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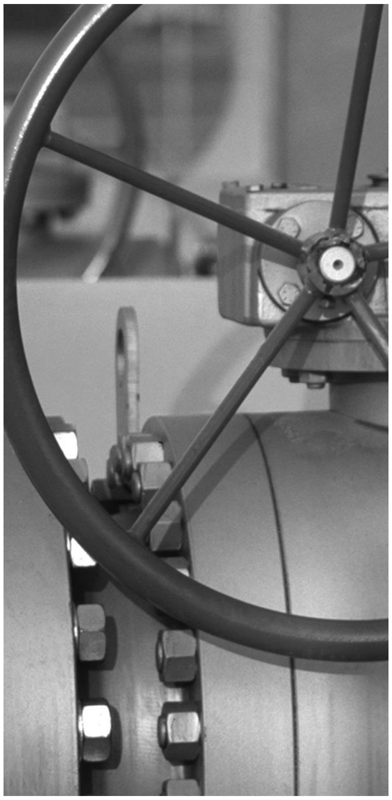
AIR QUALITY ASSESSMENT

SNC·LAVALIN



Bear Head LNG

A subsidiary company of Liquefied Natural Gas Limited

BEAR HEAD LNG

Air Quality Assessment

Bear Head LNG Corporation

01 | 04 | 2015

FINAL REPORT

622560-0001-T-30-REP-000-0001

A subsidiary company of Liquefied Natural Gas Limited

EXECUTIVE SUMMARY

SNC-Lavalin Inc. was selected by Bear Head LNG Corporation (Bear Head LNG) to carry out environmental studies for the Bear Head LNG project in Richmond County, Nova Scotia.

The site is located on the shoreline of the Strait of Canso at the end of Bear Island Road, which was constructed to access to the subject site. The subject site underwent approved development in 2005 for construction of an LNG import facility. Site work was suspended in 2007. Bear Head LNG has recognized the potential of the site for continued development, and proposes to construct an LNG export facility with an annual production capacity of eight (8) million tonnes per annum (mtpa). Development of the site is being resumed following acquisition of the site and assets of Bear Head LNG by Bear Head LNG Corporation on August 27, 2014.

An air emission inventory was estimated based on the characteristics of the equipment to be installed at the Bear Head Project including all sources in normal operation (gas turbines, auxiliary boilers, thermal oxidizers) 350 days a year, flaring upset conditions 1% of the time at the three flares, the emergency diesel generator, the two diesel fire water pump engines and the two diesel seawater pump engines all assumed to be in operation 100 hours a year. The fugitive emissions from piping components were also estimated in terms of VOC. All the sources will be in compliance with emission standards (federal regulations).

Overall effects on air quality in the local air shed during the Project's construction and operation phase are not expected to be significant. The Bear Head project will comply with ambient air quality standards, in normal operation conditions as well as in all potential upset conditions, with and without a LNG carrier in hotelling while loading LNG.

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LIST OF ACRONYMS

AAQS	Ambient Air Quality Standard
AERMOD	**A**merican Meteorological Society/US-**E**PA **R**egulatory Dispersion **Mod**el
AQMS	Air Quality Management System
AQS	Air Quality Standard
AP	Air Pollutant
BOG	Boil-off Gas
BLIER	Base-Level of Industrial Emissions Requirements
BPIP	Building Profile Input Program
CAAQS	Canadian Ambient Air Quality Standards
CALMET	California Meteorological Model
CALPUFF	California Puff Dispersion Mode
CAMS	Comprehensive Air Management System
CCME	Canadian Council of Ministers of the Environment
CDEM	Canadian Digital Elevation Model
COARE	Coupled Ocean Atmosphere Response Experiment (overwater boundary layer model)
CT	Combustion Turbine
DOEC	Department of Environment and Conservation (Newfoundland & Labrador)
FAR	Field Auxiliary Room
FEED	Front-End Engineering Design
FERC	United States Federal Energy Regulatory Commission
GLC	Ground Level Concentrations
HP	High Pressure
HHC	Heavy Hydrocarbons (C3+)
IMO	International Maritime Organization
LDAR	Leak Detection and Repair
LNG	Liquefied Natural Gas
LP	Low Pressure

MARPOL	International Convention for the Prevention of Pollution from Ships
MR	Mixed Refrigerant
NAECA	North American Emission Control Area
NAPS	National Air Pollution Surveillance Program
NCEP	National Center for Environmental Prediction
NRC	Natural Resources Canada
NS	Nova Scotia
NSE	Nova Scotia Environment
NSEA	Nova Scotia's Environmental Act
NSPI	Nova Scotia Power Inc.
NPRI	National Pollutant Release Inventory
SMR	Single Mixed Refrigerant
US-EPA	United Sates Environmental Protection Agency
WHR	Waste Heat Recovery
WRF	Weather Research and Forecast (Meteorological Model)

LIST OF CHEMICAL SYMBOLS

CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
H_2S	Hydrogen Sulfide
N_2	Nitrogen
NH_3	Ammonia
NOx	Nitrogen Oxides
NO_2	Nitrogen Dioxide
O_3	Ozone
PM_t	Particulate Matter (Total)
PM_{10}	Particulate Matter under 10 microns
$PM_{2.5}$	Particulate Matter under 2.5 microns
SO_2	Sulfur Dioxide
VOC	Volatile Organic Compounds

1 INTRODUCTION

The Liquefied Natural Gas (LNG) facility in Cape Breton will meet all air quality requirements set by Nova Scotia's Environmental Act (NSEA) and Canadian Ambient Air Quality Standards (CAAQS). With the knowledge acquired through the years in the LNG industry, this modern facility will benefit from all the technological progress in the field of atmospheric emissions.

The purpose of this report is to examine the air quality impacts associated with the proposed Bear Head Project during the construction, operation and decommissioning phase. An inventory of the Project's emissions is presented in this report, and the mitigation measures to reduce air quality impacts are described.

This analysis is based on Bear Head LNG's Basis of Design, Pre-FEED and other detailed engineering from the facility design.

2 CURRENT AIR QUALITY

2.1 AMBIENT AIR

Since 2010, an ambient air monitoring station from the National Air Pollution Surveillance Program (NAPS) is in operation in Port Hawkesbury, the nearest populated area to the project site. Table 1 presents a summary of results at this station for the 2010 to 2012 period for sulphur dioxide (SO_2), nitrogen dioxide (NO_2), ozone (O_3) and fine particulates ($PM_{2.5}$). The level of completeness for the recorded data had been greater than 90% in 2011 and 2012, as shown in Table 1. Overall, the ambient air quality in Port Hawkesbury is excellent, with maximum ground-level concentrations (GLCs) of less than 10% of the SO_2 air quality standards (AQS) and less than 20% of the NO_2 AQS.

The results for fine particulates also meet the Canadian Ambient Air Quality Standards (CAAQS) [1] for $PM_{2.5}$, which is 28 µg/m^3 based on the 3-year average of the annual 98th percentile of the daily 24-hour average concentrations. For ozone and $PM_{2.5}$, observed concentrations are below the NS AQS and the CAAQS for 2015 and 2020, which is currently not the case for several urbanized areas in Canada.

In addition to ambient air standards, NSE has a provincial annual SO_2 cap of 119,070 t/y that will be progressively reduced to 54,625 t/y in 2030. Air emission standards are presented in the following sections as they are compared with project's emissions.

[1] http://www.ccme.ca/en/current_priorities/air/caaqs.html

Table 1 Summary of Ambient Air Quality Monitoring Results in Port Hawkesbury

Sulphur Dioxide (SO_2) - ppb				
Year	**1-hour Maximum**	**24-hour Maximum**	**Annual Average**	**% Completeness**
2010	30	4	N.D.	12
2011	27	10	1	91
2012	39	9	1	97
NS AQS	340	110	20	N.A.
Nitrogen Dioxide (NO_2) - ppb				
Year	**1-hour Maximum**	**24-hour Maximum**	**Annual Average**	**% Completeness**
2010	26	11	3	57
2011	41	11	2	94
2012	30	10	2	93
NS AQS	210	N.A.	50	N.A.
Ozone (O_3) - ppb				
Year	**1-Hour Maximum**	**Daily 8-hour Maximum**	**99e Percentile of Daily 8-Hour Maximums**	**% Completeness**
2010	63	58	54	50
2011	75	62	52	90
2012	60	54	50	98
NS AQS	82	N.A.	N.A.	N.A.
3-year Average	N.A.	N.A.	52	N.A.
CAAQS 3-year Average	N.A.	N.A.	65 for 2015 62 for 2020	N.A.
Fine Particulates ($PM_{2.5}$) - µg/m³				
Year	**Daily Maximum**	**98e Percentile of Daily Maximums**	**Annual Average**	**% Completeness**
2010	40	22	8	62
2011	29	18	7	95
2012	14	12	6	89
3-year Average	N.A.	17	7.0	N.A.
CAAQS 3-year Average	N.A.	28 for 2015 27 for 2020	10.0 for 2015 8.8 for 2020	N.A.

Source: National Air Pollution Surveillance Program (NAPS), Station 030201, Port Hawkesbury, Nova Scotia.

2.2 CURRENT AIR EMISSIONS FROM LOCAL INDUSTRIES

Table 2 presents the annual atmospheric emissions of major air contaminants from industrial and power installations in Port Hawkesbury and Point Tupper as reported to the National Pollutant Release Inventory (NPRI) for the year 2013. A summary of estimated annual air emissions for the Bear Head LNG export facility (the Project) for 350 days of operation per year is also presented, and detailed in Table 3.

Table 2 Summary of Industrial Atmospheric Emissions in the Study Area (2013)

NPRI Sources	Contaminants (metric tonnes per annum)						
	SO_2	NOx	CO	VOC	PM_t	PM_{10}	$PM_{2.5}$
ExxonMobil Canada Properties - Point Tupper Fractionation Plant		32	42	81		1.5	1.2
Nova Scotia Power inc. Point Tupper Generating Station	6,758	1,340	78		117	82	36
Port Hawkesbury Paper LP/ Port Hawkesbury Paper	237	442	421	333	112	61	21
Nova Scotia Power inc. Port Hawkesbury Biomass Cogeneration Power Plant	47	774	251		81	62	33
Total 2013	**7,042**	**2,588**	**792**	**414**	**310**	**207**	**91**
Bear Head LNG (4 trains)	154	1,167	760	67	86	86	86
Total with project	7,196	3,755	1,552	481	396	293	177

Source: National Pollutant Release Inventory for 2013.

3 AIR EMISSIONS INVENTORY

In general, emissions from the operation of the Bear Head natural gas liquefaction plant will be managed in a manner to meet ambient air quality objectives that fall under the NSEA (section 112 of the *Environment Act* S.N.S 1994-95, c. 1).

The Project will consist of the construction and operation of the following major elements:

- Gas Supply: It is anticipated that a lateral pipeline will be developed to transport feed gas to the Bear Head LNG facility. A Gas Gate Station will be required consisting of an incoming interconnect pipeline, a pig receiver, a filter/separator, multiple custody transfer meters, pressure regulators, an emergency shutdown valve, and a gas analyser.
- Pre-treatment Plant: From the Gas Gate Station, the feed gas is routed to each train and then initially passes through an inlet filter coalescer to separate any liquids prior to entering the Amine Unit. Carbon Dioxide (CO_2) in the gas is removed and directed to a thermal oxidizer. A mercury removal unit is provided to ensure any mercury in the gas is removed prior to entering the liquefaction unit.
- Heavy Hydrocarbon Liquids Removal Column: The column will consist of two sections, with a short and larger diameter rectification section and a long and narrow stripping section along with a re-boiler.
- Liquefaction Plant: A facility for converting delivered natural gas into liquefied natural gas for export to overseas markets, with a capacity of 8 mtpa of LNG. The OSMR® liquefaction plant is based on a Single Mixed Refrigerant (SMR) process comprising a simple vapour compression cycle using mixed refrigerants. The refrigerant compressor is driven by highly fuel efficient low emissions aero-derivative gas turbines with pre-cooling of combustion air using an ammonia-to air exchanger.
- LNG Tank: Two LNG storage tanks each with a net pumpable capacity of approximately 180,000 cubic meters (m^3) will store the LNG product for Trains 1 through 4.
- Boil-off Gas System: The BOG System for the 4 x 2 mtpa liquefaction trains is comprised of five low pressure compressors to recover flash gas, BOG and vessel vapour from the LNG tank; and a simple re-liquefaction and nitrogen rejection system to both ensure the required LNG composition is met.
- The auxiliary ammonia refrigeration plant provides the cooling medium for the mixed refrigerant in the ammonia/MR pre-cooler, inlet air for the gas turbines, wet gas exiting the amine contractor and dry gas exiting the mercury guard bed. The auxiliary ammonia system greatly improves output and efficiency of the SMR process and stabilizes operation of the plant by dampening the impact of variations in ambient air temperatures

- Waste Heat Recovery (WHR) and Steam Plant: For each train, exhaust gas from the two gas turbines will feed two steam generators utilised to provide compression power and heat for the plant. An auxiliary boiler and two steam turbines will complete the steam supply to the system.
- Power Substation: Electrical power would be required to run motors for LNG loading pumps and Boil-Off Gas (BOG) compressors, lighting, and other items. There is a nearby NSPI substation that can provide electrical power to the Project site. A diesel generator will be provided for emergency power.
- Utilities: The flare systems are comprised of two separate process flares (Warm and Cold flares) and a marine flare for the whole facility that will be operated periodically for maintenance and process upset conditions. Other process and utilities systems for the plant include instrument air and nitrogen generation, utility water system, firewater and safety systems. Buildings include control room, field auxiliary room (FAR), offices and workshop/store. Shelters will be provided for some process and utility equipment.

The assessment of air emissions from the operation of the natural gas liquefaction plant was conducted in two steps:

1. An inventory of all combustion emissions was developed and compared to the emissions inventory for the Province of NS.
2. An air dispersion modeling study was performed to predict the impacts on ambient air quality around the natural gas liquefaction plant property.

3.1 Approach for Calculation of Emissions

The following sections provide an assessment of air emissions projected to be generated from the operation of the proposed natural gas liquefaction plant. The Bear Head project beneficiates from the advanced design studies conducted on the Magnolia project, an 8 mtpa LNG plant to be built in Lake Charles, Louisiana. The approach to develop the inventory was to adapt the air emission data generated for Magnolia to the Bear Head project, by taking into account the stream flows and components found in the mass balance developed for the Bear Head project. The following documents were used to develop the air emission inventory:

- Magnolia LNG Project Application to Federal Energy Regulatory Commission (FERC) – dated 30 April 2014. Responses to FERC on 05 September 2014.
- Bear Head Heat and Material Balance Sheet (Document BH-DP-10-001 rev C – 28 Nov.2014);

Air emissions for the Project were predicted on the basis of the following activities and components:

- LNG facility including gas turbines, auxiliary boiler, thermal oxidizer, ammonia vent, cold flare, warm flare, marine flare, emergency generator, fire water pumps and sea water fire deluge pumps;

- LNG carriers while docking in, hotelling during LNG loading and docking out ; and
- Fugitive gas emissions from the LNG processing.

Two scenarios were assessed, the facility operating under normal conditions and emergency or upset conditions. In addition to all of the sources for normal conditions, emergency conditions include mainly flaring activities.

3.2 Inventory of Project Emissions

Table 3 provides a summary of the annual air emissions estimated to be produced by the operation at full production 350 days a year of the proposed Bear Head LNG plant. Emissions of greenhouse gases are provided in a separate report.

Table 3 Estimated Annual Emissions – Proposed Natural Gas Liquefaction Plant (Tonnes/Year)

Sources	NO_x	CO	VOC	PM_t	PM_{10}	$PM_{2.5}$	SO_2	NH_3
	t/y	t/y	t/y	t/y	t/y	t/y	t/y	t/y
Continuous Sources (per train – 4 trains)								
Gas Turbine A	118.6	72.2	4.6	8.5	8.5	8.5	0	N.A.
Gas Turbine B	118.6	72.2	4.6	8.5	8.5	8.5	0	N.A.
Thermal Oxidizer	10.0	7.2	3.2	1.2	1.2	1.2	37.9	N.A.
Auxiliary Boiler	18.9	13.0	0.13	2.6	2.6	2.6	0	N.A.
Ammonia Vent	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	0.52
Each LNG train	266.1	164.6	12.5	20.7	20.7	20.7	37.9	0.52
LNG Carriers (120 vessels/y)	85	10.1	4.3	1.3	1.3	1.1	2.3	N.A.
Fugitive Emissions – 4 trains (Piping Components)			12.2					1.3
Total (4 trains)	**1149**	**669**	**66**	**84**	**84**	**84**	**154**	**3.4**
Intermittent Sources								
Warm Flare	7.5	40.6	0.65	0.82	0.91	0.91	0	0
Cold Flare	9.1	49.6	0.011	1.00	1.00	1.00	0	0
Marine Flare	0.13	0.71	0.0003	0.014	0.014	0.014	0	0
Emergency Generator (1 MW)	0.64	0.35	0.065	0.020	0.016	0.016	0.0005	0
Firewater Pump Eng. (250 kW)	0.21	0.18	0.021	0.011	0.009	0.009	0.0004	0
Seawater pump Eng. (600 kW)	0.77	0.42	0.077	0.024	0.020	0.020	0.0006	
TOTAL	**1167**	**760**	**67**	**86**	**86**	**86**	**154**	**3.4**

Fugitive Emissions from Piping Components

During facility operation, fugitive emissions from gas and liquid process streams would be released. Potential fugitive emissions may come from piping components, such as from pipe flanges, valves and other components. Based on preliminary design information for the Magnolia project, there are five separate process streams at the facility that contain components with potential VOC release. The composition of each stream is based on the mass balance developed for Bear Head. Table 4 provides the estimated component counts, process stream gaseous constituents, and emission factors for VOCs. The total VOC emission is estimated to be 12.2 t/y from piping components.

Table 4 Fugitive Emissions – Piping Components

Stream [1]	# Flange	# Open end	# Pump	# Valve	# Compressor Seals	# Relief / Blowdown Valves	Mol Weight	VOC Mass%
Stream 1	440	20	0	670	40	500	17.39	4.90%
Stream 2	120	8	16	260	10	120	18.21	8.38%
Stream 3	40	12	24	80	3	40	57.71	90.25%
Stream 4	920	20		880	0	320	27.56	15.37%
Stream 5	200	10	10	460	0	215	17.34	4.61%
Stream 6	840	10	12	1280	35	445	17	0%
Total (VOC)	1720	70	50	2350	53	1142		
g/h/comp G[2]	0.82	46.63	2.91	0.57	46.69	0.19		
g/h/comp L[2]	0.160	46.63	2.91	0.86	-	0.19		
kg VOC/h	**0.080**	**0.75**	**0.07**	**0.21**	**0.26**	**0.02**	**TOTAL 1.389 kg/h**	
t VOC/y	**0.70**	**6.54**	**0.60**	**1.81**	**2.31**	**0.21**	**12.17 t/y**	

(1) Stream 1: Gate Gas / Feed Gas / HP Fuel gas
Stream 2: HHC inlet to HC Liquids Column, LP Fuel Gas
Stream 3: HHC Outlet from HC Liquids Column
Stream 4: Mixed Refrigerant
Stream 5: LNG
Stream 6: Ammonia system – Ammonia is not a VOC
VOC Mass Fraction (calculations provided in Table 4b)
(2) Source: g/h/component – G (Gas) and L (Liquid) extracted from *CAPP (2014), Table 10 – Post-2007 Results*

A Leak Detection and Repair Program (LDAR) will be implemented to monitor fugitive emissions. Results of the LDAR will be provided with the annual atmospheric emissions sampling report:

- Measures will be taken quarterly for pump, compressor and agitator seals and once a year for all other parts;
- Bear Head LNG will repair any leakage within a prescribed 45 day period. Its objective will be to repair any major leak within 5 days;
- Bear Head LNG will consider a major leak one that is of more than 10,000 ppm;
- However, if repairing the leak requires the interruption of an on-going process, the repair will be carried out no later than the next shutdown of the process involved.
- Several different leak detectors and monitoring equipment will be strategically placed to detect LNG and ammonia leakage and to respond quickly and efficiently. The LDAR aims to detect micro leaks at much lower levels than those requiring an emergency response.

Table 4b (cont'd): Fugitive Emissions – Piping Components
Calculations of VOC Mass Fraction

Mass Balance Stream	M.W.	Stream Volumetric Fraction (%) # 704 1- HP fuel	# 710 2- LP Fuel	# 311 3-HHC out	# 320 4- MR	# 307 5- LNG	Stream Mass Fraction (%) # 704 1-HP fuel	# 710 2-LP Fuel	# 302 3-HHC out	# 320 4-MR	# 307 5-LNG
CO_2	44.01	0.0005%	0.0006%	0.0005%		0.0005%	0.0013%	0.0014%	0.0004%	0.0000%	0.0013%
N_2	28.01	0.4070%	1.252%	0.0005%	16.9020%	0.4076%	0.6556%	1.9261%	0.0002%	17.1801%	0.6582%
CH_4	16.04	92.5746%	88.460%	10.1164%	30.0035%	92.6839%	85.3999%	77.9070%	2.8116%	17.4642%	85.7139%
ethane	30.07	5.2105%	7.117%	13.3125%	45.8061%	5.2005%	9.0110%	11.7506%	6.9361%	49.9839%	9.0162%
propane	44.1	1.4446%	2.417%	15.8856%		1.4406%	3.6639%	5.8532%	12.1385%	0.0000%	3.6629%
i- butane	58.12	0.1018%	0.209%	4.0111%		0.1012%	0.3403%	0.6657%	4.0394%	0.0000%	0.3391%
n-butane	58.12	0.1018%	0.254%	8.0461%	7.2883%	0.1009%	0.3403%	0.8115%	8.1028%	15.3718%	0.3381%
i-pentane	72.15	0.0458%	0.124%	14.7757%		0.0353%	0.1900%	0.4900%	18.4718%	0.0000%	0.1468%
n-pentane	72.15	0.0458%	0.104%	18.7704%		0.0292%	0.1900%	0.4108%	23.4657%	0.0000%	0.1215%
n-hexane	86.18	0.0153%	0.014%	7.1700%		0.0003%	0.0758%	0.0672%	10.7066%	0.0000%	0.0015%
benzene	78.11	0.0051%	0.005%	2.3844%		0.0001%	0.0229%	0.0202%	3.2271%	0.0000%	0.0005%
cyclohexane	84.16	0.0004%	0.000%	0.1903%			0.0019%	0.0018%	0.2775%	0.0000%	0.0000%
n-heptane	100.21	0.0051%	0.005%	2.3625%			0.0294%	0.0259%	4.1021%	0.0000%	0.0000%
toluene	92.14	0.0007%	0.001%	0.3307%			0.0037%	0.0035%	0.5280%	0.0000%	0.0000%
n-octane	114.23	0.0051%	0.005%	2.3601%			0.0335%	0.0295%	4.6713%	0.0000%	0.0000%
p-xylene	106.17	0.0003%	0.000%	0.1416%			0.0018%	0.0017%	0.2605%	0.0000%	0.0000%
ethylbenzene	106.17	0.0003%	0.000%	0.1416%			0.0018%	0.0017%	0.2605%	0.0000%	0.0000%
H_2S	34	0.0000%	0.000%				0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Ammonia	17	0.0000%	0.000%				0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
Water	18	0.0354%	0.032%				0.0366%	0.0320%	0.0000%	0.0000%	0.0000%
		100.0%	100.0%	100.0%	100.0%	100.0%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%
Mol. Weight		**17.39**	**18.21**	**57.71**	**27.56**	**17.34**					
				VOC Mass Fraction (%)			**4.8955%**	**8.3828%**	**90.2516%**	**15.3718%**	**4.6104%**

Table 5 Assumptions Used for the Emission Factors, Stack Concentration and Heat Input Feed Rate [1]

Equipment	# on Site	Heat Input GJ/h	Annual Hours of Operation	Units	NO_X	CO	VOC	PM_t	PM_{10}	$PM_{2.5}$	SO_2
Gas Turbines	8	339	8760	ppmvd at 15% O_2	25	25	15 [11]	2.85 g/GJ [2]			Null
Thermal Oxidizers	4	16	8760	ppmvd at 3% O_2	40	62 mg/Nm^3	99% [10]	10 mg/Nm^3			4 ppm H_2S in feed gas
Auxiliary Boilers	4	89	8760	ppmvd at 3% O_2	23 g/GJ	50	99.9% [10]	3.21 [3]			Null
Warm Flare	1	2603	88	g/GJ	29.3 [4]	159.5 [4]	99.5% [10]	3.21 [3]			Null
Cold Flare	1	1399	100								
Marine Flare	1	2214	4								
Emergency Generator	1	9.8	100	g/kWh	6.4 [5]	3.49 [5]	0.64 [5]	0.20 [5]	0.16 [6]	0.13 [6]	0.65 g/GJ [6]
Firewater Pump Engine	2	2.5	100	g/kWh	4.02 [7]	3.49 [5]	0.40 [7]	0.20 [5]	0.16 [6]	0.13 [6]	0.65 g/GJ [6]
Seawater Pump Engine	2	5.2	100	g/kWh	6.44 [5]	3.49 [5]	0.64 [5]	0.20 [5]	0.16 [6]	0.13 [6]	0.65 g/GJ[6]
LNG Carrier [8]	1	5,700 kW	210	g/kWh	1.3	1.1	0.5	0.05	0.05	0.05	0.05
LNG Carrier [9]	1	3,000 kW	1785	g/kWh	13.6	1.40	0.60	0.19	0.19	0.17	0.36

(1) Based on vendor/supplier data unless otherwise specified

(2) US EPA, AP-42 emission factors section 3.1 - Stationary Gas Turbines

(3) US EPA, AP-42 emission factors section 1.4 - Natural Gas Combustion

(4) US EPA, AP-42 emission factors section 13.5 - Industrial flares

(5) US EPA, Non-Road Tier 2 standards

(6) US EPA, AP-42 emission factors section 3.4 - Large Stationary Diesel and All Stationary Dual-fuel Engines

(7) Non-Road Tier 3 standards

(8) LNG Carrier manoeuvring with propulsion turbine generator on natural gas – 22,800 kW at 25% load - 2 h total for each docking/undocking

(9) Auxiliary Generator 3000 kW – 105 vessels/y – Hotelling - 17 h load/vessel on marine oil

(10) Hydrocarbon destruction efficiency (%)

(11)20% of HC emissions considered as VOC, the rest is assumed to be methane

3.3 Source Characterization

The emission sources will be modeled as point sources. The Project emission source inventory, heat input ratings and anticipated hours of operation are presented in Table 5. Preliminary specifications and emission rates developed for Magnolia were used for the auxiliary boiler, thermal oxidizer, emergency use engines, the emergency generator and firewater pump, and for flares. Data sheets from supplier were available for the gas turbines. Table 6 shows preliminary stack parameters for the Project emission sources as currently known. The following paragraphs provide a description of the equipment planned for the Bear Head Facilities.

Gas Turbines

Each train will use two 34 MW aero-derivative units produced by General Electric, model PGT25+G4. Each gas turbine will burn only pipeline quality natural gas and will be equipped with dry-low emissions (DLE – 25 ppm NOx) and a waste heat recovery unit. Each unit's heat input rating is shown in Table 5. The inlet combustion air for the gas turbines is cooled using ammonia refrigerant, as cooler inlet air actually increases the power output of the gas turbines.

Auxiliary Boilers

The vendor for the auxiliary boilers has not been selected yet. However, the data presented are reasonable approximations of the performance characteristics of the boilers. The boiler efficiency will be approximately 84%. The estimated destruction efficiency for Volatile Organic Compounds (VOC) in the combustion process is 99.99%. For the potential to emit estimate, it is assumed the composition of the fuel gas is primarily low pressure (LP) fuel gas recovered from flash gas and boil off gas (BOG) system (e.g. from LNG tanks and LNG carriers). NOx emissions from the boilers will meet the *Federal Multi-Sector Air Pollutants Regulation*. The worst-case is assumed in terms of emissions, which is an emission intensity limit of 23 g NOx/GJ for an alternative gas and a boiler efficiency of 90%. If the efficiency of the selected boiler is 84%, the NOx emission intensity limit would be reduced to 21.7 g/GJ, resulting in a lower emission.

Thermal Oxidizer

The thermal oxidizer would consist of a low NOx burner firing upward into the base of a leg-supported, refractory-lined incinerator. A carbon dioxide (CO_2) waste gas stream containing hydrogen sulfide from the feed gas pre-treatment plant would enter the unit near the base of the incinerator vessel near the burner. This physical arrangement allows the burner to use the cool, inert waste gas as a means to reduce NOX production during operation. The feed gas would mix with the waste gas in the combustion process to form the hot flue gas that would be discharged from the unit at the top.

LNG Carriers

The Project is being designed with a single new docking berth to accommodate LNG carriers. LNG tankers that may call on the facility would range in cargo capacity from 125,000 m^3 up to 267,000 m^3 capacity. It is currently projected that, on average, up to two LNG carriers per week would make port calls at the Project terminal when operating at full plant capacity. Using an average LNG carrier capacity of 170,000 m^3, approximately 105 to 120 LNG carriers could load LNG at the Bear Head LNG terminal. Current projections of port call frequency are based on the nominal LNG output of 8 mtpa and average LNG carrier cargo capacity of 170,000 m^3.

Fuel type and blends used by the LNG carrier may be marine diesel and/or boil-off gas for both propulsion and generator set engines. Fuel use would vary depending on the type of propulsion system employed and presence or lack of an onboard boil-off gas compressor on the LNG carrier. LNG carrier emissions are governed by the International Convention for the Prevention of Pollution from Ships (MARPOL) Annex VI of the International Maritime Organization (IMO); NOX emission regulations are found in Regulation 13 and SO_X regulations are found in Regulation 14. The IMO and the US EPA have established the North American Emission Control Area (NAECA) that is applicable to the entire coastlines of the United States and Canada. In calendar year 2015, all vessels operating within 200 nautical miles of the coast will be required to use fuel with a sulphur content less than 0.1%.

LNG vessel emissions are based on a typical 170,000 m^3 capacity vessel with compression ignition/electric propulsion. Propulsion emission factors are based on typical vessel engine manufacturer data for a Wartsila 50 DF operating primarily on natural gas with a small quantity of pilot marine gas oil fuel (0.1% sulfur). It is assumed the vessel primarily would operate on boil-off gas.

Typically, docking and undocking requires approximately one hour each to complete. Typically during docking/undocking, the vessel engine would be operating on natural gas at low regime (25%).

At the standard LNG loading rate of 10,000 m^3/hour, it would take approximately 17 hours to load a 170,000-m^3 LNG carrier. For short term (i.e., 1-hour to 24-hour) emission rate purposes, the worst-case short-term emission rate scenario from marine sources is expected to be the LNG carrier in hotelling mode. While hotelling during LNG loading, it is assumed the main propulsion engines would be shutdown with hotelling requirements supplied by auxiliary generator set engines operating solely on marine gas oil and operation limited to a load necessary to meet the electrical load demand from the vessel's systems while docked. Power for pumping LNG to the tanker would be provided by electric motor driven pumps powered using electricity from the grid and located onshore.

The inventory of annual emissions for LNG Carriers (Table 3) includes the emissions related to docking/undocking and hotelling mode.

Emergency Use Diesel Engines

Diesel engines would be provided to operate an emergency electrical generator (1,000 kW), two fire water pumps (250 kW each), and two LNG tank deluge water pumps (600 kW each). Emissions for each unit are based on a limit of 100 hours per year and low sulfur fuel (sulfur content of 15 ppm).

Flares

The cold and warm process flare will not be used during normal operation; however, a small pilot light will be continuously lit should flaring be needed. Flaring is not used during normal operation because the boil-off-gas generated from the LNG tank will be used as fuel gas in the auxiliary boiler. However, when maintenance is required, process lines may need to be manually vented and purged. There may also be occasions of automated venting from Pressure Relief Valves, Process Shutdowns, and Emergency Shutdown. During these events, flaring will be necessary. It is estimated that the flares would be operating 1% of the time. Cold flare will relieve the gas from the cold parts of the process at a load estimated to 80,000 kg/h. Process upset gases at ambient temperature will be directed to the warm flare at a load estimated to 60,000 kg/h.

Also referred as tankage flare, the marine flare is a low pressure flare to relieve tank vapour and vessel vapour, when the boil-off gas compressors are down. The cold process flare was deemed not a best option for relieving this vapour and a separate marine flare was added, as commonly used in LNG facilities. The design case relieving load was based on failure of two BOG compressors. This was estimated as 25,000 kg/hr. The BOG compressors may trip once every quarter at the most during the first year, and the frequency of these trips will reduce after. Flaring is estimated to be 0.5 to 1 hr during this period, therefore a maximum of 4 hours per year.

The durations and quantities of gas sent to the flares, excluding the use of pilots, but including an approximate composition, will be reported for each flaring event.

Estimated quantities for flaring will be confirmed during the detailed design phase of the Bear head LNG project and pending vendor data.

4 COMPLIANCE WITH AIR EMISSION STANDARDS

The applicable air emission standards to the Bear Head LNG facility are the federal emissions standards from the *Multi-Sector Air Pollutants Regulations* and the *Canadian Base Level Industrial Emissions Requirements* (BLIER).

The *Multi-Sector Air Pollutants Regulations* imposes mandatory national performance standards on various industrial equipment groups. For boilers, the regulations impose limits on the amount of nitrogen oxides (NO_X) that can be emitted.

In 2011, a Combustion Turbine (CT) working group was formed under the Canadian Air Quality Management System (AQMS) to develop BLIER for new CT in Canada. The work of this working group was a continuation of the previous efforts by a sub working group in 2009 and 2010 under the Comprehensive Air Management System (CAMS). The 2001 CT working group established BLIERS for NO_X emissions for new combustion turbines fueled by natural gas. The older Canadian Council of Environment Ministers (CCME) 1992 guideline continues to be the national emissions reference (e.g. heat recovery allowance for cogeneration systems and emissions standards for liquid-fuelled combustion turbines) for other contaminants and fuels.

This section compares the project design criteria compared to air emissions standard from the *Multi-Sector Air Pollutants Regulations* and the BLIER. As shown in table 6, air emissions from the project will be lower than maximum allowable emissions.

Table 6 Comparison of Project's Emissions with NO_X Air Emissions Limits

Equipment	Regulated Activities	Project Design Criteria	Emission Limits
Boiler (1)	Alternative gas combustion with an efficiency higher than 90%(3)	23 g/GJ	≤23 g/GJ (3)
Combustion Turbine (2)	Natural gas combustion	25 ppmvd at 15% O_2 dry	≤25 ppmvd at 15% O_2 dry

(1) *Multi-Sector Air Pollutants Regulations – Proposed Federal Regulation – Article 5*
(2) *Canadian Base Level Industrial Emissions Requirements (BLIER)*
(3) If the boiler's thermal efficiency is less than 80%, the air emission limit is reduced to 20.8 g/GJ for an alternative gas. If the efficiency ranges between 80% and 90%, then the limit is linearly proportional to the efficiency and is bounded by the upper and lower limit for an alternative gas, 23 g/GJ and 20.8 g/GJ respectively.

5 AIR DISPERSION MODELING

5.1 AIR DISPERSION METHODOLOGY

In the absence of specific air dispersion modeling guidelines in Nova Scotia, modeling guidelines from Quebec and Newfoundland and Labrador were considered (Leduc, 2005 and DOEC 2012) for air dispersion modelling.

5.1.1 Air Dispersion Model

For industrial sources such as the proposed Project, the ***A****merican Meteorological Society/***E****nvironmental Protection Agency* ***Reg****ulatory Air Dispersion* ***Mod****el (*AERMOD), also a regulatory model in all Canadian provinces, would be the model of choice if the project was not located in a coastal environment.

Since the Bear Head LNG Project is located in a coastal environment, the CALMET/CALPUFF (EarthTech, 2000a, 2000b) air dispersion modelling system was used to estimate ground level concentrations of contaminants in ambient air. CALPUFF is an advanced non-steady-state meteorological air quality modelling system developed by the Atmospheric Science Group of TRC in the USA. CALMET is the meteorological model for CALPUFF that generates 3D meteorological fields and boundary layer parameters from hourly surface and twice daily upper air observations and/or from the hourly outputs of meteorological models. Overwater observations, from meteorological buoys or meteorological models, especially the sea-air temperature differential is also preferable for modelling in coastal regions.

The basic data required by the CALMET/CALPUFF modelling system includes:

- Gridded topographical and land use data.
- Hourly meteorological surface observations, upper air observation soundings (at least twice per day) and/or 3D meteorological fields generated by an advanced prognostic meteorological model (temperature, wind speed and direction, etc.).
- Source emission characteristics: emission rates of contaminants in the exhaust gas, the gas exit temperature and velocity, stack coordinates, configuration, diameter and height.
- Location and elevation of receptors.
- Dimensions and coordinates of buildings on-site that present wake effects causing plume downwash.

The CALPUFF model calculates the concentration of pollutants at all receptors on an hourly basis during the period under consideration. When there are multiple emission sources, the resulting concentration at each receptor is estimated by summing the individual contributions from each source. Average longer-term concentrations (3, 8 and 24 hours, 1 year) are obtained by combining the average hourly concentration at each receptor for the period.

5.1.2 Meteorological Data and Configuration of CALMET

5.1.2.1 Meteorological Domain, Topography and Land Use

CALMET was used to produce refined meteorological fields for a 25 x 25 km domain with a 500 m horizontal resolution and 11 vertical levels (top faces at: 20, 40, 80, 160, 320, 640, 1000, 1500, 2000, 2500 and 3000 metres above ground). Figure 1 presents the CALMET modelling domains. The Canadian Digital Elevation Model (CDEM, Natural Resources Canada, 2013) topographic data was used to set the elevation of each cell in the domain and also to set the ground elevation of receptors. Land use classifications (circa 2000 – Vector) from Natural Resources Canada Land Cover (NRC, 2014) were gridded for the CALMET meteorological domain.

Surface characteristic parameters per land use classification and season are reproduced in Table 7. Winter is defined as the months with snow on the ground and summer for month with fully developed vegetation.

Sea ice is normally absent in the Canso Strait according to the long-term normal maps found in the Sea Ice Climatic Atlas – East Coast 1981-2010 produced by the Canadian Ice Service of Environment Canada. CALMET's overwater boundary layer sub-model was therefore used year round.

For this modelling project, 3D meteorological data fields (wind, temperature, humidity, pressure and geo-potential height) covering a 50 x 50 km domain centered on the Project site with a 4 km horizontal resolution generated by the *Weather Research and Forecast* (WRF) meteorological model for the 2009 to 2013 period were used to provide all meteorological information for CALMET. WRF is a prognostic meteorological model developed by the Pennsylvania State University and the U.S. National Center for Atmospheric Research (NCAR). Figure 1 shows some of the WRF grid points over the CALMET domain.

The WRF data was provided by Lakes Environmental who run the WRF meteorological model based on the National Centers for Environmental Prediction (NCEP) Final Operational Global Analysis (1° x 1° resolution) data sets using nested grids covering a much larger domain than previously stated. The data was provided in CALMET's 3D.DAT format version 2.12, which includes sea surface temperature and above water air temperature required for the COARE overwater boundary layer model in CALMET and hourly precipitation rates for the wet deposition model.

Local hourly observations of wind at the Port Hawkesbury Airport meteorological monitoring site, located 12 km north-west of the proposed LNG processing plant (Figure 1), were analysed and compared to the CALMET generated hourly winds for the same location. The wind roses plotted on Figure 2 show good agreement between observations and modelled meteorology and that the

WRF/Calmet combination is able to adequately reproduce the local climatology of the region. Figure 3 presents the WRF/CALMET modelled wind rose for the whole modelling period (2009-2013) at the Bear Head Project Site.

Local observations were not used as input to the modelling system because of potential problems related to inconsistencies between observations and the WRF data or between the WRF and CALMET sub-models (wind extrapolation primarily). Also, observations at the Port Hawkesbury Airport do not cover a complete five year period.

Figure 1 CALMET Modelling Domain, WRF Grid Points. Land Use and Topography

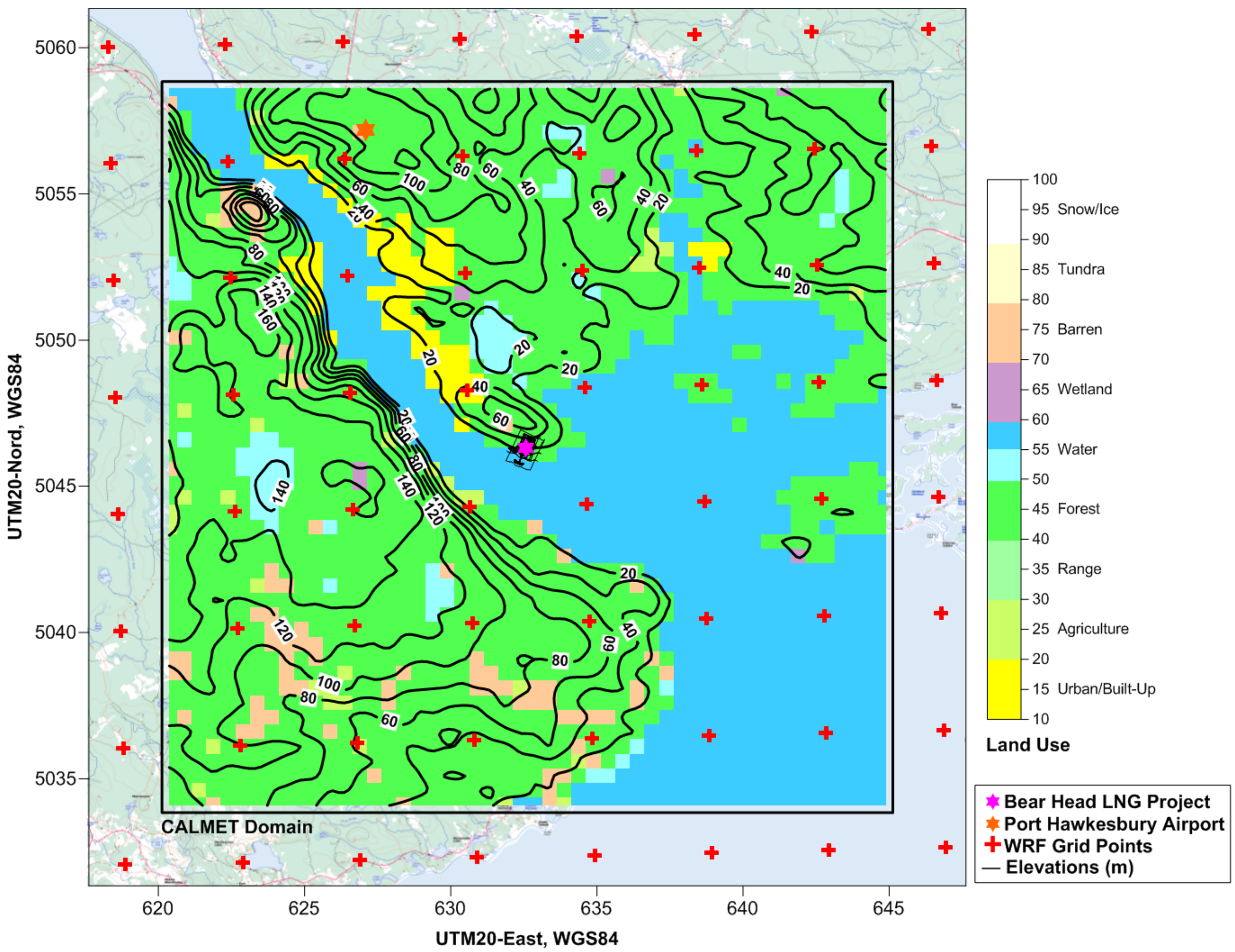


Table 7 Surface Parameters per Land Use Class and Season used in CALMET

Land Use	z_0 (m)	Albedo	Bowen Ratio	Soil Heat Flux Parameter
Winter (December to March)				
Inland Water	0.002	0.7	0.5	0.15
Canso Strait, Ocean*	0.001	0.1	0.1	1.0
Exposed Land, Rock/Rubble	0.05	0.6	0.5	0.15
Developed	1.0	0.35	0.5	0.15
Mosses, lichen	0.05	0.6	0.5	0.15
Shrubs	0.15	0.5	0.5	0.15
Wetland – Wood	0.3	0.3	0.5	0.15
Wetland – Herb	0.1	0.3	0.5	0.15
Perennial Cropland and Pasture	0.01	0.6	0.5	0.15
Evergreen Forest	1.3	0.35	0.5	0.15
Deciduous Forest	0.81	0.42	0.5	0.15
Spring (April, May)				
Inland Water	0.001	0.1	0.1	1.0
Canso Strait, Ocean*	0.001	0.1	0.1	1.0
Exposed Land, Rock/Rubble	0.05	0.2	1.5	0.15
Developed	1.0	0.18	1.5	0.25
Mosses, lichen	0.05	0.2	1	0.15
Shrubs	0.3	0.18	1	0.15
Wetland – Wood	0.5	0.14	0.2	0.25
Wetland – Herb	0.2	0.14	0.1	0.25
Perennial Cropland and Pasture	0.03	0.14	0.3	0.15
Evergreen Forest	1.3	0.12	0.7	0.15
Deciduous Forest	1.1	0.14	0.7	0.15
Summer (June to September)				
Inland Water	0.001	0.1	0.1	1.0
Canso Strait, Ocean*	0.001	0.1	0.1	1.0
Exposed Land, Rock/Rubble	0.05	0.2	1.5	0.15
Developed	1.0	0.18	1.5	0.25
Mosses, lichen	0.05	0.2	1	0.15
Shrubs	0.3	0.18	1	0.15
Wetland – Wood	0.5	0.14	0.2	0.25
Wetland – Herb	0.2	0.14	0.1	0.25
Perennial Cropland and Pasture	0.15	0.2	0.5	0.15
Evergreen Forest	1.3	0.12	0.3	0.15
Deciduous Forest	1.3	0.14	0.3	0.15
Autumn (October, November)				
Inland Water	0.001	0.1	0.1	1.0
Canso Strait, Ocean*	0.001	0.1	0.1	1.0
Exposed Land, Rock/Rubble	0.05	0.2	1.5	0.15
Developed	1.0	0.18	1.5	0.25
Mosses, lichen	0.05	0.2	1	0.15
Shrubs	0.3	0.18	1.5	0.15
Wetland – Wood	0.4	0.14	0.3	0.25
Wetland – Herb	0.2	0.14	0.1	0.25
Perennial Cropland and Pasture	0.02	0.18	0.7	0.15
Evergreen Forest	1.3	0.12	0.8	0.15
Deciduous Forest	0.9	0.14	1	0.15

* Overwater boundary layer sub-model is used for this land use class, surface parameters are not used.

Figure 2 Observations and CALMET (10-m) Wind Roses for Port Hawkesbury Airport (2011-2013)

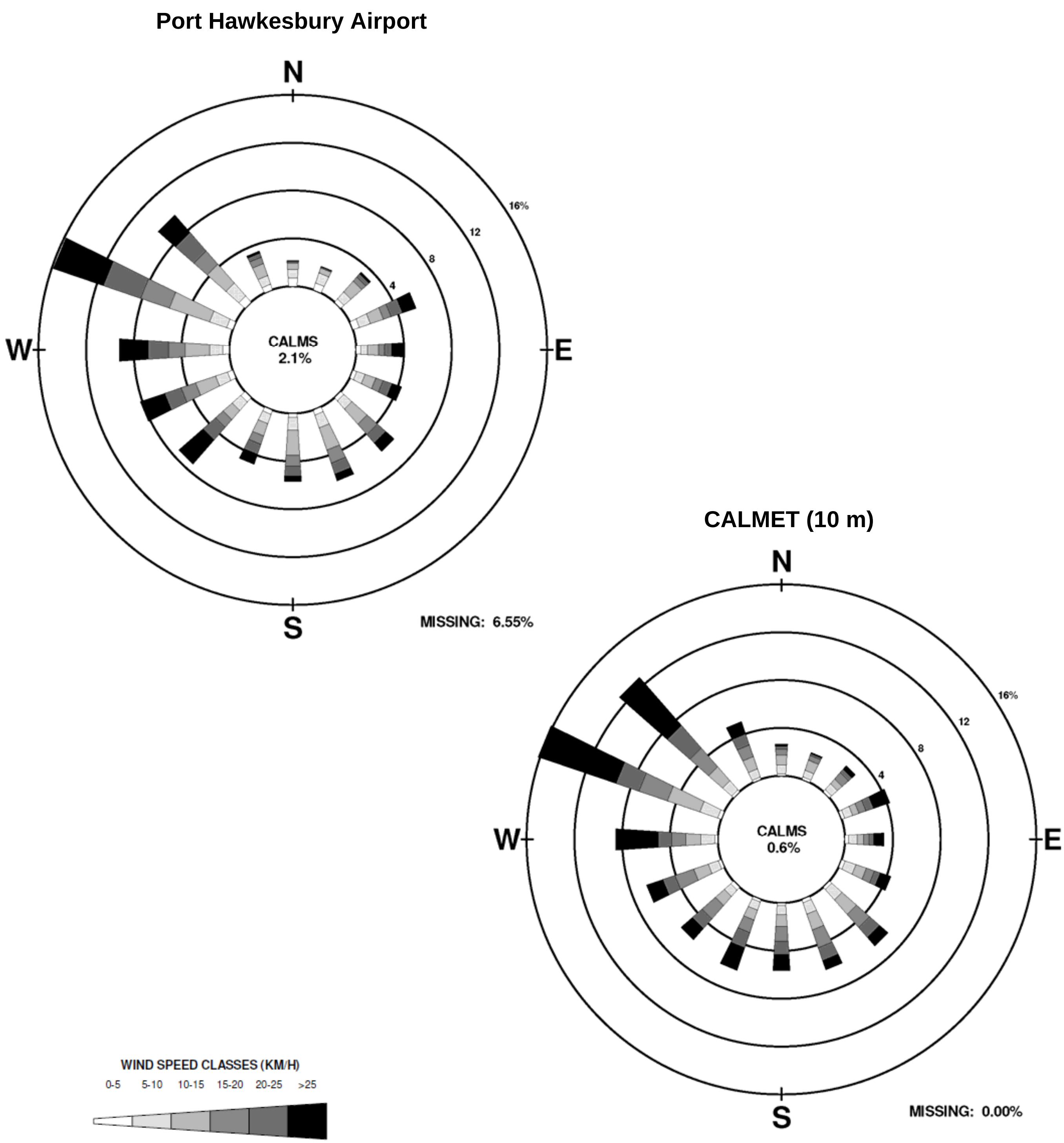
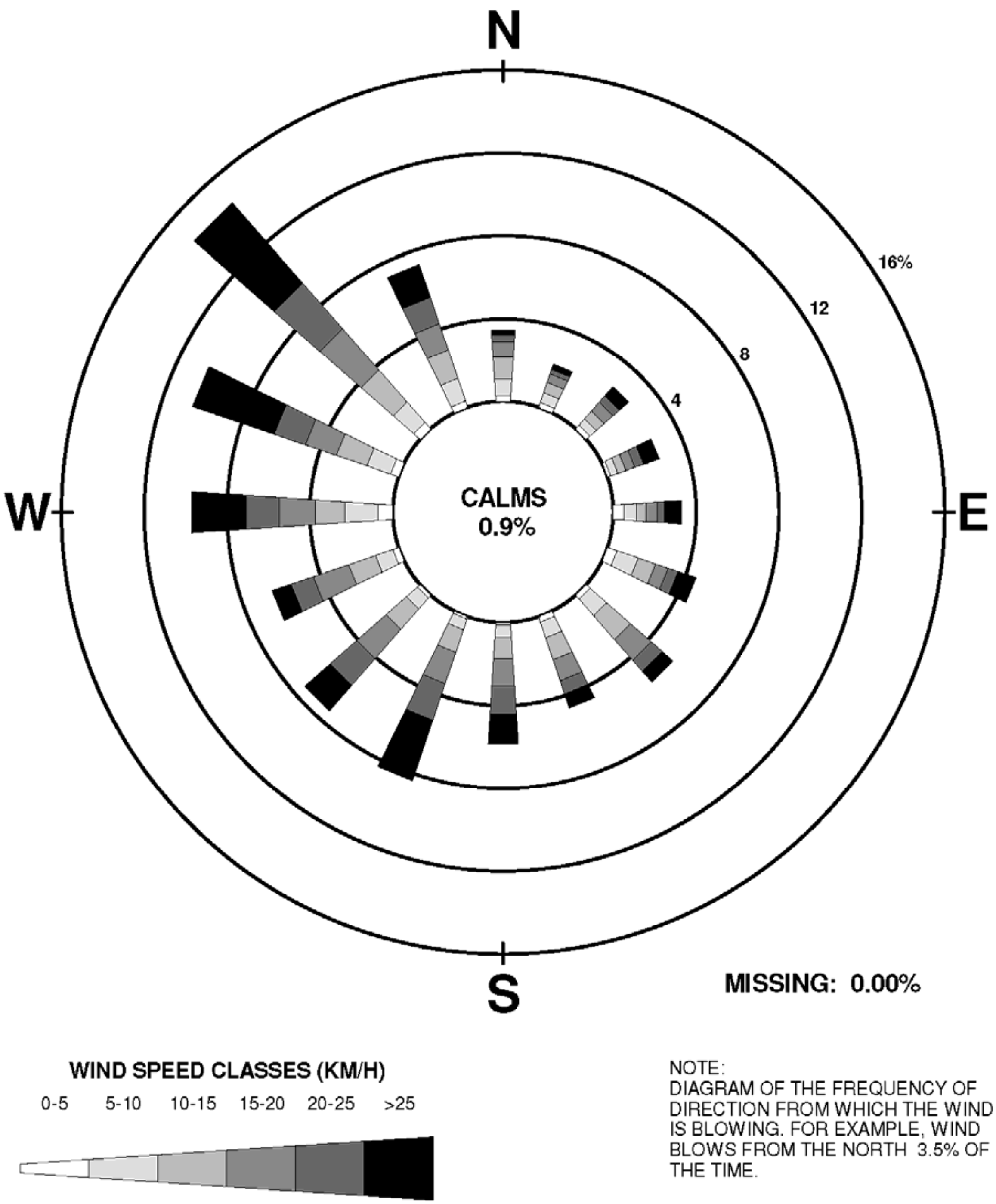


Figure 3 CALMET (10 m) Wind Rose for the Bear Head LNG Project Site (2009-2013)



5.1.2.2 CALMET Options and Generation of Meteorological Fields

In general, most default CALMET options were selected, with the exception of options related to the use of a data set from a weather model and coastal effects. The wind field calculations were initialised using the WRF data (CALMET 3D.DAT format).

All non default CALMET selected options are listed in Table 8.

Table 8 CALMET Configuration - Non Default CALMET Options

CALMET options	Selected non default option values	
No observation mode	NOOBS = 2	No surface, overwater, or upper air observations Use MM4/MM5/3D.DAT for surface, overwater, and upper air data
Cloud data option	ICLOUD = 4	Gridded cloud cover from prognostic relative humidity at all levels
Relative humidity option	IRHPROG = 1	3D relative humidity from prognostic data
Precipitation option	ICLOUD = 4	Gridded cloud cover from prognostic relative humidity at all levels
Spatial averaging search radius	MNMDAV = 2	Temperature and mixing height spatial averaging is based on a 2 grid cell distance (2 x 500 m =1 km)
Wind Field Options*		
Use gridded prognostic wind field model output fields as input to the diagnostic wind field model	IPROG = 14	Yes, use winds from MM5/3D.DAT file as initial guess field.
Radius of influence of terrain features	TERRAD = 4 (no default)	Terrain effects are considered up to 4 km for each grid point.
Temperature Field Options		
3D temperature from observations or from prognostic data	ITPROG = 2	No surface or upper air observations. Use MM5/3D.DAT for surface and upper air data.
Land use categories for temperature interpolation over water	JWAT1= 55 JWAT2= 55	Temperature overwater for land use code 55 (salty water, Canso Strait)) will be based on WRF overwater air temperatures.
Overwater Options		
Option for overwater lapse rates used in convective mixing height growth	ITWPROG = 2	Use prognostic lapse rates and prognostic delta T.
Land use categories for using the overwater boundary layer sub model	IWAT1= 55 IWAT2= 55 (defined in GEO.DAT)	For land use code 55 (salty water, Canso Strait) the overwater boundary layer sub model will be used.

* Wind field generation parameters (R1, R2, RMAX1, RMAX2, RMAX3, RMIN, and LVARY) are irrelevant when no observation mode is used.

5.1.3 Configuration of CALPUFF

5.1.3.1 Receptors

A nested grid pattern covering a 20 x 20 km domain was used for the receptors:

- 100 m spacing from the centre of the operation out to 1 km;
- 250 m spacing from 1 km out to 2.5 km;
- 500 m spacing from 2.5 km out to 10 km.

Additional receptors were placed at a finer resolution every 25 m along the property line, for a total of 2,427 receptor points located at ground level (flagpole height at zero). The receptor grids and additional receptors are shown on Figure 4.

5.1.3.2 Building Wake Effects

Building wake effects on plume rise and atmospheric dispersion were considered within CALPUFF. Building dimensions and stack heights (presented in Section 5.2 and Figure 5) were processed with the Building Profile Input Program (BPIP) to generate the characteristic dimensions required by CALPUFF's PRIME building wake sub model.

5.1.3.3 Special CALPUFF Options

CALPUFF default options were used in the model configuration, with the exceptions presented in Table 9. Dispersion coefficients based on micrometeorological parameters (MDISP=2) and the use of a probability density function under convective conditions (MPDF=1) were selected to be consistent with the AERMOD model and requirements of air dispersion modelling guidelines from Quebec and Newfoundland & Labrador.

To obtain conservative estimates of ground level concentrations of air contaminants, modelling of chemical transformations (MCHEM=0) and deposition (MDRY=0, MWET=0) was not considered. Also, since flares are modelled using pseudo-physical parameters (see section 5.2), stack tip downwash modelling was turns off for these sources (MTIP=0).

Figure 4 CALPUFF Domain, Receptor Grids and Discrete Receptors

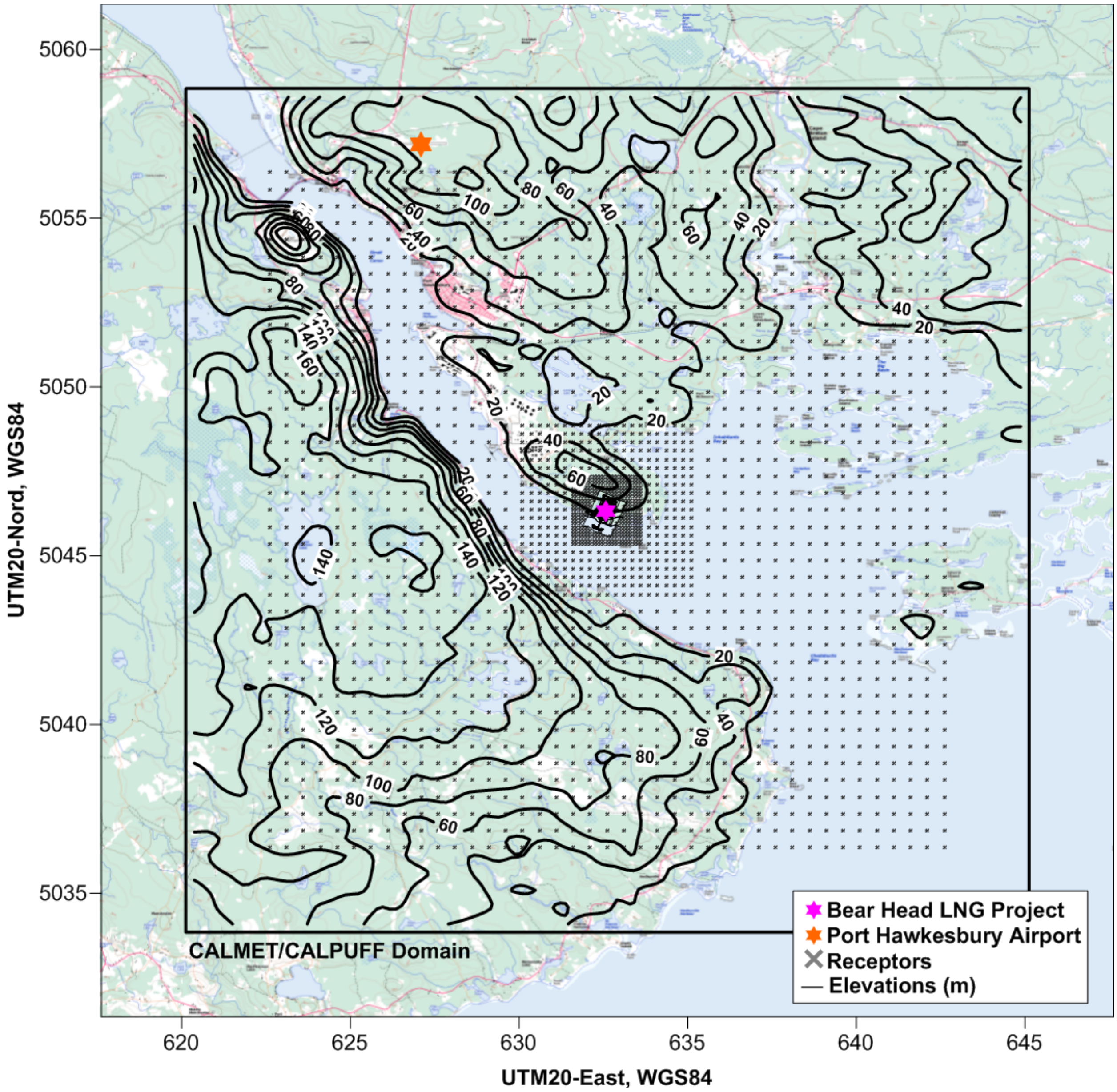


Table 9 CALPUFF Configuration - Non Default CALPUFF Options

Parameter	Name of parameter and interpretation	Default value	Selected value	Selected value interpretation
NSE	Number of emitted species	3	5	Emitted species
NSPEC	Number of chemical species	5	5	Emitted species and species implicated in chemical transformations
MBDW	Method used to simulate building downwash	1	2	PRIME method
MTIP	Stack Tip Downwash Option	1	0 for conventional visible flame flares. 1 for all other point sources.	Stack tip downwash not considered for conventional flares which are modeled with pseudo-diameters based on released heat rate (see section 5.2)
MDRY	Dry Deposition	1	0	Dry deposition not modelled
MWET	Wet Deposition	1	0	Wet deposition not modelled
MCHEM	Chemical mechanism	1	0	Chemical transformations not modelled
MDISP	Method used to compute dispersion coefficients	3	2	Dispersion coefficients from internally calculated micrometeorological variables
MPDF	Probability density function (PDF) used for dispersion under convective conditions	0	1	Yes
MREG	Test options specified to verify if they conform to (US-EPA) regulatory values	1	0	No checks are made

5.1.4 Background Concentrations and Air Quality Standards

The atmospheric dispersion model is used to estimate the plant's contribution to air contaminants. Background concentrations represent the concentrations of air contaminants already in the area or from other sources not included in the air dispersion model. These background concentrations are added to the results of the atmospheric dispersion model and the resulting concentrations are then compared to the ambient air quality standards.

The background concentrations were determined from the results of air quality monitoring at the Port Hawkesbury monitoring site from the NAPS (section 2.1) for SO_2, NO_2 and $PM_{2.5}$. For CO, monitoring results from the NAPS station in Sydney (Cap Breton) were considered. In the absence of monitoring results for PM_t, it was assumed that PM_t was 4 times the $PM_{2.5}$ values ($PM_{2.5}$ representing 25% of PM_t is a conservative assumption). Monitoring results for the last available years (2010-2012) were considered, but year 2010 was not integrated because of lower data availability (65% or less).

- One to 24-hour: 3-year average of the 99th percentile over one and eight hours for gases.
- 24-hour $PM_{2.5}$: 98th percentile of two years of daily averages for $PM_{2.5}$.
- Annual: averages over two years for all contaminants.

Selected ambient background concentrations are presented in Table 10 with the Nova Scotia AAQS and the Canadian Standards for 2020 for $PM_{2.5}$.

Table 10 Background Concentrations and Ambient Air Quality Standards

Pollutant	Period	Background Concentrations (µg/m³)	Nova Scotia AAQS (µg/m³)
NO_2	1-hour	25	400
	Annual	3.8	100
SO_2	1-hour	31	900
	24-hour	16	300
	Annual	2.6	60
CO	1-hour	458	34,600
	8-hour	458	12,700
PM_t	24-hour	60	120
	Annual	26	70
$PM_{2.5}$	24-hour	15	27*
	Annual	6.5	8.8*

* Canadian Standards for 2020.

5.1.5 Conversion of NO to NO_2

The NO_x emissions due to the combustion of natural gas usually consist of 90% of NO and 10% of NO_2. In the atmosphere, NO reacts quickly with the ozone (O_3) and more slowly with air oxygen to form NO_2 in both cases. The presence of VOC accelerates the process by which NO is transformed into NO_2. Furthermore, an inverse reaction occurs because NO_2 breaks up under the effect of sunrays to form NO and ozone. Several other reactions involving NO_x, free radicals and VOC occur in the atmosphere, particularly in urban areas.

The OLM "*ozone limiting method*" *(*Cole & Summerhays, 1979*)* was used to estimate hourly maximum ground-level concentrations considering a high ambient ozone concentration of 110 µg/m³, typical of the 99th hourly percentile value in Port Hawkesbury (2011-2012 average), and an initial stack $[NO_2]/[NO_x]$[2] ratio of 10%.

[2] Molar or volumetric concentrations.

- If the $[O_3]$ ambient concentration is greater than (1-stack$_{ratio}$)*$[NO_x]$ concentration, then total conversion is assumed ➔ $[NO_2] = [NO_x]$;

- If the 0.9*$[NO_x]$ concentration is greater than the $[O_3]$ concentration, the formation of NO_2 is limited by the ambient O_3 concentration ➔ $[NO_2]$ = stack$_{ratio}$*$[NO_x]$ + $[O_3]$.

The OLM method was applied to CALPUFF maximum NO_x hourly concentrations to estimate maximum NO_2 concentrations, prior to adding background concentrations. For annual averages, total conversion of NO to NO_2 was assumed.

5.2 AIR EMISSIONS PARAMETERS

Table 11 presents the emission parameters of all the sources considered for air dispersion modelling. Emissions rates are consistent with information presented in Chapter 3.

Figure 5 presents a schematic layout of the Bear Head LNG Plant where sources (stacks) locations are indicated as well as the main structures that were considered in the building wake analysis with BPIP. Base elevations and height of sources and structures are also indicated on the figure.

The flares with visible flames are modeled as point sources (stacks) using emission pseudo-parameters determined according the US EPA (1992) method:

- the speed is fixed at 20 m/s;
- the temperature is fixed at 1 000°C ;
- the effective diameter (d_{eff}, m) and the effective height (h_{eff}, m) are calculated in function of the rate of heat released by the gas combustion (Q, cal/s) and the height of the flare (h_s, m) in the following manner:

$$\boldsymbol{d_{eff} = 0{,}000663\sqrt{Q}} \quad (1)$$

$$\boldsymbol{h_{eff} = h_s + 0{,}00456\, Q^{0{,}478}} \quad (2)$$

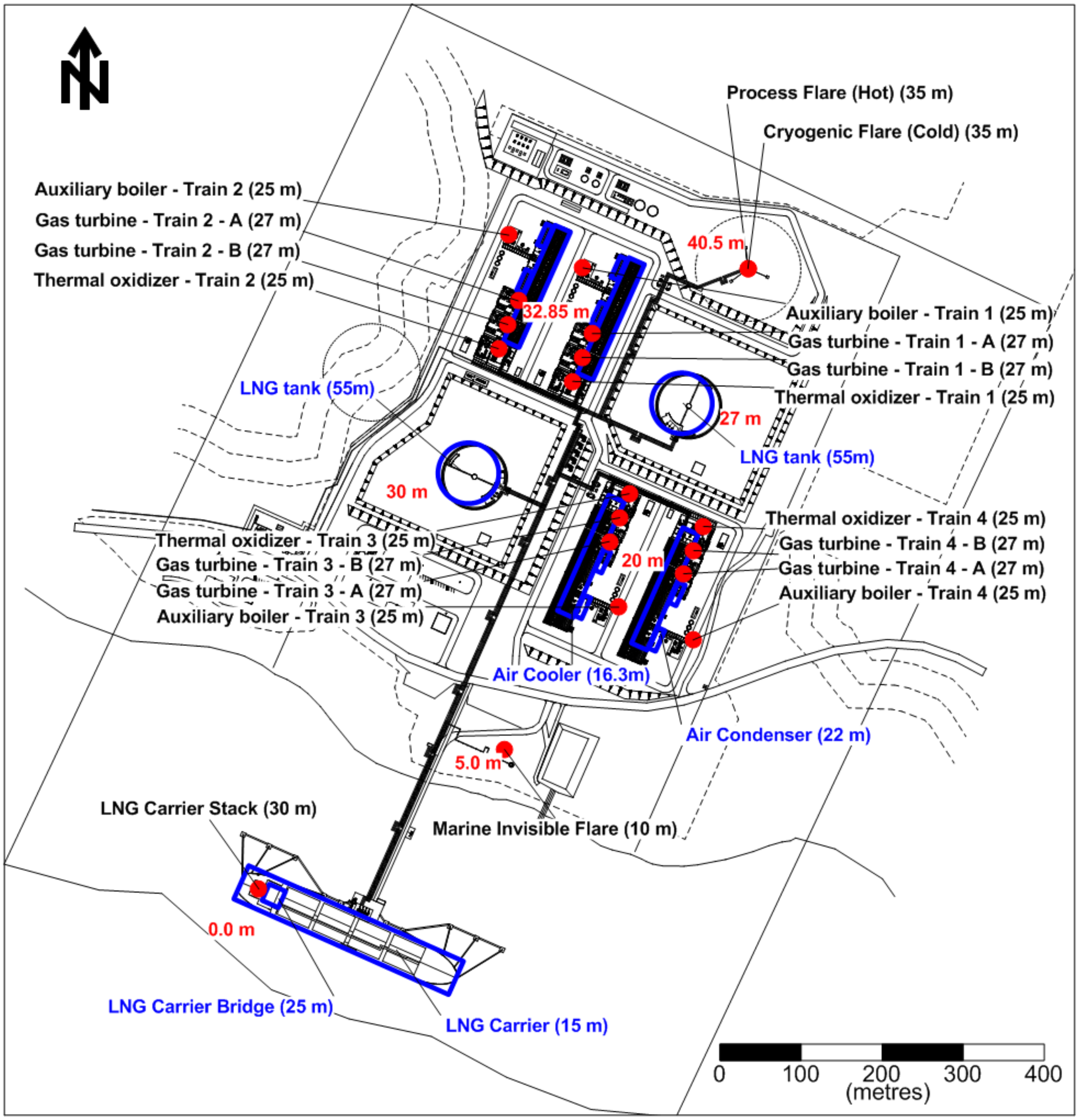
For this project, since the flares are subject to building wake effects from one of the LNG tanks, the effective height (h_{eff}) was considered equal to the flare height (h_s). Also, as modeling considers a pseudo-diameter, stacks tip downwash modelling was turned off in CALPUFF for those sources.

Table 11 Air Emission Parameters Considered in Air Dispersion Modelling

Sources per Train (4 Trains)	Stack Height above ground	Stack Diameter	Exhaust Velocity	Exhaust Temperature	NO_x	CO	SO_2	PM_t	PM_{10}	$PM_{2.5}$
	(m)	(m)	(m/s)	(°C)	(g/s)	(g/s)	(g/s)	(g/s)	(g/s)	(g/s)
Gas Turbines (2 units)	27	3.3	15.0	200	3.92	2.39	0.00	0.280	0.280	0.280
Auxiliary Boiler (1 unit)	25	1.0	15.7	150	0.624	0.430	0.00	0.0871	0.0871	0.0871
CO_2 Vent - Thermal Oxidizer (1 unit)	25	1.20	15.4	816	0.329	0.239	1.25	0.0386	0.0386	0.0386
For the whole plant - Intermittent Sources										
Process Flare (flaring event, 88 h/y)	35 (1)	8.7 (1)	20 (1)	1000 (1)	23.5	128	0.00	2.58	2.58	2.58
Cryogenic Flare (flaring event, 100 h/y)	35 (1)	6.4 (1)	20 (1)	1000 (1)	12.7	68.9	0.00	1.39	1.39	1.39
Marine Invisible Flare (4h/year)	10.0	3.0	21.5	500	18.2	99.3	0.00	2.00	2.00	2.00

(1) Following US-EPA procedures (1992), visible flares were modelled using pseudo-parameters: 1000°C temperature, 20 m/s exhaust velocity and effective diameter based on heat rate. Since these flares as subject to downwash from the LMG tanks, effective release heights were not considered, i.e release height are set to the flare heights. In addition, as a large pseudo-diameter is considered, stack-tip downwash modelling was not considered in Calpuff for those sources.

Figure 5 Bear Head LNG Processing Plant – Sources and Building Elevations



Notes: All sources (red dots) and buildings (blue lines) heights are given above local ground levels. Local ground levels elevations are in red.

5.3 AIR DISPERSION MODELLING RESULTS

This section presents the CALPUFF modelling results at and beyond the Bear Head LNG Project property fence line and over the whole receptor domain.

5.3.1 Summary of Maximum Predicted Concentrations

Table 12 presents a summary of maximum predicted concentrations for each year of the modelling period for the plant in normal operation with a LNG carrier hotelling. For every year, modelling results are in compliance with the AAQS for all contaminants (SO_2, NO_2, CO, PM_t and $PM_{2.5}$) and averaging periods (1-hour, 8-hour, 24-hour and annual).

The highest contributions from the Bear Head Project in normal operation to ground level concentrations relative to the AAQS are for short-term averaging periods (24-hour or less), with the most significant contributions being related to NO_2 (59% and 26% respectively of the 1-hour and annual AAQS) and $PM_{2.5}$ (33% of the 24-hour AAQS).

Table 13 presents maximum predicted concentrations with consideration of background concentrations and still show compliance with the AAQS. For $PM_{2.5}$, the maximum concentrations almost reach 90% of the AAQS for daily and annual $PM_{2.5}$.

Tables 14 and 15 present similar results for upset conditions. This scenario includes all continuous sources for the LNG plant, a LNG carrier hotelling and flaring at maximum capacity at all flares (hot, cold and marine flare). Since this situation is unlikely to occur and, if it would, it would be of short duration, only maximum hourly and daily predicted concentrations are presented. Results show a significant increase in maximum predicted ambient air concentrations for CO, but results remain well below the AAQS with a maximum included background of 7.7% for an 8-hour period. Maximum predicted concentrations of NO_2 remain unchanged for the normal operation scenario and $PM_{2.5}$ concentrations increase lightly. Flares generate large amount of very hot gases that rise quickly in the atmosphere, thus reducing the air quality impacts.

All these maximum contributions in normal or upset conditions only occur at specific receptors very near to the installations as it will be shown in the next sub-section.

Table 12 Summary of Yearly Maximum Predicted Concentration in Ambient Air for the LNG Plant, including LNG Carrier Hotelling – Normal Operation

Pollutant	Period	2009	2010	2011	2012	2013	Maximum		AAQS (µg/m³)
		(µg/m³)	(µg/m³)	(µg/m³)	(µg/m³)	(µg/m³)	(µg/m³)	% AAQS	
NO_2	1 h	195	196	197	185	235	235	59%	400
	Annual	20	26	20	25	23	26	26%	100
SO_2	1 h	90	118	91	86	90	118	13%	900
	24 h	18	20	20	19	18	20	6.6%	300
	Annual	3.7	3.3	3.9	3.8	3.9	3.9	6.5%	60
CO	1 h	158	162	203	185	161	203	0.59%	34,600
	8 h	77	74	71	72	74	77	0.60%	12,700
PM_t	24 h	8.9	9.0	7.9	8.4	8.3	9.0	7.5%	120
	Annual	1.2	1.1	1.2	1.2	1.3	1.3	1.8%	70
$PM_{2.5}$	24 h	8.9	9.0	7.9	8.4	8.3	9.0	33%	27*
	Annual	1.2	1.1	1.2	1.2	1.3	1.3	14%	8.8*

*: New Canadian Standard for 2020.

Table 13 Summary of Maximum Predicted Concentration in Ambient Air for the LNG Plant, including LNG Carrier Hotelling and Background Concentrations – Normal Operation

Pollutant	Period	Maximum Predicted (2009-2013)		Background		Total		AAQS (µg/m³)
		(µg/m³)	% AAQS	(µg/m³)	% AAQS	(µg/m³)	% AAQS	
NO_2	1 h *	235	59%	24	6.1%	259	65%	400
	Annual	26	26%	3.8	3.8%	30	30%	100
SO_2	1 h	118	13%	31	3.5%	149	17%	900
	24 h	20	6.6%	16	5.2%	36	12%	300
	Annual	3.9	6.5%	2.6	4.4%	7	11%	60
CO	1 h	203	0.59%	458	1.3%	661	1.9%	34,600
	8 h	77	0.60%	458	3.6%	535	4.2%	12,700
PM_t	24 h	9.0	7.5%	60	50%	69	58%	120
	Annual	1.3	1.8%	26	37%	27	39%	70
$PM_{2.5}$	24 h	9.0	33%	15	54%	23	87%	27*
	Annual	1.3	14%	6.5	74%	7.8	88%	8.8*

*: New Canadian Standard for 2020.

Table 14 Summary of Yearly Maximum Predicted Concentration in Ambient Air for the LNG Plant with Flaring, including LNG Carrier Hotelling – Normal Operation

Pollutant	Period	2009	2010	2011	2012	2013	Maximum		AAQS (µg/m³)
		(µg/m³)	(µg/m³)	(µg/m³)	(µg/m³)	(µg/m³)	(µg/m³)	% AAQS	
NO_2	1 h	195	196	197	185	235	235	59%	400
SO_2	1 h	90	118	91	86	90	118	13%	900
	24 h	18	20	20	19	18	20	6.6%	300
CO	1 h	1,601	1,020	998	1,711	1,366	1,711	4.9%	34,600
	8 h	298	287	369	514	306	514	4.1%	12,700
PM_t	24 h	9.3	10	9.2	10	9.2	10	8.5%	120
$PM_{2.5}$	24 h	9.3	10	9.2	10	9.2	10	38%	27*

*: New Canadian Standard for 2020.

Table 15 Summary of Maximum Predicted Concentration in Ambient Air for the LNG Plant with Flaring, including LNG Carrier Hotelling and Background Concentrations – Normal Operation

Pollutant	Period	Maximum Predicted (2009-2013)		Background		Total		AAQS (µg/m³)
		(µg/m³)	% AAQS	(µg/m³)	% AAQS	(µg/m³)	% AAQS	
NO_2	1 h	235	59%	24	6.1%	259	65%	400
SO_2	1 h	118	13%	31	3.5%	149	17%	900
	24 h	20	6.6%	16	5.2%	36	12%	300
CO	1 h	1,711	5.0%	458	1.3%	2,169	6.3%	34,600
	8 h	514	4.1%	458	3.6%	972	7.7%	12,700
PM_t	24 h	10	8.5%	60	50%	70	59%	120
$PM_{2.5}$	24 h	10	38%	15	54%	25	92%	27*

*: New Canadian Standard for 2020.

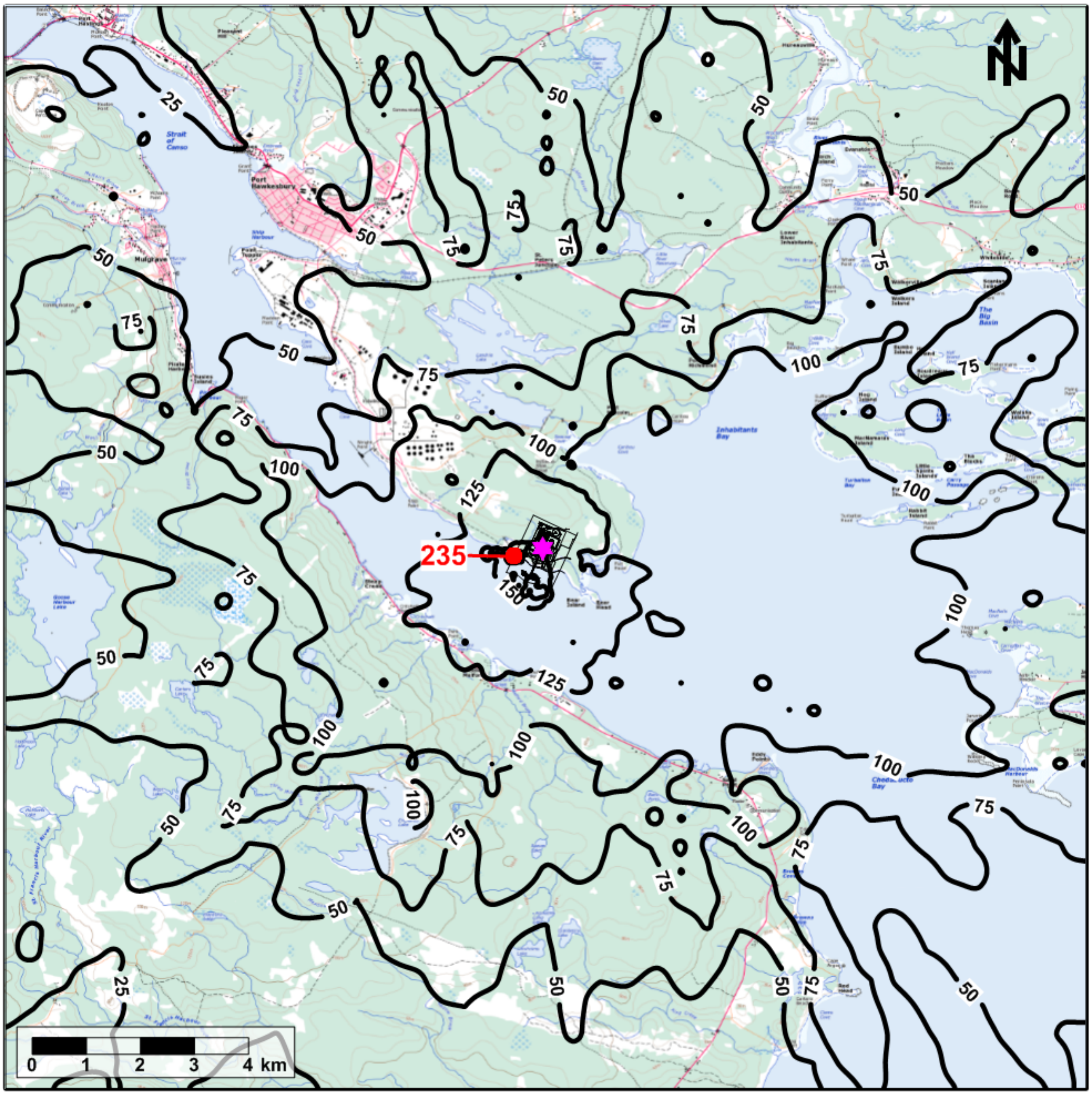
5.3.2 Results over the Modelling Domain

The previous section focussed on the maximum predicted concentrations over the modelling domain and showed compliance with the AAQS. These maximum concentrations do not occur over the entire modelling domain and are localised at specific locations. They also do not occur very frequently. This section presents maximum concentrations for NO_2 and $PM_{2.5}$ for different averaging periods over the entire modelling domain. These contaminants were selected because they reach the highest levels relative to the AAQS.

Figures 6 and 7 present the maximum hourly and annual predicted concentrations in ambient under normal operation. Both maximum occur over water near the plant boundary. Figures 8 and 9 respectively present the maximum predicted daily and annual $PM_{2.5}$ concentrations. Maximum predicted concentrations on the West shore on the Canso Strait and in Port Hawkesbury are much lower that the maximums predicted near the plant.

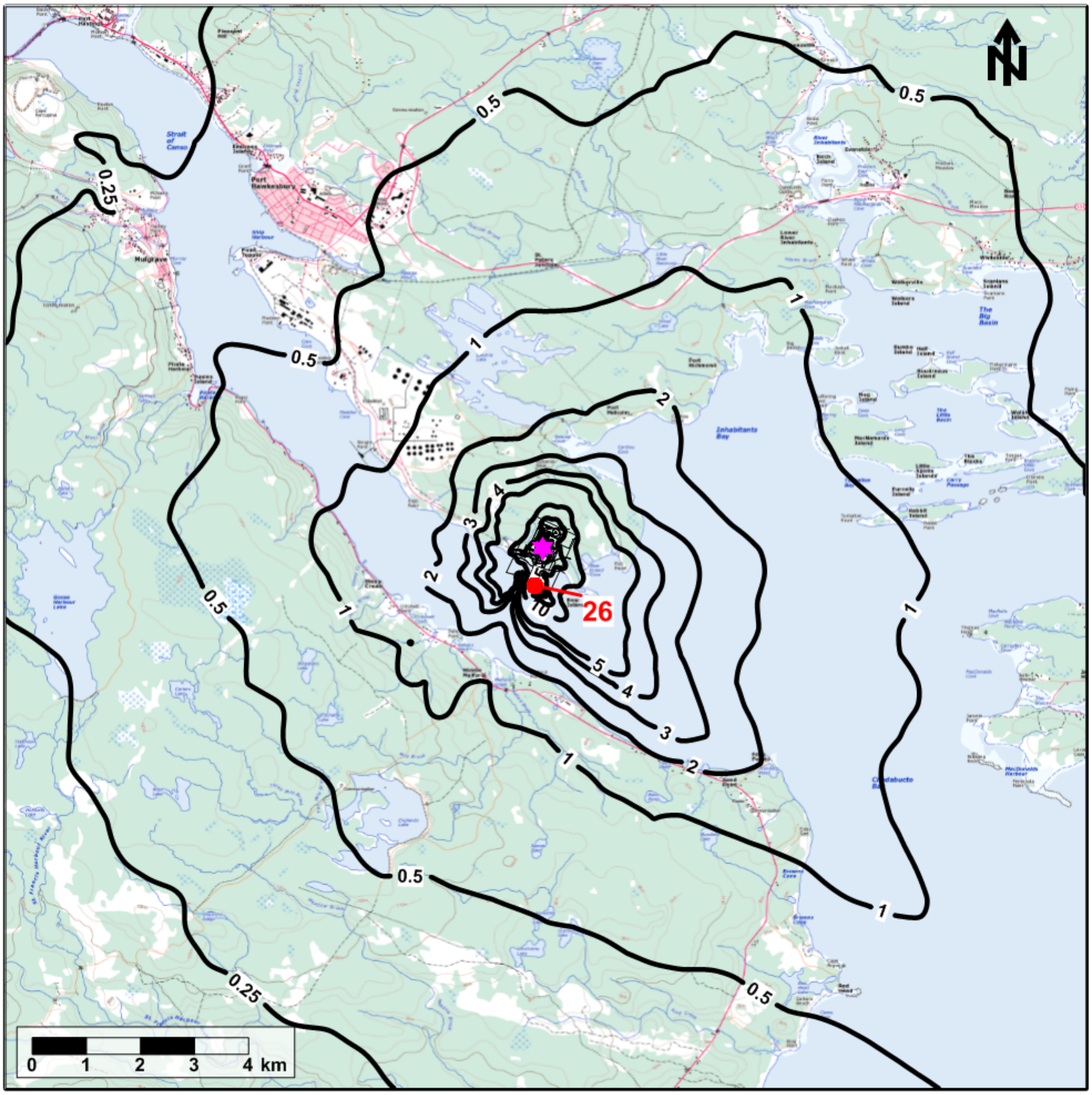
Figures 10 and 11 present maximum short term 1-hour NO_2 and daily $PM_{2.5}$ predicted concentrations during upset conditions with all flares in operation. Results are only slightly higher than in normal operation over the entire modeling domain.

Figure 6 **Maximum Hourly Predicted NO_2 Concentrations in Ambient Air (µg/m³) – Bear Head LNG Plant with LNG Carrier – Normal Operation**



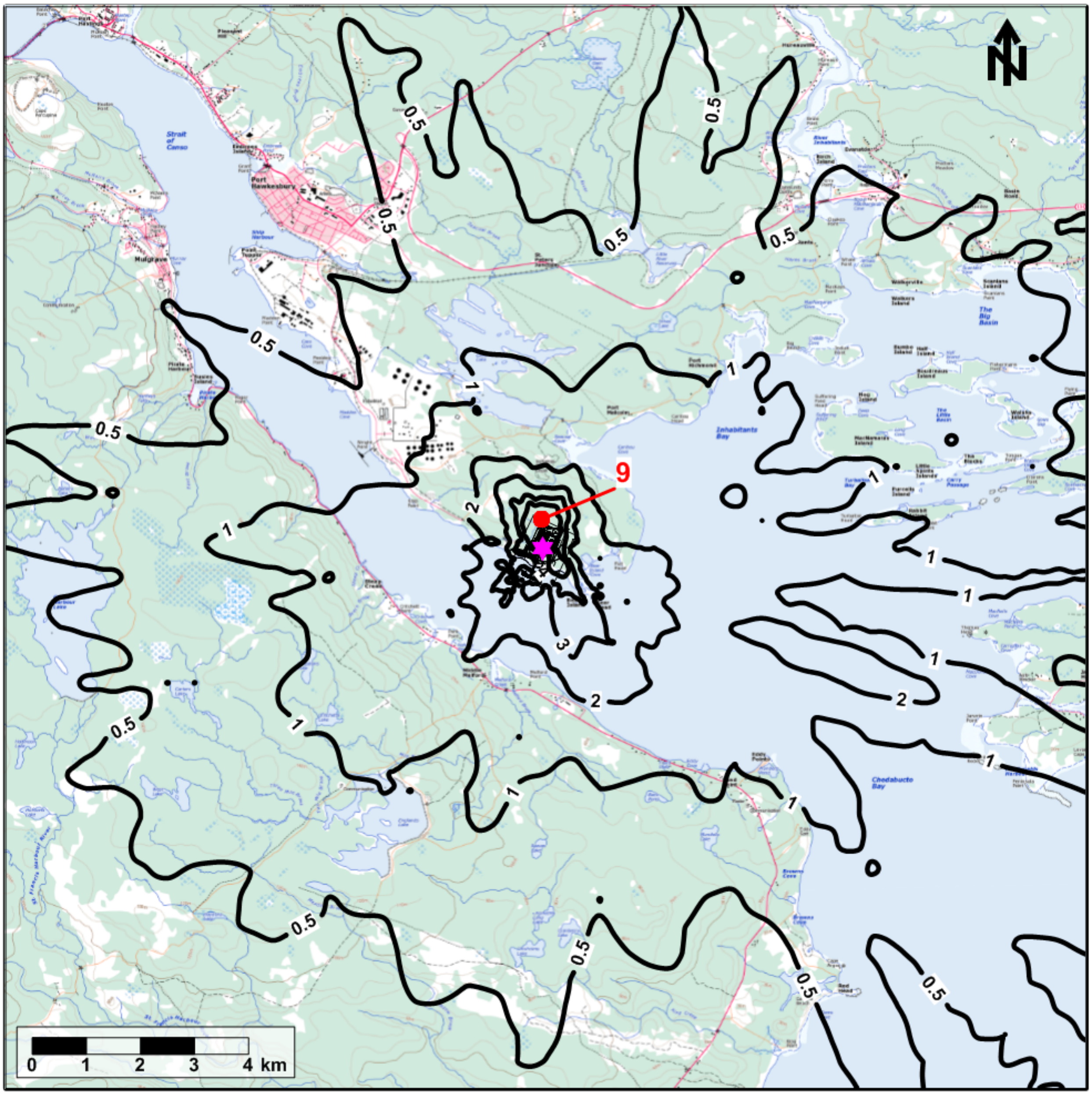
Notes: Project contribution only.
Maximum indicated in red.
Nova Scotia Ambient Air Quality Standard: 400 µg/m³.

Figure 7 **Maximum Annual Predicted NO_2 Concentrations in Ambient Air (µg/m³) – Bear Head LNG Plant with LNG Carrier – Normal Operation**



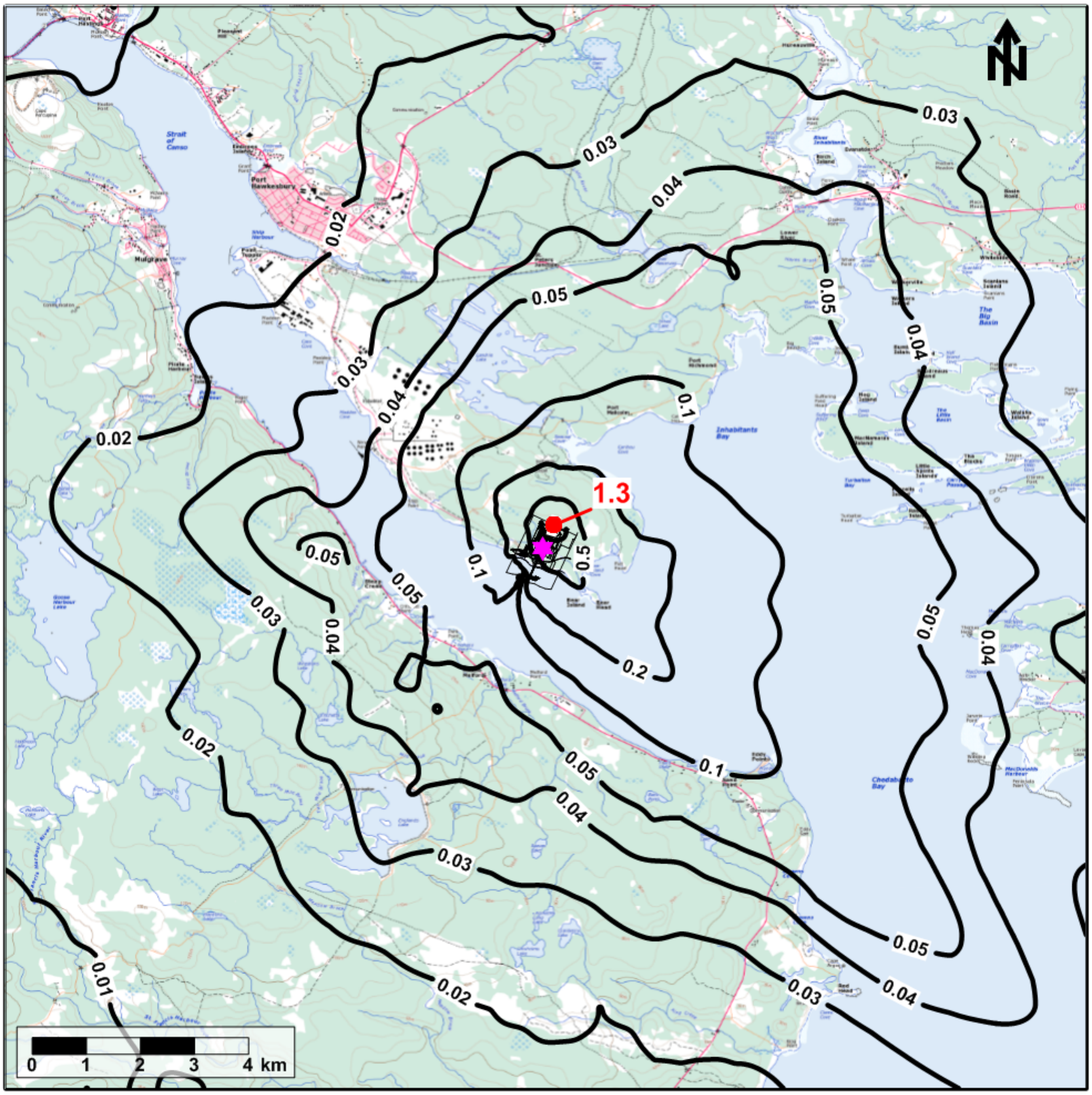
Notes: Project contribution only.
Maximum indicated in red.
Nova Scotia Ambient Air Quality Standard: 100 µg/m³.

Figure 8 **Maximum Daily Predicted $PM_{2.5}$ Concentrations in Ambient Air (µg/m³) – Bear Head LNG Plant with LNG Carrier – Normal Operation**



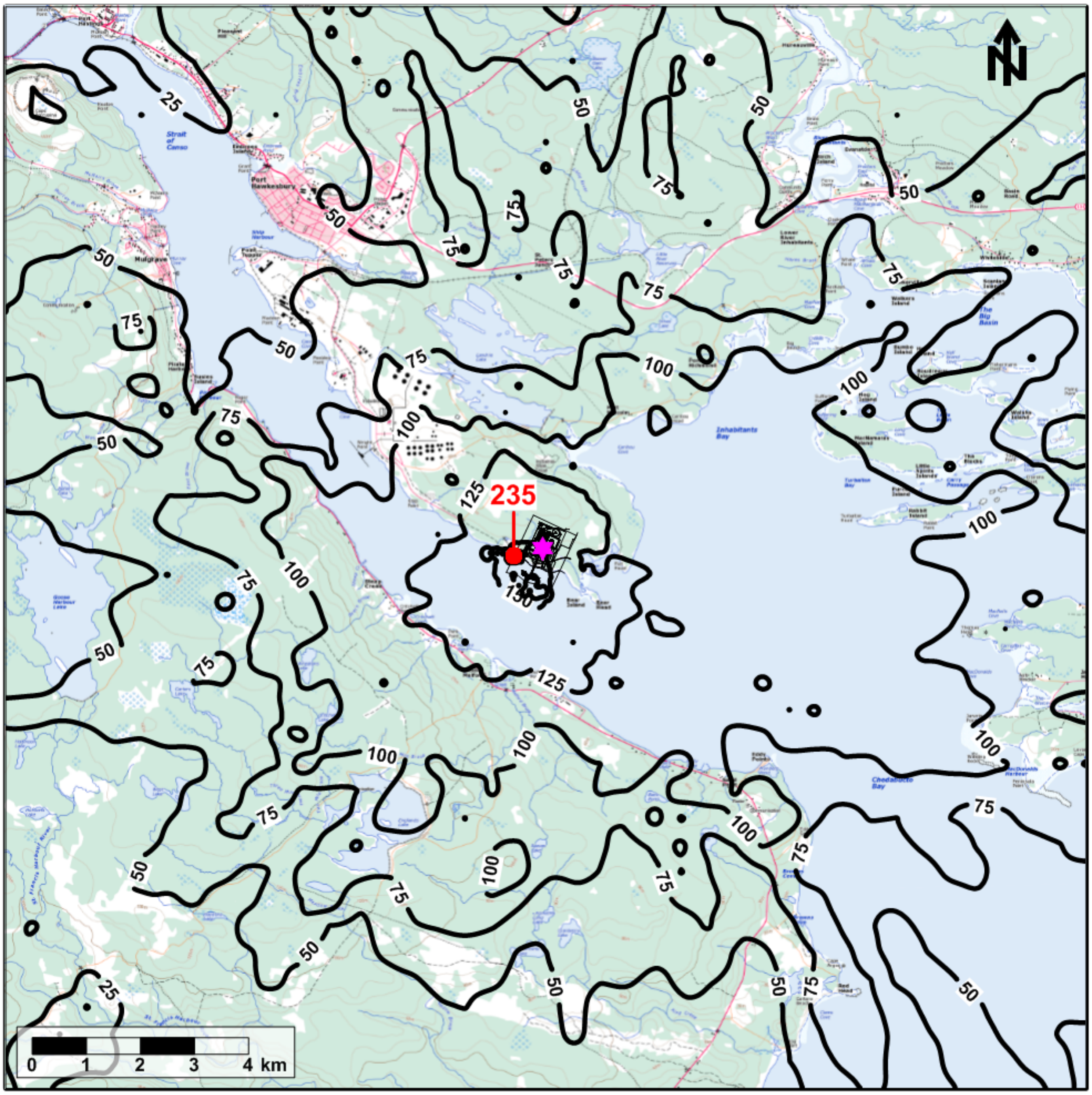
Notes: Project contribution only.
Maximum indicated in red.
Canadian Ambient Air Quality Standard for 2020: 27 µg/m³.

Figure 9 **Maximum Annual Predicted $PM_{2.5}$ Concentrations in Ambient Air (µg/m³) – Bear Head LNG Plant with LNG Carrier – Normal Operation**



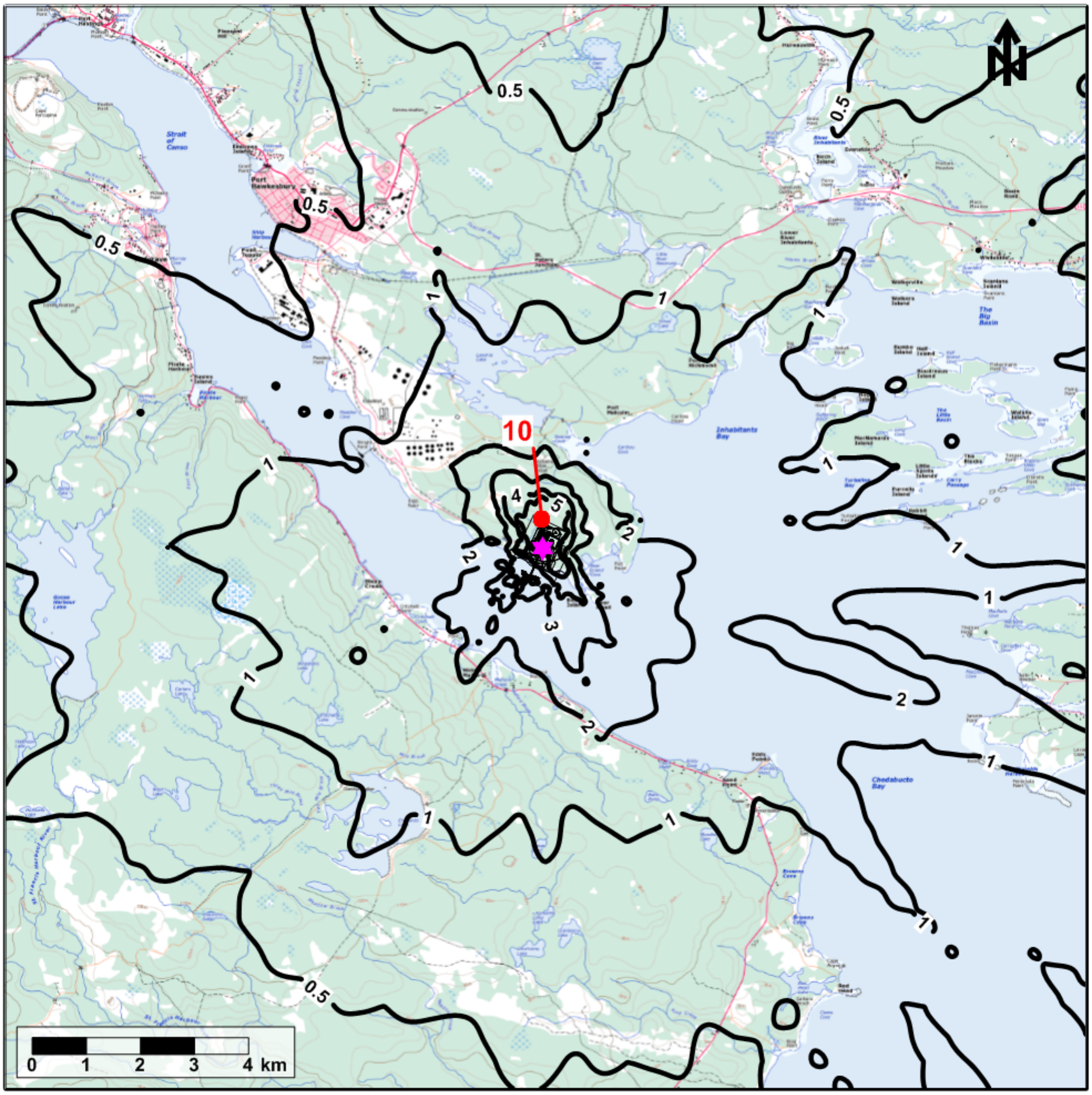
Notes: Project contribution only.
Maximum indicated in red.
Canadian Ambient Air Quality Standard for 2020: 8.8 µg/m³.

Figure 10 **Maximum Hourly Predicted NO_2 Concentrations in Ambient Air (µg/m³) – Bear Head LNG Plant with LNG Carrier and all Flares – Upset Condition**



Notes: Project contribution only.
Maximum indicated in red.
Nova Scotia Ambient Air Quality Standard: 400 µg/m³.

Figure 11 Maximum Daily Predicted $PM_{2.5}$ Concentrations in Ambient Air (µg/m³) – Bear Head LNG Plant with LNG Carrier and all Flares – Upset Condition



Notes: Project contribution only.
Maximum indicated in red.
Canadian Ambient Air Quality Standard for 2020: 27 µg/m³.

6 SUMMARY

An emission inventory was estimated for the characteristics of the equipment to be installed at the Bear Head Project including all sources in normal operation 350 days a year (gas turbines, auxiliary boilers, thermal oxydizers), flaring upset conditions 1% of the time at the three flares, the emergency diesel generator, the two diesel fire water engines and the two diesel seawater pump engines assumed to be in operation 100 hours a year. The fugitive emissions from piping components were also estimated in terms of VOC. All the sources will be in compliance with emission standards (Federal regulations and BLIERs).

Overall effects on air quality in the local air shed during the Project's construction and operation phase are not expected to be significant. The Bear Head project will comply with ambient air quality standards, in normal operation conditions as well as in all potential upset conditions, with and without a LNG carrier in hotelling while loading LNG.

Over the last 20 years regulations on internal combustion engines have become increasingly stricter, resulting in a significant lowering of priority pollutants in engine exhaust. This trend is expected to continue. The Project will use state of the art equipment that will conform to industry emissions standards, as these standards are developed in the future with the intention to further reduce emissions as new emissions reducing technologies become available. In addition, the primary fuel source for combustion throughout the Bear Head LNG export facility is natural gas; which is a much cleaner burning fuel than other potential options.

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