue no. 57-003-X.

Wigle, Randy. (2007). BMRT V 1.0 Model Documentation. Working Paper. Department of Economics Wilfred Laurier University.

GOVERNMENT OF NEWFOUNDLAND AND LABRADOR
Office of Climate Change, Energy Efficiency, and Emissions Trading
(GNL - CCEEET)

OFFSHORE OIL & GAS – NEWFOUNDLAND AND LABRADOR
GHG REDUCTION OPPORTUNITIES & COMPETITIVE IMPLICATIONS

SUMMARY OF FINDINGS & ADDENDUM REPORT
(Project Extension Scope of Work)

FINAL REPORT

Submitted to:

GNL - CCEEET
P.O. Box 8700
St. John's, Newfoundland
A1B 4J6

Submitted by:

AMEC Environmental & Infrastructure
a Division of AMEC Americas Limited
160 Traders Blvd., Suite 110
Mississauga, Ontario
L4Z 3K7

May 2013

TC121804

May 2nd 2013

TC121804

Office of Climate Change, Energy Efficiency & Emissions Trading
Executive Council
Government of Newfoundland and Labrador
P.O.Box 8700
St.John's, NL, A1B 4J6

Attention: Mr. Gerald Crane

Dear Mr. Crane:

Re: Offshore Oil & Gas – Newfoundland and Labrador, Greenhouse Gas Reduction – Addendum Report – for Client Review

AMEC Environment & Infrastructure, and its associate company Performance Improvements Limited have pleasure in providing you with this draft copy of the final Summary Addendum Report on the Offshore Oil & Gas GHG Reduction study.

This report provides a summary of the main findings and also contains the further analysis requested in Q1 2013 with respect to contract extension.

The report incorporates your comments the very limited feedback from the NL offshore sector Operators on the exact nature of technical best practices and technology already implemented at their facilities. It also incorporates update of 2010 and 2011 data received from C-NLOPB in April 2013.

Yours truly,
AMEC Environment & Infrastructure
a Division of AMEC Americas Limited

Stephen Lamming, Ph.D., EP
Project Manager
Direct Tel.: (905) 568-2929 X4159
Direct Fax: (905) 568-1686
E-mail: steve.lamming@amec.com

Canada's Top 100 Employers 2013

EXECUTIVE SUMMARY

The report is an addendum report to a study commissioned by the Government of NL Office of Climate Change, Energy Efficiency, and Emissions Trading (CCEEET) and conducted by AMEC and partner Navius Research to "Identify Greenhouse Gas (GHG) Reduction Opportunities and Competitiveness Implications for the Offshore Oil and Gas Industry in Newfoundland and Labrador". It approaches the subject in the context of helping inform the objectives of the Government of Newfoundland and Labrador (GNL) 2011 Climate Change Action Plan, within which the GNL committed to develop, and publicly release, a detailed approach for reducing GHG emissions from the energy-intensive sectors of the province, including provincial targets for 2020. The offshore petroleum sector, comprising three large oil production facilities and a fourth due before 2020, is the largest single sector contributor to provincial GHG emissions, comprising 35% of GHG emissions from large industry in 2010.

All three existing facilities are beyond their peak oil production rates but continue to require high levels of energy use to maintain reservoir pressure and/or conserve associated gas. A unique aspect of offshore oil production (which is very distinct from conventional onshore or oil sands production) is that the energy intensity and the GHG emissions intensity (per unit of oil production) will tend to rise as oil production declines over field life. This is because gas compression and water injection pumping, the most energy intensive users of power generated from fuel combustion, are designed to maximise oil production with no direct correlation to oil decline, and with limited turndown capability. Additional analysis also shows that there is limited correlation of GHG emissions with overall production (oil, gas, and produced water).

For existing facilities GHG abatement opportunities relating to flaring (non-fuel) reduction best practices (flare management) are likely to be more practical and cost-effective than abatement opportunities relating to fuel combustion reduction. A number of best practice flare management measures are already being followed, and have allowed flare rates at existing facilities to be brought down significantly since 2007 cutting the proportion of GHG attributed to flaring down from [redacted] to [redacted]. For the sector as a whole there is estimated to be some further reduction in flaring possible of the order of [redacted] – [redacted], although some facilities are closer to practical safe limits than others. For combustion plant (primarily gas turbines), the theoretical potential for increased waste heat recovery is not practical nor cost effective, as it is severely constrained by available useful process duties on the facilities. In the medium to long term, optimisation of the main energy users (compressors and pumps) at key stages in field life has the potential for [redacted] reduction of fuel emissions. Fuel substitution has little potential since diesel use is already minimised to periods of fuel gas unavailability. Variable speed drive (VSD) technology should be considered Best Available Technology (BAT) on new projects, and will help optimise motor energy use over field life.

The policy analysis shows that application of various performance standards could reduce sector emissions by between [redacted] and [redacted] from their business-as-usual trajectory by 2020. However, the choice of compliance options and benchmark has an important implication on compliance costs. The availability of a technology fund achieves greater reductions in emissions

and reduces compliance costs in comparison to the availability of offsets Allowing facilities to comply with a policy by accessing a technology fund ensures that revenues collected are used to reduce GHG emissions in the sector and also reduce compliance costs. It is likely that greater reductions could be achieved from the sector with greater constraints on offset availability and more emphasis on a technology fund.

The choice of benchmark affects the portion of compliance achieved through direct reductions and the level of contributions to a technology fund or from accessing other flexibility mechanisms. On one end of the spectrum, calling for a reduction from the fuel benchmark approach used in the EU ETS would require fewer reductions, while on the other end a reduction in emissions intensity from a production-based benchmark would require significant actual reductions from the sector. In the latter policy, compliance with the policy would become increasingly difficult as each field matures. While this leads to greater contributions to the technology fund and greater reinvestment of the technology fund in low emissions options in the sector, it also substantially increases the cost of compliance.

Increasing the price for accessing the technology fund achieves greater reductions, but at a diminishing rate. The main opportunities for reducing emissions from NL's offshore oil industry identified in this analysis are from flaring via improved flare managements and critical rotating equipment reliability. These reductions have relatively low cost in comparison to most other fuel-based options. However, once these options have been undertaken, there are fewer opportunities to achieve significant reductions in GHG emissions.

The analysis explicitly shows that a policy design option based on an oil production benchmark would achieve GHG reductions at significantly greater cost in comparison to other options. A production-based benchmark is difficult for the offshore oil industry to achieve due to the independence of relatively fixed combustion plant energy requirements with falling oil production rates. A benchmark based on historic emissions intensity becomes increasingly difficult to achieve even with maximum abatement from the sector. The balance must be met with either contributions to a technology fund or some other flexibility mechanism, which impose a financial cost on the sector. If flexibility mechanisms are not available, this performance standard may not be achievable for some facilities, and they would either have to fall out of compliance or shut down. The findings of this study's analysis are in line with the independent third party findings for the European offshore petroleum sector under EU-ETS Phase III policy design, where production based benchmarks were deemed inappropriate to offshore facilities and a fuel (combustion) benchmark has been used instead.

The potential to use a natural gas performance standard for offshore power generation (similar to the one used at a federal level for coal-fired electricity generation) is constrained by the thermal efficiency of existing offshore power generation technology, combined with the fact that high efficiency combined cycle gas turbine technology and/or carbon capture and storage are currently not viable or not cost-effective technology solutions for retrofit to offshore facilities. Offshore power generation facilities are not 'base load' plant, and turbine efficiencies reduce as process demand load decreases. A performance standard could be a perverse disincentive.

TABLE OF CONTENTS

PAGE

1.0 INTRODUCTION 1
1.1 Purpose 1
1.2 Background 1
1.3 Scope – Additional Analysis 2
2.0 FINDINGS OF MAIN STUDY 4
2.1 Offshore Sector Characteristics 4
2.2 Offshore Resource Management 5
2.3 Sources of GHG Emissions 6
2.4 Combustion Plant Characteristics 8
2.5 Main Energy Consumers 8
2.6 Production, Energy and GHG Intensity 9
2.7 GHG Abatement Opportunities – Best Practice and Best Available Technologies 9
2.8 GHG Abatement Opportunities – Emerging Technologies 12
2.9 GHG Policy Options and Criteria 13
2.10 GHG Policy Evaluation 13
3.0 FACILITY PRODUCTION & GHG DATA 15
3.1 NL Offshore Oil & Gas Sector Production Data 15
3.1.1 Historical Production Data (2004 to 2012) 15
3.1.2 Forecast Production data (to 2025) 15
3.2 Associated Gas Utilisation Data 15
3.3 Power Generation Data 16
4.0 PRODUCTION BASED GHG INTENSITY 19
4.1 Historic Production based GHG Intensity 19
4.1.1 Forecast Production based GHG Intensity 20
5.0 PERFORMANCE STANDARDS 27
5.1 Background to Performance Standard 27
5.1.1 Canadian Coal-Fired Electricity Regulations 27
5.1.2 Combined Cycle Technology 27
5.2 Analysis of Offshore Power Generation Emissions Intensity 28
5.2.1 Simple Cycle Gas Turbine Technology 28
5.2.2 Power Generation Emissions Intensity Calculation Approach 29
5.2.3 Power Generation Emissions Intensity for Offshore Facilities 30
5.2.4 Implications of an Offshore Power Generation Performance Standard 34
5.3 Offshore Flaring 38
5.3.1 Intensity Based Approach 38
5.3.2 Flaring Performance Standard 38
6.0 REFERENCES 39

LIST OF TABLES

Table 3.1: Hibernia Platform – Main Gas Turbine Plant and Duty 17
Table 3.2: Terra Nova FPSO – Main Gas Turbine Plant and Duty 17
Table 3.3: White Rose (Sea Rose FPSO) – Main Gas Turbine Plant and Duty 17
Table 5.1: Canadian Natural Gas Heating Values 31
Table 5.2: CO_2 Emission Factors for Natural Gas Fuel Combustion 32
Table 5.3: Estimation of Power Generation Intensity Factors for Offshore Facilities 33

LIST OF FIGURES

Figure 4.1a Hibernia - Historic Production 21
Figure 4.1b Hibernia - Historic Fuel, Flare, and GHG Emissions 21
Figure 4.1c Hibernia - Historic GHG Emissions Intensity 22
Figure 4.1d Hibernia - Forecast GHG Emissions Intensity 22
Figure 4.2a Terra Nova - Historic Production 23
Figure 4.2b Terra Nova - Historic Fuel, Flare, and GHG Emissions 23
Figure 4.2c Terra Nova - Historic GHG Emissions Intensity 24
Figure 4.2d Terra Nova - Forecast GHG Emissions Intensity 24
Figure 4.3a White Rose - Historic Production 25
Figure 4.3b White Rose - Historic Fuel, Flare, and GHG Emissions 25
Figure 4.3c White Rose - Historic GHG Emissions Intensity 26
Figure 4.3d White Rose - Forecast GHG Emissions Intensity 26
Figure 5.1: An Illustration of range of Power Generation GHG Emissions Intensity 36
Figure 5.2: Power Generation GHG Emissions Intensity with reference to NL Offshore Sector 37

ABBREVIATIONS

ALARP	As Low As Reasonably Practicable
AMEC E&I	AMEC Environment & Infrastructure
BAT	Best Available Techniques
BBLS	Barrels
BCF	Billion Cubic Feet
BCM	Billion Cubic Metres
BOE	Barrels of Oil Equivalent
BP	Best Practice
CAPP	Canadian Association of Petroleum Producers
CCEEET	Climate Change, Energy Efficiency, and Emissions Trading
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CH_4	Methane
C-NLOPB	Canada Newfoundland and Labrador Offshore Petroleum Board
CO_2	Carbon Dioxide
CSR	Comprehensive Study Report
EC	European Commission
EU	European Union
EU ETS	European Union Emissions Trading System
FEED	Front End Engineering and Design
FPSO	Floating Production Storage and Offloading
GBS	Gravity Base Structure
GC	Gas Compressor
GDP	Gross Domestic Product
GGFR	Global Gas Flaring Reduction
GGFVRS	World Bank Global Gas Flaring & Venting Voluntary Reduction Standard
GHG	Greenhouse Gas
GNL	Provincial Government of Newfoundland and Labrador
GT	Gas Turbine
GWh	Gigawatt hour
HP	High Pressure
HPC	High Pressure Compression
H_2S	Hydrogen Sulphide
kt	kilotonnes
LHV	Lower Heating Value
LP	Low Pressure
LPC	Low Pressure Compression
LPG	Liquefied Petroleum Gas
Mboe	Thousands barrels oil equivalent
MMboe	Million barrels oil equivalent
mg/l	milligrams per litre
MP	Medium Pressure
MPC	Medium Pressure Compression
Mt	Million tonnes
MW	Megawatt

MW_{th}	Megawatt Thermal
NGL	Natural Gas Liquids
NL	Newfoundland and Labrador
NM^3	Normal Meter Cubed
N_2O	Nitrous Oxide
NS	Nova Scotia
O&G	Oil and Gas
OEM	Original Equipment Manufacturer
PI	Performance Improvements Ltd
PWRI	Produced Water Re-Injection
SO_x	Sulphur Dioxide
TEG	Tri-ethylene Glycol
TJ	Terajoule
UNFCCC	United Nations Framework Convention on Climate Change
UK DECC	United Kingdom Department of Energy and Climate Change
VRU	Vapour Recovery Unit
WHRU	Waste Heat Recovery Unit
WCI	Western Climate Initiative
WI	Water Injection

1.0 INTRODUCTION

1.1 Purpose

This Addendum Report summarizes the main findings from an independent study conducted during 2012 to "Identify Greenhouse Gas (GHG) Reduction Opportunities and Competitiveness Implications for the Offshore Oil and Gas Industry in Newfoundland and Labrador (NL)" [Ref 1].

This report also provides the results of a more in-depth review and analysis of offshore sector production data, power generation data, and energy intensity data with a view to assessing the following technical parameters:

i) The range of different production-based benchmark metrics which could be considered for the Offshore Petroleum Sector, incorporating not just oil production but also natural gas production / conservation, and potentially overall produced fluids.

ii) The implications of the potential to apply a natural gas performance standard for power generation on offshore facilities, and an intensity-based system for offshore sector flaring. The metrics for the natural gas performance standard would potentially be along similar lines to the performance standard which the federal government has already established onshore for coal-fired electricity generation.

iii) The implications of applying a natural gas performance standard for power generation on offshore facilities, and a separate flaring performance standard.

This report is aimed at providing a concise review of offshore sector technical characteristics to help inform discussion between stakeholders of potential benchmark and performance-standard approaches for the offshore sector. It is also aimed at informing discussions between provincial and federal government departments with respect to applying appropriate and meaningful mechanisms for achieving a degree of GHG reduction equivalency within regulatory approaches, based on the unique technical characteristics of the NL Offshore Petroleum sector.

1.2 Background

In its 2011 Climate Change Action Plan, the GNL committed to develop, and publicly release a detailed approach for reducing GHG emissions from the energy-intensive sector. This approach will include a GHG reduction target for the energy-intensive sector and will be guided by 11 core principles in line with economic, social, and environmental objectives [Ref 2].

Currently the Offshore Oil and Gas production industry in NL and the Offshore Gas production industry in Nova Scotia (NS) are unique within Canada; the rest of the oil and gas production industry across Canada being primarily Onshore (including significant contribution from Alberta, British Columbia, and Saskatchewan). The NL offshore sector is also unique from the perspective that current offshore oil production is from remote oil fields where the associated gas is currently 'stranded', i.e. lacking the infrastructure (such as pipelines) that would allow

economic monetisation of natural gas reserves as happens in onshore industry. All four offshore projects in NL are located in remote and harsh environments exposed to cold weather and ice conditions, in the Jean D'Arc basin 300 km east of St John's, NL. They lack the practical infrastructure for electricity grid connection, and also lack the infrastructure, footprint, and process duty demand for large scale heat integration. In common with the standard world-wide design of offshore petroleum facilities the Canadian offshore facilities consist of power generation 'islands' producing their own captive power using simple cycle gas turbine technology, using a proportion of their produced natural gas for primary fuel. In addition, Oil export from facilities is by shuttle tanker as opposed to by pipelines to shore. **In this report 'power generation' encompasses gas turbine power output used for either electricity generation or for direct mechanical drive of large process units such as compressors.**

In its 2011 Climate Change Action Plan, one of the key goals of the GNL, at a provincial economy level, is to pursue the GHG reduction targets of the Conference of New England Governors and Eastern Canadian Premiers on a provincial basis: 10 percent below 1990 levels (8.4 MT) by 2020, and 75 – 85 percent below 2001 levels by 2050. It can be noted that NL provincial economy emission levels were around the same level in 2010 as they were in 1990. Therefore, looking forwards to 2020, the provincial target effectively corresponds to reducing the economy GHG emissions by approximately 10 percent between 2010 and 2020, at a time when certain sectors of large industry, including the offshore sector will expand production capacity. The Hebron facility is planned to come on-stream in 2018, as the fourth NL offshore project.

1.3 Scope – Additional Analysis

The scope of the additional analysis covered in this addendum report is to review and analyse:

i) The application of a "total fluids" denominator including oil, gas and water (the required data can be found at http://www.cnlopb.nl.ca/stat_rm.shtml); and

ii) The application of a "total petroleum products" denominator including oil and gas production (incorporating produced gas which at present is largely re-injected).

With respect to performance based standards, the scope is to analyze a single performance standard approach and a hybrid approach using performance standards and an intensity based reduction. This analysis is conducted along two lines:

i) The application of a performance standard for power generation on offshore platforms and an intensity-based system for offshore flaring. The Canadian federal government has established a similar performance standard for coal-fired electricity generation with a limit set at 420 tonnes/Gwh [Ref 3]; and

ii) The application of a performance standard for power generation on offshore facilities and a flaring performance standard. The federal government has not discussed a flaring performance standard with the province at the time of this study report.

AMEC Environment & Infrastructure (AMEC E&I Canada) coordinated the main study during 2012 – 2013, supported by specialist teams from AMEC Performance Improvements (AMEC-PI) and Navius Research. The additional technical review contained in this addendum has been completed by AMEC E&I in conjunction with offshore sector specialists from AMEC-PI (UK).

2.0 FINDINGS OF MAIN STUDY

The following main findings and conclusions are made with respect to the characteristics of the offshore petroleum sector comprising the three existing facilities (Hibernia, Terra Nova, White Rose) and the planned Hibernia project. White Rose project is implemented via the 'Sea Rose' FPSO. Where 'future facilities' are mentioned, no reference to any specific new facilities is intended, and the conclusions are aimed at 'new entrants' to the sector in a general sense.

2.1 Offshore Sector Characteristics

i) The NL offshore petroleum sector is unique to the rest of Canada's oil and gas production industry, the majority of which is located onshore. The remote offshore location poses **unique environmental as well as health and safety constraints**. This translates to higher capital costs for major technology projects compared to technology applied within an onshore context. This applies to GHG emission reduction projects just as much as it does to production-critical operations and maintenance activities (e.g. turnarounds) or infrastructure projects. This is reflected in the relative attributes of the provisional GHG marginal abatement cost information developed as part of this project; project costs are high, and there is no 'silver bullet'. Demonstrating Operations and Maintenance 'best practice' has a major role to play.

ii) The NL offshore petroleum sector has been developed for oil production monetisation not natural gas. Lacking export-to-shore pipeline infrastructure the **associated gas is 'stranded'** from economic monetisation; instead the majority is re-injected for pressure maintenance of enhance oil recovery and/or to preserve gas reserves for potential future monetisation. The large distance from shore and from sizeable natural gas markets, the unique environmental conditions of 'iceberg alley', and various inter-related factors are an **economic barrier to pipeline export**.

iii) The NL offshore petroleum sector has more **similarities with conventional offshore oil producing regions** worldwide than it has with onshore oil production elsewhere in Canada (especially oil sands). Similar offshore technology is employed in Europe's North Sea, the US Gulf of Mexico, offshore Brazil, offshore West Africa, and various regions of offshore Australasia. Appropriate technology and regulatory experiences from these regions have been used for comparative purpose within this study, in particular AMEC's extensive database and experience from the offshore European North Sea.

iv) The **NL facilities employ one of two types of construction, GBS or FPSO**. Whilst these are of quite different physical design, the main energy intensive process technology used on board the facilities for the produced oil, natural gas, and water processes is in general very similar. Being maritime vessels, however, the FPSO facilities are unique in requiring periodic 'off-station' maintenance, whereas maintenance turnarounds on the GBS are done 'in-field'. This impacts the implementation timescale for any major retrofit work which requires planning outside of production-critical operations.

v) The three most significant industry sector high level characteristics impacting GHG emissions and the potential for GHG emission reductions are; firstly the **lack of an electricity grid** infrastructure (requiring local power generation at facilities), secondly the **lack of a natural gas export pipeline** (requiring a prudent gas utilisation strategy), and thirdly the difficulty of integrating facility operations with other sectors of industry (e.g. via conventional CHP or CCGT technology). A major conclusion of this report is that **these factors play such a significant role in constraining the range of GHG reductions opportunities in the sector, that they warrant special consideration within GHG regulatory policy**, if the national and international market competiveness of NL offshore facilities is to be retained. An analogy in other regulatory jurisdictions is the way that the EU-ETS Phase III (from January 2013) has recognised the need to accommodate specific measures and allowances for sectors deemed most at risk to 'carbon leakage' with respect to economic disadvantage risk; Offshore Petroleum is one of these sectors.

2.2 Offshore Resource Management

i) The resource management of the associated gas has a direct relationship with sector GHG emissions and for the potential for GHG emission reductions at facilities. This is a common situation worldwide for offshore facilities processing significant amount of associated gas. It is particularly acute where, as in NL, there is no established natural gas export infrastructure. The NL offshore petroleum regulator **C-NLOPB has in place a comprehensive approach to monitoring gas utilisation** profiles.

ii) On each facility, the separation of produced oil from the associated natural gas and water uses similar processes. **Separating and offloading the crude oil to tanker is of itself a relatively low energy intensive process**. However, the majority of the produced gas is re-injected back into the field via a high pressure (high energy intensive) gas compression process. Depending on reservoir specifics this gas re-injection serves the dual purpose of preserving natural gas resources whilst also helping to maintain reservoir pressure to help prolong oil production flow rates and to optimise cumulative oil extraction volumes from available oilfield reserves.

iii) In addition to **gas re-injection**, reservoir pressure is maintained to enhance / prolong oil recovery via a high pressure process of sea **water injection** into the reservoir. After gas re-injection, water injection is the second most **energy intensive process duty** on all four NL offshore facilities. Critically, because relatively steady gas re-injection and water injection duties are required in the face of gradually falling oil production rates, in a BAU case offshore facilities (worldwide, not just in NL) are **characterised by rising energy intensity as oil production declines** from peak. The rate of production decline can be slowed by tying-back new discoveries to the facility, something which is generally slightly easier to do for GBS facilities than it is for FPSO. FPSO on the other hand have the potential to be re-fitted and re-deployed to new field locations once the production from a field reaches its economic end of field life (cessation of production).

iv) Because the gas is 'stranded', gas which is not re-injected or which cannot be used as fuel gas to generate power on the facilities for driving the energy-intensive processes is flared locally to atmosphere at each facility. The amount of **flaring is sensitive to production process stability** and to the design capacities of process equipment items across the design life of each field. Process plant stability is highly sensitive to process **equipment reliability and performance**, which in turn is sensitive both to plant configuration and to plant **operations and maintenance best practices**. It is therefore considered that **Flare Management** has to be a core focus area for GHG abatement on all offshore facilities. **The C-NLOPB already addresses this focus area with facilities by agreeing facility-specific flare allowances and flaring procedures**.

v) Natural gas resource management is therefore one of the greatest challenges of the offshore sector and is a core focus area for both the C-NLOPB regulator and the facilities. Good gas resource management will also generally translate into good GHG management. For the sector as a whole (and ignoring facility commissioning periods when flaring is highest) **the proportion of produced gas volume being separated and conserved via gas re-injection has improved gradually over the past decade** from being marginally below 85% of total gas production in 2004 to being marginally above 90% today (2010 official data). However, there are significant variations between facilities. Data for 2011 indicates that the figure for Hibernia GBS is highest (around 92%), that of Sea Rose FPSO is lowest (slightly below 75%), whilst Terra Nova FPSO is in the middle (around 87%). This is largely due to the unique factors at each facility.

2.3 Sources of GHG Emissions

i) The vast majority [redacted] of GHG emissions on all existing offshore projects is the result of CO_2 emissions arising either from the **consumption of natural gas fuel** (a fraction of the associated gas) in simple-cycle combustion gas turbines used for power generation, or in the **safety flaring** of natural gas during both **normal and upset / emergency** process scenarios. Respectively, these are **'fuel' and 'non-fuel'** categories, and although formal reporting to the Environment Canada large facility emitter database does not explicitly require these to be disaggregated, this is useful in the current context.

ii) All NL facilities use **simple-cycle medium size gas turbines for power generation**, as electricity generators (for powering motors driving process and utility equipment) or alternatively for direct mechanical drive of the gas re-injection compressors. This is standard power generation equipment in the offshore petroleum industry, and is a direct consequence of a lack of economically-viable connection to onshore grids. Due to the remote location constraints, more thermally-efficient combined cycle gas and steam turbine **CCGT configurations or integrated CHP solutions are not as practical offshore**, compared to their use as BAT in onshore facilities close to industrial complexes. This is an inherent disadvantage of the offshore location.

iii) Natural gas **safety flaring comprises three generic elements**; firstly a **background flare** comprising pilot, purge, flash gas, and routine leaks to flare arising from normal

stable operations, secondly additional **flaring arising from periodic controlled changes in process duty**, and thirdly **emergency flaring** arising from process upsets, major equipment trips, and production shutdowns / re-starts. Frequent or prolonged flaring as a result of upset/emergency leads to a step-increase in GHG emissions from non-fuel use, and commonly results from unplanned trips of the gas compressors, whereby the large gas volume has to be relieved locally at flare to prevent unsafe gas pressure build-up on the facility. The **C-NLOPB issues strict procedures for the practice and reporting of emergency flaring** by facilities.

iv) Between 2004 and 2007 (ignoring 2006 when White Rose was being commissioned and Terra Nova was on major off-station turnaround), the proportion of sector CO_2 emissions arising from flaring (non fuel) was [redacted] This could be deemed as being a relatively high proportion of flaring in relation to combustion plant emissions.

v) Since 2007 (the year after White Rose came on), the sub-total **CO_2 emissions from fuel consumption for the sector have remained fairly steady** at just over [redacted] ktonnes CO_2, despite declines in oil production. The main reasons for this de-coupling of fuel gas consumption from oil production relates to gas and water injection duty.

vi) In comparison the **CO_2 emissions from flared gas (non fuel) wastage have reduced from being just below [redacted] ktonnes in 2007 to around [redacted] ktonnes in 2010**. As a result, between 2007 and 2011, total CO_2 emissions for the sector have reduced from ~2,000 ktonnes to ~1,500 ktonnes due primarily to reduction in flaring; CO_2e emissions due to flaring have dropped from being [redacted] of total CO_2 emissions to being [redacted] over this period.

vii) Sector GHG emissions from flaring have been reduced significantly year on year over the past 5 years largely due to implementation of flare management best practices on all facilities, in line with falling C-NLOPB flare allowances. However, flaring still accounts for a significant proportion of overall GHG emissions in the sector, being [redacted] in 2010 and [redacted] in 2011.

viii) The amount of GHG (CO_2e) emissions from other sources is relatively small in comparison with gas combustion and gas flaring and includes; diesel combustion for power generation (when oil and gas production is interrupted and natural gas is not available to burn), venting of methane rich natural gas and of volatile organic compounds from vessels, storage tanks and transfer equipment during crude oil unloading to tanker. The turbines for electricity generation are dual fuel, normally run on natural gas but are capable of being switched to diesel when gas plant is down. For all facilities, however, **operation on diesel is kept to a minimum**, and generally restricted to plant outages to supply accommodation and emergency loads only.

2.4 Combustion Plant Characteristics

i) The two FPSO facilities (Sea Rose and Terra Nova) are 'all-electric' facilities. They have combustion gas turbines used solely to generate electricity, and their main process equipment items including gas compressors and water injection pumps are all driven by electric motors. This is a common configuration on FPSO where space and weight are at a premium. Sea Rose has 3 x Rolls Royce RB211 gas turbines and normally runs [redacted] whilst Terra Nova has 2 x GE Frame 6 gas turbines and normally runs [redacted] **On Terra Nova the lack of a standby gas turbine combined with only a single process compressor train is a significant practical design constraint with respect to operations and maintenance strategy**.

ii) Hibernia and Hebron have a split configuration more commonly found in the design of fixed platform facilities worldwide. They have some **gas turbines for electricity generation and others for mechanical drive** of the large gas compressor trains. Hibernia has 4 x LM2500 gas turbines, with 2 generating electricity and 2 others directly driving the [redacted] duty gas compressor trains. With respect to most aspects of operation and maintenance this is a more flexible configuration. However, it does not necessarily translate into reduced GHG emissions, although it has potential to do so indirectly via better plant stability and/or more controlled response to upsets.

iii) The Hibernia and Sea Rose facilities use **aero-derivative gas turbine technology** (as will Hebron). These are more efficient at rated duty than the heavy industrial gas turbines used on Terra Nova. On all four offshore projects the **typical thermal efficiency of the gas turbine units will be in the range 25% to 40%** at normal duties, without any heat recovery of hot exhaust gases, where the majority of the energy from combustion is wasted up the exhaust stack. Highest thermal efficiencies will occur when operating closest to rated design, [redacted]

iv) Additional combustion duty is attributable to gas fired process boilers used for process heat generation and the emergency diesel generators used in shutdowns.

2.5 Main Energy Consumers

i) On all four offshore projects **the main energy consumers (energy demand side) are the gas re-injection compressors and the water injection pumps**. Together they account for close to [redacted] of the emissions arising from gas fuel consumption in the main gas turbine power generation plant. These consumers are therefore the 'big ticket' items for meaningful short and long term reduction of GHG emissions on the 'demand side' of the fuel category.

ii) Both FPSO facilities being vessels require positioning capability via internal weather vaning turret or thrusters. The Sea Rose FPSO (weather-vaning FPSO) does not make use of thrusters, whereas the Terra Nova FPSO (modified tanker) has a system of 5 thrusters, a sub-set of which are used to maintain heading during crude offloading. The

electric power duty of the **thrusters** is another significant but intermittent/variable load dependent on weather and sea state.

2.6 Production, Energy and GHG Intensity

i) **All three existing facilities are beyond their peak oil production rates but continue to require high levels of energy use**. By end of 2011, Hibernia (peak in 2004) was at ~75% of peak oil, Terra Nova (peak in 2003) was at ~33% and White Rose (peak in 2007) was at ~30%. Yet for all facilities the required energy from combustion fuel for power generation was relatively steady. The more rapid natural decline of FPSO facility oil production is a characteristic of the worldwide offshore industry since FPSO are more commonly used on projects as a lower initial capital cost alternative to fixed platforms where field reserves are smaller or lie in deep water.

ii) **A unique aspect of offshore oil production is that the energy intensity and the GHG emissions intensity (per unit of oil production) will tend to rise as oil production declines.** Gas compression and water injection pumping are the most energy intensive users of power generated from fuel combustion, and are designed to maximise oil production, such that the overall energy requirement on the facilities does not decline at as fast a rate as their oil production; the two profiles are largely independent of each other since plant equipment is largely fixed by upfront design.

iii) The historical energy intensity from fuel combustion at all three installations has increased significantly over the period 2007 to 2011 in line with static fuel use and declining oil production. In terms of overall GHG intensity this has been offset slightly by reductions in 'non-fuel' flaring over this period, particularly at Terra Nova and Hibernia. At the end of 2010 the GHG emission intensity (relative to oil production) was Hibernia (12.1 $kgCO_2$/boe), Terra Nova (19.6 $kgCO_2$/boe), and White Rose (20.8 $kgCO_2$/boe). The straight average of the three facilities in 2010 was 17.5 $kgCO_2$/boe, and the weighted average of total sector emissions was 16.4 $kgCO_2$/boe.

iv) **A realistic target for average intensity for the two FPSO in the period to 2020 is in the range [redacted] $kgCO_2$/boe**. Relative to 'years in production', the 2010 emission intensities of the FPSO facilities are slightly above the average business as usual GHG intensity of FPSO facilities in the North Sea (for similar age).

v) **A realistic target for average intensity for Hibernia GBS in the period to 2020 is in the range [redacted] tCO_2/boe**. Relative to current years in production, the 2010 GHG emission intensity of Hibernia GBS is in line with the average GHG intensity of platform facilities in the North Sea. A realistic target for Hebron is [redacted] $kgCO_2$/boe.

2.7 GHG Abatement Opportunities – Best Practice and Best Available Technologies

i) The main abatement opportunities can be logically split into '**Best Practices**' (BP) and '**Best Available Technologies**' (BAT) for each of the main process areas and each facility. In general the implementation of BAT will require higher capital project budgets

and in many cases will require planned shutdowns or off-station downtime. There is currently limited planned opportunity for this in the run-up to 2020.

ii) Discussions with the facilities and with C-NLOPB indicates that **a number of best practice flare management measures are already being followed, and have allowed flare rates at existing facilities to be brought down since 2007**. These include improvements to help minimise background emissions, and also improvements in the reliability of critical rotating machinery equipment items to reduce the frequency and duration of upset events which lead to spikes in flare rates.

iii) On the whole, and in the medium term (to 2020), **GHG abatement opportunities relating to flare (non-fuel) reduction best practices are likely to be more promising and cost-effective than abatement opportunities relating to fuel combustion reduction** at existing facilities.

iv) Flaring is currently attributable for [redacted] of GHG emissions for the sector. For the three existing NL facilities collectively, **improved flare management could amount to a further [redacted] reduction in GHG emissions for the sector from 2010 levels by 2020, with flaring dropping below [redacted] of total GHG emissions**. [redacted] One should also expect Hebron to quickly match low levels of flaring once it has completed commissioning, since it is likely to have many of the best practice measures built into the plant O&M philosophy. Experience from mature offshore sectors such as the North Sea indicates that it is possible for gradual improvement in implementing flaring best practices to allow the proportion of GHG emissions attributed to flaring to be reduced to a value in the range [redacted] of overall GHG emissions at oil facilities, without expensive technology. More rigorous use of BAT and investment as has occurred in Norway has resulted in levels in the range 10% - 15% at facilities.

v) **Flare gas recovery (FGR) technology recovers and recycles the background flare gas, and has the potential to reduce the sector GHG emissions from flaring further on top of standard best practice measures**. This could equate to a further reduction of [redacted] in overall emissions from 2010 levels by 2020. It would appear that a local robust 'safety case' review of FGR implementation has not yet been made by the industry and regulator C-NLOPB. It was considered for the Hebron project design but was rejected primarily for this reason. The technology has been field proven in the North Sea, has been widely deployed offshore in Norway (led fundamentally by offshore Operator Statoil) and on a handful of other projects worldwide. FGR is also currently being adopted as BAT for several deepwater FPSO facilities offshore Brazil, including by Statoil on the Peregrino FPSO. Statoil has a diverse exploration portfolio in Brazil in partnership with Petrobras, Repsol and others. In particular FGR has significant potential application for any new-entrant facilities to the NL petroleum sector. Given that Statoil have extensive experience of FGR in the North Sea and are deploying this elsewhere, it could be reasonable to anticipate that this technology might feature in the design appraisal of the future development of the Mizzen project in offshore NL.

vi) With respect to **stationary combustion plant, aero-derivative gas turbines are widely in use** (on all facilities except Terra Nova), and represent existing BAT for offshore facilities. Terra Nova's industrial frame gas turbines are not quite as efficient but it would be prohibitive in cost, downtime, and risk to justify replacement. However, for all gas turbines in use, incremental thermal efficiency improvements in the order of [redacted] – [redacted] might be achieved by implementing the turbine OEM's latest technology upgrades, including improved turbine hot section components. The best time to consider these upgrades is when each gas turbine reaches its next scheduled major-overhaul milestone. These occur infrequently (typically every 3-10 years) and as such this constitutes a medium term as opposed to short term opportunity, and one which would have to be planned coincident with major turnaround/off-station outages.

vii) **Terra Nova is unique in that it operates without a stand-by gas turbine and compression train plant equipment, which leads to operational and maintenance constraints in relation to plant uptime**. The potential to install a third power generation gas turbine (possibly a smaller aero-derivative unit) on the facility would contribute to improved O&M flexibility and would also potentially generate GHG reductions of up to [redacted] below the facility's 2010 overall GHG footprint.

viii) **Theoretically, on all facilities the increased use of waste heat recovery (WHR) from the gas turbine exhaust stacks has the largest potential for GHG reductions from stationary combustion activities**. However, in practical terms this is severely constrained by the lack of adequate process duty to utilise the full WHR potential; there is no large process requirement. It is for this reason that the WHR units that are fitted to existing facilities are working significantly under-capacity. Realistically, abatement opportunity is likely to be a few percent only, at best. More beneficial design implementations of WHR should be considered in future new entrant projects.

ix) There has been insufficient information-response from facilities to quantify the degree to which **combustion plant standard best practices** are already in place. Collectively these are estimated to have a GHG abatement potential up to [redacted] of combustion emissions, with a portion of this likely to have been already achieved by the facilities.

x) **The most productive abatement best practices relating to gas compression plant is to focus on areas which improve machine reliability and machine performance**. The former will reduce compression plant trips and hence help minimise emergency flaring, whilst the latter will help reduce power demand and hence reduce the fuel gas consumption in gas turbine units. There is insufficient information from operators to confirm to what extent standard best practices are being followed at facilities, but abatement opportunities (2010 to 2020) are likely to be in the range [redacted] of the sub-total of GHG from combustion activities.

xi) **Gas compressor re-wheeling (aerodynamic re-design of internal components) has abatement potential at key points in field life.** It helps re-optimise the compressor to changing production profiles over field life, but also provides a GHG abatement opportunity due to potentially lower energy duties. This is especially relevant to the

situation where gas injection flow starts to reduce within the bounds of natural field decline, though the use of fixed speed motor drives can constrain re-wheel opportunities.

xii) **Variable Speed Drive (VSD) technology for large motor drives is regarded as energy efficient BAT since it has the capacity to better match motor power consumption with changing process duty across the field life.** The existing three facilities utilise large water injection pumps (WIP) with fixed speed motors. These will have been sized for peak duties and will have limited turndown capacity later on in field life. The Hebron project is adopting VSD on its WIP motor drives. In the long term life of field, reductions in WIP energy use and combustion GHG emissions of the order of [redacted] can be achieved using VSD technology. There may be potential to retrofit VSD to existing installations during key turnarounds, although costs are likely to be higher than for new facility designs. VSD should be considered BAT on all new projects.

xiii) **Replacing WIP cartridge internals with latest high-efficiency designs may be another option for mature installations**, helping re-optimise pump 'sweet spots' with changes in process duty. This has more modest abatement potential in the order of [redacted] of WIP energy costs. Likewise WIP pipe work system pressures can be reconfigured throughout field life to generate similar levels of abatement opportunity.

xiv) Although not a high energy duty, crude oil stabilisation, storage, and offloading can be optimised using best practices and BAT to generate incremental savings. Use of closed loop inert gas systems and vapour recovery units can contribute to typically [redacted] reductions in overall GHG emissions. [redacted]

xv) The operation of weather-vaning positioning systems on FPSO facilities can reduce their electrical demands and contribute to modest improvements in energy efficiency. FPSO designs based on tanker conversions will likely require more energy for thrusters.

xvi) Fuel substitution is not regarded as having any significant potential offshore NL, since consumption of diesel fuel is already low and restricted to when gas plant is down. However, it does become a consideration for any new-entrants that might be gas-limited, and gas import pipeline infrastructure from surrounding facilities would be relevant.

2.8 GHG Abatement Opportunities – Emerging Technologies

i) Relevant emerging technologies should be considered for new projects post 2020. These include offshore mini-LNG, integrated CCGT systems, new motor technology, and power from shore options where distance is not a barrier. Experiences from other offshore regions (e.g. Europe, South America, Australia, West Africa) are relevant.

ii) Such emerging technologies could be ideal candidates for attracting investment from a Technology Fund, very much in line with how such funds are used for R&D in other jurisdictions. The Norwegian and the Brazilian offshore petroleum sectors are examples of where R&D investment into such technologies is currently underway, incentivised by access to funds generated via GHG regulation policy (Tech Funds or Carbon Taxes).

iii) Some emerging technologies could have important cross-sector benefits in addition to direct benefits within the NL offshore sector. For example, offshore technologies that enable the monetisation of NL offshore natural gas reserves (e.g. mini-LNG or pipeline) would potentially allow fuel substitution onshore in other industries; for example replacing fuel oil combustion with natural gas combustion in the NL onshore refinery sector. This would have economic and GHG benefits across multiple sectors.

2.9 GHG Policy Options and Criteria

i) The policy options evaluated in this study using the Navius GEEM model have been designed to draw insight about the impact of alternative policy designs. Given the level of uncertainty regarding alignment with the likely federal policy preferences, the policies covered do not necessarily correspond to a policy that is likely to be implemented by the government of NL, but rather the analytical value is in showing tradeoffs between different policy designs. This should be informative to NL policy in relation to considering alternative mechanisms towards achieving equivalency.

ii) This analysis examines performance standards under five scenarios with the "Base" scenario being the base against which all other policies are compared. The base scenario features the following characteristics; trading of Emissions Performance Credits (EPCs), access to a technology fund at $40 per tonne of CO_2e, but not access to offsets, a benchmark based on historic 2011 levels of emissions, and a 20% reduction in emissions from 2011 levels of emissions by 2020. Each additional scenario changes a single policy characteristic for comparative purposes.

2.10 GHG Policy Evaluation

The key findings from the policy analysis are:

i) The various performance standards reduce emissions by between [redacted] and [redacted] from their business-as-usual trajectory between 2010 and 2020. However, the choice of benchmark can have a dramatic impact on compliance costs.

ii) **The availability of a technology fund) achieves greater reductions in emissions and reduces compliance costs in comparison to the availability of offsets.** Allowing facilities to comply with a policy by accessing a technology fund ensures that revenues collected are used to reduce GHG emissions in the sector and also reduce compliance costs. The analysis highlights that greater reductions can be achieved from the sector with greater constraints on offset availability and greater emphasis on a technology fund. However, the analysis also acknowledges that investment opportunities for the technology fund do not necessarily need to be limited to the offshore oil industry, and could include opportunities in other sectors of the economy. In fact this may be optimal from a provincial GHG perspective if opportunities in other sectors have lower costs. As the technology fund is reinvested in other sectors of the economy, a policy will increasingly mimic the effect of the availability of offsets as shown in this analysis. The

use of a technology fund and offsets is already field trialed as part of Canadian provincial policy in other sectors of industry, and similarly as part of Norwegian offshore sector policy and EU-ETS Clean Development Mechanism (CDM). A technology fund is also at the heart of the Brazil's new offshore petroleum sector GHG policy; a growth petroleum region where significant numbers of FPSO projects are currently under approval.

iii) **The choice of benchmark affects the portion of compliance achieved through direct reductions and the level of contributions to a technology fund.** On one end of the spectrum, calling for a reduction from the benchmark approach used in the EU ETS would require fewer reductions, while on the other end a reduction in emissions intensity from a production-based 2011 benchmark would require significant reductions from the sector. In the latter policy, compliance with the policy would become increasingly difficult as each field matures. While this leads to greater contributions to the technology fund and greater reinvestment of the technology fund in low emissions options in the sector, it also substantially increases the cost of compliance.

iv) **Increasing the price for accessing the technology fund achieves greater reductions, but at a diminishing rate.** The main opportunities for reducing emissions from NL's offshore oil industry identified in this analysis are from flaring. These reductions have relatively low cost in comparison to most other fuel-based options. However, once these options have been undertaken, there are relatively fewer opportunities to achieve significant reductions in GHG emissions.

v) **The analysis explicitly shows that a policy design option based on an oil production benchmark would achieve GHG reductions at significantly greater cost in comparison to other options**. A production-based benchmark is difficult for the offshore oil industry to achieve due to the independence of relatively fixed combustion plant energy requirements with falling oil production rates. A benchmark based on historic emissions intensity becomes increasingly difficult to achieve even with maximum abatement from the sector. The balance must be met with either contributions to a technology fund or some other flexibility mechanism, which impose a financial transfer on the sector. If flexibility mechanisms are not available, this performance standard may not be achievable for some facilities, and they would either have to fall out of compliance or shut down. The findings of this study's NL analysis are in line with the independent third party findings for the European offshore petroleum sector under EU-ETS Phase III policy design, where production based benchmarks were deemed inappropriate to offshore facilities and a fuel (combustion) benchmark was used instead.

3.0 FACILITY PRODUCTION & GHG DATA

This section of the report summarises the source and details of facility production and GHG data used in the further technical analysis in terms of:

i) The historical field production data used in the analysis.

ii) The forecast field production estimates used in the analysis.

iii) The historical combustion fuel and non fuel (flare) data used in the analysis.

iv) The power generation data used in the analysis.

3.1 NL Offshore Oil & Gas Sector Production Data

3.1.1 Historical Production Data (2004 to 2012)

Historical field Production data for the three NL offshore facilities for the years 2004 – 2012 has been derived from the comprehensive monthly reports published on the C-NLOPB website. In particular annual (calendar year) information on the following production data was extracted from the C-NLOPB reports at http://www.cnlopb.nl.ca/stat_rm.shtml and used in the analysis.

i) Oil production data in mmbbls (million barrels) per year.

ii) Water production data in mmbbls (million barrels) per year.

iii) Associated gas production data in mmscf (million standard cubic feet) per year.

3.1.2 Forecast Production data (to 2025)

Forecast estimates for oil production from the facilities through to 2025 are available from public domain records, including the Hebron project Comprehensive Study Report (CSR) in [Ref 4]. The project team is aware that C-NLOPB forecasts for offshore have been revised more recently in 2012-2013 in line with latest information. The report does not reflect recent revisions. Note - gas production data and produced water data forecasts are currently not available in the public domain nor to this project. Therefore only analysis of historical data is possible and it has not been possible to consider levels or intensities relative to future gas or water forecasts.

3.2 Associated Gas Utilisation Data

Associated gas production from the fields can be broken down into the following categories:

i) Gas conserved via re-injection into the fields or re-circulated for gas lift in oil wells.

ii) Gas used as fuel gas for combustion activities on the facilities.

iii) Gas wasted at the facilities via flaring or venting processes.

Overall data has been downloaded from Environment Canada. Data for the split between fuel gas consumption (combustion activities) and flared gas volumes for the calendar years 2004 – 2011 has been based on information provided by C-NLOPB and Natural Resources. As part of the data analysis an estimate for the amount of gas re-injected has been derived by gas balance; by subtracting the fuel gas plus flared gas, from the gas produced, given that none of the installations export any gas. This estimate for gas re-injection would seem reasonable for the purposes used in this report.

3.3 Power Generation Data

Combustion fuel gas on installations is primarily used for power generation in combustion gas turbines, with secondary use in process boilers for onboard heating duty.

The following are the main categories of fuel gas use:

i) Fuel gas consumption in gas turbine units for power generation via high voltage electricity generation for power to large motor drives. This is applicable to all three existing facilities and also to Hebron.

ii) Fuel gas consumption in gas turbine units for power generation via direct mechanical drive of centrifugal gas re-injection compression units. This is applicable to Hibernia and Hebron project design.

iii) Fuel gas used in process boilers.

iv) Miscellaneous small amounts of LP fuel gas used for utility systems.

In addition diesel fuel is used primarily during periods when the gas plant is not available such as during maintenance outages or shutdowns/turnarounds.

The main gas turbine power generation duties at the three existing facilities are shown in Table 3.1, 3.2 and 3.3, along with their main operating parameters and assumptions used.



Table 3.1: Hibernia Platform – Main Gas Turbine Plant and Duty

Gas Turbine Make & Model	Duty – Description	Rated Duty (ISO) MW	[redacted]
GE LM2500 gas turbine generator (fitted with WHRU hot oil system)	Main Power generation	~25.0	
GE LM2500 gas turbine generator (fitted with WHRU hot oil system)	Main Power generation	~25.0	
GE LM2500 gas turbine generator	Mechanical Drive (MP & HP Compression)	~25.0	
GE LM2500 gas turbine generator	Mechanical Drive (MP & HP Compression)	~25.0	

Assumptions – Hibernia:

The two main power generation turbines operate predominantly as duty [redacted]
The two main mechanical drive turbines operate predominantly as 2 x [redacted] trains [redacted]
Rated duty show is representative of Manufacturers (GE) data as facility did not provide data.
Facility operator has not provided data on normal duty; it is assumed [redacted]

Table 3.2: Terra Nova FPSO – Main Gas Turbine Plant and Duty

Gas Turbine Make & Model	Duty – Description	Rated Duty (ISO) MW	[redacted]
GE Frame 6B gas turbine generator (fitted with WHRU hot oil system)	Main Power generation	~39.0	
GE Frame 6B gas turbine generator (fitted with WHRU hot oil system)	Main Power generation	~39.0	

Assumptions – Terra Nova:

The two main power generation turbines operate as 2 x [redacted] trains [redacted]
Rated duty show is representative of Manufacturers (GE) data as facility did not provide data.
Normal duty shown is based on June 2012 discussions with Facility Operator.

Table 3.3: White Rose (Sea Rose FPSO) – Main Gas Turbine Plant and Duty

Gas Turbine Make & Model	Duty - Description	Rated Duty (ISO) MW	[redacted]
R-R RB211 gas turbine generator	Main Power generation	~27.6	
R-R RB211 gas turbine generator	Main Power generation	~27.5	
R-R RB211 gas turbine generator	Main Power generation	~27.5	

Assumptions – White Rose:

The three main power generation turbines operate as 3 x [redacted] trains [redacted]
Rated duty show is representative of Manufacturers data and confirmed by Facility Operator.
Normal duty shown is based on June 2012 discussions and data provided by Facility Operator.

4.0 PRODUCTION BASED GHG INTENSITY

The analysis covered in this section of the report is to review and compare emissions intensity approaches using the following production-based criteria for the intensity denominator:

i) The application of a "produced oil" denominator including oil only.

ii) The application of a "total petroleum products" denominator including oil and gas production, with produced gas expressed as MMboe. Note that the gas produced is not exported but is either re-injected (~90%), used as fuel (7-8%) or flared (2-3%). The inclusion of produced gas would be contextually easy to justify given that it has a direct relationship to the energy being consumed for gas re-injection/conservation.

iii) The application of a "total fluids" denominator including oil, gas and water where produced gas is expressed as MMboe, and produced water as MMbbls. Note that the inclusion of produced water would be contextually difficult to justify given that it has no direct relationship to the energy being consumed, and also given that, unlike the produced gas it has no inherent production value.

4.1 Historic Production based GHG Intensity

Hibernia – Figure 4.1a and 4.1b show the historic production and emissions data. Figure 4.1c shows the corresponding intensity using the three different denominators. Figure 4.1d shows the forecast oil production based intensity to 2025. Historically (2004 – 2011) oil, gas and water production has been relatively steady, with a slight fall off after peak oil. However, over the same period reduction in flaring has allowed GHG emissions to reduce in line with production. However, flaring has now reduced to relatively low levels with limited further reduction possible.

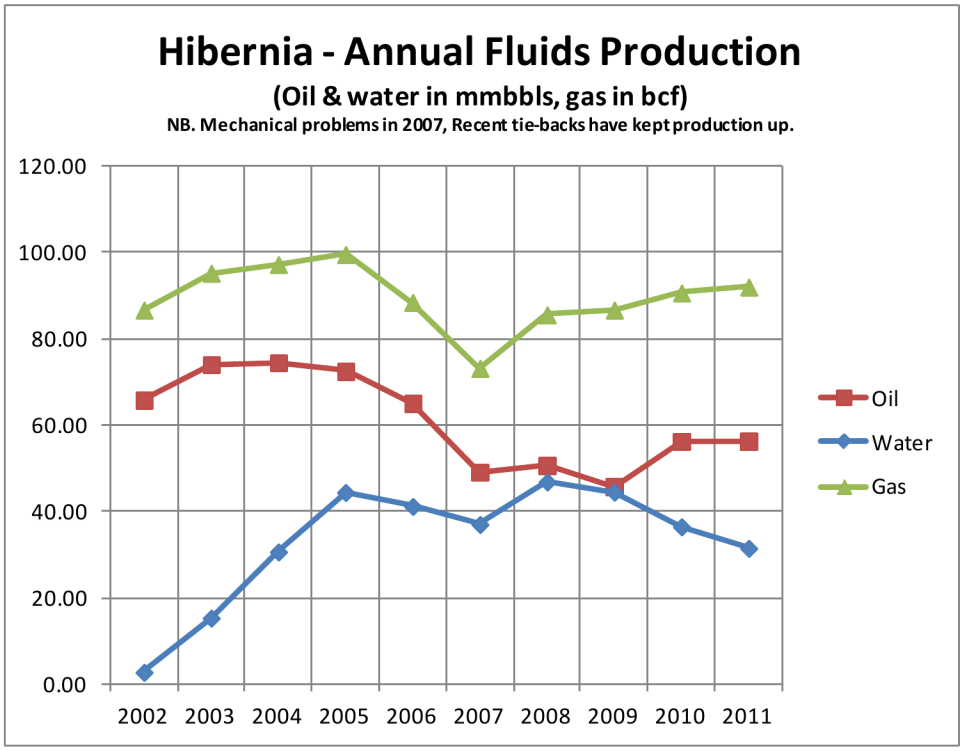
Terra Nova – Figure 4.2a and 4.2b show the historic production and emissions data. Figure 4.2c shows the corresponding intensity using the three different denominators. Figure 4.2d shows the forecast oil production based intensity to 2025. Oil production is already in natural decline with limited new production well tie-backs. Gas and water production has been rising. All three emissions intensity metrics indicate an upward trend.

White Rose – Figure 4.3a and 4.3b show the historic production and emissions data. Figure 4.3c shows the corresponding intensity using the three different denominators. Figure 4.3d shows the forecast oil production based intensity to 2025. Oil and gas production are in natural decline with the gas re-injection being to storage pool. Water production is increasing significantly.

4.1.1 Forecast Production based GHG Intensity

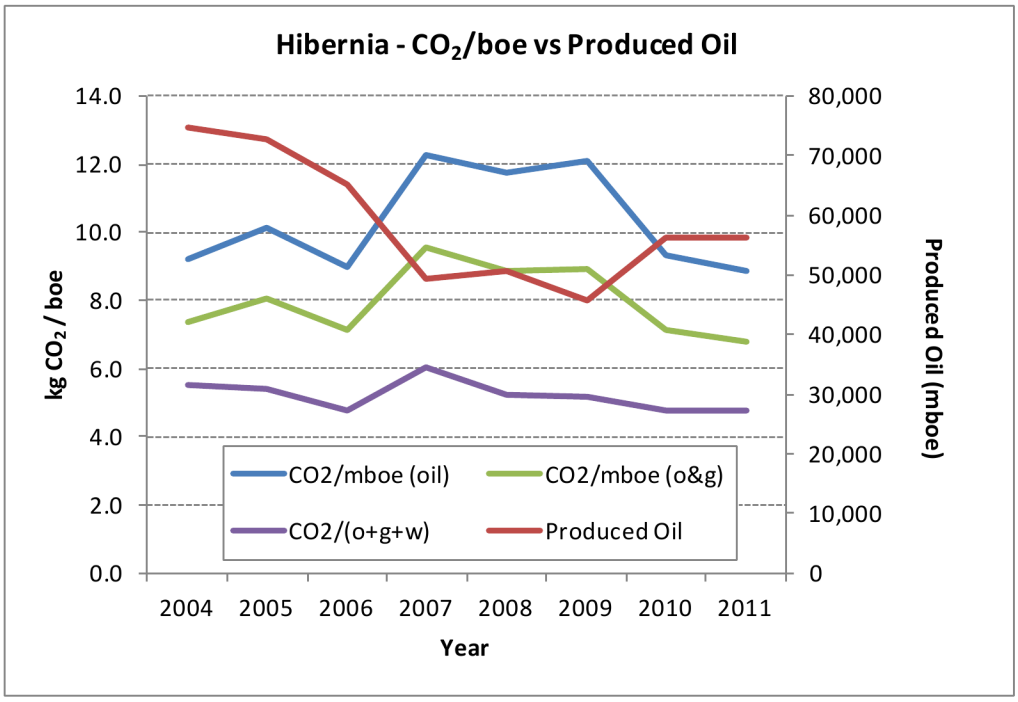
For all three facilities the data shows that for the forecast oil production and GHG to 2020 and beyond it is expected that the GHG production based intensity will rise. This is most significant for the two FPSO, where oil production decline is steepest. One might expect the GHG intensity expressed in terms of denominator using one of the other two metrics to also increase, though at a slower rate. No gas or water forecasts are currently available with which to verify this.

Figure 4.1a Hibernia - Historic Production



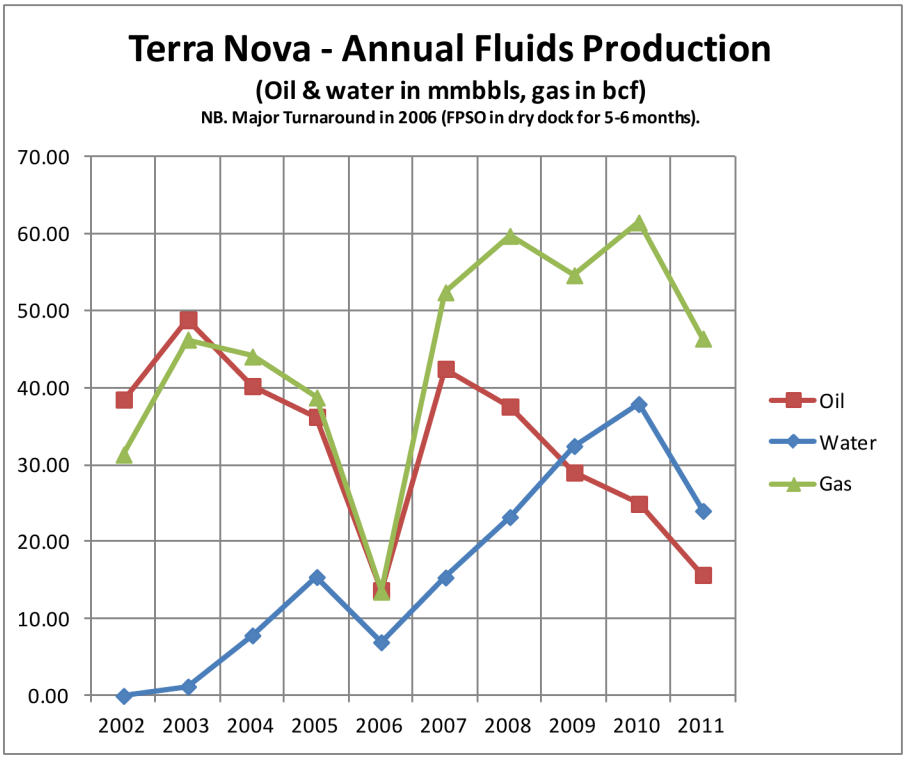
[redacted]

Figure 4.1c Hibernia - Historic GHG Emissions Intensity



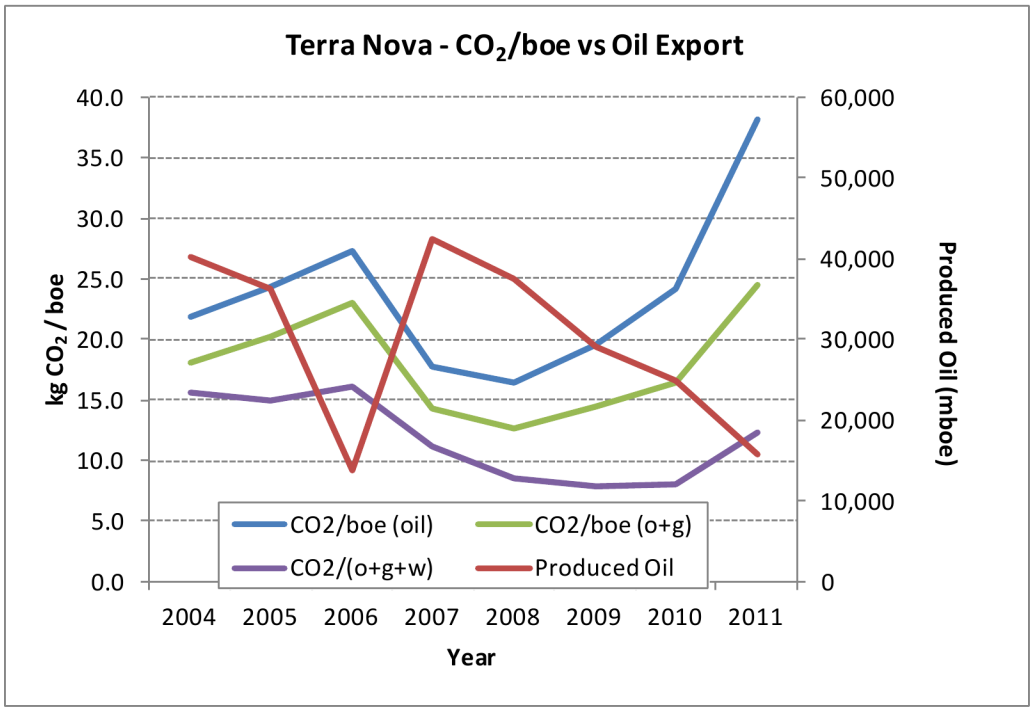
[redacted]

Figure 4.2a Terra Nova - Historic Production



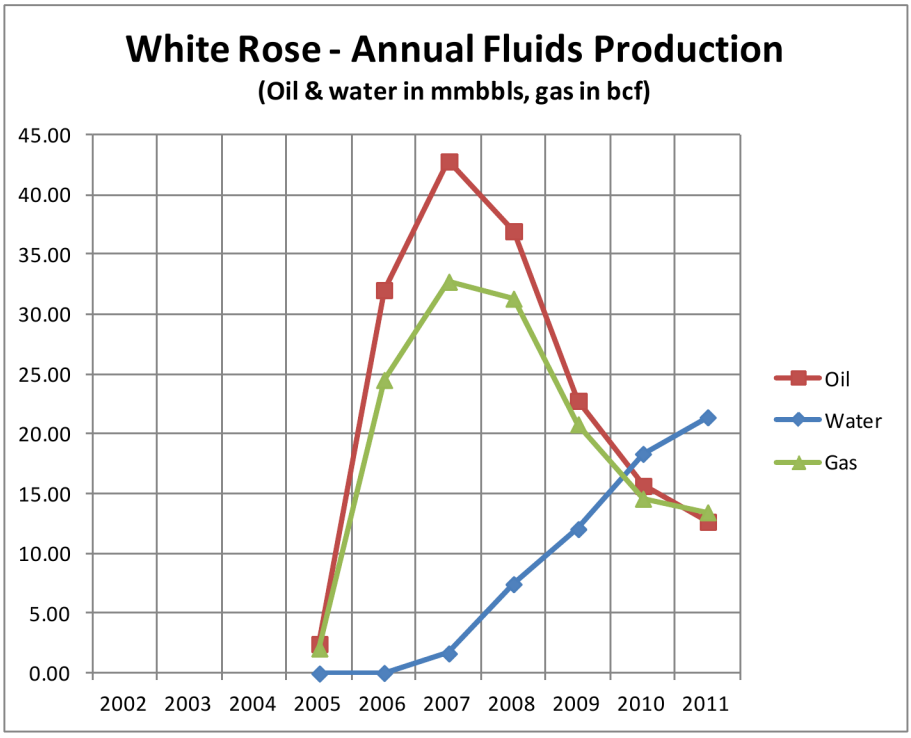
[redacted]

Figure 4.2c Terra Nova - Historic GHG Emissions Intensity



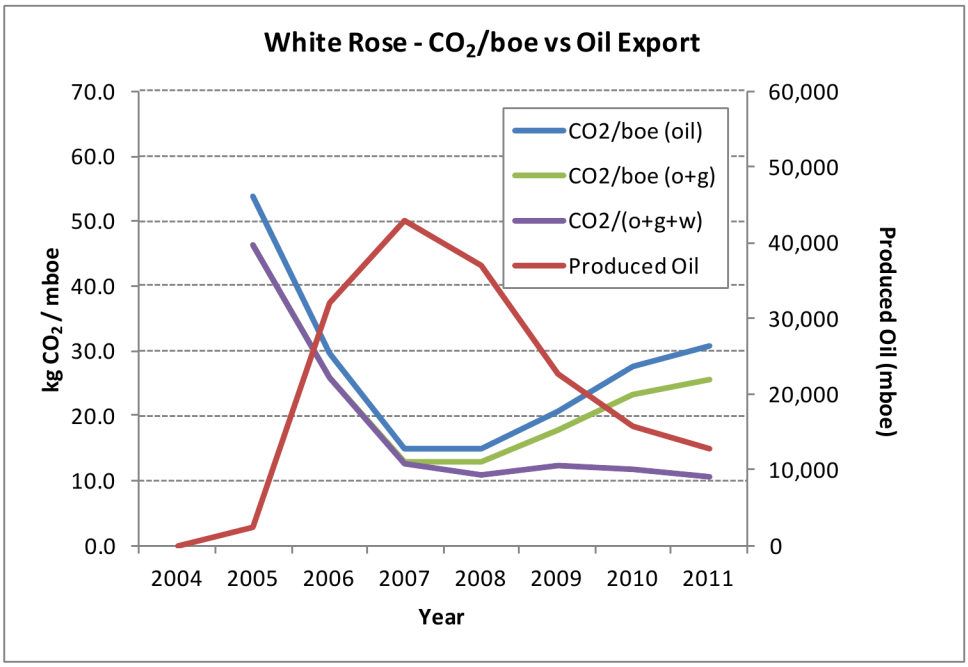
[redacted]

Figure 4.3a White Rose - Historic Production



[redacted]

Figure 4.3c White Rose - Historic GHG Emissions Intensity



[redacted]

5.0 PERFORMANCE STANDARDS

This section analyses and discusses the emissions intensity of the power generation technology used at NL offshore petroleum facilities relative to the performance standard which has been established under the new federal Coal-Fired Electricity Regulations [Ref 3], and considers what a suitable equivalent natural gas performance standard might be for the offshore sector.

The purpose of this analysis is to inform the NL provincial regulators and industry stakeholders of the implications of applying performance standards with respect to CO_2 emissions arising from fuel combustion in power generation units located at offshore facilities. Such facilities are in remote offshore locations and are 'off grid' with respect to the facilities' access to less carbon-intense sources of electricity, unlike onshore combined cycle power stations or industrial sectors connected by grid to hydroelectricity supplies.

5.1 Background to Performance Standard

5.1.1 Canadian Coal-Fired Electricity Regulations

The Canadian Federal Government proposed (gazetted) in August 2011 and in September 2012 they announced final federal regulations for reducing greenhouse gas (GHG) emissions from coal-fired electricity generation. The regulations apply a stringent performance standard to new electricity generation units and old units that have reached the end of their economic life. The new performance standard for coal-fired electricity generating facilities will come into force on July 1st 2015.

The performance standard establishes a CO_2 emissions intensity limit of 420tonnesCO_2/Gwh. A new unit or an old unit must not, on average, emit with an intensity of more than 420 tonnes CO_2 emissions from the combustion of fossil fuels in the unit for each GWh of electricity produced by the unit during a calendar year. The CO_2 emissions from a unit do not include emissions that are captured, transported, and stored via Carbon Capture & Storage (CCS) technology.

The purpose of the regulations is to provide a mechanism to incentivise new or replacement fossil fuel power generating stations to reduce their intensity, by using high-efficiency natural gas plant, and specifically for any coal fired power stations to adopt CCS technology.

5.1.2 Combined Cycle Technology

The performance standard limit of 420 tonnesCO_2/Gwh (420 gCO_2/kWh) is set at an emissions intensity level similar to that which is already achievable and in routine onshore application using natural gas combined cycle (NGCC) technology. Combined Cycle technology combines gas turbine and steam turbine technology in an integrated electricity generating facility; where gas turbine electricity generation, gas turbine exhaust heat recovery steam generation (HRSG), and additional steam turbine electricity generation are combined together in an integrated plant.

The thermal efficiency of natural gas combined cycle plant technology is typically in the range 40% to 60%. In addition to the power generated in the main gas turbine, approximately half as much power again is generated in the steam turbine from heat recovery of gas turbine exhaust gases. The latest developments in large modern integrated high efficiency combined cycle plant are pushing the 60% net thermal efficiency boundary. The norm for smaller less optimised CCGT plant is either side of the 50% efficiency band. The performance standard limit of 420 tonnesCO_2/GWh (420 gCO_2/kWh) corresponds to a modest combined cycle plant efficiency of 43%-45% based on calculations using typical heating value and CO_2 emission factor values for Canadian natural gas fuel when used in CCGT technology.

Note, in its 2012-2013 Energy Bill the UK Government is seeking to implement a similar GHG emission performance standard for its onshore electricity generation sector as a whole. The UK government is setting a performance standard limit of 450 tonnesCO_2/GWh up until 2044.

To date there has been very limited application of CCGT in offshore oil and gas plant. There have been three applications in the Norwegian sector of the North Sea installed as new units at offshore gas installations; at Oseberg, Snorre B, and Eldfisk offshore platforms. These use a relatively compact and lightweight once-through Heat Recovery Steam Generator (HRSG) technology in the gas turbine exhaust to power onboard steam turbine for additional power generation. This achieves an offshore benchmark thermal efficiency of 50%. Apart from such rare applications the vast majority of offshore installations use simple cycle gas turbines or steam turbines, as opposed to both technologies integrated in CCGT.

5.2 Analysis of Offshore Power Generation Emissions Intensity

5.2.1 Simple Cycle Gas Turbine Technology

In contrast to combined cycle gas turbine power generation plant, simple cycle gas turbine power generation units do not include steam generation and steam turbine power generation equipment. They may however, employ waste heat recovery in the turbine exhaust stacks to achieve some heat transfer to process fluids (e.g. via a hot oil system), but this typically involves much less energy recovery than in a CCGT integrated plant.

In common with the vast majority of offshore petroleum (oil and gas) production facilities worldwide, the three existing NL offshore projects and the new Hebron project all utilize simple cycle gas turbine plant for power generation. These items of equipment are the main consumers of combustion fuel; primarily natural gas fuel, with diesel fuel as standby for non-process essential electric loads (including accommodation and propulsion) during production downtime. A summary of the main gas turbine equipment used has already been given in Section 3.

The Hibernia and White Rose facilities utilize aero-derivative gas turbine units with a maximum simple cycle thermal efficiency at rated duty in the range 35% - 40%. The Terra Nova facility utilizes industrial frame gas turbine units with a maximum simple cycle thermal efficiency at rated duty in the lower range 30% - 35%. In all cases the efficiency at duties below maximum

rated design duty will be less than this. Where waste heat recovery is fitted the process duty is relatively low, for example for occasional oil stabilisation purposes only.

It should be noted that on White Rose and Terra Nova the power generated by the gas turbines is used solely to generate electricity. On Hibernia this is the case for two gas turbines, whereas for the other two the power generated is used for direct mechanical drive of the re-injection compressors. In the analysis in this report no distinction is made between power generated as high voltage electricity (for driving motors) and power generated for mechanical direct drive. In some jurisdictions a distinction has been made between these duties; in the EU-ETS for example fuel consumption and emissions from mechanical drive turbines are eligible for allowances whereas those from off-grid electricity generation offshore has been regulated under similar rules as onshore electricity generation (grid supply) and is not eligible for allowances.

5.2.2 Power Generation Emissions Intensity Calculation Approach

The following approach has been used here to calculate an estimate of the emissions intensity for the NL petroleum sector offshore gas turbine plant in terms of tonnesCO_2/Gwh.

Inputs required:

i) The typical operating duty (power generation load) of the gas turbines at a facility.

ii) The corresponding thermal efficiency of the gas turbine units at the typical duty.

iii) The fuel gas heating value in MJ/m^3 where the m^3 is at standard conditions.

iv) The CO_2 emission factor in gCO_2/m^3 where the m^3 is at standard conditions.

Note: Gas turbine utilisation (uptime during the year) is not required as an input to calculating intensity, but is required in order to calculate annual emissions from the emissions intensity.

The calculation of **emissions intensity** uses the following formula based on the above inputs:

Given that 1 GW = 1000 MW (MJ/s) and that 1 tonne (t) = 1,000,000 g and 1hr = 3600 secs:

$$\textit{Emissions Intensity } (tCO_2/GWh) = \frac{1000\ (MJ/s) * 3600 * \textit{Emission Factor } (gCO_2/m^3)}{\textit{Efficiency} * \textit{Fuel Heating Value } (MJ/m^3) * 1{,}000{,}000}$$

For calculation of **annual emissions** from fuel combustion in a given power generation plant:

Annual Total Energy (GWh) = (MW power output / 1000) * 24 * 365 * Utilisation factor on gas (%)

The Annual Total CO_2 emissions from fuel gas combustion is then Annual GWh * tCO_2/GWh.

5.2.3 Power Generation Emissions Intensity for Offshore Facilities

No facility-specific information has been provided by Operators or CCEEET for the above calculation inputs, and therefore reasonable estimates and assumptions have been used instead as stated below.

i) The thermal efficiency of the gas turbines has been based on manufacturer's brochure efficiency data for the relevant gas turbines adjusted for estimated actual operating duty of the gas turbines at the facilities in line with Section 3 assumptions.

ii) The fuel gas heating value has been based on typical Canadian data available in the CAPP guide for calculating GHG emissions as follows [Ref 5] – see Table 5.1:

   a) The typical energy content of marketable natural gas is 37.4 MJ/m^3
   b) The typical energy content of raw natural gas is 46.0 MJ/m^3

iii) The CO_2 emission factor in gCO_2/m^3 has been based on the data contained in Canada's National Inventory Report 1990 – 2010 submitted to the UNFCCC in 2012 as follows [Ref 6] – see Table 5.2 extract from Annex 8 of the NIR:

   a) The typical emission factor for marketable natural gas is 1891 gCO_2/m^3
   b) The typical emission factor for unmarketable (raw) natural gas is 2482 gCO_2/m^3

It should be noted that the fuel gas heating values and CO_2 emission factors for natural gas quoted above may differ from the actual values applicable to NL offshore facility-specific gas compositions. However, it is considered that these factors will be reasonably accurate for the NL offshore facilities for the purposes used here, on the basis of methane rich natural gas.

Table 5.1: Canadian Natural Gas Heating Values

Source: CAPP Guide to Calculating GHG Emissions (2003)

Table 1-5: Energy Content of Fuels

Fuel	Energy Content HHV (Gigajoules)
Natural gas (per 10^3 m^3)	37.4
Natural gas, raw/unprocessed (per $10^3 m^3$)	46.0
Liquid ethane (per m^3)	18.5
Liquid propane (per m^3)	25.4
Liquid butane (per m^3)	28.7
NGL (natural gas liquids, per m^3)	27.5
Crude oil, light & medium (per m^3)	38.5
Crude oil, heavy (per m^3)	41.4
Crude oil, bitumen (per m^3)	42.8
Aviation gas (per m^3)	33.5
Motor gasoline (per m^3)	34.7
Kerosene (per m^3)	37.7
Diesel fuel (per m^3)	38.7

Taken from ERCB 91-A and Environment Canada's "Inventory Methods Manual for Estimating Canadian Emissions of Greenhouse Gases".
HHV is higher heating value.

Table 5.2: CO_2 Emission Factors for Natural Gas Fuel Combustion

Source: Canada's 2012 UNFCCC Submission (GHG NIR)

Table A8–1 CO_2 Emission Factors for Natural Gas

Province	Emission Factor[3] (g/m^3)	
	Marketable[1]	Non-marketable[2]
Newfoundland and Labrador	1 891	2 482
Nova Scotia	1 891	2 482
New Brunswick	1 891	NO
Quebec	1 878	NO
Ontario	1 879	NO
Manitoba	1 877	NO
Saskatchewan	1 820	2 429
Alberta	1 918	2 380
British Columbia	1 916	2 151
Yukon	NO	2 389
Northwest Territories	2 454	2 454

Notes:

NO = Not occurring

1. The term "marketable" applies to fuel consumed by the Electric Utilities, Manufacturing Industries, Residential/Commercial and Transport subsectors.
2. The term "non-marketable" applies to raw gas consumption, mainly by natural gas producers.
3. Adapted from McCann (2000)

Canada's 2012 UNFCCC submission provides the following explanation for the different emission factors shown in Table 5.2[Ref 6]:

Quote *"CO_2 emission factors for fossil fuel combustion are dependent primarily on fuel properties such as carbon content, density and heating value and, to a lesser extent, on the combustion technology. For natural gas, there are two major qualities of fuel combusted in Canada: marketable fuel (processed for commercial (sale) and non-marketable fuel (unprocessed for internal use). As of 2007, there are nine regions in Canada that produce natural gas for commercial sale and/or for internal consumption, resulting in regional variations of marketable and non-marketable natural gas. Provincial and territorial emission factors (Table A8–1) have been developed based on data from chemical analysis of representative natural gas samples (McCann 2000) and an assumed fuel combustion efficiency of 99.5% (IPCC/OECD/IEA 1997). Non-marketable natural gas emission factors are higher than those of marketable fuels as a result of its raw nature, which may include ethane, propane and butane in addition to methane in the fuel mix."* Unquote.

Therefore, for calculations based on the NL offshore sector the relevant provincial values from table 5.1 and Table 5.2 have been used.

The results of the calculation for the three NL offshore petroleum facilities is given in Table 5.3. Note that this table includes calculations based on both the typical 'marketable natural gas' quality and the typical 'un-marketable natural gas' quality. For the purpose of the rest of the discussion in this chapter reference is made to the latter calculations since the combustion of natural gas at NL offshore facilities is at the raw (unprocessed) quality.



It should be noted that the calculation of power generation emissions intensity factor is dependent on generation plant thermal efficiency and fuel type. The calculations in Table 5.3 are based on the estimated simple cycle gas turbine efficiencies shown (at normal facility power generation duties) and operation on natural gas fuel with the properties given in Table 5.1 and 5.2. Overall annual emissions will depend on actual turbine plant operation. Table 5.2 illustrates two scenarios, the first based on [redacted] uptime (highlighted in pink), with all of this on gas fuel, and the second is based on [redacted] uptime with all of this on gas fuel. In reality there will also be some operation on diesel fuel during production downtime. This is not included in the Table 5.3 illustration. However, it is important to note that since the CO_2 emission factor for diesel is higher than that of natural gas for similar fuel energy input, any diesel consumption will bias the intensity and sub-total emissions from power generation fuel consumption higher than shown.

5.2.4 Implications of an Offshore Power Generation Performance Standard

It can be seen from Table 5.3 that for all three offshore facilities their typical power generation CO_2 emission intensity factor in tCO_2/GWh is higher than the performance standard for coal-fired power generation stations of 420tCO_2/GWh. The typical values for the offshore facilities are in fact estimated to fall in the range of [redacted] tCO_2/GWh to [redacted] tCO_2/GWh when burning natural gas fuel at typical power generation duties and corresponding efficiencies, and would be higher still during brief periods if burning diesel. This difference corresponds to a percentage of between [redacted] and [redacted] higher than the performance standard value of 420 tCO_2/GWh, with the average for the offshore sector (the three existing projects) being around [redacted] higher.

The difference is a direct result of the offshore simple cycle gas turbine power generation plant operating with thermal efficiencies much lower than a typical onshore NGCC / CCGT plant. The 420 tCO_2/GWh in the coal-fired regulations is based on typical high efficiency natural gas plant technology. Even at maximum simple cycle aero-derivative gas turbine rated duty the difference is significant. The difference is particularly higher for Terra Nova because the facility employs industrial frame gas turbines which have lower thermal efficiency than the aero-derivative gas turbines employed on Hibernia and Sea Rose.

At the level of intensity calculated, relative to the natural gas performance standard the offshore facilities are estimated to produce additional emissions (over and above the level that would be achieved if they could meet the 420 tCO_2/GWh standard) of between [redacted] and [redacted] tCO_2/year for each facility. Whereas the sector annual CO_2 emissions from fuel gas consumption using current offshore power generation technology at typical simple cycle gas turbine efficiencies is in the region of [redacted] ktonnesCO_2/year (actual 2011 data for 3 facilities), achieving the natural gas performance standard would equate to emissions from fuel combustion having to come down by one third to around [redacted] ktonnesCO_2/year.

The efficiency characteristic for a gas turbine is highest at base load duty and reduces with load reduction. Therefore, for the fixed power generation technology offshore, any reduction in load demand (due to improved process unit demand side efficiency) leading to reduced power generation and reduction in actual CO_2 emissions, will in fact lead to an increase in the emission intensity factor in terms of tCO_2/GWh, since the factor is related to thermal efficiency and gas composition only. This has the potential to be counter-productive to the objectives of incentivising a reduction in GHG emissions offshore, if technologies to improve power generation efficiency are not practical in the offshore location.

It would only be possible for offshore facility power generation units to meet a performance standard of 420 tCO_2/GWh by doing one of two things; either by installing CCGT technology or by installing CCS technology. Neither of these is so far sufficiently field-proven for adoption in the remote offshore petroleum sector, and even once proven, the technology will require considerable expense for new projects, let alone to try to retrofit to existing facilities. Space and weight restrictions alone limit these technologies as retrofits to existing offshore installations.

The above analysis only considers the CO_2 emissions from primary fuel (natural gas fuel) during normal production operations when the gas plant is operating. It does not factor in the additional emissions from having to burn secondary fuel (diesel) in power generation units in order to support any essential services (electricity consumers) during periods when oil production and/or the gas plant is down. This is an additional 'overhead'. Diesel fuel combustion overhead is kept to a minimum by having good production plant uptime. However, planned maintenance shutdowns and turnarounds and unplanned emergency production outages will occur. The result of planned or unplanned downtime and the need to burn diesel for essential services during such periods will inevitably force the emissions intensity in terms of tCO_2/GWh higher than that shown in Table 5.1 for two reasons. Firstly, the thermal efficiency at such times and at reduced duties is likely to be lower, and secondly the emissions factor from burning diesel is higher than that from burning natural gas.

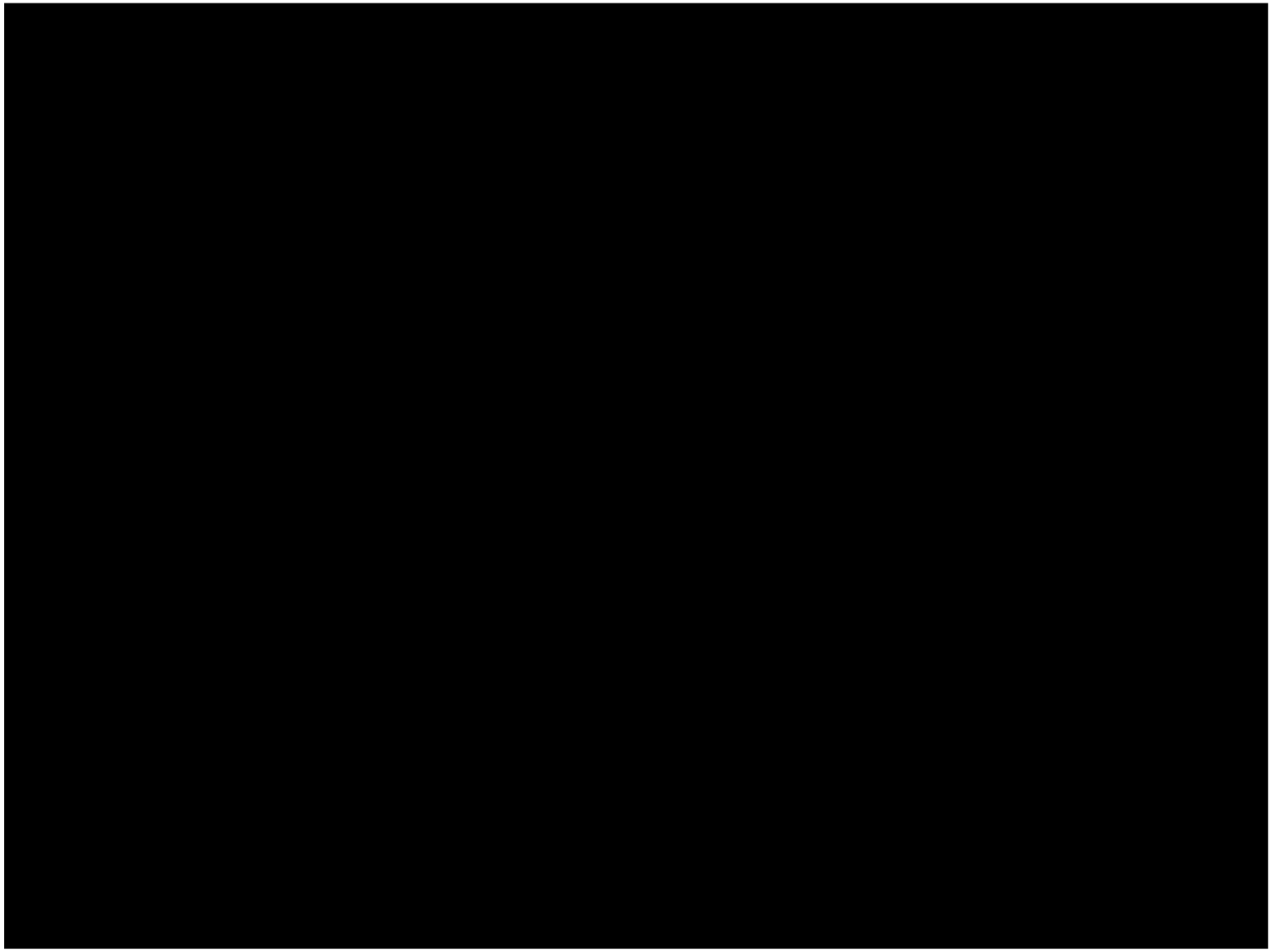
Terra Nova in particular has a significant essential service overhead, due to the fact that it has (due to vessel design) ship positioning thrusters which typically require around [redacted] of electricity supply, and potentially more during rough sea conditions. The CO_2 emissions from consumption of diesel fuel on Terra Nova can be expected to be higher than that on the other two facilities, other things (including uptime) being equal.

Figures 5.1 and 5.2 illustrate the variation of power generation CO_2 intensity with technology and fuel. Calculations indicate that a performance standard for the offshore sector on natural gas fuel could be complied with at around [redacted] – [redacted] tCO_2/GWh for existing facilities when operating plant well loaded ([redacted] efficiency), or the range [redacted] – [redacted] tCO_2/GWh for new facilities (around [redacted] efficiency). However, because turbine efficiency reduces with reduced load, intensity would rise should load demand efficiencies be implemented; the use of such a performance standard could be a perverse disincentive to practical emission reductions, because offshore power generation facilities are not 'base load' electricity generating stations.

A performance standard approach based on power generation intensity also has practical difficulties to implement offshore. Good records would be required for operational variability including running hours, load variations, and thermal efficiency of the gas turbines, since facilities often do not have reliable electricity meters to monitor consumption, especially for gas turbines generating power to directly drive mechanical process units such as gas compressors.

In conclusion a performance based standard equivalent to the limit laid down in the federal coal-fired generation of electricity regulations does not lend itself to the existing offshore oil and gas sector power generation equipment, because the power generation units will not always run at base load and the existing facility design is not conducive to implementation (via retrofit) of the technologies which would allow the performance standard to be met. However, it would be possible to identify a similar performance standard at a higher level of intensity which would incentivise new off shore facilities to implement the latest in high-efficiency aero-derivative power generation gas turbines in their project design, whilst keeping diesel consumption to a bare minimum. The limit of 420tCO_2/GWh could be met via offshore CCGT on new projects.





5.3 Offshore Flaring

Finally, considering the potential performance standard and intensity based approaches which could be used for CO_2 emissions from offshore flaring activity as distinct to those from fuel consumption. In 2007 flaring accounted for [redacted] of offshore sector CO_2 emissions. In 2010 this had reduced to around [redacted].

5.3.1 Intensity Based Approach

The production based intensity of GHG emissions from flaring currently varies between [redacted] $kgCO_2$/mboe to [redacted] $kgCO_2$/mboe, with Hibernia being at the low end of the range and Terra Nova and White Rose being at the high end.

An intensity benchmark in the range [redacted] to [redacted] $kgCO_2$/mboe would be consistent with best practice at a large installation where oil production was not in natural decline from peak, without appreciable new production well tie-backs. For small installations or where oil production has declined significantly from peak it should be expected that flare rates can also fall but most likely not at the same rate as oil production. This is particularly so because upset flaring of gas has limited correlation with oil production rates.

5.3.2 Flaring Performance Standard

A suitable flaring performance standard should include elements of flaring best practise for flare reduction along suitable verifiable monitoring and reporting requirements.

Currently the C-NLOPB has agreed flaring guidelines with offshore facilities in line with their objectives for gas resource conservation. It is recommended that any performance standard for the purpose of CO_2 emissions regulation should be built upon and consistent with the existing C-NLOPB policies and procedures. This will ensure all aspects of safety are considered along the GHG reduction environmental considerations.

The current C-NLOPB flaring consents specify the flare volume that must not be exceeded over a given 12 months. Annual reductions are currently achieved through close cooperation between C-NLOPB and the facility operators.

The performance standard should differentiate between different categories of flaring & venting:

i) Routine background flaring and potential minimisation and flare recovery techniques.

ii) Process flaring from planned controlled changes to production duties and setpoints.

iii) Process flaring from upset / emergency conditions (e.g. plant trips).

iv) Any venting of raw natural gas.

Further discussion of the above three categories is contained in the Main Report [Ref 1].

6.0 REFERENCES

1. "Greenhouse Gas Reduction Opportunities & Competitive Implications – Offshore Oil & Gas, Province of Newfoundland & Labrador" study report by AMEC Americas Limited for the Government of Newfoundland and Labrador, April 2013.

2. "Climate Change Action Plan 2011" Provincial Government of Newfoundland and Labrador, Office of Climate Change, Energy Efficiency and Emission Trading.

3. "Reduction of Carbon Dioxide Emissions from Coal-fired Generation of Electricity Regulations" Federal Government of Canada, Canada Gazette Registration SOR/2012-167 Aug 30 2012, under the Canadian Environmental Protection Act 1999.

4. "Hebron Project Comprehensive Study Report, June 2010" available as a download from the C-NLOPB website

5. "Guide to Calculating Greenhouse Gas Emissions, April 2003", Canadian Association of Petroleum Producers (CAPP).

6. "Canada's Greenhouse Gas National Inventory Report (NIR) 1990 – 2010", part of Canada's 2012 UNFCCC submission.

Signed



Steve Lamming
Project Manager
AMEC Environment & Infrastructure



Sikobe Litaba
Energy & Emissions Specialist
AMEC Performance Improvements Ltd