150 MW (Nominal) Avalon Combustion Turbine Project

Environmental Assessment Registration

March, 2025

Table of Contents

List of Tables

List of Figures

List of Appendices

Acronyms

AAQS	Ambient Air Quality Standards
ACCDC	Atlantic Canada Conservation Data Center
ACT	Avalon Combustion Turbine
BACT	Best Available Control Technology
EA	Environmental Assessment
CBS	Conception Bay South
CER	Clean Electricity Regulations
CLC	Community Liaison Committee
CO	Carbon Monoxide
COSEWIC	Committee on the Status of Endangered Wildlife in Canada
dBA	Decibels (A-weighted)
DFO	Department of Fisheries and Oceans
DLE	Dry Low Emissions
DLN	Dry Low NO_x Combustors
DPFs	Diesel Particulate Filters
DOCs	Diesel Oxidation Catalysts
DOECC	Department of Environment and Climate Change
EDI	Equity, Diversity and Inclusion
EMS	Environmental Management System
EPCM	Engineering, Procurement and Construction Management
ESPs	Electrostatic Precipitators
FEED	Front End Engineering and Design
GAP	Storage and Handling of Gasoline and Associated Products Regulations
GESH	Good Engineering Stack Height
GHGs	Greenhouse Gases
%HA	Percentage Change in High Annoyance
HRM	HTGS Emergency Response Manual
HTGS	Holyrood Thermal Generating Station
IEC	Independent Environmental Consultants
Leq	Equivalent Continuous Sound Level
LNB	Low NO_x Burners
LSD	Low Sulphur Diesel
MGGA	Management of Greenhouse Gas Act
MW	Megawatt
NMP	Noise Management Plan
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxides
NOC	National Occupational Classification
PM	Particulate Matter
PPD	Pollution Prevention Division
PPM	Parts Per Million
RFIs	Requests for Information
SAC	Singular Annular Combustion
SAR	Species at Risk
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulphur Dioxide
SOCC	Species of Conservation Concern
tCO_2e	Tonnes of Carbon Dioxide Equivalent
TSP	Total Suspended Particulate
RRA	Reliability and Resource Adequacy Study
ULN/ULNB	Ultra-low NO_x / Ultra-low NO_x Burners
ULSD	Ultra-Low Sulphur Diesel

1.0 INTRODUCTION

1.1 **Name of Undertaking**

150 MW (Nominal) Avalon Combustion Turbine (the "project").

1.2 **Proponent Information**

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1.3 **Project Overview**

To ensure reliable system operations and address a forecasted increase in electricity demand, Newfoundland and Labrador Hydro ("Hydro") is proposing to install 150 megawatts ("MW") of combustion turbine generation as recommended in its 2024 Resource Adequacy Plan[1]. The proposed project, known as the Avalon Combustion Turbine ("ACT"), will be located on Hydro owned property adjacent to the existing Holyrood Thermal Generating Station ("HTGS"). The facility will provide a source of peaking support and backup generation.

This undertaking involves the construction of a gas turbine electric power generating plant with a capacity of more than one (1) MW and requires registration, review and approval pursuant to the requirements of the Newfoundland and Labrador *Environmental Protection Act* (Part X) and its associated *Environmental Assessment Regulations*.

[1] This plan is available at https://nlhydro.com/power-the-province/.

1.4 **Project Purpose/Rationale/Need**

Hydro has been analyzing the island electricity system for the timing and magnitude of the next required resource options since 2018, when Hydro completed its first Reliability and Resource Adequacy ("RRA") Study. In the most recent Resource Adequacy Plan, filed with the Public Utilities Board ("the Board") in July 2024[2], Hydro focused on the production of an Island Interconnected System Expansion Plan to satisfy both capacity and energy requirements. The analysis highlights that, in all modelled scenarios, urgent investment in increased electrical supply within the next 10 years is essential and justified to maintain a reliable power supply for customers. It is imperative to action new resource options now, as the Island Interconnected System is currently capacity-constrained, there is a need to retire aging thermal assets and there is an extensive timeframe required to construct new assets.

In the 2024 Resource Adequacy Plan, in the Reference Case Expansion Plan scenario (the scenario most likely to occur), Hydro's analysis determined that approximately 525 MW of new generation is required by 2034 to address the additional Island demand and to allow for the retirement of aging thermal assets, including HTGS. The requirement for additional on-Island capacity is driven by a variety of factors including load growth, the retirement of aging assets and system reliability. Hydro's strategy in the 2024 Resource Adequacy Plan, with consideration of feedback from customers, recommends an expansion plan that meets reliability criteria under the Minimum Investment scenario while balancing cost and environmental considerations[3]. Appendix A contains a summary of the expansion plan.

Subsequent to filing its 2024 Resource Adequacy Plan, Hydro and its experts participated in a series of technical conferences in the fall of 2024 with the Board staff and intervening parties, along with their experts. The parties agreed that Hydro analyzed an appropriate range of scenarios and sensitivities in the analysis to support Hydro's recommendation regarding the minimum investment required being Bay d'Espoir Unit 8 and the Avalon Combustion Turbine (Figure 1). Hydro submitted its application for further review and approval of these projects to the Board on March 21, 2025.

[2] Filed as an update to the RRA Study as part of the RRA Study Review proceeding with the Board. Hydro's filings within the RRA Study Review are available on the Board's website: http://pub.nl.ca/applications/NLH2018ReliabilityAdequacy/index.php.

[3] The *Electrical Power Control Act*, mandates that power be delivered to consumers in the province at the lowest possible cost, in an environmentally responsible manner, consistent with reliable service.

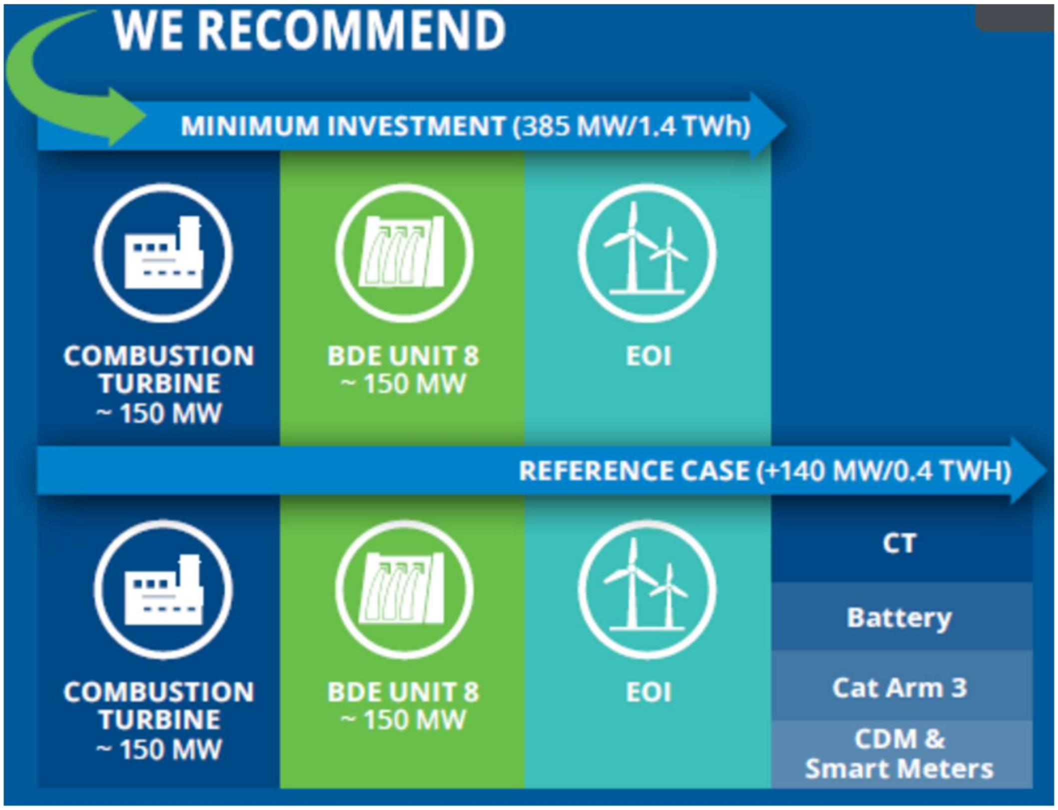

Figure 1. Expansion Plan Reference Case and Minimum Investment Scenario

Hydro's 2024 Resource Adequacy Plan, and the related proceeding, has established the need for additional combustion turbine generation for peaking and backup generation support. This proposed undertaking is in response to this established need.

1.5 **Approval of the Undertaking**

In addition to approval through the provincial Environmental Assessment ("EA") process, the project will require a number of other provincial and federal permits and authorizations. Hydro is committed to obtaining and complying with the conditions of these required approvals during project construction and operations and will require the same of any and all contractors that are involved in this project. Hydro will ensure contractor execution plans are consistent with permit requirements and will monitor for compliance throughout the course of the project.

Some of the key environmental permits and approvals that may be required for the project include those listed in Appendix B.

1.5.1 Federal Clean Energy Regulations

In December 2024, the Government of Canada finalized the *Clean Electricity Regulations* ("CER"), the draft versions of which were key considerations in Hydro's evaluation of potential new sources of generation during preparation of the 2024 Resource Adequacy Plan. The ACT will be compliant with the CER based on its use as a peaking facility or for providing backup generation in the event of high demand periods or during contingency events. The ACT will be able to utilize renewable fuels in the future and may aid in the implementation of renewable supply resources by providing firm, reliable backup at times when intermittent renewable resources are not available. The CER acknowledges the role that these resources will play in the transition to a clean electricity grid.

As required by Section 7 of the CER, Hydro will submit a registration report for the ACT prior to putting the facility into operation.

2.0 PROJECT DESCRIPTION

The following section provides a description of the proposed project, including an overview of its various components and planned activities.

2.1 Project Status and Execution Approach

Front-end engineering and design ("FEED") for the project was substantially completed by Hatch Ltd. in 2024. In 2025, Hydro will award a contract for detailed engineering, procurement, and construction management ("EPCM") services. Hydro's Major Projects team will manage the EPCM consultant and provide general oversight and monitoring of the project.

While detailed engineering and plan refinement will continue through 2025/2026, the project scope and potential environmental interfaces are defined. In parallel with this EA registration, on March 21, 2025, Hydro submitted an application to the Board for project review and approval.

2.1.1 Procurement of Combustion Turbines

The procurement effort for the supply of combustion turbine units is being advanced by Hydro prior to award of the EPCM contract. This is due to the long lead time required to procure the equipment.

While the FEED effort and this EA registration reflect a three-unit configuration, other configurations may be proposed by vendors during the procurement process. Should another configuration ultimately be selected, Hydro will review potential project scope impacts with the Department of Environment and Climate Change – Environmental Assessment Division to determine next steps.

2.2 Project Location

The Northeast Avalon is the preferred location for the project due to the appreciable transmission constraints that limit power flow to the Avalon Peninsula. The requirement for future transmission reinforcements is reduced if generation supply is located closer to the

Northeast Avalon as the main load center. Figure 2 illustrates the electrical grid infrastructure on the Avalon and shows the location of the Holyrood industrial site.

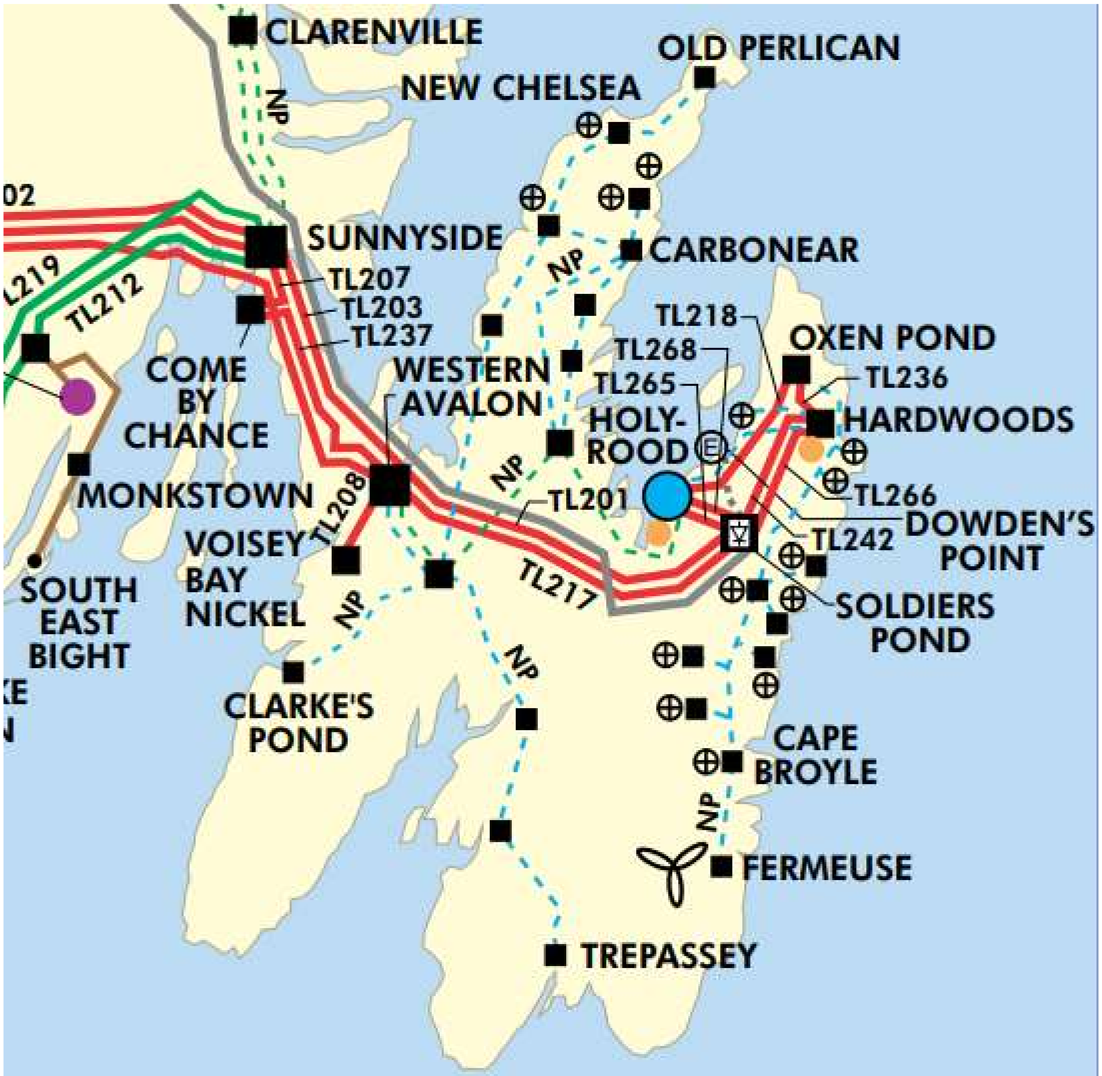

Figure 2. Avalon Peninsula Electrical Grid and Holyrood Location

The project is proposed for construction on Hydro owned property adjacent to the existing HTGS. The project is located within the municipality of Holyrood and the site is zoned IG – Industrial General[4]. The town of Conception Bay South ("CBS") is located to the east, on the east side of Quarry Brook, where the nearest dwellings are approximately 150 - 170 meters from the main construction site. The Butter Pot Provincial Park boundary is located approximately 3 km to the southeast of the project location. The T'Railway Provincial Park runs

[4] The existing HTGS site is zoned IH – Industrial Hazardous. Hydro has confirmed with the Department of Municipal and Provincial Affairs that rezoning from IG to IH is not required for the project.

along the north western boundary of Hydro's property, approximately 500 meters from the main construction site.

The project site is partially developed and generally bound by existing infrastructure – roads, power lines, and the HTGS industrial site (Figure 3). The site is accessed off Route 60, via Thermal Plant Road.

Figure 3. General Project Location Adjacent to HTGS

The area outlined above in blue represents the approximate proposed footprint of the facility (i.e., the developed area for the powerhouse, fuel storage, terminal station and related infrastructure) while the larger area outlined in red encompasses additional project activities associated with power line relocations and interconnections.

2.3 Major Project Activities and Components

The project involves the construction, commissioning, and operation of a new 150 MW (nominal) combustion turbine generating facility. Figure 4 provides an illustration of the main components of the facility. Specific details and specifications for the various components of the proposed facility will be finalized during detailed engineering design which will be completed by the EPCM contractor in 2026. Based on FEED, the project will generally include the following activities and components:

- vegetation clearing, earth work and civil pad construction;
- transmission and distribution line relocations and interconnections;
- No.2 diesel bulk fuel storage, containment dyke and fuel delivery and transfer system;
- enclosed powerhouse building with black start diesel generators;
- combustion turbine units (nominal 150 MW) and associated stacks;
- balance of plant auxiliary mechanical, electrical, protection and control and communications systems;
- generation step-up transformers and isolated phase bus;
- terminal station with control building and tie-in to TL 218;
- new raw water intake at Quarry Brook and associated pumphouse, waterline and storage tank; and
- fuel pipeline for possible future transfer of No.2 diesel from the existing marine jetty.

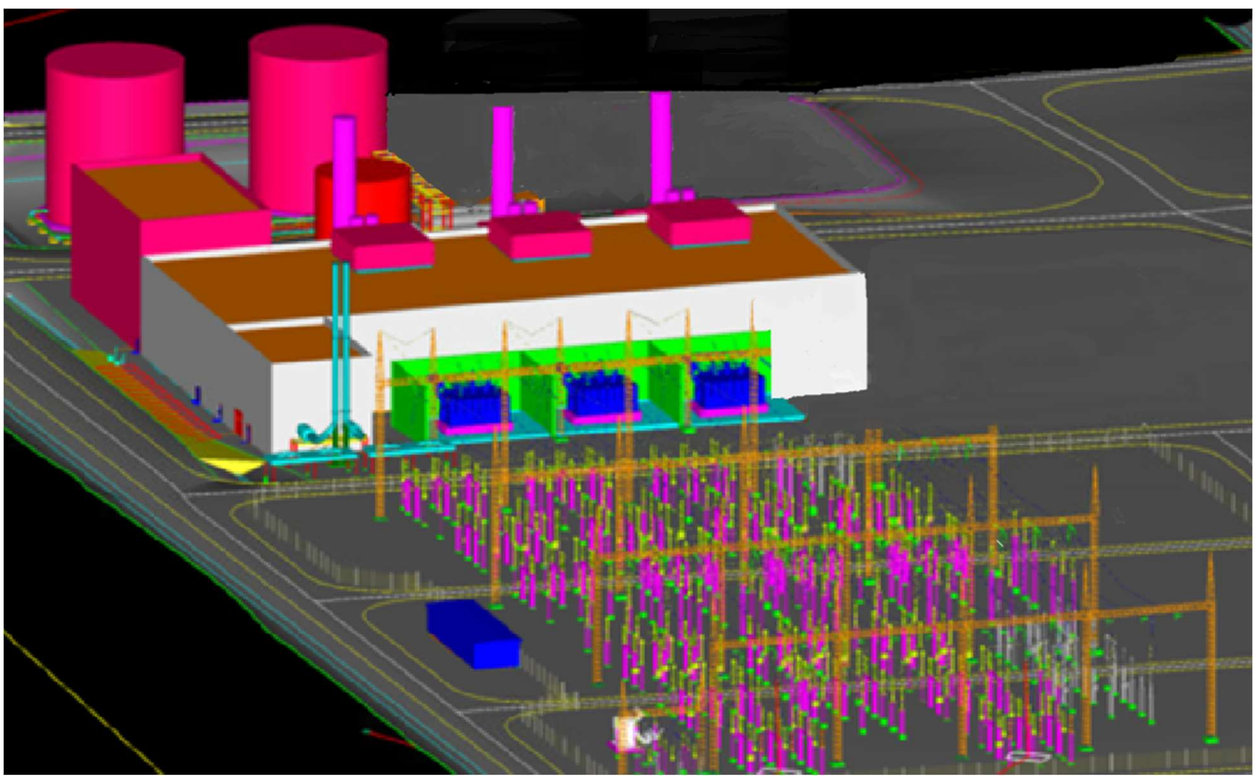

Figure 4. Conceptual Facility Rendering

The extent of site preparation to accommodate the tank farm, powerhouse, terminal station, construction laydown areas and related infrastructure, is estimated at 11.8 hectares. Additional vegetation removal within the general project location will also be necessary for transmission and distribution line relocations and interconnections, estimated at 4.9 hectares. The general site layout is illustrated below.

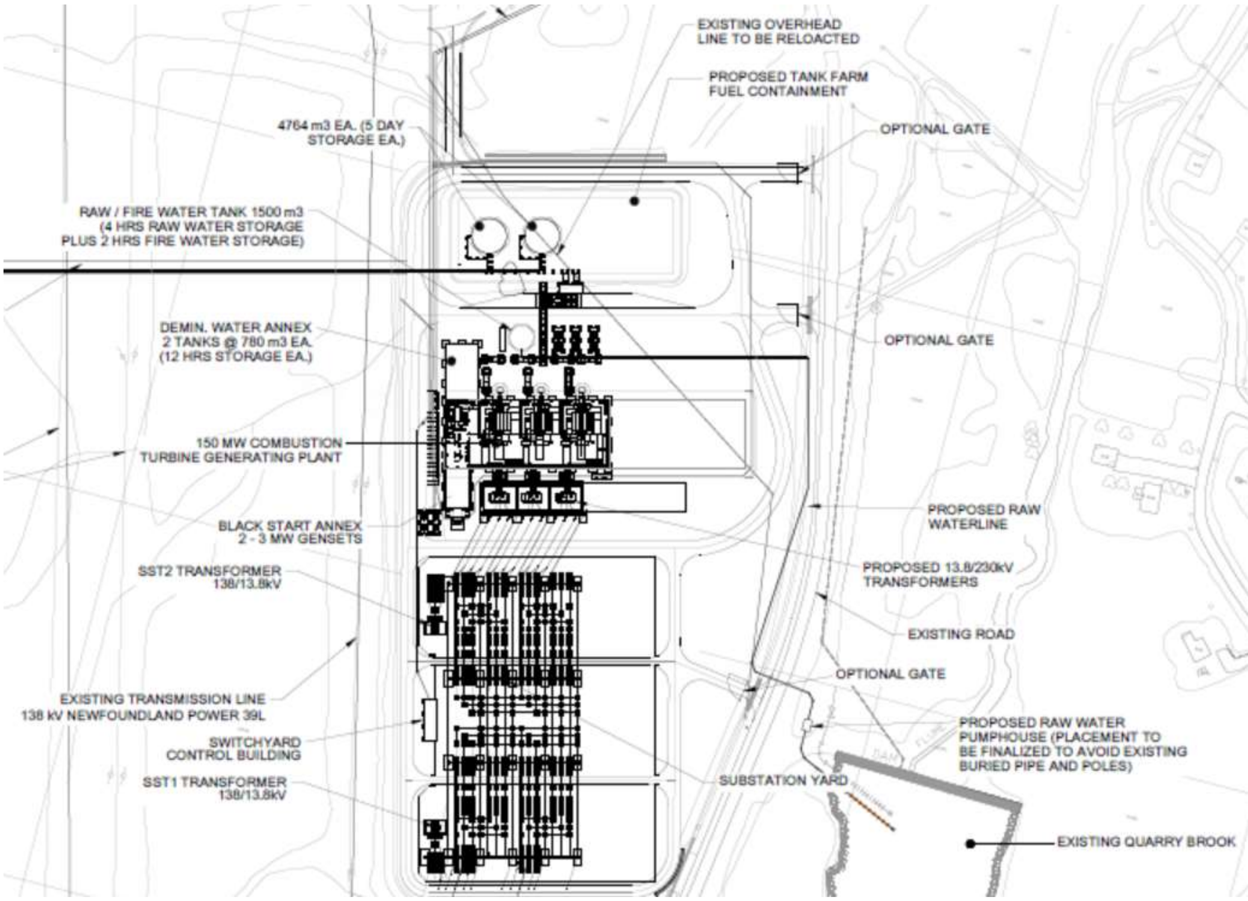

Figure 5. General Site Layout

2.3.1 Potential Sources of Pollutants

2.3.1.1 Construction Phase

During project construction, emission sources will include diesel and gasoline powered mobile equipment and stationary equipment such compressors, generators, pumps and light plants. Delivery, handling and storage of fuels and other hazardous materials required during the construction phase presents a potential source of spills and contamination. Testing and commissioning activities associated with combustion turbines and black start generators will also temporarily contribute to airborne emissions. Temporary washroom and kitchen/lunchroom facilities will be self-contained with effluent removed by a certified waste contractor as needed. Solid waste associated with packaging, material shipment and general construction activities will be managed throughout the construction phase.

2.3.1.2 Operations Phase

The combustion turbines will produce airborne emissions during facility operation. Delivery, handling and storage of fuels and other hazardous materials required during the operating phase presents a potential source of spills and contamination. Oil/water separators will be incorporated into the design of the powerhouse, transformer(s) location and the fuel offloading, storage and handling area with discharge locations confirmed during final engineering design. Water and sewer infrastructure options will be evaluated and confirmed during final design. Management of wastes from the facility will be incorporated into the existing Waste Management Plan for HTGS during the operating phase.

2.4 **Project Construction Schedule**

A schedule for the undertaking has been developed during the FEED effort. At this time, the schedule is sensitive to the procurement timelines for major components, such as transformers and combustion turbine units, and will be refined as the project advances.

Construction is planned to commence with site preparation activities in the third quarter ("Q3") of 2025. Vegetation clearing and relocation of existing power lines are necessary in 2025 to prepare the site for the 2026 construction effort and ensure the facility is ready for operation by the end of 2029. Notable schedule references are provided below in Table 1.

Table 1. High Level Project Schedule

Activity	Timeframe	Comments
EA release	Q2 2025	Important for project commencement.
Commence site preparation	Q3 2025	Existing power line relocations, vegetation clearing, limited earth work as needed.
Commence general construction	Q2 2026	Heavy civil site development followed by various scopes: switchyard, powerhouse, tank farm, interconnections etc.
Substantial completion of detailed engineering	Q3 2026	EPCM consultant
Transformers	Q3 2028	Estimated delivery to site
Combustion turbine units	Q1 2029	Estimated delivery to site
Startup and testing	Q3 2029	Mechanical, electrical, ancillary systems
Ready for operation	Q4 2029	Commissioning and testing complete and ready for operation

2.5 Alternatives to the Undertaking

As part of its 2024 Resource Adequacy Plan, Hydro has evaluated an extensive list of prospective supply resource additions. These included hydroelectric generation at existing hydro sites as well as greenfield locations, combustion turbines that can use renewable fuels, wind, battery energy storage systems, solar, and transmission requirements. Hydro will continue to evaluate traditional and emerging solutions as part of its ongoing resource planning efforts.

Each potential supply option carries its own costs, implementation timeframes, and technical considerations, all of which must be considered in selecting those that are most suitable to address the needs of the system at this time.

Hydro's plan to address forecasted electricity requirements and maintain system reliability involves a program of proposed energy development on the Island over the coming years that includes: (1) More Hydro Capacity – Bay d'Espoir Unit 8 addition, (2) Maintaining Reliability – Combustion Turbines on the Avalon for backup and peaking support, and (3) More Energy – Expression of Interest for development and integration of more wind energy. Refer to Appendix A for a summary of the expansion plan.

2.6 **Alternative Methods to Carrying Out the Undertaking**

In 2022, Hydro engaged an engineering consultant to assist with the study of alternatives associated with the proposed addition of combustion turbine generation on the Northeast Avalon. Significant alternatives studied are discussed below.

2.6.1 Alternate Locations

As part of the study, various sites on the Northeast Avalon were evaluated for construction of a combustion turbine facility.

Following consideration of protected or potential public water supply areas, six (6) sites were shortlisted for further evaluation: Holyrood Thermal Generating Station, Paddy's Pond, Sugar Loaf, Soldier's Pond, Bremigen's Pond, and Petty Harbour-Long Pond (Figure 6).

Figure 6. Evaluated Locations for a Combustion Turbine Facility

The shortlisted sites were evaluated under three criteria categories:

1. Technical and Operational, including land suitability, proximity to transmission lines and stations, fuel supply and delivery, and water availability;

2. Environmental and Social, including protected areas, rare flora and fauna, watersheds and wetlands, recreation, public safety, and archaeological potential; and
3. Regulatory and Legal, including water use and water rights, land zoning and jurisdiction, permitting, regulatory delay potential, and other constraints.

A characterization and evaluation workshop was held in April 2023. Shortlisted sites were characterized according to the criteria and weighting was assigned to each criterion. A consolidated summary of results is provided in Table 2 below.

Table 2. Project Location Evaluation Summary

Category	Weight (%)	Options					
		A. HTGS	B. Paddy's Pond	C. Sugar Loaf	D. Soldier's Pond	E. Bremigans Pond	F. Petty Harbour Long Pond
		Scoring (%)					
Technical and Operational	47	40	32	19	34	25	15
Environmental and Social	32	28	21	20	25	16	20
Regulatory and Legal	21	19	9	13	11	11	6
Total Score	100%	87%	62%	52%	70%	52%	41%

Option A: HTGS ranked highest with a score of 87%, followed by Option D: Soldiers Pond, with a score of 70%. A subsequent detailed analysis of the two highest ranked options was completed, confirming the HTGS location as the recommended site for the project due, in part, to advantages relating to water use, water rights and fuel delivery.

2.6.2 Plant Capacity

The study examined the feasibility of three plant sizes—150 MW, 300 MW, and 450 MW. These sizes were selected to examine a broad range of combustion turbine supply options. These capacity options also allowed for consideration of possible phases of future development.

The consultant recommended that capacity be limited to 150 MW due to the ability to source the required diesel fuel. Supplying diesel to operate a combustion turbine of more than 150

MW would provide significant challenges to sourcing and maintaining deliveries in the current market.

2.6.3 Operational Considerations

Various technical options have been considered as part of the study and in the development of specifications for the proposed combustion turbine facility. These include the requirement for the facility to have synchronous condensing capability and the ability to operate, or be converted to operate, on alternate fuels in the future (e.g., biodiesel, natural gas, natural gas/hydrogen blend fuels).

2.7 **Employment**

2.7.1 Occupations

A breakdown of anticipated occupations for the project, by National Occupational Classification ("NOC") 2021, is provided in Table 3 below. Construction of the ACT will be executed through various construction contracts and managed by an EPCM consultant. Members of Hydro's Major Projects team will manage the EPCM consultant and provide general oversight and monitoring of the project.

It is expected that construction will proceed six days per week as a single 10 - 12 hour shift. Employment will be full-time in nature for the duration required to complete the various scopes/phases.

Once commissioned, the ACT facility will be operated and maintained by existing Hydro personnel. Any adjustments to staffing will be considered at a later time in conjunction with general workforce planning for the Holyrood site.

Table 3. Occupations for Undertaking

Occupation	NOC Code	Number of Positions
Project Manager	00015	2
Planning / Scheduling	14405	2
Procurement / Contracts Manager	10019	2
Construction Manager	70010	1
Site Lead Engineer	20010	1
Site Engineers (Civil / Structural)	21300	2
Site Engineers (Mechanical)	21301	2

Occupation	NOC Code	Number of Positions
Site Engineers (Electrical / Instrumentation)	21310	3
HS&E Manager	21120	1
Geotechnical Engineer	21331	1
Surveyor	21203	2
Site Supervisor	82020	6
Heavy Equipment Operators	73400	4
Crane Operator	72500	2
Truck Operator	73300	6
Industrial / Power System Electrician	72201 / 72202	18
Concrete Forming Operators	94103	12
Concrete Finisher	73100	6
Steel Erector	72010	4
Roofer	73110	8
Plumber	72300	4
Pipefitter	72012	12
Carpenter	72310	12
Ironworker	72105	6
Welder	72106	6
Electrical Power Line Worker	72203	4
Heavy Equipment Mechanic	72401	12
Painter	73112	4
Driller / Blaster	73402	4
Labourer	75110	20
	Total	169

2.7.2 Equity, Diversity and Inclusion

Hydro's commitment to equity, diversity and inclusion ("EDI") continues to evolve as part of a multi-year strategy to support and enhance EDI. Hydro welcomes all experiences, knowledge and backgrounds, recognizing that it enhances our culture and contributes to success. In 2024, Hydro received Atlantic Business Magazine's *Employers of Diversity Award* as recognition of its inclusive corporate culture. Hydro will not be directly involved in recruiting the construction workforce; however, our commitment to EDI extends to the project management team as it evolves to support the project.

3.0 PROJECT ENVIRONMENTAL SETTING

The project is proposed on Hydro-owned property immediately adjacent to HTGS, a site that has been utilized for power generation for more than 50 years. Several transmission and distribution lines are located within, or adjacent to, the project area as well as previously developed laydown/parking areas and roads; however, the majority of the proposed project site is undeveloped.

3.1 **Atmospheric Environment - Local Air Quality**

Hydro has operated an ambient air monitoring program in the area surrounding the HTGS since 1977 to test for air quality relative to requirements of the *Air Pollution Control Regulations.* In addition to monitoring levels of air contaminants of concern relative to emissions from sources at the HTGS, these ambient air monitoring stations provide data on overall air quality in the area surrounding the HTGS which may also include sources other than those at the HTGS.

Levels of SO_2, Nitrogen Oxides ("NO_x"), Nitrogen Dioxide ("NO_2") and particulate matter 2.5 microns or less ("$PM_{2.5}$") are monitored continuously at the Butter Pot, Green Acres, Indian Pond, Lawrence Pond and Lower Indian Pond Drive monitoring stations using methodologies and equipment conforming to the requirements of the provincial *Guidelines for Ambient Air Monitoring*. The Main Gate monitoring station monitors $PM_{2.5}$ only.

Table 4 provides a summary of ambient air monitoring data showing the maximum hourly and daily readings for the period January 1, 2023 through December 31, 2024. The applicable Ambient Air Quality Standards ("AAQS") are included for reference.

Hydro also reports annual Greenhouse Gas ("GHG") emissions to the Department of Environment and Climate Change – Climate Change Branch. Over the past two years, reported GHG emissions for the facilities at the Holyrood site exceeded 600,000 tonnes of carbon dioxide equivalent ("tCO_2e").

Table 4. Maximum Readings from Ambient Air Monitoring Stations for the Period January 1, 2023 to December 31, 2024[5]

Monitoring Site	Contaminant	Maximum Hourly AAQS	Maximum Hourly Concentration (ug/m^3)	Month Recorded	Maximum Daily AAQS	Maximum Daily Concentration (ug/m^3)	Month Recorded
Butter Pot	SO_2	900	111.43	Mar. 2023	300	29.80	Mar. 2023
	NO_x	400	51.50	Aug. 2024	200	10.43	Mar. 2023
	NO_2	400	32.34	Mar. 2023	200	7.10	Mar. 2023
	$PM_{2.5}$	n/a	37.50	Sept. 2023	25	14.70	June 2023
Green Acres	SO_2	900	221.87	Mar. 2024	300	28.69	Feb. 2024
	NO_x	400	87.93	Mar. 2023	200	13.78	Nov. 2024
	NO_2	400	45.99	Mar. 2023	200	9.76	Apr. 2024
	$PM_{2.5}$	n/a	69.00	Apr. 2024	25	16.00	June 2023
Indian Pond	SO_2	900	149.30	Jan. 2024	300	45.99	Jan. 2024
	NO_x	400	177.30	Mar. 2023	200	20.15	Mar. 2023
	NO_2	400	29.40	Jan. 2024	200	12.27	Jan. 2024
	$PM_{2.5}$	n/a	87.60	Apr. 2023	25	15.10	June 2023
Lawrence Pond	SO_2	900	75.90	Mar. 2024	300	14.96	Mar. 2023
	NO_x	400	36.90	Mar. 2024	200	13.80	Apr. 2023
	NO_2	400	28.30	Mar. 2024	200	11.95	Apr. 2024
	$PM_{2.5}$	n/a	27.70	June 2023	25	14.90	June 2023
Lower Indian Pond Drive (Mobile)	SO_2	900	202.80	Mar. 2023	300	94.30	Mar. 2023
	NO_x	400	70.08	Sept. 2024	200	33.35	Mar. 2023
	NO_2	400	42.88	Jan. 2024	200	13.96	Mar. 2023
	$PM_{2.5}$	n/a	98.50	June 2024	25	15.30	June 2023
Main Gate	$PM_{2.5}$	n/a	44.70	Sept. 2023	25	13.50	June 2023

3.2 Vegetation, Soils and Surficial Geology

The proposed project is located within the Northeastern Barrens subregion of the Maritime Barrens Ecoregion of the Island of Newfoundland. This subregion has more extensive forest cover than the other three subregions; however, barrens are the most common landscape feature with bogs occurring regularly, reflecting the poor drainage and wet climate of the subregion. Balsam fir dominates the forest with common black spruce and less prevalent white birch. Forest floors are dominated by mosses. Sheep laurel, rhodora and low bush blueberry are common on open barrens. Dogberry, larch, mountain holly and pockets of stunted balsam fir are also typically found in this subregion.

The greenfield portion of the project site consists of a mosaic of coniferous forest dominated by balsam fir, black spruce, eastern larch and white birch interspersed with low-lying wetlands and poorly drained areas.

Commonly occurring mineral soils in the subregion consist of humo-ferric and ferro-humic podzols, with the latter being darker with a higher organic content. As summarized by Hatch

[5] A higher maximum daily $PM_{2.5}$ value was recorded at all sites in September 2023. This was an anomaly associated with wildfire smoke. Those maximum values ranged from 27.3 to 30.1 ug/m^3.

Ltd., two surficial geology maps are available for the area. The first, from 1994, characterizes the surficial geology at the site as a till blanket between 1.5 – 15 m thick. The second map, from 1998, characterizes the surficial geology at the site as a veneer (i.e., a deposit less than 1.5 m thick) of alluvium and/or bog.

A limited geotechnical investigation, consisting of 33 test pits, was completed in 2024. This investigation found that soils across the site were predominantly silty sand with varying amounts of gravel, along with some silty gravel with sand, well-graded sand with varying amounts of silt and well-graded gravel. Organic soil was encountered in ten of the test pits, while cobbles and boulders were encountered in all but one test pit.

3.3 **Wildlife**

Wildlife common to the Northeastern Barrens subregion include mammals such as moose, mink, snowshoe hare, red fox, little brown bat, meadow vole, and red squirrel. A variety of avifauna, including migratory breeders, forest residents and waterfowl (including over-wintering waterfowl) are found in the subregion. Populations of the introduced green frog (*Rana clamitans*) are known to inhabit ponds and marshes in the subregion.

3.4 **Fish and Fish Habitat**

The Northeastern Barrens subregion's many lakes, ponds, and rivers support a variety of fish. Atlantic salmon, brown trout, brook trout, American eel, rainbow smelt, and three-spine and nine-spine sticklebacks are the most common. Quarry Brook supports populations of brook trout and brown trout. In 1994, Hydro installed a fishway at the Quarry Brook Dam[6] to reestablish upstream passage for brown trout and sea-run brook trout.

3.5 **Species at Risk and Species of Conservation Concern**

Species at risk ("SAR") include species listed under the Newfoundland and Labrador *Endangered Species Act* and the federal *Species at Risk Act* as being either Endangered, Threatened, Vulnerable or Special Concern. Species of Conservation Concern ("SOCC") may not yet be listed under provincial or federal legislation but may have been classified by the Committee on the Status of Endangered Wildlife in Canada ("COSEWIC") as Extirpated, Endangered, Threatened or Special Concern. The Atlantic Canada Conservation Data Center ("ACCDC") also includes subnational rarity ranks, including S1 and S2 ranks defined as Critically Imperiled and Imperiled. SAR and SOCC include taxa ranked by the ACCDC as S1 or S2.

A review of ACCDC records, as of August 2024, identify twelve (12) ranked plant species and twelve (12) wildlife species within 5 km of the project area (Figure 7). None of these flora or fauna records are located within, or in the immediate vicinity of, the proposed project area.

[6] Quarry Brook Dam was constructed in the early 1970's.

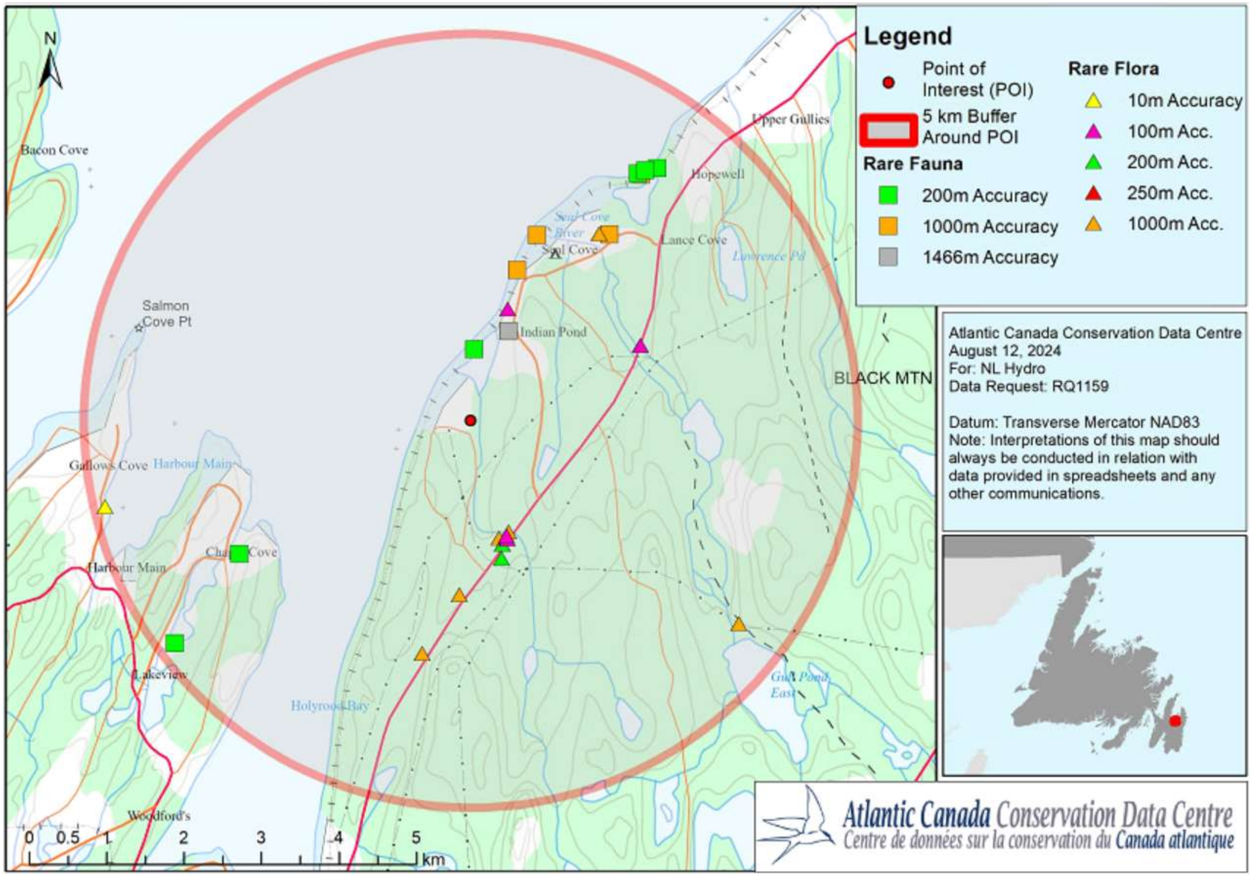

Figure 7. ACCDC Flora and Fauna Records Within 5km of the Project Area

The twelve (12) ACCDC recorded plant species are listed in Table 5 below. None of the species are identified as SAR under the provincial *Endangered Species Act* or federal *Species at Risk Ac*t and they are not identified as SOCC by COSEWIC.

Table 5. ACCDC Flora Observations

Scientific Name	Common Name
Pinus strobus	White Pine
Brachyelytrum aristosum	Northern Shorthusk
Dichanthelium acuminatum var. fasciculatum	Western Witchgrass
Pyrola americana	American Wintergreen
Bartonia paniculata	Twining Bartonia
Xyris montana	Northern Yellow-Eyed-Grass
Ilex verticillata	Black Holly
Diervilla lonicera	Northern Bush-honeysuckle
Gaylussacia bigeloviana	Dwarf Huckleberry
Galium tinctorium	Stiff Marsh Bedstraw
Juncus stygius subsp. americanus	American moor rush
Ramalina farinacea	Dotted Line Lichen

The twelve (12) ACCDC recorded wildlife species are listed in Table 6. Four of these species are identified as SAR or SOCC. The Ivory Gull is listed as Endangered and the Bank Swallow is listed as Threatened under both provincial and federal legislation. The Red-necked Phalarope and Yellow-banded Bumble Bee are provincially listed as Vulnerable and are of Special Concern federally. In addition to these 12 species, Leach's Storm Petrels are known to occasionally become stranded at the HTGS site. Leach's Storm Petrel (*Oceanodroma leucorhoa*) is a SOCC that was identified as Threatened by COSEWIC in 2020.

Table 6. ACCDC Fauna Observations

Scientific Name	Common Name
Enallagma civile	Northern Bluet
Somatochlora walshii	Brushed-tipped Emerald/ Green Eyed Skimmer
Sympetrum costiferum	Saffron-winged Meadowhawk
Pagophila eburnea	Ivory Gull
Riparia riparia	Bank Swallow
Phalaropus lobatus	Red-necked Phalarope
Tringa melanoleuca	Greater Yellowlegs
Spatula discors	Blue-winged Teal
Charadrius semipalmatus	Semipalmated Plover
Bombus terricola	Yellow-banded Bumble Bee
Calidris fuscicollis	White-rumped Sandpiper
Calidris alba	Sanderling

There are two endangered species of myotis found within Newfoundland and Labrador, northern long-eared bat (*Myotis septentrionalis*) and little brown bat (*Myotis lucifugus*). The ACCDC did not identify any observations or known populations of these endangered species within the 5 km of the project location and Hydro has not observed bats in the area of the HTGS.

3.6 **Water Resources**

Quarry Brook is a significant watercourse located near the project location. Quarry Brook has an existing dam, fishway and water intake structures associated with the historic and ongoing provision of fresh water for use at the Holyrood industrial site (Figure 8).

Figure 8. Quarry Brook and Existing Dam and Fishway

The proposed project location includes small wetlands and poorly drained areas. With the exception of Quarry Brook, there are no waterbodies (including wetlands) visible on 1:50,000 scale mapping within the project area[7].

3.7 Socioeconomic Environment

The proposed project area is located within the Town of Holyrood and adjacent to the Town of Conception Bay South. Power for the province has been generated at the Holyrood site since 1971, employing local residents for more than 50 years. Local residents and businesses, as well as businesses in other parts of the province and beyond, benefit from the supply of goods and services to facilities at the Holyrood industrial site.

Local residents and visitors to the area commonly use the T'Railway that runs adjacent to a portion of Hydro's property. Off road vehicle use is popular in the area, including on trails located on Hydro's property near the proposed project location. Indian Pond, at the mouth of Quarry Brook, is used by local residents for boating and direct access to the ocean.

There are no known historic resources or related concerns near the project location.[8]

4.0 STAKEHOLDER ENGAGEMENT

Key stakeholder engagement activities undertaken to date are summarized below. Additional information is found in Appendix C. Hydro plans to continue to engage with key stakeholders through the construction phase of the project.

4.1 Communities

Hydro representatives first met with the Chief Administrative Officers of the towns of Holyrood and Conception Bay South ("CBS") on July 23, 2024 and August 8, 2024, respectively. These discussions were intended to initiate project communication and information sharing. On November 12, 2024, Hydro met with the CBS town council to discuss the project in more detail, followed by a meeting with the Holyrood town council on December 3, 2024.

Public open house sessions were held in Holyrood and CBS (Seal Cove) on February 17 and February 20, 2025, respectively. The Holyrood session was held from 6-9 pm at the IBEW College, 160 Liam Hickey Drive. The CBS open house was held from 6-9 pm at the Parsons Rotary Clubhouse, 1706 Conception Bay Highway. Awareness of the open house sessions was accomplished through radio advertisements, social media outreach and with assistance from town councils. Attendees were provided with project overview documents and were able to review display materials and ask questions of the Hydro's project team.

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[7] Confirmed with Water Resources Management Division staff and NRCan 1:50,000 scale National Topographic System mapping (https://search.open.canada.ca/openmap/8ba2aa2a-7bb9-4448-b4d7-f164409fe056).
[8] Confirmed with the Provincial Archaeology Office.

4.1.1 Community Liaison Committee

In association with operation of the HTGS, a Community Liaison Committee ("CLC") was previously established in 1998 but it has not been active in recent years. The purpose of the CLC is to provide open communication with area stakeholders and an avenue to bring forward environmental concerns or other issues relating to the operation of HTGS. Hydro intends to pursue reinstatement of the CLC in 2025. Hydro's ACT project team will leverage the CLC for ongoing project communication and engagement during the construction phase.

4.2 **Government Agencies**

Hydro met with representatives of the Department of Environment and Climate Change ("DOECC") – Pollution Prevention Division ("PPD") in the fall of 2024 to discuss the proposed project. Meetings took place on October 24, 2024 and December 4, 2024, with discussions focused on project justification, role of the facility, and various potential environmental considerations. As emissions modelling progressed, Hydro subsequently met with PPD on February 3 and 11, 2025 to review preliminary modelling results, discuss related matters, and gather feedback.

On February 26, 2025, Hydro met with representatives from the DOECC - Environmental Assessment Division, DOECC - Climate Change Branch, and PPD to review the proposed project prior to registration. Following this meeting, Hydro engaged with DOECC – Water Resources Management Division and had follow up discussions with Climate Change Branch representatives.

4.3 **2024 Resource Adequacy Plan and Public Utilities Board Proceedings**

Although part of an independent process, stakeholder engagement efforts have been occurring in relation to Hydro's 2024 Resource Adequacy Plan, leading up to its public release in July of 2024. Hydro completed a digital public engagement survey in January 2024 with questions relating to reliability, cost, investment, growth, clean energy and options for new sources of electricity. The survey was administered by a third-party research partner and more than 2,000 responses were received. A public engagement report[9] documents the engagement effort and contains a compilation of comments and feedback, including in relation to combustion turbine generation. Findings show respondents:

- Are concerned about the rising cost of living, including electricity rates;
- Prioritize lower electricity rates over improvements in reliability or clean energy;
- Recognize that the province has a reliable system that is supplied largely from renewables;
- Agree that Hydro needs to prepare for growing electricity needs; and

[9] https://nlhydro.com/wp-content/uploads/2024/07/Final_2024-RAP_App-D_Engagement.pdf

- Have no broad alignment in their preference for types of new electricity sources.

Moving forward with the proposal to construct the ACT is consistent with customer feedback on cost and reliability as the ACT, and Bay d'Espoir Unit 8, are consistently shown to be the least-cost solutions across a broad range of scenarios modelled as part of the Resource Adequacy Plan.

As part of the RRA Study Review proceeding with the Board, there have been multiple technical conferences and formal opportunities for the Board and interveners[10] to request information ("RFIs") about Hydro's Resource Adequacy Plan and its recommendation to proceed with this project as part of its minimum investment expansion plan. Additionally, this project was submitted to the Board on March 21, 2025 for further review and approval – this will initiate another proceeding with the Board and its interveners, inclusive of opportunities for additional technical conferences and RFIs. Correspondence associated with these proceedings is publicly available on the Board's website.

4.4 Actions Taken in Response to Feedback

As a result of public feedback during the ACT engagement effort, Hydro has confirmed its commitment to ongoing communication and engagement as the project progresses, including reinstatement of the CLC. Hydro will ensure there is opportunity to raise concerns to the project management team at any time during the project. In addition to further engagement opportunities, Hydro has established a dedicated email (ProjectFeedback@nlh.nl.ca) for stakeholders to bring their comments or concerns forward.

In response to questions regarding ATV and pedestrian access to, and through, Hydro's property during the construction and operating phases, Hydro commits to ensuring that public safety is maintained at all times. Hydro will consider how potential impacts to public access can be managed during the final design and execution planning effort.

Regarding concerns related to project traffic, Hydro will ensure that potentially disruptive project deliveries (e.g., oversize loads) are identified, planned and communicated as necessary to mitigate potential impacts to local traffic. Traffic control measures will be implemented to ensure the safety of the public.

Regarding project related noise, Hydro's baseline construction schedule does not consider 24/7 activity. Hydro has committed to enclosing the combustion turbines in a building as the primary means to mitigate noise during future facility operation.

[10] Intervenors include: Consumer Advocate, Newfoundland Power, Island Industrial Customer Group, Labrador Interconnected Group.

5.0 POTENTIAL ENVIRONMENTAL EFFECTS AND THEIR MANAGEMENT

This section provides an overview of potential environmental effects and identifies measures to mitigate risk and avoid or reduce adverse effects.

5.1 General Planning and Oversight

Hydro's environmental professionals will review and approve contractor emergency response plans and environmental protection/mitigation plans, procedures and work methods. Hydro will provide risk-based environmental monitoring throughout the project construction stage. Hydro has maintained an ISO 14001 registered Environmental Management System ("EMS") for more than 20 years. The fundamental principles of Hydro's EMS will apply during project construction and the facility will be incorporated into the EMS in the operating phase.

5.2 Potential Accidental Events

Although unlikely, an accident or other unplanned event could occur in association with project activities or infrastructure. Potential accidental events could include: an accidental release of fuels or other deleterious substance to the environment, failure or malfunction of a project component, or a fire.

To mitigate the potential environmental effects associated with such an incident, contractors will be required to implement emergency response plans and environmental protection measures specific to their activities. On-site personnel must be aware of plan requirements and be appropriately trained. In the event of a significant incident at the project site, Hydro has nearby resources and personnel to assist as required. Once operational, the facility will be incorporated into Hydro's emergency response plan for the Holyrood site.

5.3 Waste Management

The project will employ standard waste management practices to the construction and operations phases of the project. Construction contractors will be required to prepare and implement Waste Management Plans appropriate to the requirements of their work scope. Contractor's plans must be consistent with legal requirements and best practices and generally align with Hydro's existing Corporate Waste Management Plan and the Waste Management Plan for HTGS. The new facility will be incorporated into the HTGS Waste Management Plan once it is ready for operation.

Waste materials generated through construction activities will be removed from the area and disposed of at an approved facility. Non-hazardous construction refuse will be stored in covered metal receptacles and will be disposed of on an as-needed basis at an approved landfill site. Waste materials will be reused or recycled where possible.

Any hazardous wastes will be stored in sealed, labeled containers and disposed of according to applicable requirements. These include procedures for the characterization/identification, storage, inspection, labeling and transportation of hazardous wastes produced at the project site, as well as emergency preparedness, prevention and training.

Hydro representatives will monitor the implementation and compliance with waste management requirements during the construction phase. There are no anticipated adverse interactions between construction waste materials and the environment.

5.4 **Fuel Management**

Delivery, handling and storage of fuels and other hazardous materials required during the construction phase will be undertaken by trained personnel using approved facilities and equipment and in accordance with applicable regulations, guidelines and environmental protection procedures. The management of fuels and other hazardous materials will be a focus of monitoring by Hydro representatives during the construction phase.

During operation, the ACT will utilize No.2 diesel. Preliminary fuel storage system design includes two tanks with a combined storage capacity of approximately 9.5 million liters. The fuel system will be subject to the requirements of the *Storage and Handling of Gasoline and Associated Products Regulation* ("GAP"). Hydro is proposing to use field erected vertical tanks surrounded by a dyke for secondary containment. Final tank and containment dyke capacity details will be determined in the final design. The dyke will be liquid tight to a permeability of at least 10^{-6} cm/second and be constructed with concrete or compacted earth with a synthetic membrane. All tanks, piping and the secondary containment dyke will be registered under GAP and tested prior to being placed into operation.

The fuel loading area will consist of a concrete pad designed to drain to a dedicated tank or oil/ water separator in the event of a spill or leak from a tanker truck during fuel transfer. The oil/water separator will be registered. All fuel transfer operations from tanker trucks will be fully supervised.

The fuel system will be reconciled for fuel inventory control. At a minimum, fuel tanks will be gauged or dipped at least weekly. Gauge or dip records will be reconciled against receipt and withdrawal records to determine any apparent fuel losses for the system. Reconciliation records will be kept for a minimum of two (2) years and Hydro will inform government immediately of any apparent losses above normal as indicated by two (2) consecutive reconciliations. Hydro will also determine cumulative apparent losses on a semi-annual basis and inform government if the apparent loss exceeds one-half of 1% throughput for the period.

The fuel system will be operated by Hydro staff. In the event of a spill or leak of fuel, Hydro will implement emergency response procedures as identified in the HTGS Emergency Response

Manual ("HRM"). Should such an event occur, Hydro will notify government agencies, remediate the affected area and restore the environment to the satisfaction of the Department of Environment and Climate Change.

While the project scope includes a pipeline for potential future marine delivery and fuel transfer, this will be further evaluated during final design. Under a separate initiative, Hydro is conducting a condition assessment of the marine jetty to explore the feasibility of long-term marine fuel delivery. This assessment and any potential marine jetty upgrades are not part of the scope of this undertaking.

5.5 **Atmospheric Environment**

Air emissions (including GHGs), dust, light, noise and vibrations associated with the operation of equipment, installation of project infrastructure and other construction and operations activities could affect the atmospheric environment.

5.5.1 Evaluation of Emissions - Air Dispersion Modelling

The proposed undertaking has the potential to impact the ground level concentrations of air pollutants from the combined operation of the proposed ACT facility and existing generation sources (the three units at HTGS, the existing 123 MW gas turbine and the six black start diesel generators). To evaluate this impact, Hydro engaged Independent Environmental Consultants ("IEC") to complete an air dispersion modelling study to assess the compliance of all existing and proposed power generation units at the site against Newfoundland and Labrador Air Quality Standards ("AQS"). The full report is included in Appendix D.

Air dispersion modelling was performed using the CALMET/CALPUFF modelling package to predict ground-level concentrations of nitrogen dioxide ("NO_2"), sulphur dioxide ("SO_2"), carbon monoxide ("CO"), total particulate matter ("TPM"), particulate matter less than 10 microns ("PM_{10}"), and particulate matter less than 2.5 microns ("$PM_{2.5}$"). To determine the potential impact of emissions on local air quality, modelled concentrations were compared to the AQS outlined in Schedule A of the *Air Pollution Control Regulations* (Table 7).

Table 7. Newfoundland and Labrador Air Quality Standards

Pollutant	Air Quality Standards (AQS)				
	1-hour	3-hour	8-hour	24-hour	Annual
SO_2	344 ppb (900 µg/m³)	229 ppb (600 µg/m³)	--	115 ppb (300 µg/m³)	23 ppb (60 µg/m³) [1]
TPM	--	--	--	120 µg/m³	60 µg/m³ [2] [3]
PM_{10}	--	--	--	50 µg/m³	--
$PM_{2.5}$	--	--	--	25 µg/m³	8.8 µg/m³ [1]
NO_2	213 ppb (400 µg/m³)	--	--	106 ppb (200 µg/m³)	53 ppb (100 µg/m³) [1]
CO	30582 ppb (35000 µg/m³)	--	13107 ppb (15000 µg/m³)	--	--

Source: AQS from Schedule A of *the Air Pollution Control Regulation, 2022* (NLR 11/22). Values in () are equivalencies for modelling purposes.
ppb: parts per billion
µg/m³: micrograms per cubic metre
Notes:
All AQS at reference conditions (25 C, 101.325 kPa)
[1] Arithmetic mean
[2] Geometric mean
[3] Per communication with the Department, the geometric mean AQS applies to discrete sampling only. The arithmetic mean applies otherwise.

5.5.1.1 Revised Administrative Boundary

To complete the dispersion modelling, it was necessary to extend the existing administrative boundary of the facility to the south to encompass the proposed ACT facility. The boundary extension follows Hydro's property boundary to the west and the existing access road to the east. The southern extent of the administrative boundary generally corresponds with the extent of the project area as shown in Figure 9.

During discussions with PPD, the issue of restricting public access within the administrative boundary was raised. While fencing the perimeter of the new facility footprint is planned (i.e., approximately the blue polygon in Figure 3), Hydro had not contemplated fencing the administrative/property boundary during FEED. With high voltage lines located along the western property boundary, the potential for electrical induction to a fence running parallel, or perpendicular, to the lines in this area requires a grounding study to determine if the risk can be adequately mitigated. Fencing within or adjacent to powerline right-of-ways would also have to be designed to consider access needs for line maintenance. Feedback from public open houses has also identified concerns regarding increased access restrictions in the area, particularly following construction as there are a number of established ATV trails in the area.

Hydro commits to further evaluation of fencing options during final design. Should complete fencing of the administrative boundary prove unfeasible, Hydro will ensure that appropriate signage is established to warn of the potential presence of air pollutants during ACT operation.

Figure 9. Proposed Administrative Boundary for the Site

5.5.1.2 Modelling Scenario

Hydro consulted with representatives from PPD to establish a worst-case emissions modelling scenario. Although highly unlikely to occur, the following power generation scenario was considered in the assessment based on historical maximum production from 2021 to 2024 and manufacturer specifications as required:

- HTGS Units 1, 2 and 3 all operate for every hour in January, February, March, and December;
- HTGS Units 1 and 2 additionally operate for every hour in April and November;
- HTGS Unit 1 operates for every hour in October;
- HTGS Unit 2 operates for every hour in May;
- All three HTGS Units are off-line for the entirety of June, July, August, and September;
- The existing GT operates for all hours of the year;
- The new combustion turbines operate for all hours of the year;

- The new black start diesel generators operate for all hours of the year; and
- The existing black start diesel generators operate for all hours of the year, subject to the operational limitations defined in Hydro's Certificate of Approval (AA22-065671).

5.5.1.3 Modelling Results

Modelling results show that the maximum predicted ground level concentrations for all pollutants and averaging periods are below their respective provincial AQS. To account for meteorological anomalies, provincial guidance considers compliance based on the following:

- 9th highest level at any given receptor for a 1-hour averaging period;
- 6th highest level at any given receptor for a 3-hour averaging period;
- 3rd highest level at any given receptor for an 8-hour averaging period;
- 2nd highest level at any given receptor for a 24-hour averaging period; and
- 1st highest level at any given receptor for an annual averaging period.

Results for each AQS are summarized below.

5.5.1.3.1 Nitrogen Dioxide

At 99.5%, the maximum 1-hour concentration of NO_2 (398.0 µg/m³) was predicted to be highest relative to the corresponding AQS (400 µg/m³). The highest 24-hour NO_2 concentration was 176.2 µg/m³, or 88.1% of the AQS. In comparison to the annual AQS standard, the maximum NO_2 concentration (28.4 µg/m³) occurred using the 2021 meteorological dataset. The operation of the existing black start generators is the primary source of the maximum NO_2 concentrations.

5.5.1.3.2 Particulate Matter

For TPM, PM_{10} and $PM_{2.5}$, the highest concentrations were all directly related to the operation of the new ACT and are similar to each other owing to the fact that the particulate emissions from the ACT are almost exclusively $PM_{2.5}$. At 93.8% of the AQS, the 24-hour concentration of $PM_{2.5}$ (23.4 µg/m³) was closest to the standard (25.0 µg/m³). On an annual basis, the maximum concentrations were less than 20% of the associated AQS.

5.5.1.3.3 Sulphur Dioxide

Over the four-year assessment period, the short-term SO_2 concentrations were predicted to be between 60% and 66% of the corresponding AQS, while the annual concentration neared 3.0 µg/m³ or 5% of the standard. The maximum SO_2 concentrations are directly related to the combustion of #6 fuel oil in HTGS Units 1, 2 and 3.

5.5.1.3.4 Carbon Monoxide

At less than 1% of the associated AQS, CO had the lowest predicted concentrations in the modelling assessment.

The modelled operating scenario represents an extreme worst case and the modelled ground level concentrations are expected to be higher than what normal operating conditions would ever produce.

The anticipated annual operation of the ACT for peaking support is 270 hours. The probability of operating the ACT at maximum capacity for a sustained period of time is very low and would only occur in the event of catastrophic unplanned outages to transmission and/or generation assets. The proposed ACT, in part, will lead to the retirement of HTGS generating assets, resulting in a significant improvement in the air emissions profile of the site.

5.5.2 Good Engineering Stack Height

Hydro consulted with representatives from PPD to consider if the proposed undertaking meets the requirements for Good Engineering Stack Height ("GESH") as per Section 5 (1) of the *Air Pollution Control Regulations.* Section 5(1) indicates that "all new stack installations with annual releases in excess of 20 tonnes of either particulate matter or sulphur dioxide shall meet good engineering stack height".

Based on a worst-case scenario of 1000 annual operating hours[11], and the manufacturer's estimate of 6.3 kg/hr of particulate matter emissions[12] per stack at 100% load, the worst-case annual particulate matter emissions will not meet the 20-tonne threshold. Final stack design will be driven by manufacturer specifications to optimize efficiency and operation of the combustion turbines.

5.5.3 Greenhouse Gas Emissions

The project will generate GHGs through the combustion of fossil fuels during the construction phase and during operation of the facility.

5.5.3.1 Construction Phase

During project construction, emission sources will include mobile and stationary equipment and temporary power generation as needed to support construction activity as well as emissions associated with delivery of materials to the site. Project vehicles and equipment will be maintained in good repair and will have exhaust systems regularly inspected to ensure proper operation. Opportunities to provide construction power from the grid will be further evaluated during final design in an effort to reduce reliance on diesel generators during the construction phase.

[11] Based on 400 hours of operation during a 6-week generation shortfall emergency scenario plus an additional 400 hours for a second emergency scenario in the same year and 200 hours for normal peaking support for the balance of the year.
[12] Sulphur dioxide emissions are significantly less than particulate matter emissions.

An estimate of annual GHG emissions generated during the construction phase (2025-2029) of the project is provided in Table 8, based on four broad categories:

<u>Civil Construction</u>

This includes all work associated with clearing, unsuitable material removal and import of suitable fill materials for preparation of the site. The estimate is derived from fuel consumption data for the required equipment operating 10 hours/day, 6 days/week. Excavated materials are assumed to be disposed of on Hydro's property (within 1km) and imported fill is assumed to originate from a quarry located 10 km from the project site.

<u>Construction – Other</u>

This includes all other construction and ongoing operation of light vehicles and cranes and stationary infrastructure such as site offices, washrooms, lighting, small generators and tool cribs to support a workforce of 120 people 10 hours/day, 6 days/week. An allowance of 36 hours of combustion turbine operation for testing and commissioning is included.

<u>Transportation</u>

This includes GHG emissions associated with the delivery of materials to the project site. Point of origin varies, including: Newfoundland, British Columbia, Ontario, California, Texas and Germany. Approximately 50% of deliveries are expected in 2028.

<u>Services/Vendors</u>

This category covers a range of activities to support the project, including: weekly potable water delivery, waste removal and miscellaneous third-party vendor deliveries and services.

Table 8. Forecasted Annual GHG Emissions During Construction (tCO_2e)

Category/ Year/ Emissions	2025				2026				2027				2028				2029			
	CO_2	CH_4	N_2O	tCO_2e	CO_2	CH_4	N_2O	tCO_2e	CO_2	CH_4	N_2O	tCO_2e	CO_2	CH_4	N_2O	tCO_2e	CO_2	CH_4	N_2O	tCO_2e
Civil Construction	193.989	0.007	0.007	196.081	820.266	0.2637	1.864	828.632	193.989	0.007	0.007	196.081	-	-	-	-	-	-	-	-
Construction - Other	-	-	-	-	-	-	-	-	1349.962	0.051	0.298	1432.755	1349.962	0.051	0.298	1432.755	4594.981	1.595	0.369	4732.378
Transportation	-	-	-	-	-	-	-	-	27.305	0.001	0.001	27.585	54.610	0.002	0.002	55.170	27.305	0.001	0.001	27.585
Services and Vendors	-	-	-	-	-	-	-	-	98.700	0.004	0.002	99.100	98.700	0.004	0.002	99.100	98.700	0.004	0.002	99.100
Totals	193.989	0.007	0.007	196.081	820.266	0.2637	1.864	828.632	1669.956	0.063	0.308	1755.521	1503.272	0.057	0.302	1587.025	4720.986	1.600	0.372	4859.063
																	Total Construction tCO_2e			9226.322

5.5.3.2 Operating Phase

Based on the anticipated annual operating requirements for ACT, the facility may emit more than 15,000 tCO_2e of GHGs per year. As such, the facility is expected to be subject to regulation under the *Management of Greenhouse Gas Act* ("MGGA").

Based on fuel consumption of 36,847.2 liters of diesel per hour, at full load, and annual operation of 270 hours[13], annual greenhouse gas emissions for the ACT facility could reach 27,584.73 tCO_2e. The actual production plan for the facility for the 10-year period 2031 to 2040 ranges from 17.0 GWh to 31.7 GWh. The resulting estimated annual GHG emissions for this period is summarized in Table 9 and ranges from 11,300 tCO_2e to 21,200 tCO_2e.

Table 9. Annual Production Plan and GHG Emissions

Fiscal Year	Fuel Offtake (TJ)	Generation (GWh)	GHG Emissions (tCO_2e)
2031	155.6	17.0	11,300
2032	157.6	17.2	11,500
2033	214.2	23.4	15,600
2034	181.1	19.8	13,200
2035	227.8	24.8	16,600
2036	196.6	21.4	14,300
2037	290.9	31.7	21,200
2038	160.5	17.5	11,700
2039	204.7	22.3	14,900
2040	216.3	23.6	15,700

[13] This is the estimated ACT annual operating hours for peaking support. Note that, while the plant may operate 270 hours on average in a year, the actual output will not always be required at 100% capacity.

5.5.4 Engineering Design and Best Available Control Technology

Potential project impacts to the atmospheric environment were considered during the early stages of design. The basis of design requires a multi-unit configuration, allowing for operational flexibility to minimize fuel consumption. The specification for the combustion turbines also requires the ability to convert to alternate fuel sources in the future that may result in reduced emissions. During detailed design, Hydro will further evaluate options for black start capability that may eliminate the need for dedicated black start diesel generators for the ACT. Potential combustion turbine vendors will be required to identify Best Available Control Technology ("BACT") in their proposals for Hydro's consideration during the evaluation and award process.

In consideration of the BACT requirements of Section 6 of the *Air Pollution Control Regulations* and Section 12.1 of the *Management of Greenhouse Gas Regulations*, Hydro completed a review of emissions control technologies and the three-unit configuration described in this registration. This BACT review was completed by Independent Engineering Consultants ("IEC") and the full report is found in Appendix E.

The BACT report identifies the common emissions control technologies available for combustion turbines for NO_x and PM, and considers their potential applicability to the ACT project with consideration of technical limitations and relative cost. The need to operate the combustion turbines on diesel fuel and the nature of the facility as a peaking and backup power supply were also important considerations in this review. Both regulations allow consideration of the performance and reliability of the available control technologies in comparable applications as well as economic feasibility.

5.5.4.1 Options for NO_x Control

NO_x emissions from combustion processes can be controlled through a variety of technologies, broadly categorized into dry combustion controls, dry post combustion controls and wet controls. In practice, selecting the appropriate NO_x control technology depends on various factors including fuel type, combustion system design, emission reduction goals and economic considerations.

NO_x control technologies are discussed in detail in the report. A summary of technologies suitable for diesel-fired combustion turbines is provided in Table 10 below.

Table 10. NO_x Control Technologies for Diesel Turbines

Emission Control Technology	NO_X Reduction Efficiency	Why It's Feasible for Diesel Turbines	Key Considerations
Selective Catalytic Reduction (SCR)	80% to 95%	Most effective NO_X reduction, works well with Ultra Low Sulphur Diesel (ULSD)	Requires ammonia or urea injection; sensitive to sulphur and PM; catalyst maintenance necessary.
Dry Low NO_X **(DLN) Combustors**	50% to 75%	Achieves low NO_X without water/steam injection; improves efficiency	Not compatible with water/steam injection; requires stable high-temperature operation. DLN uses premixed air and fuel mixture. Water or steam injection will interfere with the accurate control of burners.
Water or Steam Injection (SAC)	50% to 70%	Simple and widely used; effective in reducing combustion temperature	High water demand; increased maintenance from corrosion and deposits.
Selective Non-Catalytic Reduction (SNCR)	30% to 60%	Lower-cost alternative to SCR; no catalyst required	Requires precise temperature control (900°C to 1100°C); less effective at lower exhaust temperatures.
Ultra-Low NO_X **Burners (ULNB)**	75% to 90%	Advanced prevention-based technology; reduces NO_X during combustion	Requires specific turbine design; high initial cost but lower operational complexity.

5.5.4.2 Options for PM Control

Controlling PM and $PM_{2.5}$ requires efficient aftertreatment technologies tailored to the unique characteristics of diesel turbine exhaust, including high flow rates, variable temperatures and the potential for increased sulphur and soot content. Three primary technologies used for PM control in diesel-fired turbines are Diesel Particulate Filters ("DPFs"), Diesel Oxidation Catalysts ("DOCs") and Electrostatic Precipitators ("ESPs"), each with distinct mechanisms, efficiencies, and operational considerations. Additional technologies include fabric filters and wet scrubbers.

PM control technologies are discussed in detail in the report. A summary of technologies suitable for diesel-fired combustion turbines is provided in Table 11 below.

Table 11. PM Control Technologies for Diesel Turbines

Emission Control Technology	PM Reduction Efficiency	$PM_{2.5}$ Reduction Efficiency	Why It's Feasible for Diesel Turbines	Key Considerations
Diesel Particulate Filters (DPFs)	80% to 98%	80% to 98%	Highly effective; captures fine particles; works with low-sulphur fuel	High-pressure drop; requires consistent high exhaust temperatures for regeneration. Simple cycle generator data from manufacturers show lower exhaust temps and would need catalyst to reach regeneration temperature.
Electrostatic Precipitators (ESPs)	90%+	90%+	Ideal for high exhaust flow rates; minimal pressure drop	High capital and operational costs; large space requirement.
Diesel Oxidation Catalysts (DOCs)	20% to 40%	10% to 25%	Reduces volatile PM fraction; low backpressure	Limited $PM_{2.5}$ control; more effective on soluble organic fraction than solid soot.
Wet Scrubbers	80% to 95%	80% to 95%	Effective for both PM and sulphur-based aerosols	High-water demand; wastewater treatment required; potential for corrosion.

5.5.4.3 Cost Considerations

The review of BACT included consideration of capital and operating costs. A general summary of available cost information for control technologies is provided below (Table 12).

Table 12. Relative Cost of Control Technologies

	Technology	Capital Cost ($/MW)	Operating Cost
NO_x	**Water/Steam Injection**	$12,000–$25,000	$1,000–$3,000/year + water costs
	Selective Catalytic Reduction (SCR)	$40,000–$100,000	$0.50–$1.50/lb NO_X removed + maintenance
	Low NO_x Burners (LNB)	$5,000–$15,000	Minimal
	Dry Low Emissions (DLE) / Ultra Low NOx (ULN)	$15,000–$30,000	Moderate (control systems)
	Selective Non-Catalytic Reduction (SNCR)	$30,000–$60,000	$0.002–$0.004/kWh
PM	**Diesel Oxidation Catalysts (DOC)**	$5,000–$15,000	Low
	Diesel Particulate Filters (DPFs) - Active Regeneration	$5,000–$25,000	$2,000–$5,000/year
	Electrostatic Precipitators (ESP)	$75,000–$200,000	$0.003–$0.005/kWh

5.5.4.4 BACT Summary and Review for the ACT

The ACT is a peaking and backup facility that is anticipated to operate an average of 270 hours per year, with a worst-case emergency operating scenario of 6 weeks per year. The facility will utilize Ultra Low Sulphur Diesel[14] ("ULSD") or Low Sulphur Diesel ("LSD").

When low sulphur diesel fuel is used in diesel-fueled turbines, emission control challenges related to catalyst poisoning are significantly reduced. This reduction minimizes the risk of catalyst fouling and lowers maintenance requirements, making it possible to adopt a broader range of emission control technologies.

Accurate fuel–air ratio, effective operating controls and regular maintenance are critical for minimizing emissions in diesel-fired turbines. Proper fuel–air mixing ensures complete combustion, reducing the formation of NO_X and unburned hydrocarbons. Advanced control systems help maintain optimal combustion conditions across varying loads, while routine maintenance prevents issues like fouled injectors or degraded components that can increase emissions.

[14] Hydro's current supplier provides ULSD (maximum sulphur content of 15 parts per million ("PPM")). Hydro's fuel specification requires that sulphur content does not exceed 50 ppm. LSD has a 500 ppm maximum.

Key considerations for selecting feasible and viable NO_X control technologies for diesel turbines include:

- SCR remains the most efficient NO_X control for diesel turbines but faces challenges with ammonia slip[15], sulphur content and catalyst fouling — making it best suited for large stationary applications (25 MW and above) with low-sulphur diesel. Limited space availability poses technical challenges for using this technology, and capital and operational cost poses challenges for economic feasibility of this technology given that the ACT is a peaking and backup facility with typical annual run time of 270 hours and a worst-case contingency scenario of six weeks per year.

- ULNB and DLN combustors provide high efficiency and NO_X control without the water demand of SAC, but they require optimized air-fuel mixing and cannot operate alongside water/steam injection. Water injection is incompatible with DLN because it interferes with the carefully controlled lean premixed combustion process, risking flame instability, increased emissions and operational challenges. DLN is designed specifically to avoid the need for water or steam injection.

- Water/Steam Injection with Singular Annular Combustion (“SAC”) burners is widely used but brings increased maintenance and lower efficiency due to corrosion and water handling. However, it provides an economically and technically viable solution for diesel turbines. Hydro has significant experience utilizing this technology at the existing 123 MW facility located at Holyrood.

Particulate emissions from turbines are influenced by the design of the combustion system, fuel characteristics and operating conditions. In some jurisdictions, sulfuric acid and liquid unburned hydrocarbons may also be classified as particulate matter. Feasible control options for particulate emissions are generally limited - particularly for peaking units that have limited operation. With the exception of smoke, most particulate components are managed through fuel composition control. While smoke emissions are also influenced by fuel type, they are primarily minimized through advanced combustor design. For turbines fired with light oil, smoke is typically not a concern and, when it does occur, is usually limited to startup or shutdown periods.

[15] Ammonia slip occurs when ammonia, used as a reagent in SCR systems to convert NO_x into harmless nitrogen and water, isn't fully reacted and escapes into the exhaust stream. Unreacted ammonia can contribute to air pollution and can be a source of unpleasant odor.

Modern turbines incorporate advanced combustor designs that result in minimal particulate emissions when using low-sulfur diesel or ultra-low-sulfur diesel. Post-combustion particulate control systems are not commonly applied to simple-cycle turbine installations.

Key considerations for selecting feasible and viable PM and PM2.5 control technologies for diesel turbines include:

- DPFs and ESPs are the most effective for PM control, with ESPs being preferable for high-flow, variable-load diesel turbines due to their lower pressure drop. The space limitations and cost implications are important factors. ESPs, while highly effective for PM removal, are impractical for the ACT due to their large footprint, which is incompatible with the space limitations in the turbine generator area. ESPs also require significant energy input and complex maintenance, making them less attractive for a peaking facility focused on efficiency and reliability with limited annual operation.
- DPF pressure drop poses a significant drawback for diesel turbine applications.
- DOCs are more effective at reducing hydrocarbons than solid PM, making them a supplementary but not primary PM control method for diesel turbines. However, it features low capital and operating cost. Since the ACT units are peaking units with a typical annual run time of 270 hours and a worst-case contingency scenario of up to six weeks per year, DOCs may not be considered BACT, as the incremental emission reductions come at a cost that is not economically feasible.
- Wet scrubbers offer very high PM control but are less practical for diesel turbines due to space requirements, pressure drop, and operational complexity.

Given the constraints and considerations provided, as well as consideration of the cost, BACT for NO_X for the ACT will be achieved through:

- Water or Steam Injection with SAC combustors: Reduces peak flame temperature, lowering thermal NO_X formation; still compatible with diffusion flame combustion used in diesel turbines. Hydro has significant experience with the reliable operation of this technology[16];
- Use of ULSD/LSD: Minimizes sulphur content, which can indirectly help reduce NO_x and prevent damage to any downstream emissions control devices; and
- Good Combustion Practices: Optimized air-fuel ratios, advanced fuel injection, and regular maintenance to ensure clean, complete combustion.

[16] Hydro has not experienced issues with its water injection system at the existing combustion turbine facility since the system was expanded/upgraded in 2018. Hydro has an established preventative maintenance program for the emissions control system and keeps spare parts in stock for critical components.

Given the constraints and considerations provided, as well as consideration of cost, BACT for PM for the ACT will be achieved through:

- Use of ULSD/LSD to minimize PM formation at the source; and
- Good combustion practices, including proper turbine tuning and maintenance to optimize fuel–air mixing and reduce PM generation.

5.5.5 Dust

Dust may be generated during project construction, particularly in association with heavy civil works. Dust has the potential to adversely affect local air quality. The generation of dust from construction activities will be controlled as necessary using water or other dust control agents. The main access road to the project site is paved, which will also reduce the potential for dust generation from routine traffic. Dust will also be managed to mitigate risk to worker health and safety. Potential effects are therefore likely to be insignificant and short-term in nature.

5.5.6 Light

Light emissions associated with construction activities will be minimized by having lighting only for planned work areas as required for worker safety and by directing construction lighting downwards. The project baseline schedule does not contemplate 24-hour operations and therefore the potential effects to the surrounding area are expected to be insignificant.

5.5.7 Noise and Vibrations

A formal noise management program was originally established at HTGS in 2000 and Hydro maintains a *Noise Management Plan* ("NMP") for the Holyrood site. This NMP includes noise evaluation information and documents operational procedures and other controls to mitigate noise emissions. The NMP will be revised to incorporate the ACT once the facility is operational.

5.5.7.1 Construction Phase

Due to the proximity of the project to sensitive assets and critical infrastructure, Hydro does not anticipate that blasting will be conducted at the project site. Should quarry material be required during construction, contractors will source and import material from active quarries in the region.

Noise will be generated during the construction phase, particularly in association with the use of heavy equipment and general construction activities. The Holyrood industrial site operates year-round and includes significant annual construction activities, particularly when HTGS operations are curtailed in the summer period. In the absence of blasting and 24-hour construction activity, noise generated during the construction phase is not expected to be a significant issue. There have been no recorded noise complaints related to site operations in more than a decade.

To aid in the assessment of project noise impacts, Hydro collected baseline noise measurements[17] in adjacent residential areas on February 19 and 20, 2025. At the time, all three thermal units at HTGS were operating at 70 MW. The average morning measurement, taken at approximately 8:30 a.m. at 27 locations, was 50.2 dBA - comparable to the sound of moderate rainfall or a refrigerator. The average evening reading, taken at approximately 6:00 p.m. at 21 locations, was 46.3 dBA - comparable to that of a quiet office or dishwasher. Hydro intends to collect additional community noise measurements when HTGS is not operating and monitor community noise levels during project construction.

5.5.7.2 Operating Phase

As part of the feasibility study completed by Hatch in 2023, a preliminary assessment of sound levels emitted from the operation of the proposed facility in the neighboring community was conducted. Hydro has committed to enclosing the combustion turbines within a powerhouse structure as the primary noise mitigation measure.

As there are no provincial regulations governing noise emissions, Hatch considered the noise guidelines for the Province of Nova Scotia[18]. The following guidelines for acceptable equivalent sound levels for industrial zones were considered:

- Leq[19] of 65 dBA between 0700 to 1900 hours;
- Leq of 60 dBA between 1900 to 2300 hours; and
- Leq of 55 dBA between 2300 to 0700 hours.

The assessment was completed using the CadnaA software application developed by DataKustik. CadnaA models atmospheric sound propagation following the ISO 9613-2 standard. The model considers geometrical dispersion, atmospheric decay, ground absorption and ground topography. A summary of results for selected residential noise receptors is shown below (Table 13). There were no predicted noise levels exceeding the guidelines.

[17] Using a Casella – CEL633C Sound Level Meter.
[18] Guidelines for Environmental Noise Measurement and Assessment. Nova Scotia Environment and Climate Change.
[19] Leq is a single number representation of the average, cumulative acoustical energy over a specified time interval, typically one (1) hour. Leq is measured in dBA values, where dB stands for decibel and is the unit of sound measurement and "A" weighting is a correction to account for human hearing, as humans do not hear all frequencies equally.

Table 13. Predicted Noise Levels at Residential Receptors

Receptor	Predicted Noise Level (dBA)		Noise Limit (dBA)	
	Day	Night	Day	Night
Duffs Road	40	40	65	55
154 Indian Pond Dr.	50	50	65	55
137 Indian Pond Dr.	49	49	65	55
123 Indian Pond Dr.	48	48	65	55
110 Indian Pond Dr.	47	47	65	55
100 Indian Pond Dr.	45	45	65	55
90 Indian Pond Dr.	44	44	65	55

During FEED, Hatch conducted a noise impact assessment with reference to the federal guideline *Health Canada – Guidance for Evaluating Human Health Impacts in Environmental Assessment: Noise (2017).* Noise prediction software (Cadna-A) was used to model predicted noise levels at sensitive receptors and the percentage change in high annoyance[20] (“%HA”), as summarized in Figure 10. The %HA was compared to the 6.5%[21] threshold identified by Health Canada. Predicted noise levels at identified residential receptors ranged from 48-54 dBA[22], below the Health Canada high annoyance limit of 6.5% change[23].

[20] Annoyance can be described as the effect of noise that most people are aware of. High annoyance has been widely used as one way to estimate a community response to noise levels. Health Canada uses the change in %HA as an appropriate indicator of noise-induced human health effects from exposure to project noise.
[21] Health Canada suggests that noise mitigation measures should be considered when a change in calculated %HA at any given receptor location exceeds 6.5%.
[22] dB stands for decibel and is the unit of sound measurement. “A” weighting is a correction to account for human hearing, as humans do not hear all frequencies equally. Normal indoor conversation is 55-58 dBA.
[23] A negligible background noise level of 37dBA was assumed in the calculations.

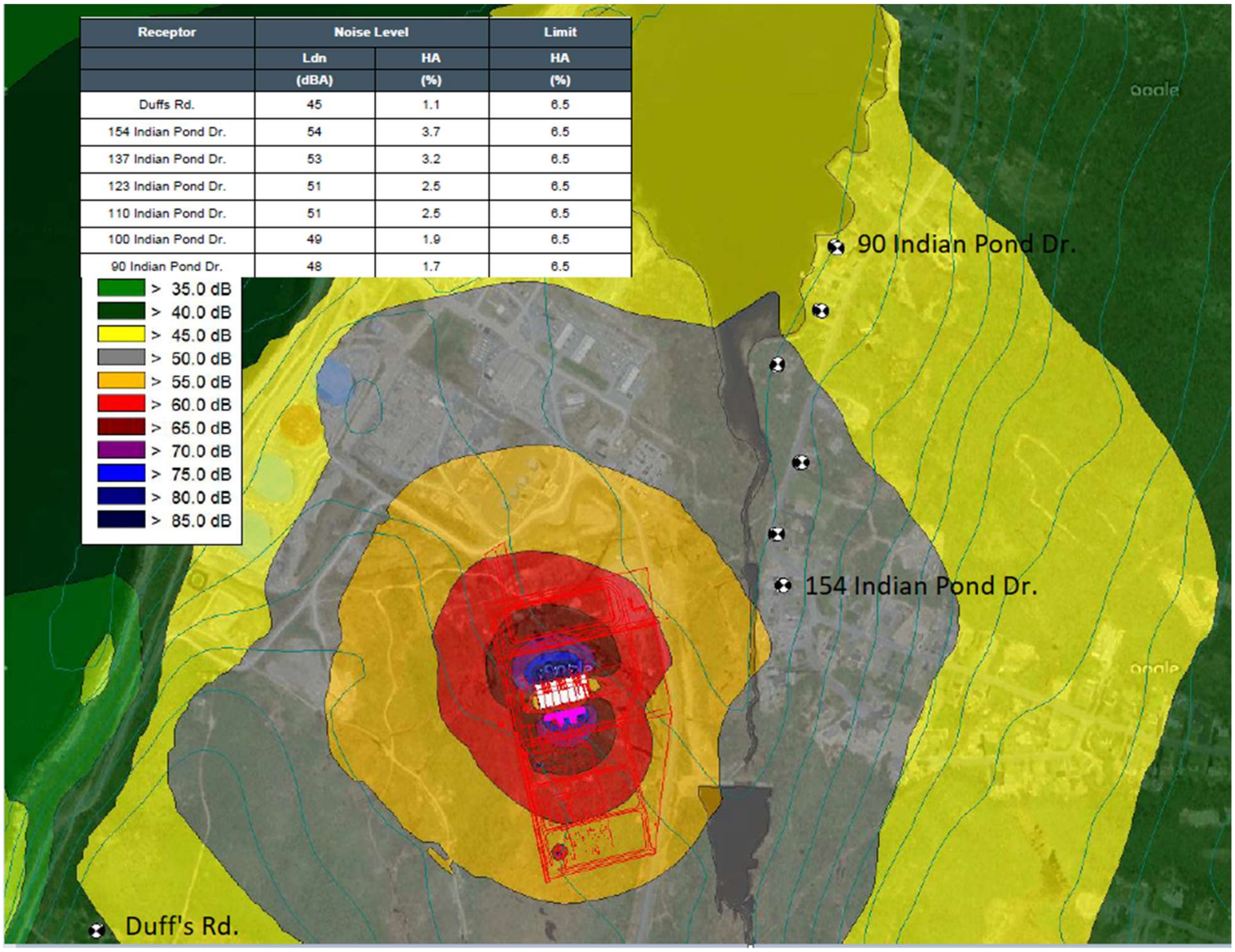


Figure 10. Site Noise Contours, Predicted Receptor Noise Levels and %HA

5.5.7.3 Cumulative Noise

It would be very unlikely for the HTGS, the existing gas turbine and the ACT to operate simultaneously once the ACT is commissioned. Upon retirement of HTGS, the ACT and the existing gas turbine may operate simultaneously for short periods for peaking support or possibly in an emergency scenario. Using 54 dBA as the maximum predicted community noise level for ACT, and assuming the same noise level for the existing gas turbine, the cumulative noise level would be approximately 57 dBA, comparable to a normal conversation or light traffic.

5.6 **Aquatic Environment**

5.6.1.1 Quarry Brook Water Use

The ACT requires a water supply for several operational purposes, including the control of emissions and for fire protection. Quarry Brook currently provides water to the existing gas turbine and the HTGS.

Hydro's existing Water Use License (WUL-21-11600) for Quarry Brook allows for withdrawal of 450,000 m^3/year[24]. Over the past eight years, annual water use ranged from 227,314.6 m^3 in 2022, to 394,216.6 m^3 in 2017 – the only year exceeding 350,000 m^3. Including 2017, the average annual water use from 2017 to 2024 was approximately 302,000 m^3.

The existing water supply from Quarry Brook was evaluated by Hatch Ltd. to support the ACT proposal. It was assumed, as a worst case, that the ACT could require a continuous demand of 100 m^3/hour for up to 1000 hours (six weeks) per year, thus adding approximately 100,000 m^3 of water consumption in a year.

Water supply adequacy was evaluated in terms of total annual volume and the ability to meet the continuous demand during periods of low natural inflow. The Environment Canada long term[25] stream gauge record for nearby South River in Holyrood was used to model inflows and adequacy of water availability from Quarry Brook. South River is close to the project location, is in a hydrologically similar region and has a drainage area similar in order of magnitude to Quarry Brook. This review determined that the existing Quarry Brook water supply has capacity to support the ACT, along with the other existing facilities. An amendment will be required to the active Water Use License to add the new facility.

5.6.1.2 Fish and Fish Habitat

A new freshwater intake and associated pumphouse will be installed at the Quarry Brook reservoir for the project, requiring work in and near fish bearing waters. Hydro will submit project information to the Department of Fisheries and Oceans ("DFO") for review once the design is complete. The intake will comply with DFO requirements for end-of-pipe screening to mitigate impacts to fish.

Work near Quarry Brook will be carefully planned to avoid adverse effects to fish and fish habitat and work execution will be monitored by Hydro's environmental staff. Contractor execution plans and work methods will be subject to review and approval by Hydro.

Discharge location(s) from oil/water separators will be confirmed during final design and may include Indian Pond. An appropriate effluent sampling and monitoring program will be established with PPD before the facility is approved for operation.

[24] The previous Water Use License permitted 630,000 m3/year. This was voluntarily reduced by Hydro in the 2021 application to more closely align with anticipated operational requirements.
[25] There are 39 years of observed daily flows, from 1983 to 2021, allowing for a good estimation of extreme low flows.

5.6.1.3 Wetlands

The project site includes poorly drained areas and small wetlands[26] that will be impacted during site development. Organic and unsuitable materials will be excavated from the project area and replaced with suitable material as needed to support the proposed infrastructure. Excavated material will be stored elsewhere on Hydro's property for potential use in future site decommissioning activities.

Due to the constrained nature of the site, project impact to wetland areas within the facility footprint is unavoidable. The most significant wetland (approximately 1.8 hectares) is located in the southwest corner of the project area, where the terminal station and high voltage interconnection are planned. During final engineering design, Hydro will endeavor to minimize encroachment on this wetland.

5.6.1.4 Water Management and Sediment Control

Given the project's proximity to Quarry Brook, and the heavy civil work required to develop the adjacent construction site, water and sediment must be effectively managed to mitigate potential adverse effects. The civil contractor will be required to prepare a Water Management and Sediment Control Plan, or equivalent, for Hydro's review and approval. Hydro's environmental staff will monitor civil works as required to ensure the effectiveness of the mitigation measures. Site grading and water management requirements will be confirmed during detailed design.

5.7 **Terrestrial Environment**

The proposed project site is primarily undeveloped and generally bound by existing infrastructure – roads, power lines, and the HTGS industrial site. Project construction will involve vegetation clearing, grubbing and removal of unsuitable soils from approximately 11.8 hectares. Unsuitable soils will be stored on Hydro's property for use in future remediation activities. Suitable fill materials are expected to be sourced, and imported, from established quarries in the region as needed. An additional 4.9 hectares of vegetation clearing is anticipated to establish safe right-of-ways for power line relocations and interconnections. There are no protected plant species known to occur in the project area.

While there are no protected wildlife species known to occur within the proposed project area, there is potential for a project interaction with nesting migratory birds between April 1 and August 31. Hydro anticipates that vegetation clearing will occur after August 31, 2025 and before April 1, 2026. Should this plan change, Hydro's *Procedure for Nesting Birds in Vegetated Areas* will be implemented. In this case, trained[27] personnel will assess the area for nesting

[26] As previously noted, the wetland areas do not show on 1:50,000 mapping and permitting will not be required.
[27] Hydro has in-house training for personnel involved with searching for bird nests.

activity prior to commencement of work, and during work execution as the work progresses. Should a nest be identified, the nest location will be protected with a buffer and activity in the immediate area will be minimized. An established buffer will not be removed until it is determined that the associated nest is inactive.

Storm Petrels are known to occasionally become stranded at the HTGS site. Hydro has established procedures in place to manage stranded seabirds and those procedures will be implemented at the ACT construction site. In the absence of 24/7 construction activity at the ACT site, lighting can be minimized during the overnight period to reduce the risk of attracting birds to the construction area.

There are two endangered species of myotis found within Newfoundland and Labrador, northern long-eared bat (*Myotis septentrionalis*) and little brown bat (*Myotis lucifugus*). The ACCDC did not identify any observations or known populations of these endangered species within the 5 km of the project location and Hydro has not observed bats in the area of the HTGS. Should a bat be observed in the area, Hydro will avoid disturbance and consult with Wildlife Division.

5.8 **Socioeconomic Environment**

With more than 50 years of power generation at the Holyrood industrial site, Hydro is aware of how its operations can impact the socioeconomic environment. Maintaining public safety during the construction phase is of utmost importance to Hydro. As discussed in Section 4.4, Hydro will consider the potential project impacts on traffic and access to the area during final design and execution planning. The project development will be visible from some local residences, particularly on the east side of Quarry Brook in the community of CBS. The project infrastructure will look similar to existing infrastructure on the adjacent industrial site.

As discussed in Section 5.5.7, Hydro does not anticipate that noise generated during construction and facility operation will cause a significant adverse effect. Hydro’s baseline construction schedule does not consider 24/7 activity and the commitment to enclosing the turbines in a building will mitigate noise during future facility operation.

The project will provide opportunities for employment (Table 3) and provision of goods and services. No significant adverse effects on community services and infrastructure are anticipated.

Hydro is committed to ongoing communication and engagement with the public, and other key stakeholders, as the project progresses. This engagement effort includes reinstating the Community Liaison Committee. By ensuring open communication and providing opportunities for stakeholders to raise concerns, Hydro is confident that issues with potential socioeconomic impacts can be effectively managed and positive opportunities can be promoted.

6.0 MONITORING AND FOLLOW UP

Hydro plans to conduct further community noise measurements and monitor noise during construction.

Hydro will ensure that monitoring programs related to effluent and emissions are established and implemented in coordination with PPD.

Should another turbine configuration be selected during the procurement effort, Hydro will review potential project scope impacts with the Department of Environment and Climate Change – Environmental Assessment Division to determine next steps.

7.0 DECOMMISSIONING AND REHABILITATION

Hydro continuously evaluates energy demand, system reliability and generation supply needs for the province. A future decision to decommission, or extend the life of, a generating asset would consider many factors as they evolve, or emerge, over time.

The proposed facility has a design life of 50 years and, with prudent maintenance and investment, this could be extended if necessary to serve the province's needs. Hydro has taken steps to ensure the proposed facility is capable of adapting to future needs through its design specification, which includes synchronous condense and future fuel conversion capability.

During construction of the ACT, Hydro intends to stockpile organic material and unsuitable overburden removed during site development. These materials can be used in future decommissioning and rehabilitation activities. The objectives of future site restoration work would include, but not be limited to:

- ensuring public health and safety;
- preventing progressive degradation and enhancing natural recovery of impacted areas;
- minimizing the requirement for long term maintenance and monitoring;
- mitigating the potential input and consequence of contaminants; and
- returning affected areas to an acceptable condition.

8.0 FUNDING

The project is 100% funded by Hydro. Hydro is requesting authorization of $891 million for the project. The project was submitted to the Public Utilities Board for review and approval on March 21, 2025.

9.0 PROJECT RELATED DOCUMENTS

Air dispersion modeling has been completed and the report is included in Appendix D. The Best Availability Control Technology ("BACT") Report is found in Appendix E.

10.0 SIGNATURE

27 March 2025

Date

Company Representative
Scott Crosbie, Vice President, Operations

Appendix A
Power the Province - Summary

POWER THE PROVINCE

BUILDING A FUTURE WITH SAFE, LEAST-COST, AND RELIABLE POWER SOLUTIONS

THE POWER OF PLANNING

We're planning for the future and working hard to power the province with safe, reliable electricity at the lowest possible cost for our customers. It's something we all need—and we will need more. Our customers have been clear. The cost of living, including electricity rates, is a concern—they prioritize lower electricity costs before investment in increased reliability or renewable technologies.

With lessons of the past in mind, and with the oversight of the Public Utilities Board, we are moving forward with what absolutely and urgently must be done to support system reliability and have supply in place to meet load growth.

TIME TO BUILD

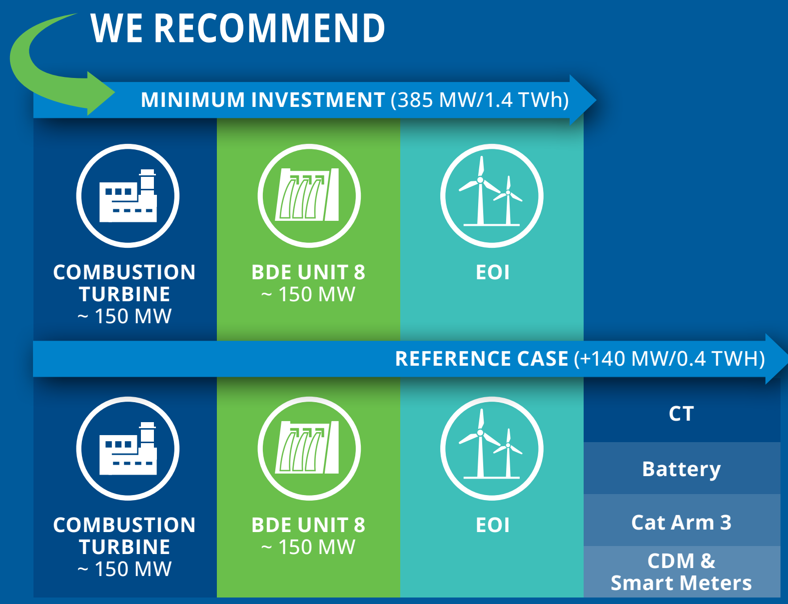
In 2024, Hydro filed our 2024 Resource Adequacy Plan (2024 Plan) with the Public Utilities Board. This was a continuation of our planning process, which addresses our long-term approach to providing continued lowest cost, reliable service for our customers.

The 2024 Plan assessed the integration of new assets, system reliability, and the effects of electrification and decarbonization across various scenarios.

Our analysis demonstrated that, in all modeled scenarios, urgent investment is required to ensure continued reliability of our electrical system and to prepare for load growth.

As a first step, and in recognition that our customers are counting on us to invest wisely and prudently, we recommended a Minimum Investment Required Expansion Plan. The plan proposed an additional 150 megawatt (MW) unit at the Bay d'Espoir Hydroelectric Generating Facility ("BDE Unit 8") and a new 150 MW combustion turbine with renewable fuel capabilities located on the Avalon Peninsula ("Avalon CT") as the preferred, least-cost, environmentally responsible resource options to address our capacity needs. Our plan also identified wind energy to meet our energy needs.

We are also working to ensure that plans are in place for scenarios with more aggressive load growth. While such cases may require additional supply, BDE Unit 8, Avalon CT, and wind energy represent the minimum investment required across all scenarios.



We have now gathered all the evidence required to support our submission of the 2025 Build Application to the Public Utilities Board for these capacity-focused solutions.

Wind does not form part of Hydro's 2025 Build Application. Rather, we will continue our ongoing analysis and will proceed with an Expression of Interest (EOI) to identify potential wind developers and development opportunities later this year. As wind requirements are confirmed, we will issue a request for proposals (RFP).

This summary presents an overview of the application.

The full application with documentation is available at PowerTheProvince.ca.

HOW MUCH DOES THE ISLAND NEED?

The 2024 Resource Plan determined we need capacity and energy.

Capacity is the maximum amount our electricity system can produce at any given time, measured in megawatts.

Energy is the amount of electricity produced over a specific period of time, measured in watt-hours.

In 2024, Island demand reached 1691 MW and is expected to grow to 1928 MW by 2035—a 14% increase. We need to add capacity to meet this demand.

In 2024, we used 7.8 TWh of energy on the Island and use is expected to grow to 9.0 TWh by 2035—that's 17% more energy.

HYDRO'S 2025 BUILD APPLICATION IS THE FIRST STEP TO ADDRESSING OUR CAPACITY NEEDS.

LISTENING TO OUR CUSTOMERS

Hydro values the perspectives of everyone who may be impacted by decisions about the delivery of safe, reliable, environmentally responsible electricity. Through a province-wide digital engagement, we engaged our customers to gather opinions about our next big decisions. Customers were very clear. The cost of living, including electricity rates, is a concern and they have a strong preference to prioritize lower electricity costs before investment in increased reliability or renewable technologies.

With this is mind, Hydro is moving forward with what absolutely and urgently must be done to support system reliability and have supply in place to meet load growth – the Avalon CT and BDE Unit 8. These proposed projects continue to be the least-cost options to provide reliable, electricity in an environmentally responsible manner.

We are also engaging and sharing information with the public and other interested groups as we plan these projects. Through various digital, phone, and in person meetings, we have engaged elected officials and senior staff from the communities that will be home to the new projects. We have also held public information sessions for area residents, and have met and shared information with other interested groups.

As we move forward, Hydro is committed to ongoing engagement and keeping the public, interested groups, and our own employees informed. We will continue to gather input as we advance though Environmental Assessment, Public Utilities Board application processes, planning, and construction.

APPROACH TO MAJOR PROJECTS

Recognizing the criticality of project oversight in the success of major projects, Hydro has taken measures to ensure the effective planning, execution, and delivery of major projects, including the two in this application. Our ability to execute these projects is supported by highly qualified project teams and a governance framework that reflects lessons learned from past projects, industry standards and good utility practice.

Hydro has built a team of experienced, subject matter experts from across the organization and representing a variety of professional and corporate services.

This team will be supplemented by external experts as necessary, and with oversight from our Executive and Board of Directors. We are leveraging insights gained from Hydro's Internal Audit & Advisory Services group, the Muskrat Falls Inquiry, other utilities such as members of the Canadian Electric Utility Project Management Network and lessons learned from previous projects. Further, our investment decisions will be tested and approved as part of a public, transparent regulatory process through the Public Utilities Board.

We are working closely with the Government of Newfoundland and Labrador (GNL) to ensure customers in this province continue to pay some of lowest electricity rates in Canada.

While GNL's Rate Mitigation Plan provides for predictability and stability of Hydro's rates out to 2030, both GNL and Hydro have expressed a commitment to continued rate mitigation post 2030.

BUILDING FOR OUR FUTURE

The Island Interconnected System is currently capacity-constrained. Given the timeframe to construct new assets, it is imperative to action new resource options now. BDE Unit 8 and the Avalon CT are the first steps to reliably serving customers on the Island as system demand grows in the coming decade. By focusing on foundational capacity supply options in the minimum investment case, we are addressing the immediate need to build and bring additional supply options online to meet the growing demand for electricity in Newfoundland and Labrador. In doing so, we also set the stage for the eventual retirement of Holyrood's thermal generating units.

While many supply options were explored, these two supply solutions were the least-cost, technically viable and reliable options for the Island Interconnected System and are supported by data, experience, expertise, and customer feedback.

Our 2025 Build Application includes all the evidence to support this decision, including an updated 2024 load forecast and refined cost estimates for both BDE Unit 8 and Avalon CT.

We need to get started so we can see both new assets brought online by 2031, as well as manage project costs.

(see project timelines on the next page)

WHY A COMBUSTION TURBINE ON THE AVALON?

The 150 MW combustion turbine facility, which will be able to use renewable fuels, will serve as an important backup power source to support system stability and energy reliability during periods when demand for electricity is at its highest. It will primarily be used when needed to help meet peak demand—this is how such assets are used across Canada today.

Several locations were considered. Evaluation criteria identified that building on the existing Holyrood site is best to meet future demand at the lowest cost. Additionally, it allows for connection on the Avalon Peninsula, where demand for electricity is the highest. This unit can be connected to existing transmission infrastructure and represents the lowest capital cost.

In December 2024, the Government of Canada finalized the Clean Electricity Regulations ("CER"). These regulations were a key consideration in Hydro's evaluation of potential new sources of generation during the 2024 Resource Adequacy Plan. The Avalon CT would be compliant with the CER, based on its use as a peaking unit or for providing backup generation in the event of high demand periods or during contingency events.

PROPOSED BUDGET ~$891M

WHY AN ADDITIONAL UNIT AT BAY D'ESPOIR?

The Bay d'Espoir generating station has been a central part of our province's electricity system for more than 50 years, and it will continue operation well into the future.

Analysis has determined that adding an eighth generating unit at the Bay d'Espoir facility will help meet growing demand for electricity, while supporting the reliability of service for customers. The addition of a new 150 MW hydroelectric unit represents the next investment required to serve customer demand now and into the future. The Bay d'Espoir facility was originally designed for the eventual addition of an eighth unit. Now that our system needs additional capacity—that future is here.

Investment in BDE Unit 8, combined with the Avalon CT, also supports the eventual retirement of Holyrood, which is currently being kept online to support the reliable operation of the power system.

PROPOSED BUDGET ~$1.08B

Proposed budgets for the new projects were determined using the confidence levels recommended by the Muskrat Falls Inquiry.

PROGRESS TO DATE

2018

- Initial Reliability and Resource Adequacy Study (RRA) filed with Public Utilities Board, with updates filed in 2019, 2021, and 2022

2024

- 2024 Resource Adequacy Plan
- Front End Engineering Design completed
- Early engagement with key parties

2025

- Early execution work planning
- Public engagement ongoing
- Build application submitted

MILESTONES*

AVALON COMBUSTION TURBINE / **BDE UNIT 8**

2025

- Environmental assessment
- Regulatory review
- Early site preparation
- Procurement begins
- Detailed engineering design
- Detailed construction planning

2026

- On site construction begins (Avalon Combustion Turbine)

2028

- On site construction begins (BDE Unit 8)

2029 (Avalon Combustion Turbine)

- Facilities completed
- Project commissioning
- Ready for operation

2030 (BDE Unit 8)

- Powerhouse completed

2031 (BDE Unit 8)

- Project commissioning
- Ready for operation

WIND (2030–2033)

Hydro expects to bring on the first wave of new energy in 2030, with incremental amounts as required in subsequent years.

2033

**Schedule reflects regulatory approvals in 2025*

Appendix B
List of Potentially Applicable Permits and Authorizations

newfoundland labrador hydro

List of Potentially Applicable Permits or Authorizations

Permit or Authorization	Agency	Comments
Release of the Undertaking from the Environmental Assessment Process	Department of Environment and Climate Change – Environmental Assessment Division	Greater than 1 MW requires registration
Cutting Permit and Operating Permit	Department of Fisheries, Forestry and Agriculture	Vegetation clearing and work near forested areas
Water Use Authorization	Department of Environment and Climate Change – Water Resources Management Division	Water withdrawal from Quarry Brook. Amendment to existing license.
Permit for Alterations to a Body of Water	Department of Environment and Climate Change – Water Resources Management Division	Includes water intake and work within 15 meters of a waterbody.
Quarry Permit or Subordinate Permit	Department of Industry, Energy and Technology	Potential for suitable material to be imported from an existing quarry
Registration of Fuel Tanks and Systems	Department of Digital Government and Service NL	Storage of gasoline and associated products
Used Oil Storage Approval	Department of Digital Government and Service NL	Used oil, oil-water separators.
Registration under Clean Electricity Regulations	Environment and Climate Change Canada	Registration Report as per Section 7
Letter of Advice	Department of Fisheries and Oceans	Request for review of activities in or near water
Septic System	Department of Digital Government and Service NL	Subject to final design
Certificate of Approval for Operation of the Facility	Department of Environment and Climate Change – Pollution Prevention Division	Existing Certificate of Approval to be amended.

Appendix C
Public Engagement – What We Heard

What We Heard

Public Open Houses February 2025
Avalon Combustion Turbine Project

Background

We're in the midst of an energy transition here in Newfoundland and Labrador – across Canada and the world – as the demand for new sources of reliable, renewable energy is on the rise.

Delivering reliable and renewable power to the people of our province is our responsibility, and our **Reliability and Resource Adequacy (RRA) study** is focused on planning to meet customer and system requirements over a 10-year planning horizon. As outlined in the 2024 iteration of the RRA, Hydro is proposing to construct a new 150MW combustion turbine facility at the Holyrood Thermal Generating Station (HTGS) site.

In recognition of this, Hydro established objectives for engagement and information-sharing, including keeping local municipal governments, community residents, businesses, and other interested groups informed; providing public information and feedback opportunities; and establishing a channel for ongoing communication and collaboration as the project continues through planning, approvals, and execution. This engagement was initiated with primary interest groups early in project planning phases, and in advance of the regulatory approval process and environment assessment registrations.

Through the course of the early-stage stakeholder engagement process beginning in August 2024, Hydro has proactively issued direct communications and project information to municipal and provincial organizations and officials. This includes presenting to the Town Councils and senior staff in November/December 2024 to create early awareness about the Project (Project rationale, construction plans, and other details) and to gather their initial feedback.

Hydro values the perspectives of everyone who has an interest in or is affected by decisions impacting the delivery of safe, reliable electricity. It's embedded in our values and is 1 of 11 Goals in our Strategic Plan—**ENGAGE WHO WE SERVE.**

"We will proactively engage and listen to our community to better understand their expectations and demonstrate our delivery on those expectations. We believe in listening to those we serve, being open and transparent about our operations, and ensuring everyone can better understand our work and our commitment to them. By proactively engaging with interested parties, we can seek to understand their needs and operate with their unique positions and interests in mind. We will do this by sharing relevant information, seeking input to expand our knowledge, and collaborating with industry peers and partners to benefit the people of the province."
-Hydro's Strategic Plan

Town officials were able to ask questions and gain an understanding of the Project and any potential impacts on nearby residents. Both towns indicated they were appreciative of the early outreach and were pleased to work with Hydro to raise awareness among residents.

Hydro indicated intentions to facilitate public engagement sessions for information sharing and to obtain feedback on analysis, issues, alternatives, and decisions in these early meetings. Town officials agreed to work collaboratively with Hydro to leverage the sessions through their networks to optimize attendance, and these Public Open Houses were organized for February 2025.

The feedback received in these engagement activities has been summarized in this report and is anticipated to continue to develop as the Project moves forward and activity increases at the site. As project planning continues, Hydro will coordinate subsequent public engagement opportunities in ongoing consultation for enhanced transparency and communication.

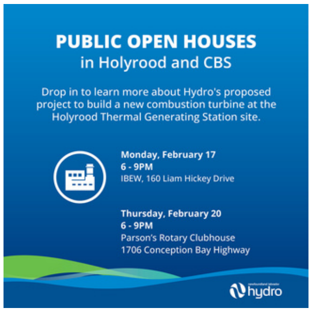
Communications Summary

Public Open Houses for the Avalon Combustion Turbine Project took place on February 17th at the IBEW College in Holyrood from 6 - 9pm, and February 20th at the Parsons Rotary Clubhouse in Conception Bay South from 6 - 9pm. The Open Houses offered residents and other interested groups flexibility to attend on either date and at any time within the 3 scheduled hours to receive information and connect with members of Hydro's project team.

These engagement opportunities were communicated broadly via the following mediums beginning February 4th:

Radio

50 30 second commercials
2-week Commercial Campaign
97.5 K-Rock and 590 VOCM Stations
Feb. 4th - 20th

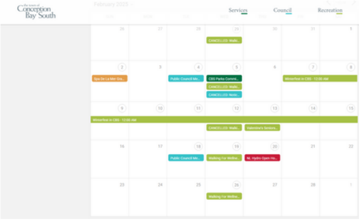


Social Media

8 Posts on Hydro's Facebook and X accounts
5 Cross-promotional posts on the Town of Holyrood and Town of CBS Facebook Pages

Town Communications

- Town of Holyrood Feb Public Meeting
- Town of Holyrood Public Notices
- Town of CBS Events Calendar
- Email Notice to Residents
- Shoreline Newspaper



Invitations to Government Officials and Special Interest Groups

An invitation to the Public Open Houses was sent to the Conception Bay Area Chamber of Commerce.

Hydro met with EcoNEXT, a provincial environmental industry association to discuss Hydro's proposed projects.

Hydro also met with members of the House of Assembly for the area, MHA Helen Conway-Ottenheimer and Barry Petten, and presented to them on the Avalon Combustion Turbine project, followed by a tour of the HTGS facility.

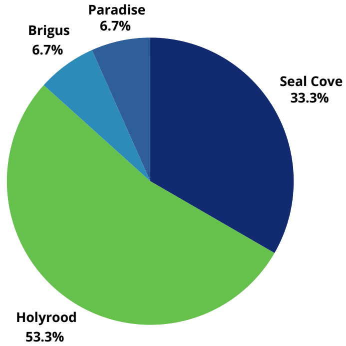
What We Did

Visitors to the Open Houses were provided information sheets upon registration and this information was broadened by a series of Poster Boards organized in categories of Health & Safety, Construction & Engineering, and Environment. Project Managers from Hydro were available to answer questions and expand on the information on display. Visitors were also provided feedback cards to leave behind any comments about the Project.

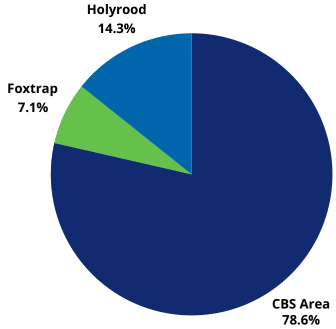
Who Participated

Twenty-nine (29) individuals attended the Public Open Houses, identifying themselves as residents and/or business owners from the communities of Holyrood, Conception Bay South, Foxtrap, Brigus, and Paradise.

Feb. 17th Open House
Holyrood - 15 Attendees



Feb. 20th Open House
CBS - 14 Attendees



CBS Mayor Darrin Bent and Town Councilors were among those who attended the CBS Public Open House

Key Themes

Remarks and questions on the Project can be organized into the following key themes:

Thermal Generation vs. Renewable Energy

Many that attended asked why Hydro was proposing combustion turbines instead of renewable energy to increase reliability. Project Managers from Hydro explained that more than 90% of the province's total generation will continue to be from renewable hydroelectricity, and engine selection criteria includes the ability to utilize or be converted to renewable fuels in the future should they become available.

The purpose of a new combustion turbine

Several questions were asked around whether the combustion turbine would be replacing the main thermal generating station. The need for the project to maintain reliability of our electricity was explained, especially as it relates to this combustion turbine being utilized primarily for capacity in times of peak energy use.

Location of the turbine on the Avalon, and specifically at the Holyrood site

Some residents questioned if other sites were considered as an alternative. Project team members noted that six (6) sites were evaluated on the Avalon as potential locations, and criteria identified that building on the existing Holyrood plant site is best to meet future demand at the lowest cost. Additionally, it allows for connection on the Avalon Peninsula, where demand is highest. The easy connection to existing transmission line (TL218) is favorable from a grid perspective, allowing for lowest capital cost of transmission, as well as access to an established water supply.

Increased emissions

Information was provided about Hydro's emissions modelling to confirm that emissions are in compliance with Provincial requirements, and will utilize best available control and performance technology to improve combustion efficiency. Efficient combustion leads to less fuel being burned, which in turn means fewer greenhouse gases are released into the atmosphere.

What Else We Heard

Other issues and questions raised by visitors in discussion include:

Noise	**Traffic Disruptions and Re-routes**
Changes to Landscape	**Employment Opportunities**
Schedule Overruns and Impacts to Cost	**Environmental Assessment Process**
Project Schedule	**Future ATV Trail Access Restrictions**
Status of Decommissioning the HTGS	**Operation**

Other Feedback and Observations

- There were expectations for the event to be a formal presentation from 6-9pm, and feedback was very positive when it was realized that it was an informal opportunity to engage directly with Hydro staff

- There is interest in the Community Liaison Committee being revived as an ongoing communication mechanism between area stakeholders and Hydro for matters pertaining to operation of the HTGS.

- Strong engagement in the planning process and projections for additional generation

- Request for more information on wind/hydrogen proponents

- Positivity around localized economic activity

- General understanding of the need for Project, especially as it relates to electrification driving demand

- Adjacent residents would benefit from reassurance that the Project will not impact their property value

Continuing the Conversation

Digital copies of the information (handouts) that were distributed at the Open Houses was sent to contacts at the Town of Holyrood and the Town of CBS, with paper copies and feedback cards hand-delivered to Town Halls to make available for residents.

Included in these materials is a dedicated email (*ProjectFeedback@nlh.nl.ca*) for all stakeholders to send questions, concerns, and all related feedback for record and response.

A Community Liaison Committee (CLC) was previously established in 1998 but it has not been active in recent years. The purpose of the CLC is to provide open communication with area stakeholders and an avenue to bring forward environmental concerns or other issues relating to the operation of HTGS. Hydro intends to present reinstatement of the CLC to Holyrood and CBS Town Councils in 2025 as a mechanism for leveraging the CLC for ongoing project communication and engagement.

Hydro is committed to organizing future public engagement opportunities for the Avalon Combustion Turbine Project as it advances, especially as activity increases at the site.

newfoundland labrador
hydro

Appendix D
Air Dispersion Modelling Report

Final Report:
CALPUFF Dispersion Modelling for the New Avalon Combustion Turbines at the Holyrood Thermal Generating Station

Prepared for:

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a nalcor energy company

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IEC Project No.: SX24-0031

March 2025

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Position	Name	Signature
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EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro (NL Hydro) operate a 500-megawatt (MW) thermal generating station in Holyrood, Newfoundland and Labrador known as the Holyrood Thermal Generating Station (HTGS or the Facility). HTGS is comprised of three (3) oil-fired thermal generators (Units 1, 2, and 3) and since 2015, NL Hydro has also operated a 123 MW diesel-fired gas turbine generator (the GT) and maintained six (6) diesel-fired black start generators, each having a nominal rating of 2 MW. Together, the HTGS, GT and black start diesel generators comprise the current power generating station at the Facility. NL Hydro intends to operate the oil-fired thermal generators until approximately 2030. The proposed 150 MW (nominal) combustion turbine facility is part of NL Hydro's expansion plan to add emergency and peaking support capacity while addressing growing system demand. Complimentary to the new CTs, two (2) new diesel-fired black start generators are to be installed for the sole purpose of firing up the CTs and will not provide power to the grid. The expected nominal rating of the new black start generators is 2 MW. Collectively, the new installations are known as the Avalon Combustion Turbine (ACT) Project. To facilitate this expansion and associated infrastructure, NL Hydro will require an amendment to its administrative boundary. This air dispersion modelling assessment was performed to demonstrate the compliance with Newfoundland and Labrador Air Quality Standards (AQS) when the proposed ACT configuration is operating in conjunction with the current configuration and evaluated against the proposed administrative boundary.

Air dispersion modelling was performed using the CALMET/CALPUFF modelling package to predict ground-level concentrations of nitrogen dioxide (NO_2), sulphur dioxide (SO_2), carbon monoxide (CO), total particulate matter (TPM), particulate matter less than 10 microns (PM_{10}), and particulate matter less than 2.5 microns ($PM_{2.5}$) resulting from the simultaneous and instantaneous operation of HTGS Units 1, 2, and 3, the GT, the existing black start generators, the new CTs, and the new black start generators. The production scenario used in the assessment was based the maximum operating loads from all units while incorporating the operational limitations of the existing black start generators per NL Hydro's Certificate of Approval (AA22-065671). While it is extremely unlikely that all power generating sources modelled will operate at once, the assessment considers this the worst-case emissions scenario.

Pollutant emissions and associated exhaust flow parameters for the existing emission sources were based on the most recent stack testing data, while emissions for the new CTs and black start generators were based on manufacturer's data.

A meteorological dataset was generated for the assessment period 2021 to 2024 using the Weather Research and Forecasting Non-hydrostatic Mesoscale Model (WRF-NMM) that was run on a three (3) kilometre (km) horizontal resolution grid; 35,064 hours of meteorology in total. The outputs from WRF-NMM were used to generate hourly surface data files (containing wind speed, wind direction, temperature, cloud cover, etc.) as well as upper air profiles for seventeen (17) "pseudo" station locations within the CALMET modelling domain. The resulting "pseudo" observations were used to run the CALMET model within a 20 km by 20 km modelling domain having a fine horizontal grid resolution of 100 m to resolve local land features like Indian Pond. Using the outputs from CALMET, CALPUFF was then run using a nested receptor grid within the model domain.

The model results showed that maximum ground-level concentrations for all pollutants (NO_2, SO_2, CO, TPM, PM_{10} and $PM_{2.5}$) over all timeframes were below their respective provincial AQS for all averaging periods. The pollutant with the highest predicted concentration relative to its AQS is NO_2. The maximum predicted concentration of 1-hour NO_2 over the 4-year meteorological period was 398.0 ug/m^3 or 99% of the AQS, while the maximum predicted concentration of 24-hour NO_2 was 176.2 ug/m^3, or 88% of the AQS. The theoretical continual operation of the existing black start generators is the primary source of NO_2 concentrations being close to the associated AQS. The installation of the new CTs and associated black start generators contributed less than 0.05% to the maximum concentrations NO_2 concentrations.

For $PM_{2.5}$ the maximum 24-hour concentration reached 23.4 ug/m^3 over the four years of meteorological data, which compares to the AQS standard of 25 ug/m^3, representing 94% of the standard. The installation of the new CTs is the primary contribution to the maximum concentrations. Maximum PM_{10} and TPM concentrations were also primarily attributable to the installation of the new CTs but less than half of their respective AQS.

The 1-hour, 3-hour and 24-hour SO_2 concentrations reached 65%, 65% and 64% of their respective AQS. The operation of and the combustion of #6 oil in Units 1, 2 and 3 is the primary contributor to the maximum concentrations. At less than 1%, CO had the lowest predicted concentrations relative to the AQS.

Overall, the modelling assessment predicts that the emissions from ACT, when combined with the emissions from the existing facility, will be compliant with Newfoundland and Labrador Air Quality Standards outside the proposed administrative boundary.

TABLE OF CONTENTS

Page No.

LIST OF TABLES

LIST OF FIGURES

1.0 INTRODUCTION

Independent Environmental Consultants (IEC), a division of SEN-X Environmental Consultants Inc., and its subcontractor Weather2Umbrella Inc. (W2U) were retained by Newfoundland and Labrador Hydro (NL Hydro) to perform an environmental assessment of the atmospheric emissions from the proposed expansion of the Holyrood Thermal Generating Station (HTGS or the Facility). The HTGS is currently comprised of three (3) oil-fired thermal generators (Units 1, 2 and 3), a 123 MW diesel-fired gas turbine generator (the GT) and six (6) diesel-fired black start generators (each having a nominal rating of 2 MW). Together, the HTGS, GT and black start diesel generators comprise the existing power generating station at the Facility. To meet projected future demand and prepare for the retirement of the existing thermal generators, NL Hydro is proposing to install three (3) new combustion turbines (CTs) as well as install two (2) new black start diesel generators referred to as the Avalon Combustion Turbine (ACT) Project. The new black start generators would be used to fire up the new CTs and will not connected to the grid. Figure 1-1 shows the general location of the Facility and the location of the new CTs and black start generators.

An air dispersion modelling assessment was performed to assess the compliance of all existing and proposed power generation units at the Facility against Newfoundland and Labrador Air Quality Standards (AQS). Air dispersion modelling of the Facility was performed using the CALMET/CALPUFF modelling package to predict ground-level concentrations of nitrogen dioxide (NO_2), sulphur dioxide (SO_2), carbon monoxide (CO), total particulate matter (TPM), particulate matter less than 10 microns (PM_{10}), and particulate matter less than 2.5 microns ($PM_{2.5}$). To determine the potential impact of the generator emissions on local air quality, modelled concentrations were compared to the air quality standards (AQS) outlined in Schedule A of the *Air Pollution Control Regulation, 2022* (NLR 11/22). The applicable AQS are provided in Table 2-1.

The air dispersion modelling assessment and this report conform to the following documents published by the Newfoundland and Labrador Department of Environment and Climate Change:

- *Guideline for Plume Dispersion Modelling. GD-PPD-019.2*, Newfoundland & Labrador Department of Environment & Conservation (DOEC, 2012a); and
- *Determination of Compliance with the Ambient Air Quality Standards. GD-PPD-009.4*, Newfoundland & Labrador Department of Environment & Conservation (DOEC, 2012b).

Section 2.0 of this report provides a description of the Facility and the production/emissions scenarios modelled. The CALMET and CALPUFF methodologies are outlined in Section 3.0, and the results of the modelling assessment are summarized in Section 4.0. Finally, Section 5.0 presents the conclusions of the study.

Figure 1-1: Site Location Plan

Legend

- Proposed Administrative Boundary
- Legal Property Boundary
- Avalon Combustion Turbine

Notes

Image Source: Google Earth 2025

Independent Envrionmental Consultants

NL Hydro
Holyrood Thermal Generating Station
Figure 1-1
Site Location Plan

Project	Date
SX24-0031	March 2025

Table 1-1: Newfoundland and Labrador Air Quality Standards

Pollutant	Air Quality Standards (AQS)				
	1-hour	3-hour	8-hour	24-hour	Annual
SO_2	344 ppb (900 µg/m³)	229 ppb (600 µg/m³)	--	115 ppb (300 µg/m³)	23 ppb (60 µg/m³) [1]
TPM	--	--	--	120 µg/m³	60 µg/m³ [2] [3]
PM_{10}	--	--	--	50 µg/m³	--
$PM_{2.5}$	--	--	--	25 µg/m³	8.8 µg/m³ [1]
NO_2	213 ppb (400 µg/m³)	--	--	106 ppb (200 µg/m³)	53 ppb (100 µg/m³) [1]
CO	30582 ppb (35000 µg/m³)	--	13107 ppb (15000 µg/m³)	--	--

Source: AQS from Schedule A of *the Air Pollution Control Regulation, 2022* (NLR 11/22). Values in () are equivalencies for modelling purposes.
ppb: parts per billion
µg/m³: micrograms per cubic metre
Notes:
All AQS at reference conditions (25 C, 101.325 kPa)
[1] Arithmetic mean
[2] Geometric mean
[3] Per communication with the Department, the geometric mean AQS applies to discrete sampling only. The arithmetic mean applies otherwise.

2.0 FACILITY DESCRIPTION

For this assessment, the Facility consists of five distinct groups of power generation units:

- The main HTGS is comprised of two (2) oil-fired 175 MW units (Units 1 and 2) and one oil-fired 150 MW unit (Unit 3), each exhausting through their own independent stack. The fuel used in all three units is #6 fuel oil.
- The GT is a 123 MW diesel-fired gas turbine generator. The GT is in its own building southeast of the main HTGS units and exhausts through its own dedicated stack.
- Six (6) trailer-mounted black start diesel generators (each rated at 2 MW each), located together in the yard west of the GT building. Each unit exhausts to the atmosphere through its own stack.
- The proposed three (3) new diesel-fired 46.6 MW CTs are to the southeast of the existing GT near the access road. Each CT will exhaust through its own stack.
- The proposed two (2) new 2 MW black start generators are to be installed in the same building as the new CTs, but in the southern end. Each black start generator will exhaust through its own stack.

Further details about the Facility, including building and stack information, production scenarios, and emission rates are outlined below.

2.1 BUILDING AND STACK INFORMATION

A scaled general layout of the Facility is illustrated in Figure 2-1, which shows the main buildings/structures at the site, the locations of the modelled stacks, and the proposed administrative boundary. The BPIP-Prime building downwash calculations considered the main HTGS building, the GT building, large fuel tanks, the new CT buildings and other smaller structures including the diesel generator trailers. The locations and heights of each structure considered in BPIP-Prime including the corners and elevations of the structures are also summarized in Table 2-1.

Table 2-2 presents the stack parameters for the various sources as maximum load.

The power generation scenario used in the air dispersion modelling assessment was based on historical maximum production from 2021 to 2024 and manufacturer specifications as required. Specifically, the assessment considered the power generation as follows:

- Units 1, 2 and 3 all operate for every hour in January, February, March, and December;
- Units 1 and 2 additionally operate for every hour in April and November;
- Unit 1 operates for every hour in October;
- Unit 2 operates for every hour in May;
- All three HTGS Units are off-line for the entirety of June, July, August, and September;
- The existing GT operates for all hours of the year;
- The new CTs operate for all hours of the year;
- The new black starts operate for all hours of the year; and
- The existing black starts operate for all hours of the year, subject to the operational limitations defined in NL Hydro's Certificate of Approval (AA22-065671), specifically:

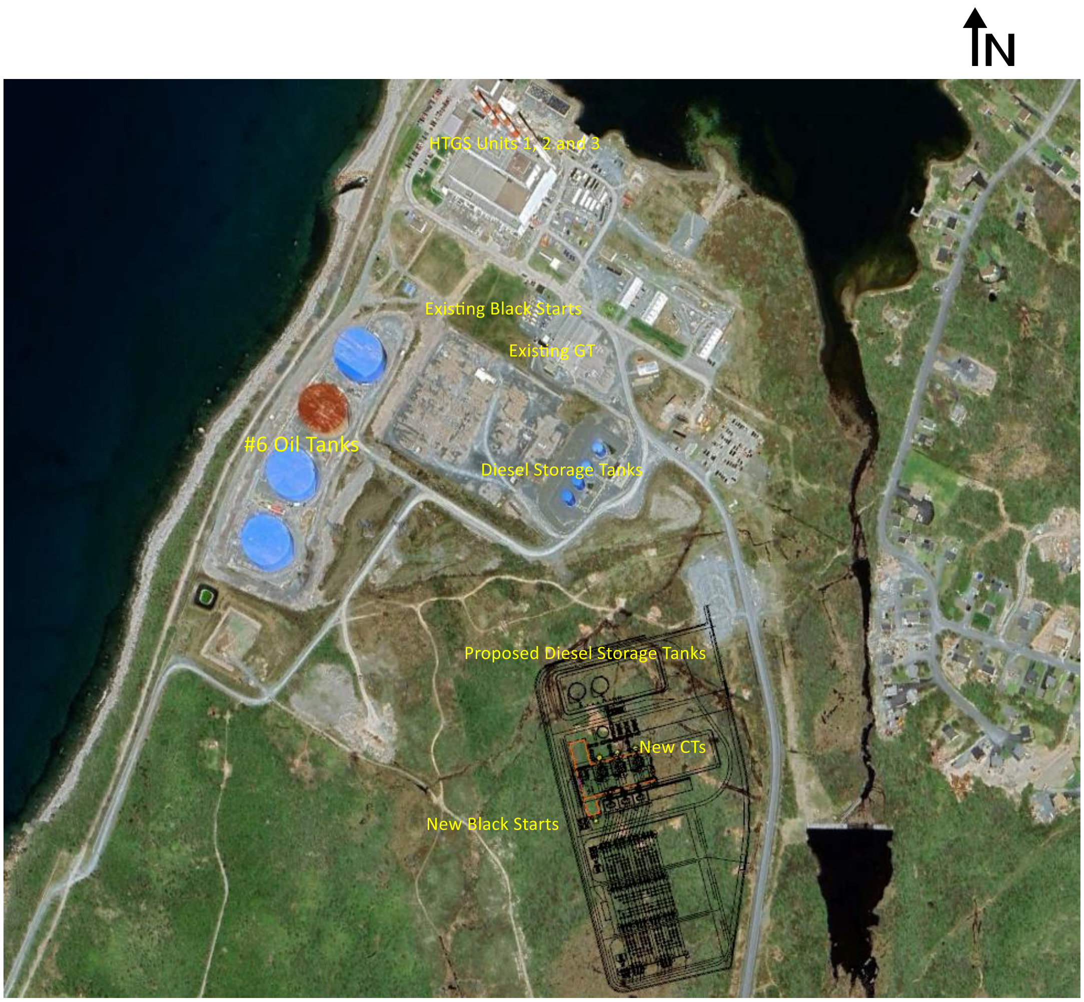
Diesel Generators

31. HYDRO shall operate no more than any five (5) of the six (6) diesel generators at **87% load** from **6:00 AM** to **10:00 AM** and from **4:00 PM** to **8:00 PM** to generate up to **8 MW** of power from ***November 1*** to ***April 30*** for peaking purposes.

32. HYDRO shall operate no more than any five (5) of the six (6) diesel generators at **67% load**, 24 hours a day, 365 days a year to generate up to **6 MW** of power for emergency purposes.

It is recognized that this modelling setup for the existing generation sources has never occurred and could only possibly occur in the event of the simultaneous catastrophic failure of other generation sources and/or transmission infrastructure within the network during the highest demand period, and during the transition period when the new CTs are coming on-line and the old HTGS Units are being decommissioned. As such, this modelling setup is considered to be very conservative.

Figure 2-1: General Site Layout



Legend

Notes

Image Source: Google Earth 2025

Independent Envrionmental Consultants

NL Hydro
Holyrood Thermal Generating Station

Figure 2-1

General Site Layout

Project	Date
SX24-0031	March 2025

Table 2-1: Building Information for BPIP-Prime

Building	Corners	UTM Easting (m)	UTM Northing (m)	Base Elevation (m)	Height Above Grade (m)
HTGS Main Powerhouse	1	341804	5257645	10.00	15.24
	2	341847	5257712		
	3	341942	5257650		
	4	341898	5257584		
	1	341826	5257643		23.47
	2	341864	5257701		
	3	341942	5257650		
	4	341904	5257592		
	1	341826	5257643		28.96
	2	341858	5257692		
	3	341936	5257641		
	4	341904	5257592		
	1	341844	5257670		44.50
	2	341858	5257692		
	3	341930	5257645		
	4	341916	5257623		
Fuel Oil Tank #1	1	341726	5257485	15.95	14.60
	2	341706	5257477		
	3	341698	5257458		
	4	341706	5257438		
	5	341726	5257430		
	6	341745	5257438		
	7	341753	5257458		
	8	341745	5257477		
Fuel Oil Tank #2	1	341684	5257424	15.95	14.70
	2	341665	5257416		
	3	341657	5257397		
	4	341665	5257377		
	5	341684	5257369		
	6	341704	5257377		
	7	341712	5257397		
	8	341704	5257416		
Fuel Oil Tank #3	1	341647	5257354	16.04	14.60
	2	341627	5257346		
	3	341619	5257326		
	4	341627	5257307		
	5	341647	5257299		
	6	341666	5257307		
	7	341674	5257326		
	8	341666	5257346		
Fuel Oil Tank #4	1	341615	5257280	16.05	14.60
	2	341595	5257272		
	3	341587	5257252		
	4	341595	5257233		
	5	341615	5257224		
	6	341635	5257233		

Building	Corners	UTM Easting (m)	UTM Northing (m)	Base Elevation (m)	Height Above Grade (m)
	7	341643	5257252		
	8	341635	5257272		
GT Fuel Tank #1	1	341989	5257334	13.00	10.00
	2	341991	5257338		
	3	341990	5257343		
	4	341986	5257346		
	5	341981	5257345		
	6	341978	5257340		
	7	341979	5257335		
	8	341983	5257333		
GT Fuel Tank #2	1	341976	5257313	13.00	10.00
	2	341979	5257317		
	3	341977	5257322		
	4	341973	5257325		
	5	341968	5257324		
	6	341966	5257319		
	7	341967	5257314		
	8	341971	5257312		
GT Fuel Tank #3	1	341965	5257296	13.00	10.00
	2	341968	5257300		
	3	341966	5257305		
	4	341962	5257308		
	5	341957	5257307		
	6	341955	5257303		
	7	341956	5257297		
	8	341960	5257295		
GT Fuel Tank #4	1	341953	5257279	13.00	10.00
	2	341955	5257283		
	3	341954	5257288		
	4	341950	5257291		
	5	341945	5257290		
	6	341942	5257285		
	7	341943	5257280		
	8	341948	5257278		
Gas Turbine Generator Building	1	341957	5257490	13.00	10.67
	2	341926	5257444		
	3	341953	5257426		
	4	341983	5257472		
	1	341934	5257424		10.67
	2	341934	5257431		
	3	341938	5257432		
	4	341940	5257435		
	5	341935	5257438		
	6	341933	5257436		
	7	341932	5257437		
	8	341928	5257437		
	9	341924	5257431		

Building	Corners	UTM Easting (m)	UTM Northing (m)	Base Elevation (m)	Height Above Grade (m)
Diesel Generator Trailer #1	1	341918	5257485	13.00	4.27
	2	341917	5257482		
	3	341907	5257489		
	4	341908	5257491		
Diesel Generator Trailer #2	1	341920	5257489	13.00	4.27
	2	341918	5257487		
	3	341908	5257493		
	4	341910	5257495		
Diesel Generator Trailer #3	1	341921	5257494	13.00	4.27
	2	341919	5257492		
	3	341910	5257498		
	4	341911	5257500		
Diesel Generator Trailer #4	1	341922	5257499	13.00	4.27
	2	341921	5257497		
	3	341911	5257503		
	4	341912	5257505		
Diesel Generator Trailer #5	1	341924	5257504	13.00	4.27
	2	341922	5257501		
	3	341912	5257508		
	4	341913	5257510		
Diesel Generator Trailer #6	1	341925	5257509	13.00	4.27
	2	341924	5257507		
	3	341914	5257513		
	4	341915	5257515		
Diesel Generator Fuel Tank	1	341922	5257516	13.00	3.15
	2	341921	5257513		
	3	341931	5257507		
	4	341932	5257510		
New CT Powerhouse	1	342033	5257000	16.00	13.78
	2	342041	5256966		
	3	341973	5256950		
	4	341977	5256930		
	5	341964	5256927		
	6	341951	5256981		
CT Aux Building	1	341962	5257014	16.00	18.66
	2	341968	5256985		
	3	341951	5256981		
	4	341945	5257010		
CT1 Cooling	1	341975	5256980	16.00	17.38
	2	341977	5256971		
	3	341988	5256973		
	4	341986	5256983		
CT2 Cooling	1	341996	5256985	16.00	17.38
	2	341998	5256976		
	3	342009	5256978		
	4	342007	5256988		
CT3 Cooling	1	342016	5256990	16.00	17.38

Building	Corners	UTM Easting (m)	UTM Northing (m)	Base Elevation (m)	Height Above Grade (m)
	2	342018	5256980		
	3	342029	5256983		
	4	342027	5256992		
New Fuel Tank 1	1	341981	5257083	16.00	21.32
	2	341987	5257081		
	3	341990	5257076		
	4	341989	5257070		
	5	341984	5257066		
	6	341978	5257066		
	7	341974	5257070		
	8	341972	5257076		
	9	341976	5257081		
New Fuel Tank 2	1	341955	5257077	16.00	21.32
	2	341961	5257075		
	3	341964	5257070		
	4	341963	5257064		
	5	341958	5257060		
	6	341952	5257060		
	7	341947	5257064		
	8	341946	5257070		
	9	341949	5257075		
New Water Tank	1	341983	5257027	16.00	14.04
	2	341987	5257026		
	3	341989	5257022		
	4	341988	5257018		
	5	341985	5257015		
	6	341981	5257015		
	7	341978	5257018		
	8	341977	5257022		
	9	341979	5257026		

Table 2-2: Stack Parameters at Maximum Production

Generator Unit	Capacity (MW)	UTM Easting (m)	UTM Northing (m)	Base Elevation (m)	Stack Height Above Grade (m)	Stack Diameter (m)	Average Stack Temperature (K)	Average Exhaust Flow Rate (m^3/min)
HTGS Unit 1	175	341882	5257701	10	91.44	4.115	469.4	20,188
HTGS Unit 2	175	341904	5257687	10	91.44	4.115	515.1	25,535
HTGS Unit 3	150	341934	5257668	10	109.72	3.048	463.4	21,890
GT	123	341926	5257454	13	15.24	4.404	761.8	65,596
Black Start Diesel Generators	2.0	341916	5257485	13	12.18	0.406	660.9	359
	2.0	341917	5257490	13	12.18	0.406	660.9	359
	2.0	341918	5257495	13	12.18	0.406	660.9	359
	2.0	341920	5257499	13	12.18	0.406	660.9	359
	2.0	341921	5257504	13	12.18	0.406	660.9	359
	2.0	341922	5257509	13	12.18	0.406	660.9	359
New CT1	46.6	341977	5256994	16	29.35	3.000	728.3	15,501
New CT2	46.6	341998	5256999	16	29.35	3.000	728.3	15,501
New CT3	46.6	342018	5257004	16	29.35	3.000	728.3	15,501
New Black Start 1	2.0	341970.5	5256922.9	16	28.05	0.910	660.9	462
New Black Start 2	2.0	341971.9	5259923.2	16	28.05	0.910	660.9	462

2.2 AIR EMISSIONS

For this assessment, air emissions for SO_2, NO, NO_2, CO, TPM, PM_{10} and $PM_{2.5}$ were derived. For Units 1, 2 and 3, as well as the GT, the maximum rates from the previous 2017 to 2020 compliance modelling report were used (IEC, 2022). For the existing black starts, the emissions were as per the 2017 to 2020 compliance modelling and applied to the new black starts. For the new CTs, engineering design specifications were used assuming 100% load.

The speciation of NO_x into NO and NO_2 is required when using the RIVAD / I ISORROPIA option in CALPUFF. For the existing emission sources where stack sampling has been historically completed, the emissions of NO and NO_2 were taken directly from the stack sampling report. For all other sources, the emissions of NO_2 and NO were based on a molar NO_2/NO_x ratio of 10%, as advised by the DOECC (personal communication with Government official, January 2017) and calculated as follows:

$NO_2 = NOx \times 10\%$

and

$NO = (NO_x - NO_2) \times (MW\ of\ NO \div MW\ of\ NO_2) = (NO_x - NO_2) \times (30 \div 46)$

where:

MW = molecular weight in g/mol.

Table 2-3 provides the summary of emissions used in the dispersion modelling.

Table 2-3: Stack Emission Rates at Maximum Production

Source	Emission Rates (g/s)						
	SO_2	NO	NO_2	CO	TPM	PM_{10}	$PM_{2.5}$
HTGS Unit #1	131.02	31.19	0.60	0.45	13.30	9.95	9.17
HTGS Unit #2	145.67	29.08	0.45	1.58	11.38	5.55	4.81
HTGS Unit #3	135.90	63.95	3.11	4.25	9.42	6.18	5.59
GT	0.61	13.95	2.67	9.54	6.22	5.17	2.89
Existing Black Starts	0.0034	2.64	0.45	0.36	0.028	0.028	0.028
New CTs	0.09	4.80	0.25	3.06	1.75	1.75	1.75
New Black Starts	0.0034	2.64	0.45	0.36	0.028	0.028	0.028

3.0 MODELLING METHODOLOGY

3.1 Model Selection

The CALMET/CALPUFF modelling system is the preferred regulatory model in Newfoundland and Labrador. At the request of the DOECC, Version 7.0 of the CALMET and CALPUFF models were used. CALMET is a meteorological model that produces hourly, three-dimensional (3-D) gridded wind fields from available meteorological, terrain and land use data. CALPUFF is a non-steady state puff dispersion model that utilizes the CALMET wind fields and accounts for spatial changes in meteorology, variable surface conditions, and plume interactions with terrain. CALPUFF can handle both simple and complex terrain.

The Facility is in an area with complex terrain and is near the shoreline of Conception Bay, Newfoundland, emphasizing the need to use CALPUFF to resolve these features.

3.2 CALMET

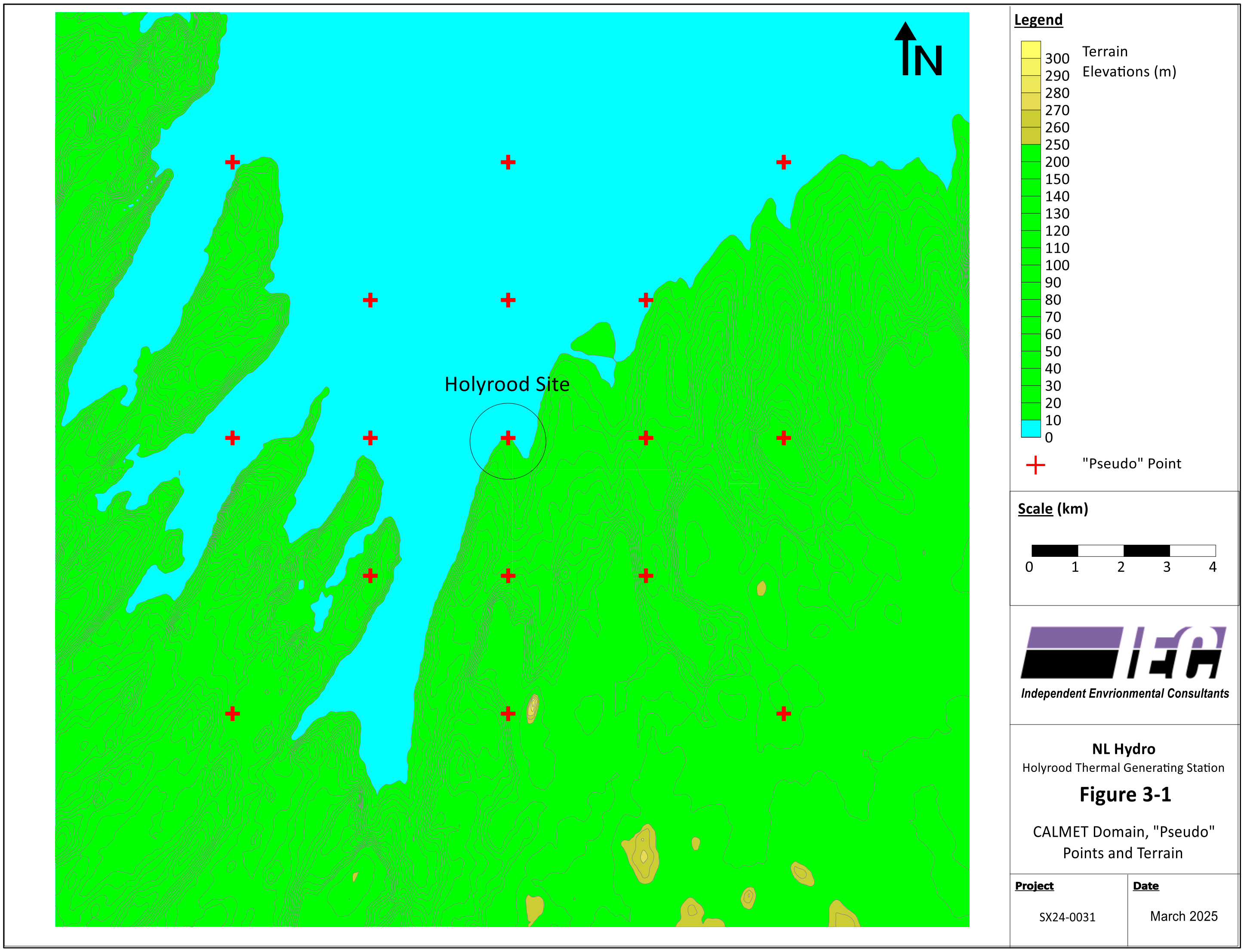
The CALMET model was used to develop hourly meteorological data fields to use in CALPUFF. Four (4) years of meteorological data (35,064 hours) were developed covering the period 2021 to 2024. The CALMET model was run over a large 20 km by 20 km modelling domain having a fine horizontal grid spacing of 100 m to resolve local land features like Indian Pond. Figure 3-1 shows the CALMET modelling domain.

The outputs from the CALMET model were used to capture the regional wind flow pattern and were used as the inputs into CALPUFF's air dispersion calculations. Ten (10) vertical layers were included for the wind field. The layer heights are shown in Table 3-1.

Table 3-1: CALMET Wind Field Layer Heights

Vertical Height of Layer (m)	Layer Height of Top (m)	Notes
20	20	10-meter meteorology
20	40	30-meter meteorology
40	80	
80	160	
140	300	
300	600	
400	1,000	
500	1,500	
700	2,200	
800	3,000	

Figure 3-1: CALMET Domain, "Pseudo" Points and Terrain Contours



3.2.1 Meteorology

As outlined in provincial modelling guidance (DOEC, 2012a), CALMET can accept inputs from mesoscale meteorological models. The mesoscale model outputs can be directly applied to CALMET or used to generate hourly surface and upper air data. The latter approach was used for this assessment. The mesoscale model used was the Weather Research and Forecasting Non-hydrostatic Mesoscale Model (WRF-NMM). WRF-NMM was initialized using archived Global Model analysis wind fields produced by the National Center for Environmental Prediction (NCEP). The Global analysis data is generated every 6 hours over a 30 km by 30 km grid and is based on all available surface and upper air observations. The WRF-NMM modelling was used to cover a large area with a horizontal resolution of approximately 3 km by 3 km. Additional details about the WRF-NMM model are available under separate cover (IEC, 2016).

The output from the WRF-NMM model was used to generate hourly surface data (wind speed, wind direction, temperature, cloud cover, etc.) in CD-144 format at 17 "pseudo" stations, as well as upper air profiles at the same locations. The locations of the 17 pseudo stations are shown in Figure 3-1.

3.2.2 Terrain Data

Terrain data inputs for CALMET were processed through the TERREL program. TERREL is a pre-processor program provided with the CALMET/CALPUFF modelling system that accepts surface elevation data in a variety of formats to produce grid-cell averaged terrain files for use in the MAKEGEO processor. For this modelling assessment, Canadian Digital Elevation Model (CDED) files were used. CDED files are available online from the Government of Canada (http://maps.canada.ca/czs/index-en.html).

The resulting gridded terrain file produced by TERREL is presented graphically in Figure 3-1. The outputs from TERREL were also used to assign ground elevations to the receptors, emission sources and buildings used in CALPUFF (see Section 3.3.1).

3.2.3 Land Use Data

Gridded land use classifications were provided by the DOECC for the CALMET meteorological domain. This land use data was further edited by recoding small inland water bodies (land use code 51) and large water bodies or (i.e., the ocean or land use code 55) to reflect times of the year when the water bodies are covered in ice. For such periods, the land use classification was changed to 90 (perennial snow or ice). Periods with sea ice were classified using Multisensor Analyzed Sea Ice Extent (MASIE) data available from the National Ice Data Centre (NIC) (NIC and NSIDC, 2010). MASIE products include image files showing sea ice over the entire Northern Hemisphere with 16 separate Arctic regions identified. The input data comes from the 1 km and 4 km Interactive Multisensor Snow and Ice Mapping System (IMS) snow and ice product produced by the NIC. NIC utilizes visible imagery, passive microwave data, and NIC weekly analysis products to create their data product.

The different periods used to generate the CALMET land use files are outlined in Table 3-2, while the surface parameters used in CALMET are provided in the modelling guidance (DOEC, 2012a). However, the surface parameters are reproduced in Table 3-3 for completeness.

The resulting gridded land use file produced by MAKEGEO for the 'non-winter' and 'winter without snow' period is provided in Figure 3-2, while the land use file for the 'winter with snow' period is provided in Figure 3-3.

Table 3-2: Seasonal Land Use Periods used in CALMET

Season	Julian Days			
	2021	2022	2023	2024 [1]
Non-winter	136-304	136-304	136-304	137-305
Winter **without** snow	91-135 and 305-365	91-135 and 305-365	91-135 and 305-365	92-136 and 306-366
Winter **with** snow	1-90	1-90	1-90	1-91
Frozen Ocean	Not frozen	Not frozen	Not frozen	Not frozen
Frozen Lakes	1-82 and 350-365	1-87	1-102	1-70

Notes:
[1] Leap year with 366 days

Table 3-3: Season Land Use Parameters

Non-Winter [1]							
Input Land Use Category	**z_0 (m)**	**Albedo**	**Bowen Ratio**	**Soil Heat Flux Parameter**	**Anthropogenic Heat Flux (W/m²)**	**Leaf Area Index**	**Output Category ID**
31 - Herbaceous Rangeland	0.05	0.25	1.0	0.15	0.0	0.5	30
32 - Shrub and Brush Rangeland	0.05	0.25	1.0	0.15	0.0	0.5	30
41 - Deciduous Forest Land	1.0	0.1	1.0	0.15	0.0	7.0	40
42 - Evergreen Forest Land	1.0	0.1	1.0	0.15	0.0	7.0	40
43 - Mixed Forest Land	1.0	0.1	1.0	0.15	0.0	7.0	40
51 - Fresh Water	0.001	0.1	0.0	1.0	0.0	0.0	51
55 - Salt Water	0.001	0.1	0.0	1.0	0.0	0.0	55
61 - Forested Wetland	1.0	0.1	0.5	0.25	0.0	2.0	61
62 - Non-forested Wetland	0.2	0.1	0.1	0.25	0.0	1.0	62
74 - Bare Exposed Rock	0.05	0.3	1.0	0.15	0.0	0.05	70
77 - Mixed Barren Land	0.05	0.3	1.0	0.15	0.0	0.05	70
81 - Shrub and Brush Tundra	0.2	0.3	0.5	0.15	0.0	0.0	80
82 - Herbaceous Tundra	0.2	0.3	0.5	0.15	0.0	0.0	80
90 - Perennial Snow or Ice	0.05	0.7	0.5	0.15	0.0	0.0	90

Winter with Snow Cover [1]							
Input Land Use Category	**z_0 (m)**	**Albedo**	**Bowen Ratio**	**Soil Heat Flux Parameter**	**Anthropogenic Heat Flux (W/m²)**	**Leaf Area Index**	**Output Category ID**
31 - Herbaceous Rangeland	0.005	0.7	0.5	0.15	0.0	0.5	30
32 - Shrub and Brush Rangeland	0.005	0.7	0.5	0.15	0.0	0.5	30
41 - Deciduous Forest Land	0.5	0.5	0.5	0.15	0.0	0.0	40
42 - Evergreen Forest Land	1.3	0.35	0.5	0.15	0.0	7.0	40
43 - Mixed Forest Land	0.9	0.42	0.5	0.15	0.0	3.5	40
51 - Fresh Water	0.001	0.7	0.5	0.15	0.0	0.0	51
55 - Salt Water	0.001	0.7	0.5	0.15	0.0	0.0	55
61 - Forested Wetland	0.5	0.3	0.5	0.15	0.0	0.0	61
62 - Non-forested Wetland	0.2	0.6	0.5	0.15	0.0	0.0	62
74 - Bare Exposed Rock	0.002	0.7	0.5	0.15	0.0	0.0	70
77 - Mixed Barren Land	0.002	0.7	0.5	0.15	0.0	0.0	70
81 - Shrub and Brush Tundra	0.005	0.7	0.5	0.15	0.0	0.0	80
82 - Herbaceous Tundra	0.005	0.7	0.5	0.15	0.0	0.0	80
90 - Perennial Snow or Ice	0.05	0.7	0.5	0.15	0.0	0.0	90

Winter without Snow Cover [1]							
Input Land Use Category	**z_0 (m)**	**Albedo**	**Bowen Ratio**	**Soil Heat Flux Parameter**	**Anthropogenic Heat Flux (W/m²)**	**Leaf Area Index**	**Output Category ID**
31 - Herbaceous Rangeland	0.01	0.20	1.0	0.15	0.0	0.5	30
32 - Shrub and Brush Rangeland	0.01	0.20	1.0	0.15	0.0	0.5	30
41 - Deciduous Forest Land	0.6	0.17	1.0	0.15	0.0	7.0	40
42 - Evergreen Forest Land	1.3	0.12	0.8	0.15	0.0	7.0	40
43 - Mixed Forest Land	0.95	0.14	0.9	0.15	0.0	7.0	40
51 - Fresh Water	0.001	0.10	0.0	1.0	0.0	0.0	51
55 - Salt Water	0.001	0.10	0.0	1.0	0.0	0.0	51
61 - Forested Wetland	0.6	0.14	0.3	0.25	0.0	2.0	61
62 - Non-forested Wetland	0.2	0.14	0.1	0.25	0.0	1.0	62
74 - Bare Exposed Rock	0.05	0.20	1.5	0.15	0.0	0.05	70
77 - Mixed Barren Land	0.05	0.20	1.5	0.15	0.0	0.05	70
81 - Shrub and Brush Tundra	0.100	0.20	1.0	0.15	0.0	0.0	80
82 - Herbaceous Tundra	0.1	0.20	1.0	0.15	0.0	0.0	80
90 - Perennial Snow or Ice	0.002	0.70	0.50	0.15	0.0	0.0	90

Notes:
For periods used in CALMET, see Table 3-2.

Figure 3-2: CALMET Land Use (Non-Winter and Winter Without Snow)

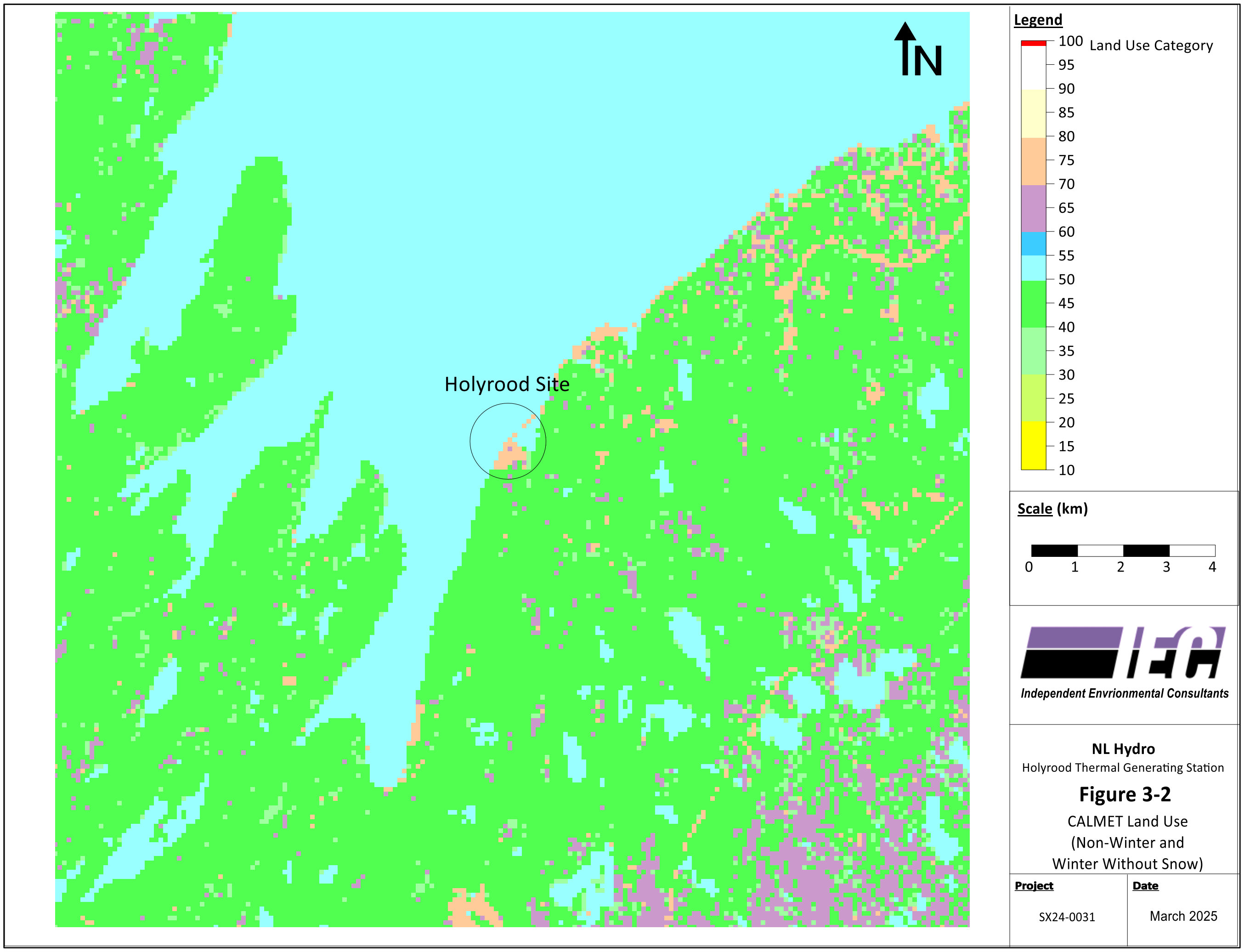
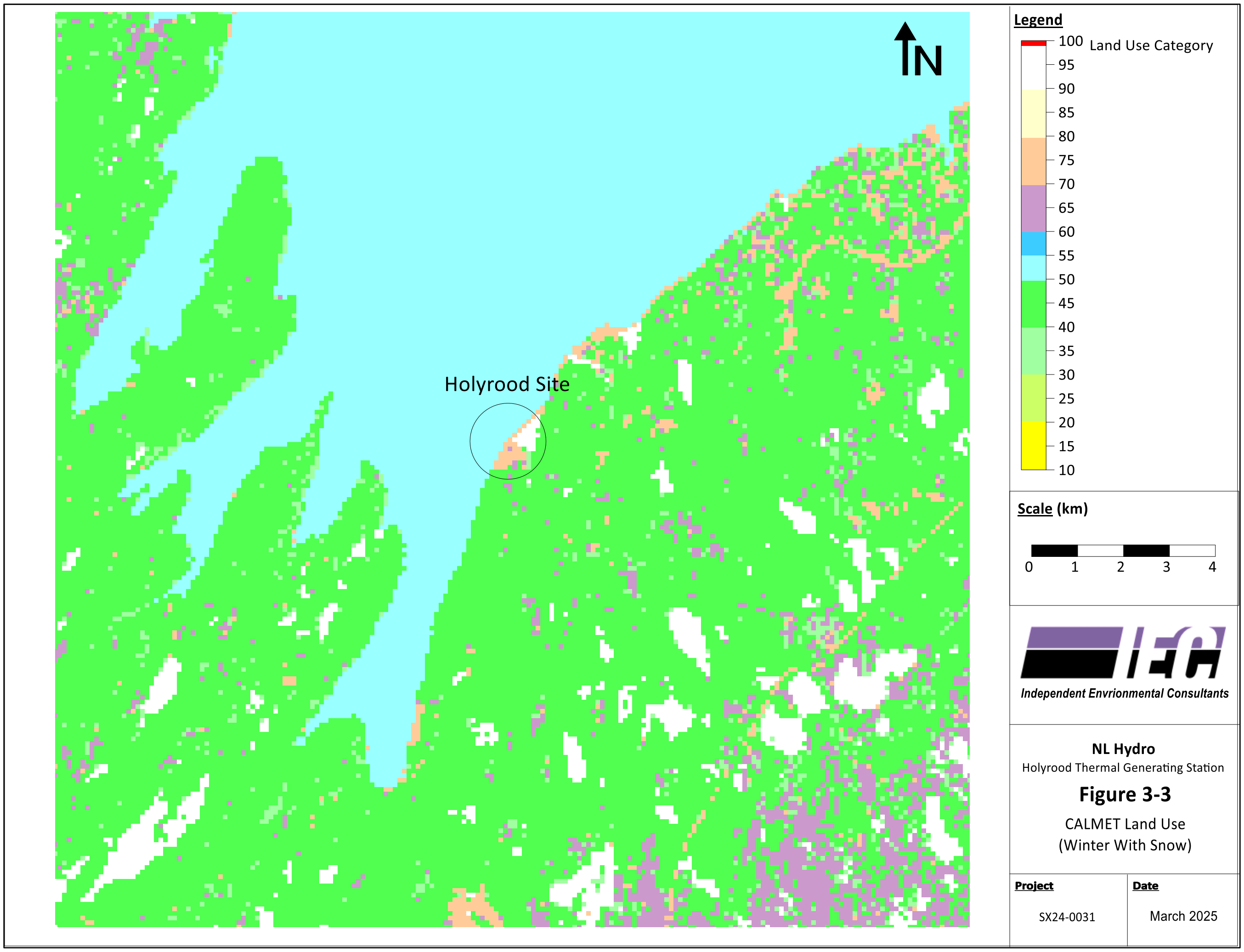


Figure 3-3: CALMET Land Use (Winter with Snow)



3.2.4 CALMET Options

Provincial modelling guidance (DOEC, 2012a) was followed when selecting the appropriate CALMET options. The main CALMET options used are summarized in Table 3-4.

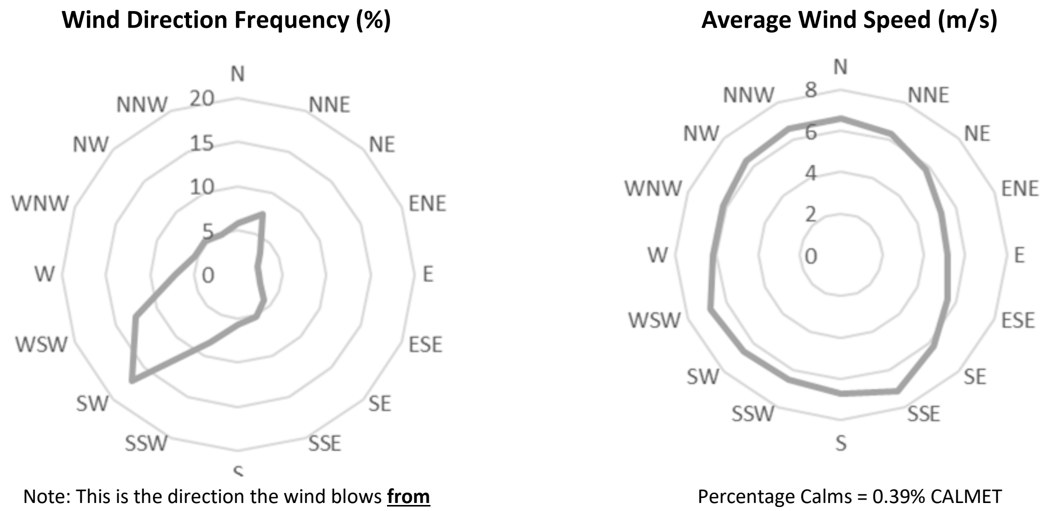
Table 3-4: CALMET Options

CALMET Option	Selected Option	Explanation
No. of Vertical Layers	NZ = 10	10 vertical layers used: 0, 20, 40, 80, 160, 300, 600, 1000, 1500, 2200, 3000 m
No Observation Mode	NOOBS = 0	Use surface, overwater, or upper air observations
Method to compute cloud fields	ICLOUD = 0	Gridded clouds not used
Use varying radius of influence	LVARY = T	Use varying radius of influence
Maximum radius of influence over land in the surface layer	RMAX1 = 5	Maximum radius of influence of surface stations over land is 5 km
Maximum radius of influence over land in the layer aloft	RMAX2 = 5	Maximum radius of influence of upper air stations over land is 5 km
Maximum radius of influence over water	RMAX3 = 5	Maximum radius of influence of upper air stations over water is 5 km
Minimum radius of influence used in the wind field interpolation	RMIN= 0.1	Minimum radius of influence of stations is 0.1 km
Radius of influence of terrain features	TERRAD = 1 (No default)	Terrain effects are considered up to 1 km for each grid point
Relative weighting of the first guess field and observations in the surface layer	R1 = 1	Weighting used for surface layer is 1km
Relative weighting of the first guess field and observations in the layers aloft	R2 = 1	Weighting used for layers aloft is 1 km
Surface met. station to use for the surface temperature	ISURFT = -1	Use 2-D spatially varying surface temperatures
Option for overwater lapse rates used in convective mixing height growth	ITWPROG = 0	Use SEA.DAT lapse rates and deltaT (or assume neutral conditions if missing)
3D relative humidity from observations or from prognostic data	IRHPROG = 0	Use RH from SURF.DAT file
3D temperature from observations or from prognostic data	ITPROG = 0	Use Surface and upper air stations
Land use categories for temperature interpolation over water	JWAT1 = 999 JWAT2 = 999	Temperature interpolation disabled using 999

3.2.5 CALMET Results

Wind direction frequencies and the average wind speed (by direction) generated by CALMET are presented as a wind rose in Figure 3-4 for a grid point near the Facility. For the 2021 to 2024 modelling period, the most frequent wind direction is southwest (17.0% of the time), and the average wind speed is 6.3 m/s.

Figure 3-4: WRF-NMM and CALMET Wind Rose near HTGS, 2021-2024



Observations collected at a nearby weather station were not available for comparison. However, validation of WRF-NMM has been completed for several airport weather stations throughout Newfoundland and Labrador (IEC, 2016). Overall, WRF-NMM shows good performance; therefore, there is less uncertainty in the dispersion modelling, meaning that predicted CALPUFF concentrations are likely to be more realistic.

As a second measure of model performance, Figure 3-5 shows the daily profile of mixing heights for a CALMET grid point near the Facility. For each modelling year, the Figure demonstrates a typical mixing height profile, which shows how the height grows after sunrise and collapses after sunset. Similarly, Figure 3-6 presents the average temperature daily profiles by the year for 2021 through 2024. These profiles provide further confirmation that CALMET can reproduce the physical parameters that are important for air dispersion modelling.

Figure 3-5: Daily Mixing Height Profiles near HTGS from CALMET, 2021 to 2024

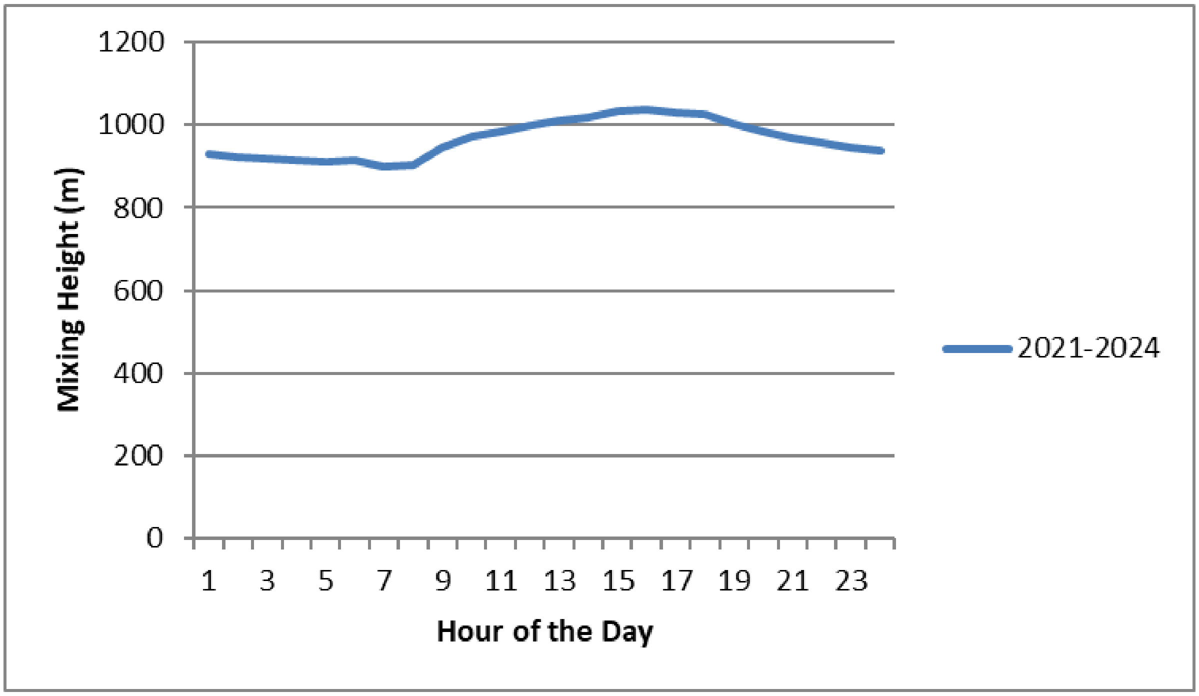
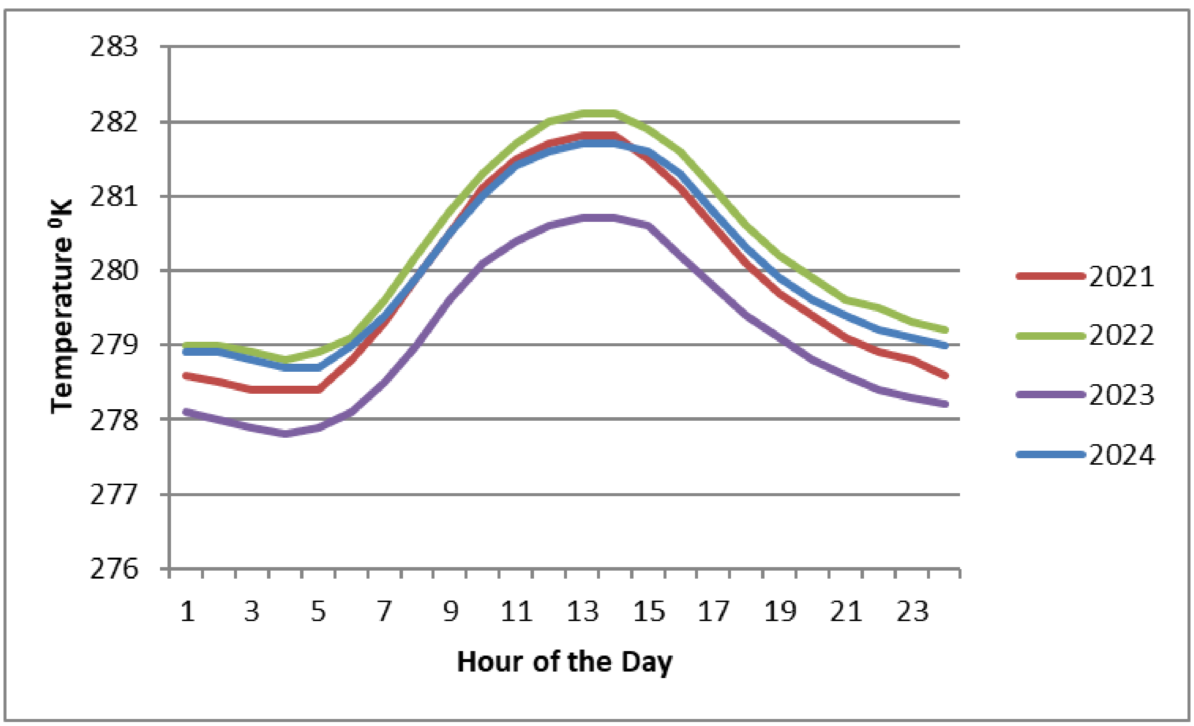


Figure 3-6: Daily Temperature Profiles near HTGS from CALMET, 2021 to 2024



3.3 CALPUFF

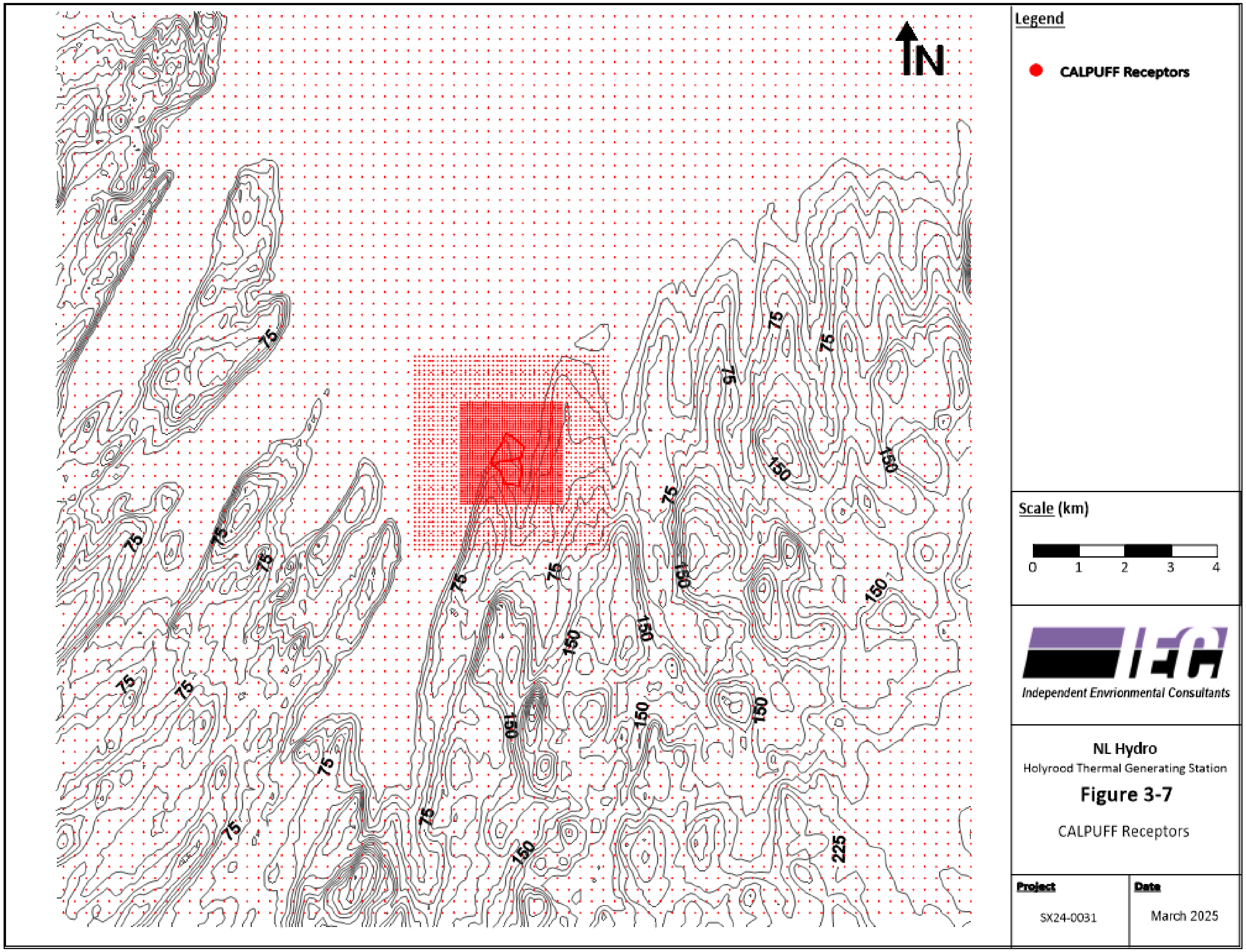
3.3.1 Modelling Domain and Receptor Grid

A modelling domain of approximately 20 km by 20 km was used in the CALPUFF model runs. Receptors were chosen based on recommendations provided in the modelling guidance (DOEC, 2012a) based on proximity to residential areas. Specifically, a nested receptor grid, centered on the Facility, was placed as follows:

- 50 m spacing within 1 km of the proposed administrative boundary;
- 100 m spacing within all areas located between 1 km and 2 km of the proposed administrative boundary; and
- 250 m spacing within all areas located beyond 2 km from the proposed administrative boundary.

In addition, discrete receptors were placed, at a maximum, every 20 m along the proposed administrative boundary. The full receptor grid contains 9,777 receptors and is illustrated in Figure 3-7.

Figure 3-7: CALPUFF Receptors



3.3.2 Building Downwash

The effects of building wake on plume rise and dispersion were considered in the modelling assessment. Building dimensions and stack heights were processed with the Building Profile Input Program (BPIP) to generate the characteristic dimensions required by CALPUFF's PRIME building wake sub-model. As discussed in Section2.1 , the existing and proposed HTGS and GT buildings, the black start diesel generator enclosures and various fuel tanks were considered in the PRIME sub-model. The corners, heights and elevations of the buildings/structures were provided previously in Table 2-1.

3.3.3 CALPUFF Options

Provincial modelling guidance (DOEC, 2012a) was followed when selecting the appropriate CALPUFF options. The options used in this assessment are presented in Table 3-5.

Table 3-5: CALPUFF Options

Parameter	Name of parameter and interpretation	Default value	Selected value	Selected value interpretation
NSE	Number of emitted species	3	7	Emitted species (7)
NSPEC	Number of chemical species	5	10	Emitted species and species implicated in chemical transformations (10)
MBDW	Method used to simulate building downwash	1	2	PRIME method
MSPLIT	Puff splitting allowed	0	1	Yes
MCHEM	Chemical mechanism	1	6	Updated RIVAD scheme with ISORROPIA equilibrium
MAQCHEM	Aqueous phase transformation	0	1	Transformation rates and wet scavenging coefficients adjusted for in-cloud aqueous phase reactions
MLWC	Liquid water content	1	0	Water content estimated from cloud cover and presence of precipitation
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
MOZ	Ozone data input option	1	0	Monthly background value
MH2O2	H2O2 data input option	1	0	Monthly background value
NINT	Number of particle size intervals	9	5	Used to evaluate effective particle deposition velocity

3.3.4 Chemical Characteristics of Modelled Species

As required by provincial modelling guidance (DOEC, 2012a), the RIVAD/ISORROPIA chemical mechanism, inclusive of wet and dry deposition of particles as gases, was modelled. This mechanism requires a special sequence of pollutants: SO_2, SO_4, NO, NO_2, HNO_3 and NO_3; however, none of the generators emit SO_4, HNO_3 or NO_3.

The dry and wet deposition parameters used were based on modelling guidance (DOEC, 2012a) and are presented in Table 3-6 (dry deposition parameters for particles), Table 3-7 (dry deposition parameters for gases), and

Table 3-8 (wet deposition parameters). Background concentrations of ozone (O_3), ammonia (NH_3), and hydrogen peroxide (H_2O_2) are required for the RIVAD/ISORROPIA chemical mechanism. In the absence of local monitoring data, default data from the modelling guide (DOEC, 2012a) was used, which is summarized in

Table 3-9. The exception is ozone data, which was provided by the DOECC for Eastern Newfoundland (e-mail communication with DOECC, November 2021).

Table 3-6: Dry Deposition Parameters for Particle Species

Species	Geometric Mass Mean Diameter (µm)	Geometric Standard Deviation (µm)
SO_4	0.48	2
NO_3	0.48	2
P1 (d < 2.5 µm)	1.25	1.242

Table 3-7: Dry Deposition Parameters for Gaseous Species

Species	Diffusivity (cm^2/s)	Alpha Star	Reactivity	Mesophyllic Resistance	Henry's Law Coefficient
SO_2	0.1509	1000	8	0	0.04
NO	0.1345	1	2	25	18
NO_2	0.1656	1	8	5	3.5
HNO_3	0.1628	1	18	0	8.0E-08
CO	0.186	1	2	61	44

Table 3-8: Wet Deposition Parameters for Modelling Species

Species	Scavenging Coefficient	
	Liquid Precipitation	Frozen Precipitation
SO_2	3.0E-05	0
SO_4	1.0E-04	3.0E-05
NO	0	0
NO_2	0	0
HNO_3	6.0E-05	0
NO_3	1.0E-04	3.0E-05
P1 (d < 2.5 µm)	1.0E-04	3.0E-05
CO	0	0

Table 3-9: Monthly Background Concentrations of O_3, NH_3, and H_2O_2

Month	Ozone (O_3) (ppb)	Ammonia (NH_3) (ppb)	Hydrogen Peroxide (H_2O_2) (ppb)
January	28	0.5	0.2
February	31	0.5	0.2
March	33	0.5	0.2
April	32	0.5	0.2
May	26	0.5	0.2
June	20	0.5	0.2
July	18	0.5	0.2
August	17	0.5	0.2
September	17	0.5	0.2
October	20	0.5	0.2
November	25	0.5	0.2
December	30	0.5	0.2

4.0 MODELLING RESULTS

The following sections outline the results of the air dispersion modelling assessment in accordance with section 5 of the *Plume Dispersion Modelling Guideline* (DOEC, 2012a). Compliance is assessed in Section 4.1, which compares the maximum predicted concentrations outside of the proposed administrative boundary to applicable air quality standards. As stated in provincial guidance for the determination of compliance (DOEC, 2012b), meteorological anomalies may result in the over prediction of modelled concentrations. As a result, compliance for each modelled year is based on the following:

- 9^{th} highest level at any given receptor for a 1-hour averaging period,
- 6^{th} highest level at any given receptor for a 3-hour averaging period,
- 3^{rd} highest level at any given receptor for an 8-hour averaging period,
- 2^{nd} highest level at any given receptor for a 24-hour averaging period, and
- 1^{st} highest level at any given receptor for an annual averaging period.

Background concentrations were not added to the predicted concentrations, and modelled results were directly compared to the air quality standards.

4.1 MAXIMUM PREDICTED CONCENTRATIONS

Table 4-1 and Table 4-2 provide the maximum predicted concentrations of NO_2, SO_2, CO, TPM, PM_{10}, and $PM_{2.5}$ for the modelled year (2021 to 2024) for all sources. As can be seen in the Tables, the maximum ground-level concentrations for all pollutants and averaging periods were predicted to be below their respective provincial Air Quality Standards (AQS). The results can be summarized as follows:

- At 99.5%, the maximum 1-hour concentration of NO_2 (398.0 µg/m³) was predicted to be highest relative to the corresponding AQS (400 µg/m³). The highest 24-hour NO_2 concentration was 176.2 µg/m³, or 88.1% of the AQS. In comparison to the annual AQS standard, the maximum NO_2 concentration (28.4 µg/m³) occurred using the 2021 meteorological dataset. The operation of the existing black start generators is the primary source of the maximum NO_2 concentrations.
- For TPM, PM_{10} and $PM_{2.5}$, the highest concentrations were all directly related to the operation of the new CTs and are similar to each other owing to the fact that the particulate emissions from the CT are almost exclusively $PM_{2.5}$. At 93.8% of the AQS, the 24-hour concentration of $PM_{2.5}$ (23.4 µg/m³) was closest to the standard. On an annual basis, the maximum concentrations were less than 20% of the associated AQS.
- Over the four-year assessment period, the short-term SO_2 concentrations were predicted to be between 60% and 66% of the corresponding AQS, while the annual concentration neared 3.0 µg/m³. The maximum SO_2 concentrations are directly related to the combustion of #6 fuel oil in Units 1, 2 and 3.
- At less than 1% of the associated AQS, CO had the lowest predicted concentrations in the modelling assessment.

For comparison, Table 4-3 and Table 4-4 present the maximum concentrations for just the ACT Project (i.e., the emission from the three new CTs, plus the two new black starts generators). Note the maximum concentrations in Table 4-3 and Table 4-4 from the operation of ACT are not directly comparable in space and time with the maximum concentrations when all sources in operation.

Table 4-1: Summary of Short-Term Maximum Predicted Concentrations, All Sources

Pollutant	Averaging Period	Highest	AQS (µg/m³)	2021 - 2024	
				Conc.(µg/m³)	% Of AQS
NO_2	1-hour	9th	400	398.0	99.5%
	24-hour	2nd	200	176.2	88.1%
SO_2	1-hour	9th	900	588.8	65.4%
	3-hour	6th	600	391.1	65.2%
	24-hour	2nd	300	190.7	63.6%
CO	1-hour	9th	35,000	67.5	0.2%
	8-hour	3rd	15,000	56.6	0.4%
TPM	24-hour	2nd	120	23.7	19.7%
PM_{10}	24-hour	2nd	50	23.5	47.1%
$PM_{2.5}$	24-hour	2nd	25	23.4	93.8%

Table 4-2: Summary of Annual Predicted Concentrations, All Sources

Pollutant	AQS (µg/m³)	2021		2022		2023		2024	
		Conc. (µg/m³)	% Of AQS	Conc. (µg/m³)	% Of AQS	Conc. (µg/m³)	% Of AQS	Conc. (µg/m³)	% Of AQS
NO_2	100	28.4	28.4%	27.5	27.5%	25.0	25.0%	28.1	28.1%
SO_2	60	3.0	4.9%	2.6	4.3%	2.9	4.8	2.8	4.7%
TPM	60	1.6	2.6%	1.3	2.2%	1.2	2.0%	1.4	2.4%
PM_{10}	N/A	1.6	N/A	1.3	N/A	1.2	N/A	1.4	N/A
$PM_{2.5}$	8.8	1.6	17.7%	1.3	15.0%	1.2	13.6%	1.4	16.0%

Table 4-3: Summary of Short-Term Maximum Predicted Concentrations, ACT Project Only

Pollutant	Averaging Period	Highest	AQS (µg/m³)	2021 - 2024	
				Conc. (µg/m³)	% Of AQS
NO_2	1-hour	9th	400	202.4	50.6%
	24-hour	2nd	200	147.8	73.9%
SO_2	1-hour	9th	900	1.6	0.2%
	3-hour	6th	600	1.4	0.2%
	24-hour	2nd	300	1.1	0.4%
CO	1-hour	9th	35,000	62.3	0.2%
	8-hour	3rd	15,000	56.3	0.2%
TPM	24-hour	2nd	120	23.3	19.4%
PM_{10}	24-hour	2nd	50	23.3	46.6%
$PM_{2.5}$	24-hour	2nd	25	23.3	93.2%

Table 4-4: Summary of Annual Predicted Concentrations, ACT Project Only

Pollutant	AQS (µg/m³)	2021		2022		2023		2024	
		Conc. (µg/m³)	% Of AQS	Conc. (µg/m³)	% Of AQS	Conc. (µg/m³)	% Of AQS	Conc. (µg/m³)	% Of AQS
NO_2	100	22.6	22.6%	23.2	23.2%	18.3	18.3%	24.4	24.4%
SO_2	60	0.1	0.1%	0.1	0.1%	0.1	0.1%	0.1	0.1%
TPM	60	1.5	2.4%	1.3	2.1%	1.1	1.8%	1.3	2.2%
PM_{10}	N/A	1.5	N/A	1.3	N/A	1.1	N/A	1.3	N/A
$PM_{2.5}$	8.8	1.5	16.6%	1.3	14.2%	1.1	12.4%	1.3	15.3%

4.2 Isopleths of Predicted NO_2, SO_2 and $PM_{2.5}$ Concentrations

Provincial modelling guidance (DOEC, 2012a) requires that isopleths be created for each pollutant and averaging time that has a modelled concentration greater than 50% of the AQS. As shown in Table 4-1 and Table 4-2, there are six (6) isopleths required, namely:

- 1-hour NO_2;
- 24-hour NO_2;
- 1-hour SO_2;
- 3-hour SO_2;
- 24-hour SO_2; and
- 24-hour $PM_{2.5}$.

For all other pollutants and averaging times, the maximum predicted concentrations are less than 50% of their respective AQS. The six (6) isopleths have been prepared to summarize the results of the modelling assessment and are presented in Figure 4-1to Figure 4-6.

Figure 4-1 and Figure 4-2 present, respectively, the isopleths for 1-hour and 24-hour NO_2 concentrations. As shown in the figures, the highest predicted off-property concentrations of NO_2 are expected in the area immediately west and south of the proposed administrative boundary with the overall off-property maxima occurring at a receptor located along the proposed administrative boundary.

Figure 4-3, Figure 4-4 and Figure 4-5 present the concentration isopleths for 1-hour SO_2, 3-hour SO_2 and 24-hour SO_2 respectively. As shown in the figures, the highest predicted concentrations for all averaging periods are expected off-property in the area northeast and south of the main HTGS Units.

Figure 4-6 presents the concentration isopleths for 24-hour $PM_{2.5}$. While the highest concentrations occur on-property and as a result of building downwash from the installation of the new CTs, the maximum off-property concentrations occur just outside the wake of the downwash, and along the southern edge of the proposed administrative boundary.

Figure 4-1: 9th Highest 1-hour NO_2 Concentrations (ug/m^3), 2021 to 2024

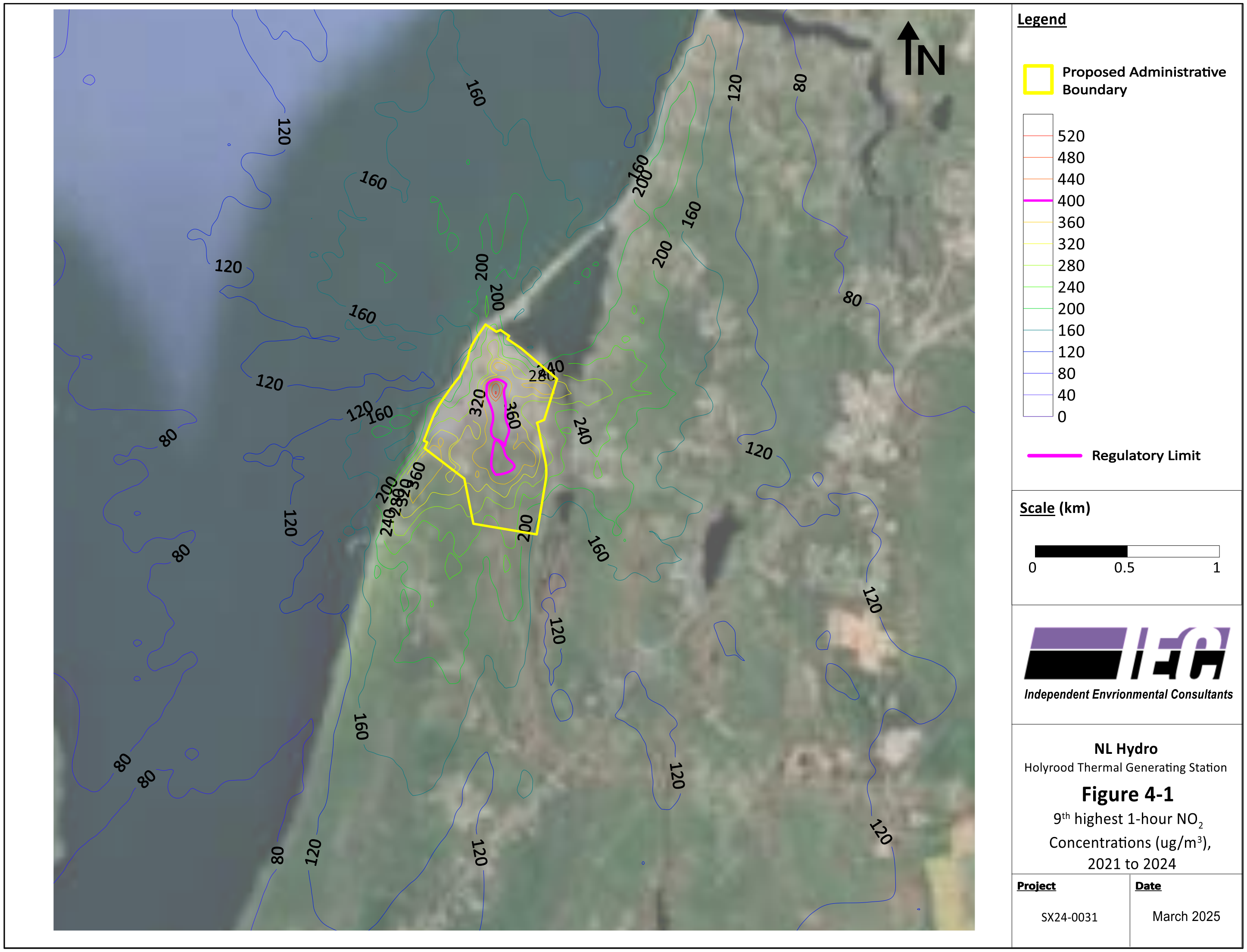


Figure 4-2: 2nd Highest 24-hour NO_2 Concentrations (ug/m³), 2021 to 2024

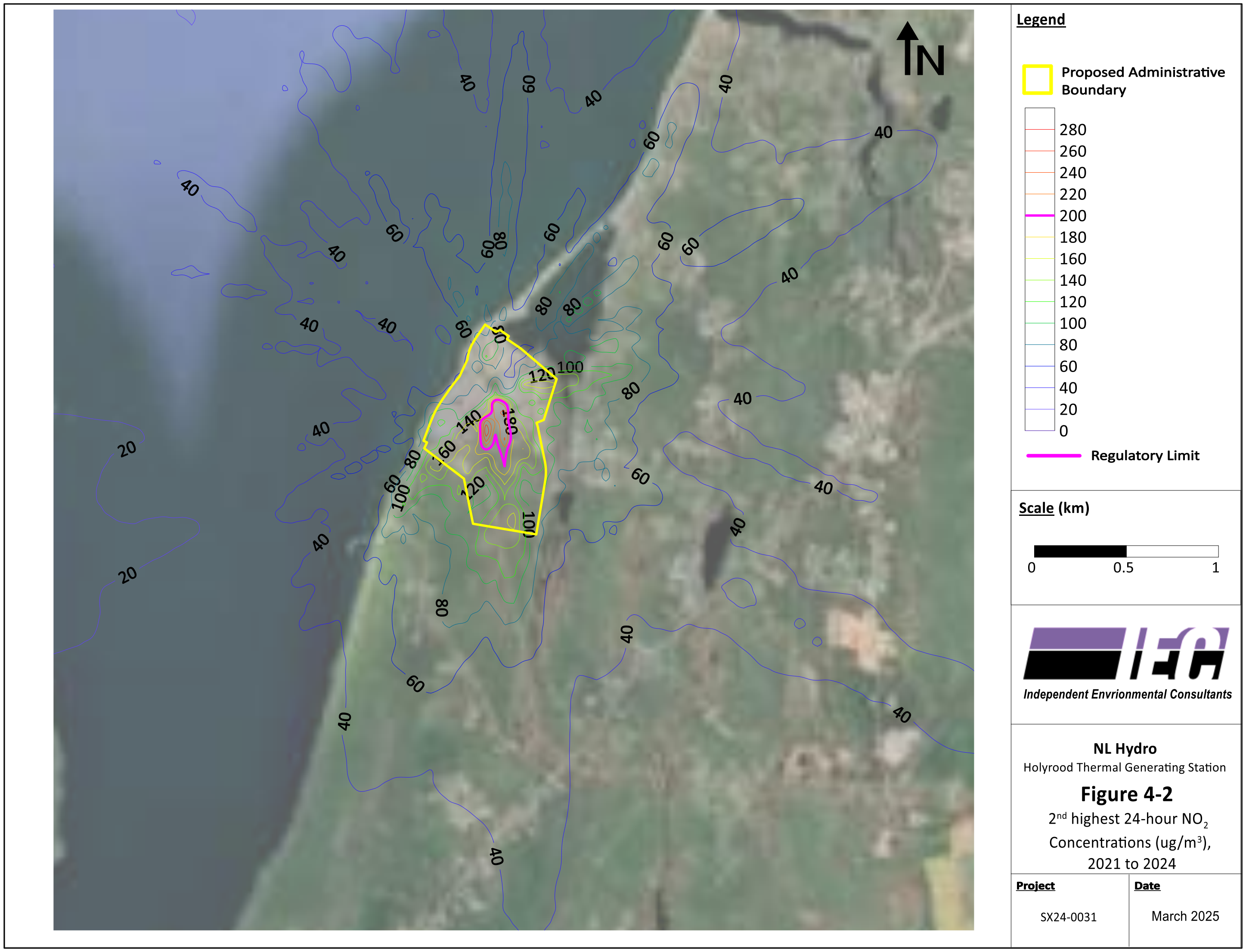


Figure 4-3: 9th Highest 1-hour SO_2 Concentrations (ug/m^3), 2021 to 2024

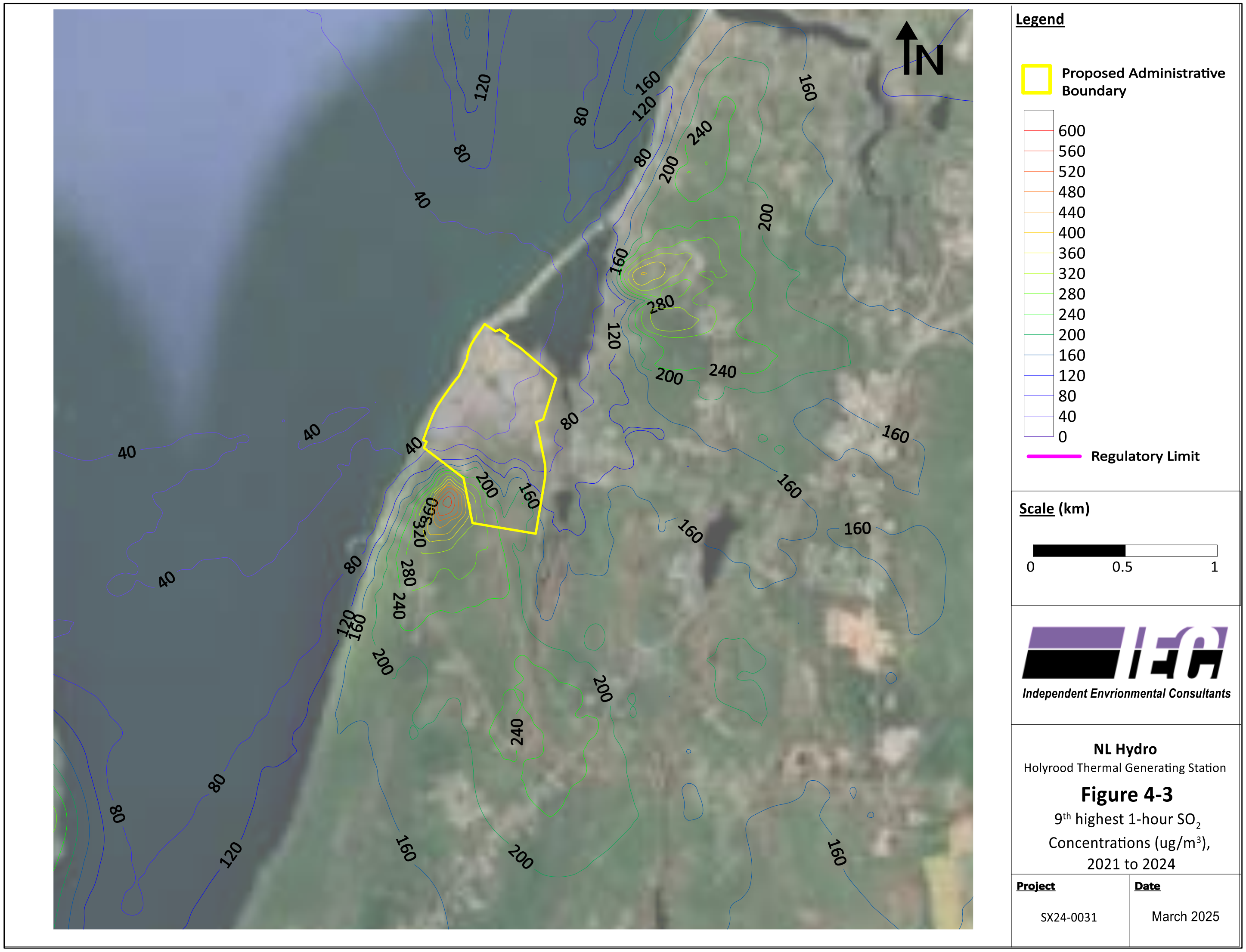


Figure 4-4: 6th Highest 3-hour SO_2 Concentrations (ug/m³), 2021 to 2024

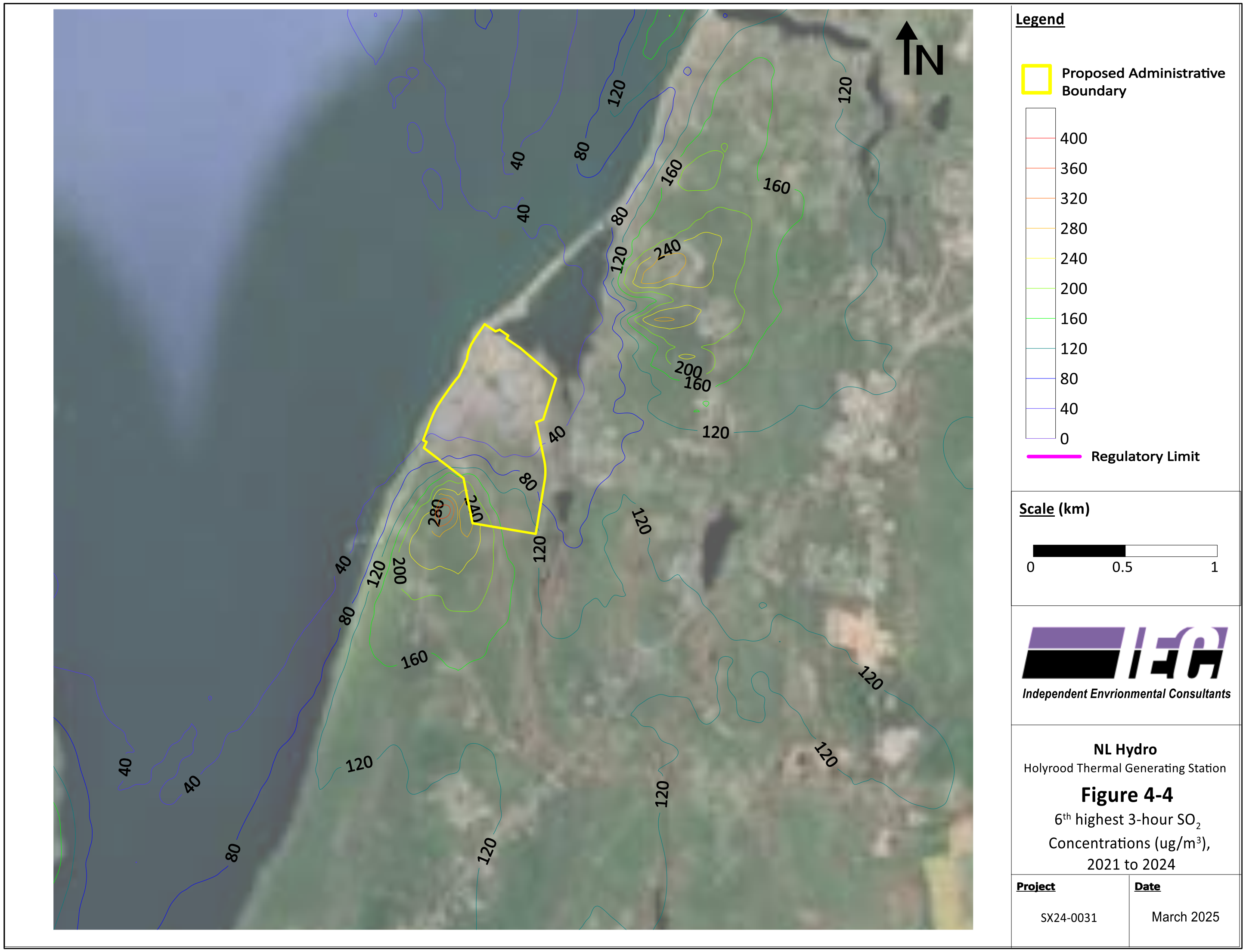


Figure 4-5: 2nd Highest 24-hour SO_2 Concentrations (ug/m^3), 2021 to 2024

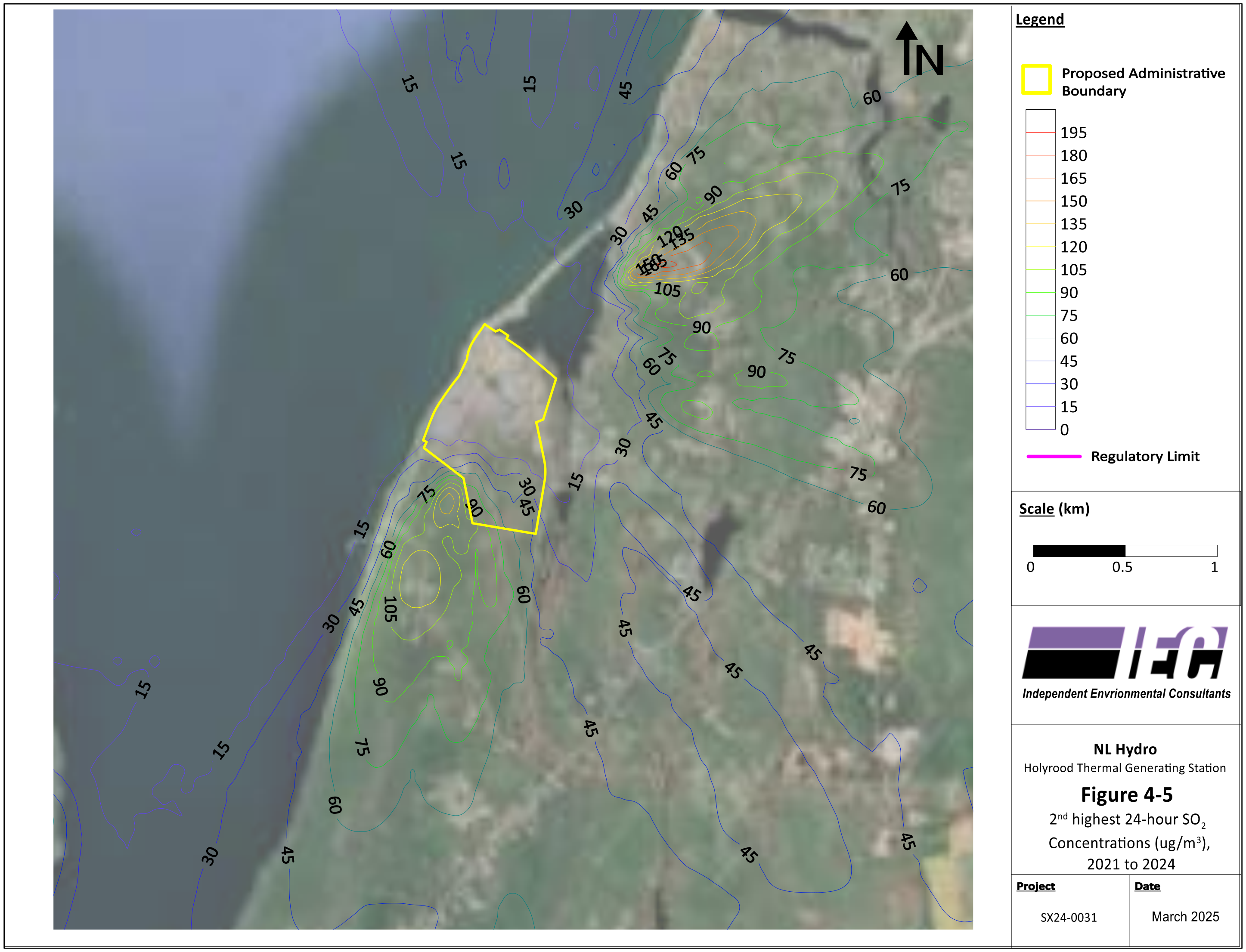
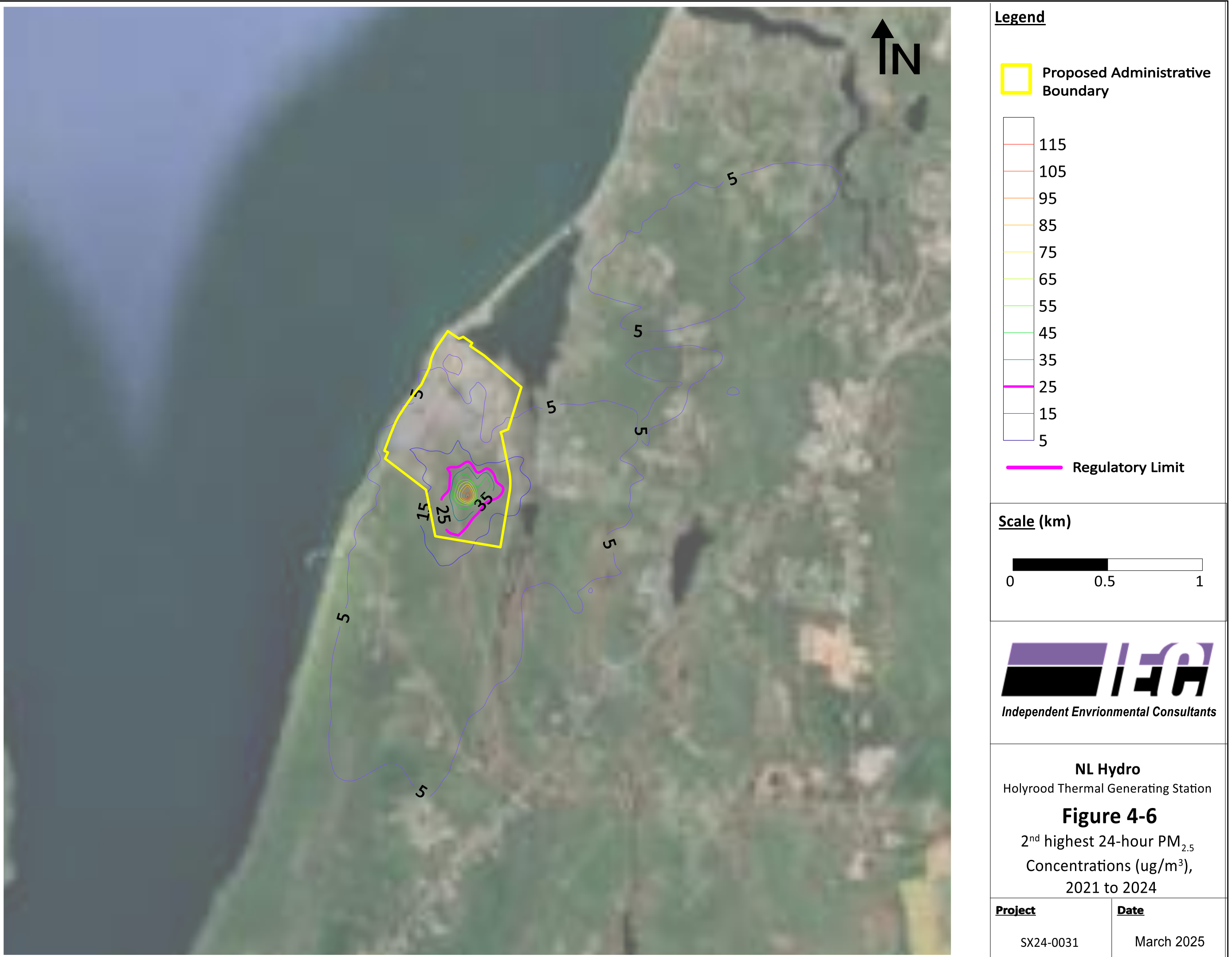


Figure 4-6: 2nd Highest 24-hour $PM_{2.5}$ Concentrations (ug/m^3), 2021 to 2024



NL Hydro
Holyrood Thermal Generating Station

Figure 4-6
2nd highest 24-hour $PM_{2.5}$ Concentrations (ug/m^3), 2021 to 2024

Project	Date
SX24-0031	March 2025

4.3 TOP-50 TABLES

In addition to isopleths, provincial modelling guidance (DOEC, 2012a) requires that Top-50 event tables be produced for all pollutants and averaging times exceeding more than 50% of an AQS. Top-50 tables do not have meteorological anomalies removed; therefore, they represent the overall maximum modelling results.

Table 4-5 to Table 4-10 provide the Top-50 tables corresponding to the concentration isopleths presented in Section 4.2. Specifically:

- Table 4-5presents the top 1-hour NO_2 concentrations,
- Table 4-6 presents the top 24-hour NO_2 concentrations,
- Table 4-7 presents the top 1-hour SO_2 concentrations,
- Table 4-8 presents the top -hour SO_2 concentrations,
- Table 4-9 presents the top 24-hour SO_2 concentrations, and
- Table 4-10 presents the top 1-hour $PM_{2.5}$ concentrations.

Table 4-5: Top-50 Off-Property Event Table for 1-hour NO_2 Concentrations

Year	Day	Time (HHMM)	Receptor	Conc.(µg/m³)	UTM_x (km)	UTM_y (km)
2022	348	1000	9739	**669.21**	341.748	5257.601
2022	348	1000	9740	**657.49**	341.750	5257.616
2022	348	1000	9738	**639.90**	341.741	5257.584
2022	348	1000	9741	**631.11**	341.753	5257.630
2022	348	1000	9742	**601.44**	341.757	5257.646
2022	348	1000	9737	**596.33**	341.734	5257.569
2022	348	1000	9743	**565.57**	341.764	5257.663
2023	76	200	9681	**550.06**	341.514	5257.118
2023	76	200	9707	**548.49**	341.521	5257.133
2023	76	200	9680	**538.39**	341.529	5257.106
2023	76	200	9708	**535.60**	341.529	5257.149
2024	108	1800	9667	**524.88**	341.729	5256.954
2022	348	1000	9736	**524.35**	341.726	5257.554
2022	348	1000	9744	**517.32**	341.771	5257.679
2021	104	1900	4175	**505.48**	341.550	5257.016
2023	62	1800	9590	**501.21**	342.173	5257.020
2023	62	1800	9591	**500.53**	342.173	5257.017
2023	62	1800	9589	**499.69**	342.173	5257.021
2023	62	1800	9588	**499.35**	342.172	5257.024
2024	108	1800	9666	**499.14**	341.733	5256.935
2023	76	200	4122	**498.31**	341.500	5257.116
2023	62	1800	9587	**498.00**	342.172	5257.026
2023	62	1800	9592	**497.99**	342.173	5257.015
2024	108	1800	9668	**496.56**	341.714	5256.965
2023	62	1800	9586	**494.93**	342.172	5257.029
2022	317	1900	4175	**493.96**	341.550	5257.016
2023	62	1800	9585	**492.93**	342.172	5257.031
2023	62	1800	9593	**492.45**	342.174	5257.013
2024	67	800	4117	**491.89**	341.500	5256.866
2023	62	1800	9584	**491.61**	342.171	5257.035
2023	62	1800	9583	**489.16**	342.171	5257.037
2023	62	1800	9582	**487.97**	342.170	5257.040
2021	104	1800	4175	**487.92**	341.550	5257.016
2023	7	1800	9723	**487.77**	341.603	5257.370
2024	108	1800	4373	**486.71**	341.700	5256.866
2023	62	1800	9594	**486.63**	342.174	5257.009
2021	104	1800	9676	**485.84**	341.591	5257.060
2023	7	1800	9724	**485.30**	341.613	5257.384
2024	121	1700	9677	**484.99**	341.575	5257.070
2023	62	1800	9581	**484.99**	342.170	5257.042
2022	348	1000	4477	**483.44**	341.750	5257.666
2023	62	1800	9595	**483.26**	342.174	5257.007
2022	317	1900	9677	**482.95**	341.575	5257.070
2021	104	1800	4118	**482.95**	341.500	5256.916
2023	76	200	4121	**480.41**	341.500	5257.065
2023	62	1800	9580	**480.04**	342.170	5257.044
2024	108	1800	4374	**479.59**	341.700	5256.916
2023	75	1700	4120	**478.95**	341.500	5257.016
2021	104	1900	4119	**478.37**	341.500	5256.965
2023	62	1800	9596	**477.15**	342.174	5257.004

Note:
Predicted unfiltered concentrations above the 1-hour NO_2 AQS of 400 µg/m³ are shaded and in **bold**.

Table 4-6: Top-50 Off-Property Event Table for 24-hour NO_2 Concentrations

Year	Day	Receptor	Conc.(µg/m³)	UTM_x (km)	UTM_y (km)
2022	340	4174	198.09	341.550	5256.965
2022	340	4230	196.53	341.600	5257.016
2021	4	9668	195.69	341.714	5256.965
2021	4	4375	191.12	341.700	5256.965
2022	340	9675	190.30	341.606	5257.047
2021	4	9669	186.08	341.698	5256.977
2022	340	9674	183.86	341.621	5257.036
2022	340	4118	181.35	341.500	5256.916
2021	4	4374	181.14	341.700	5256.916
2021	98	9673	180.15	341.637	5257.023
2022	340	4173	180.09	341.550	5256.916
2021	4	9667	176.74	341.729	5256.954
2021	98	9674	176.15	341.621	5257.036
2022	340	9676	175.88	341.591	5257.060
2022	340	4117	175.21	341.500	5256.866
2023	361	9553	175.05	342.227	5257.477
2023	361	9552	172.38	342.233	5257.495
2022	340	4175	171.49	341.550	5257.016
2024	34	9679	169.83	341.544	5257.095
2021	98	9672	169.70	341.652	5257.013
2022	340	4229	169.62	341.600	5256.965
2021	104	9676	167.08	341.591	5257.060
2022	340	4029	166.68	341.450	5256.815
2021	104	9677	164.17	341.575	5257.070
2023	61	9555	164.05	342.215	5257.439
2021	98	4230	163.74	341.600	5257.016
2021	104	4175	163.29	341.550	5257.016
2023	99	9554	162.22	342.221	5257.458
2022	340	9673	161.63	341.637	5257.023
2022	340	4030	161.58	341.450	5256.866
2023	361	5159	159.29	342.250	5257.465
2021	98	9675	159.11	341.606	5257.047
2023	113	9647	158.97	341.912	5256.686
2024	349	9551	158.94	342.218	5257.507
2022	345	9642	158.48	342.007	5256.669
2022	345	4798	158.40	342.000	5256.666
2023	152	9667	157.99	341.729	5256.954
2024	349	9550	157.74	342.203	5257.521
2023	99	9553	157.72	342.227	5257.477
2023	61	9554	157.57	342.221	5257.458
2021	364	4798	157.49	342.000	5256.666
2021	364	9642	157.26	342.007	5256.669
2021	4	9666	156.97	341.733	5256.935
2023	152	9666	156.63	341.733	5256.935
2023	113	4622	156.55	341.900	5256.666
2023	71	9645	156.35	341.950	5256.680
2023	361	9551	156.34	342.218	5257.507
2023	71	9646	155.77	341.931	5256.683
2021	27	9644	155.70	341.969	5256.676
2021	364	9643	155.64	341.988	5256.673

Note:
Predicted unfiltered concentrations above the 24-hour NO_2 AQS of 200 µg/m³ are shaded and in **bold**.

Table 4-7: Top-50 Off-Property Event Table for 1-hour SO_2 Concentrations

Year	Day	Time (HHMM)	Receptor	Conc.(µg/m³)	UTM_x (km)	UTM_y (km)
2024	85	1400	4166	**963.05**	341.550	5256.565
2024	85	1400	4165	**956.90**	341.550	5256.516
2024	85	1400	4167	**956.01**	341.550	5256.616
2024	85	1400	4111	**953.57**	341.500	5256.565
2024	85	1400	4110	**948.13**	341.500	5256.516
2024	85	1400	4221	**947.53**	341.600	5256.565
2024	85	1400	4112	**943.11**	341.500	5256.616
2024	85	1400	4222	**942.10**	341.600	5256.616
2024	85	1400	4220	**939.88**	341.600	5256.516
2024	85	1400	4164	**936.13**	341.550	5256.465
2024	85	1400	4168	**932.28**	341.550	5256.666
2024	85	1400	4109	**930.71**	341.500	5256.465
2024	85	1400	4223	**918.38**	341.600	5256.666
2024	85	1400	4219	**918.15**	341.600	5256.465
2024	85	1400	4113	**915.54**	341.500	5256.666
2024	85	1400	4024	**914.59**	341.450	5256.565
2024	85	1400	4023	**913.95**	341.450	5256.516
2024	86	1100	9774	**913.14**	343.034	5257.313
2024	86	1100	6237	**912.07**	343.050	5257.266
2024	86	1100	6238	**911.41**	343.050	5257.315
2024	86	1100	6183	**911.38**	343.000	5257.315
2024	86	1100	6182	**910.65**	343.000	5257.266
2024	85	1400	4276	**906.16**	341.650	5256.565
2024	85	1400	4163	**904.07**	341.550	5256.416
2024	85	1400	4022	**901.85**	341.450	5256.465
2024	86	1100	6236	**900.42**	343.050	5257.215
2024	85	1400	4108	**900.04**	341.500	5256.416
2024	86	1100	6096	899.99	342.950	5257.315
2024	85	1400	4275	899.56	341.650	5256.516
2024	85	1400	4025	899.44	341.450	5256.616
2024	85	1400	4277	898.66	341.650	5256.616
2024	86	1100	6184	898.36	343.000	5257.366
2024	86	1100	6095	897.95	342.950	5257.266
2024	86	1100	6181	896.41	343.000	5257.215
2024	86	1100	6239	896.16	343.050	5257.366
2024	86	1100	6292	889.38	343.150	5257.266
2024	86	1100	6097	887.57	342.950	5257.366
2024	85	1400	4169	886.73	341.550	5256.715
2024	85	1400	4218	885.11	341.600	5256.416
2024	86	1100	6094	881.58	342.950	5257.215
2024	85	1400	4278	878.18	341.650	5256.666
2024	86	1100	6235	877.86	343.050	5257.166
2024	85	1400	4021	876.56	341.450	5256.416
2024	85	1400	4274	876.47	341.650	5256.465
2024	85	1400	4224	876.10	341.600	5256.715
2024	86	1100	6007	876.07	342.900	5257.315
2024	86	1100	6006	873.57	342.900	5257.266
2024	86	1100	6185	871.36	343.000	5257.416
2024	86	1100	6180	870.60	343.000	5257.166
2024	86	1100	6291	868.23	343.150	5257.166

Note:
Predicted unfiltered concentrations above the 1-hour SO_2 AQS of 900 µg/m³ are shaded and in **bold**.

Table 4-8: Top-50 Off-Property Event Table for 3-hour SO_2 Concentrations

Year	Day	Time (HHMM)	Receptor	Conc.(µg/m³)	UTM_x (km)	UTM_y (km)
2024	37	1200	4281.00	**659.380**	341.65	5256.815
2024	37	900	4226.00	**637.600**	341.6	5256.815
2024	37	900	4227.00	**626.350**	341.6	5256.866
2024	37	1200	4280.00	590.990	341.65	5256.766
2024	37	1200	4282.00	585.420	341.65	5256.866
2024	85	1200	4109.00	578.110	341.5	5256.465
2023	68	900	4281.00	577.560	341.65	5256.815
2024	85	1200	4108.00	574.680	341.5	5256.416
2024	85	1200	4110.00	571.690	341.5	5256.516
2024	85	1200	4021.00	571.530	341.45	5256.416
2024	85	1200	4022.00	571.000	341.45	5256.465
2024	85	1200	4164.00	568.430	341.55	5256.465
2024	85	1200	4165.00	564.690	341.55	5256.516
2024	85	1200	4020.00	564.680	341.45	5256.366
2024	85	1200	4163.00	564.010	341.55	5256.416
2024	85	1200	4107.00	564.000	341.5	5256.366
2024	85	1200	4023.00	560.920	341.45	5256.516
2024	85	1200	4111.00	557.980	341.5	5256.565
2024	85	1200	4166.00	551.800	341.55	5256.565
2024	85	1200	4162.00	551.100	341.55	5256.366
2024	85	1200	4019.00	550.890	341.45	5256.315
2024	37	900	4225.00	550.450	341.6	5256.766
2024	37	1200	4372.00	550.240	341.7	5256.815
2024	85	1200	4106.00	548.000	341.5	5256.315
2024	85	1200	3932.00	546.430	341.4	5256.416
2024	85	1200	3931.00	545.570	341.4	5256.366
2023	68	900	4373.00	544.600	341.7	5256.866
2024	85	1200	4024.00	543.900	341.45	5256.565
2024	85	1200	4219.00	543.640	341.6	5256.465
2024	85	1200	3933.00	542.050	341.4	5256.465
2024	85	1200	4220.00	541.410	341.6	5256.516
2023	68	900	4372.00	540.280	341.7	5256.815
2024	85	1200	4218.00	538.050	341.6	5256.416
2024	85	1200	3930.00	537.160	341.4	5256.315
2024	85	1200	4112.00	534.450	341.5	5256.616
2024	37	1200	4373.00	534.400	341.7	5256.866
2024	85	1200	4161.00	532.690	341.55	5256.315
2024	85	1200	4167.00	531.140	341.55	5256.616
2024	85	1200	4018.00	530.880	341.45	5256.266
2024	85	1200	4221.00	530.580	341.6	5256.565
2024	85	1200	3934.00	530.300	341.4	5256.516
2024	86	900	6291.00	527.620	343.15	5257.166
2024	85	1200	4105.00	526.920	341.5	5256.266
2023	68	900	4282.00	526.530	341.65	5256.866
2024	86	900	6354.00	525.670	343.2	5257.116
2024	85	1200	4217.00	524.170	341.6	5256.366
2024	37	900	4171.00	522.750	341.55	5256.815
2024	37	900	4170.00	522.720	341.55	5256.766
2024	86	900	6235.00	522.450	343.05	5257.166
2024	86	900	6290.00	521.680	343.15	5257.065

Note:
Predicted unfiltered concentrations above the 3-hour SO_2 AQS of 600 µg/m³ are shaded and in **bold**.

Table 4-9: Top-50 Off-Property Event Table for 24-hour SO_2 Concentrations

Year	Day	Receptor	Conc.(µg/m³)	UTM_x (km)	UTM_y (km)
2023	79	5857	204.97	342.750	5258.065
2023	79	5912	202.96	342.800	5258.065
2024	19	5969	202.32	342.850	5258.166
2024	19	6024	199.33	342.900	5258.166
2024	19	5913	198.91	342.800	5258.116
2024	19	5858	195.85	342.750	5258.116
2024	19	5914	195.10	342.800	5258.166
2023	79	5767	194.62	342.700	5258.016
2023	79	5967	193.65	342.850	5258.065
2024	19	6201	192.86	343.000	5258.215
2024	19	6114	192.74	342.950	5258.215
2023	79	5768	192.37	342.700	5258.065
2023	79	5856	191.72	342.750	5258.016
2024	37	4225	190.94	341.600	5256.766
2024	19	6113	190.85	342.950	5258.166
2024	19	5968	190.80	342.850	5258.116
2023	79	5968	190.69	342.850	5258.116
2024	19	6256	188.53	343.050	5258.215
2024	37	4224	188.39	341.600	5256.715
2024	19	6025	187.79	342.900	5258.215
2024	37	4281	187.07	341.650	5256.815
2023	79	6023	186.90	342.900	5258.116
2023	79	5913	186.57	342.800	5258.116
2024	37	4280	186.48	341.650	5256.766
2024	19	6257	186.27	343.050	5258.266
2024	37	4226	185.60	341.600	5256.815
2023	79	6022	183.01	342.900	5258.065
2024	19	6202	181.64	343.000	5258.266
2023	79	5911	181.58	342.800	5258.016
2024	19	6200	181.39	343.000	5258.166
2024	37	4223	180.80	341.600	5256.666
2024	19	5769	180.22	342.700	5258.116
2023	79	6112	179.76	342.950	5258.116
2024	19	5970	178.26	342.850	5258.215
2024	37	4279	177.67	341.650	5256.715
2024	19	6023	176.99	342.900	5258.116
2024	37	4168	176.70	341.550	5256.666
2024	19	5768	175.42	342.700	5258.065
2024	37	4169	175.19	341.550	5256.715
2024	37	4222	174.17	341.600	5256.616
2024	37	4167	174.09	341.550	5256.616
2024	18	6255	173.68	343.050	5258.166
2024	18	6200	173.66	343.000	5258.166
2024	19	5859	173.06	342.750	5258.166
2024	19	5857	172.80	342.750	5258.065
2024	18	6112	172.62	342.950	5258.116
2024	19	6302	172.58	343.150	5258.266
2023	79	5676	172.29	342.650	5258.016
2024	18	6023	172.11	342.900	5258.116
2024	19	6115	170.75	342.950	5258.266

Note:
Predicted unfiltered concentrations above the 24-hour SO_2 AQS of 300 µg/m³ are shaded and in **bold**.

Table 4-10: Top-50 Off-Property Event Table for 24-hour $PM_{2.5}$ Concentrations

Year	Day	Receptor	Conc.(µg/m³)	UTM_x (km)	UTM_y (km)
2021	40	9618	**26.36**	342.172	5256.950
2021	40	9619	**26.33**	342.172	5256.947
2021	40	9617	**26.32**	342.172	5256.953
2021	40	9616	**26.15**	342.173	5256.955
2021	40	9615	**25.97**	342.173	5256.958
2021	40	9614	**25.79**	342.173	5256.959
2021	40	9613	**25.46**	342.173	5256.962
2021	40	9612	**25.04**	342.174	5256.964
2021	40	9620	24.96	342.169	5256.931
2021	40	9611	24.57	342.174	5256.967
2021	5	9649	24.26	341.874	5256.692
2024	37	9647	24.17	341.912	5256.686
2021	40	9610	24.06	342.174	5256.970
2021	42	9602	23.87	342.175	5256.989
2021	42	9603	23.87	342.175	5256.987
2021	42	9601	23.87	342.175	5256.993
2021	42	9600	23.81	342.175	5256.995
2021	42	9604	23.77	342.175	5256.984
2021	42	9605	23.74	342.174	5256.982
2021	42	9599	23.67	342.174	5256.998
2021	5	9648	23.66	341.893	5256.689
2022	254	9650	23.59	341.855	5256.695
2021	42	9598	23.51	342.174	5257.000
2021	40	9609	23.45	342.174	5256.973
2021	42	9606	23.45	342.174	5256.979
2024	37	9648	23.45	341.893	5256.689
2024	30	9649	23.32	341.874	5256.692
2021	5	9650	23.26	341.855	5256.695
2021	42	9607	23.26	342.174	5256.978
2024	30	9650	23.19	341.855	5256.695
2021	42	9597	23.16	342.174	5257.002
2024	37	9646	23.06	341.931	5256.683
2022	254	9649	23.01	341.874	5256.692
2021	40	9608	23.00	342.174	5256.975
2021	42	9596	22.90	342.174	5257.004
2021	42	9608	22.89	342.174	5256.975
2022	254	9651	22.81	341.836	5256.699
2024	37	4622	22.66	341.900	5256.666
2021	42	9609	22.57	342.174	5256.973
2021	42	9595	22.46	342.174	5257.007
2021	40	9607	22.22	342.174	5256.978
2022	350	9651	22.17	341.836	5256.699
2022	350	9650	22.10	341.855	5256.695
2024	30	9648	22.09	341.893	5256.689
2021	42	9594	22.08	342.174	5257.009
2021	42	9610	22.05	342.174	5256.970
2023	67	9652	22.03	341.816	5256.702
2024	30	9651	21.86	341.836	5256.699
2024	6	9622	21.83	342.163	5256.896
2023	67	9651	21.82	341.836	5256.699

Note:
Predicted unfiltered concentrations above the 24-hour $PM_{2.5}$ AQS of 25 µg/m³ are shaded and in **bold**.

5.0 CONCLUSIONS

Air dispersion modelling using the CALMET/CALPUFF modelling system was performed to evaluate the impacts of the existing Holyrood Thermal Generating Station and the proposed ACT Project on local air quality. NO_2, SO_2, CO, TPM, PM_{10} and $PM_{2.5}$ were modelled, and predicted concentrations were compared to Newfoundland and Labrador Air Quality Standards (AQS) in accordance with provincial guidance. A four-year meteorological period (2021 to 2024) was used and results were compared against the revised administrative boundary that is proposed to incorporate the ACT facility.

The conclusions of this air dispersion modelling assessment are:

- For each timeframe modelled, the resulting concentrations of NO_2, SO_2, CO, TPM, PM_{10} and $PM_{2.5}$ were compliant with applicable AQS for all averaging periods (1-hour, 3-hour, 8-hour, 24-hour and annual) for all modelled sources.
- The installation of the ACT increases off-property concentrations of 24-hour $PM_{2.5}$, however at 93.8%, those concentrations are still below the associated AQS.
- The pollutant with the highest predicted concentration relative to its AQS is NO_2. The maximum predicted concentration of 1-hour NO_2 was 398.0 µg/m³ (or 99.5% of the AQS), and the maximum predicted concentration of 24-hour NO_2 was 176.2 µg/m³ (or 88.1% of the AQS). The operation of the existing black start generators are the primary contributors to the elevated concentrations.
- The installation of the ACT has minimal impact on the SO_2 concentrations as the operation of HTGS Units 1, 2 and 3 and the combustion of #6 fuel oil are the primary contributors to ground-level concentrations.
- The balance of the predicted pollutant concentrations and averaging periods were all less than 50% of the corresponding AQS. At less than 1% of the AQS, CO had the lowest predicted concentrations in the modelling assessment.

6.0 REFERENCES

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Appendix E
Best Available Control Technology Report

BEST AVAILABLE CONTROL TECHNOLOGY ASSESSMENT - THE NEW AVALON COMBUSTION TURBINES AT THE HOLYROOD THERMAL GENERATING STATION

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DOCUMENT APPROVAL

VERSION CONTROL

Rev. No.	Description	Prepared by	Reviewed by	Date
0	Preliminary draft	MM	PK / BL	14March25
1	Final	MM	BL	21March25

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

Acronyms

ACT	Avalon Combustion Turbine
BACT	Best Available Control Technology
CO	Carbon Monoxide
COPD	chronic obstructive pulmonary disease
CIMAC	Conseil International des Machines à Combustion
CRT	Continuously Regenerating Trap
DOCs	Diesel Oxidation Catalysts
DPFs	Diesel Particulate Filters
DLE	Dry Low Emissions
DLN	Dry Low NO_X
ESPs	Electrostatic Precipitators
EPA	Environmental Protection Agency
HTGS	Holyrood Thermal Generating Station
IEC	Independent Environmental Consultants
LNBs	Low-NO_X Burners
LSD	Low-Sulphur Diesel
NO	Nitric Oxide
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxides
OSTI	Office of Scientific and Technical Information
PM	Particulate Matter
ppmv	Parts Per Million by Volume
SCR	Selective Catalytic Reduction
SNCR	Selective Non-Catalytic Reduction
SAC	Single Annular Combustion
SO_2	Sulphur Dioxide
SO_3	Sulphur Trioxide
ULN	Ultra-Low NO_X
ULNBs	Ultra-Low NO_X Burners
ULSD	Ultra-Low-Sulphur Diesel
WHO	World Health Organization

1 INTRODUCTION

Independent Environmental Consultants (IEC) was retained by Newfoundland and Labrador Hydro (NL Hydro) to perform an assessment of the Best Available Control technology (BACT) for the proposed expansion of the Holyrood Thermal Generating Station (HTGS or the Facility). The HTGS is currently comprised of three (3) oil-fired thermal generators (Units 1, 2 and 3), a 123 MW diesel-fired gas turbine generator (the GT) and six (6) diesel-fired black start generators (each having a nominal rating of 2 MW). Together, the HTGS, GT and black start diesel generators comprise the existing power generating station at the Facility. To meet projected future demand and to retire the existing thermal generators, NL Hydro is proposing to install three (3) new combustion turbines (CTs) as well as install two (2) new black start diesel generators and referred to as the Avalon Combustion Turbine (ACT) Project. The new black start generators would be installed to fire up the new CTs and not connected to the grid. Figure 1-1 shows the general location of the HTGS and the location of the new Combustion Turbines and black start generators. Figure 1-2 shows the layout of the turbine generators.

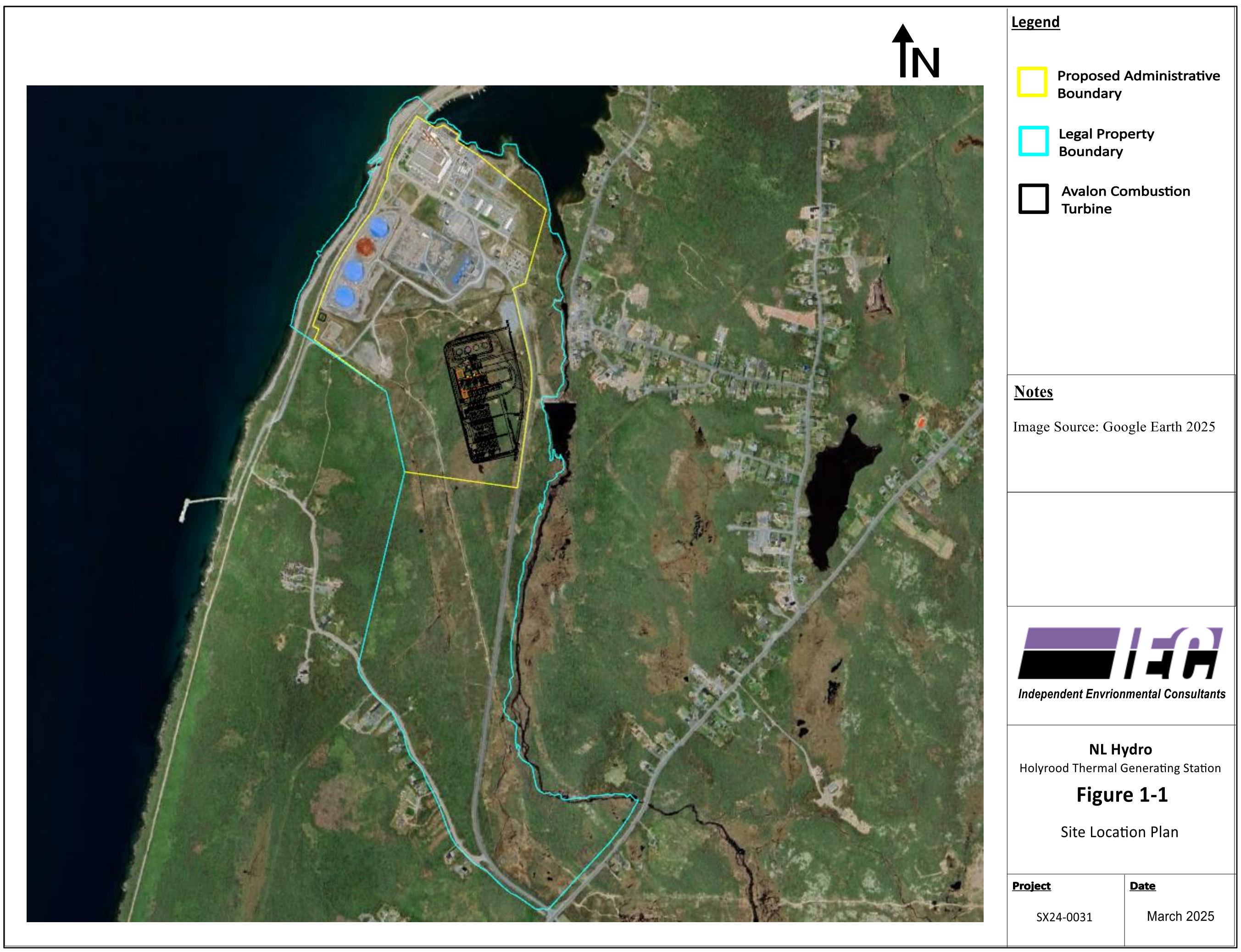

Figure 1-1: Site Location Plan

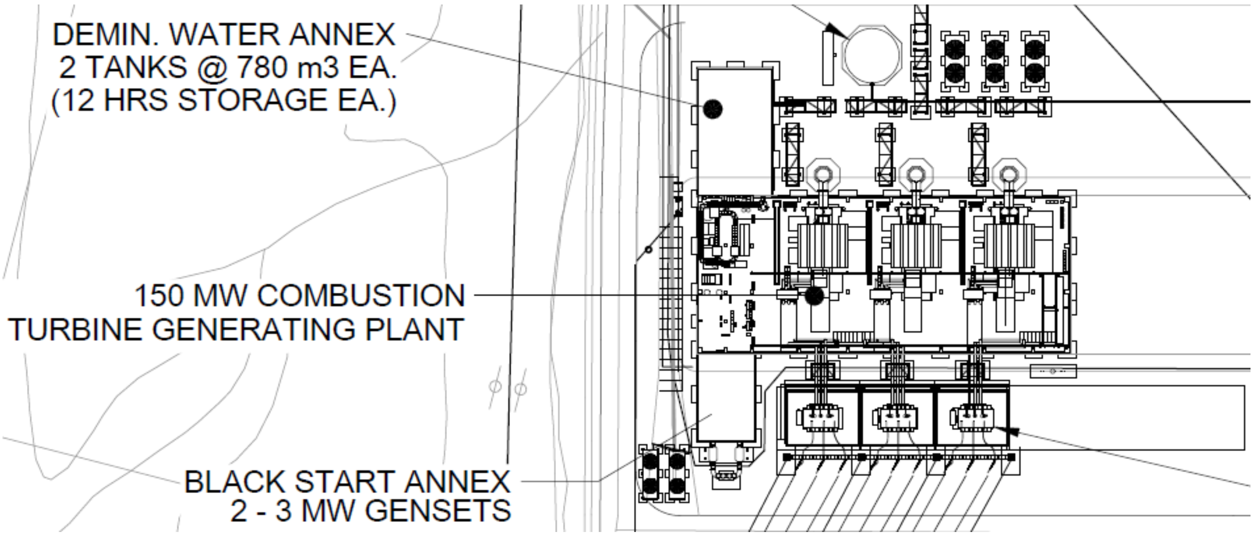

Figure 1-2: Turbine Generators layout

1.1 Description of the New Combustion Turbines

The Project involves constructing a 150 MW (nominal) CTs adjacent to the existing HTGS, aimed at improving the reliability of the province's electricity supply by addressing anticipated demand increases and ensuring stability during peak periods. The Project includes three new simple cycle diesel-fired 46.6 MW CTs located southeast of the existing 123 MW diesel-fired gas turbine generator near the access road. Each of these turbines will exhaust through its own stack, further contributing to the overall capacity and operational flexibility of the site. The CTs will operate on diesel fuel but will be designed for future conversion or retrofitting to run on natural gas, hydrogen-natural gas blends, biofuels, and/or renewable diesel. In the worst-case scenario, the CTs are expected to operate for up to six weeks per year.

1.2 Scope and Objectives of the Assessment

The scope of this assessment is the three new simple cycle diesel-fired 46.6 MW CTs and the objective is to identify the Best Available Control Technologies (BACT) that can be deployed to the CTs to ensure that emissions from the CTs comply with applicable environmental standards and reflect the highest practicable level of emissions control. According to the Air Pollution Control Regulations 11/22 BACT shall, in that particular circumstance, be the most effective and stringent, proven reliable, economically feasible, and acceptable to the Department of Environment and Climate Change (Newfoundland and Labrador, 2022).

1.3 Structure and Content of This Report

This report is structured to provide a comprehensive assessment of the BACT for the ACT at the HTGS. The document is organized into the following sections:

- **Section 1: Introduction** – This section outlines the purpose of the report, the project description, and the structure of the document.
- **Section 2: Environmental Impacts of Emissions** – This section evaluates the environmental and health impacts of emissions from combustion turbines, focusing on nitrogen oxides (NOX) and particulate matter (PM).

- **Section 3: NOX Emissions from Turbines** – This section details the mechanisms of NOX formation in combustion turbines, factors influencing emissions, and regulatory emission limits.
- **Section 4: PM Emissions from Turbines** – This section analyzes sources of PM emissions, influencing parameters, and regulatory considerations.
- **Section 5: Options for NOX Control** – This section presents and evaluates various NOX reduction technologies, including dry low NOX combustors, water/steam injection, and post-combustion controls.
- **Section 6: Options for PM and $PM_{2.5}$ Control** – This section discusses available control technologies for PM emissions, such as Diesel Particulate Filters (DPFs), Diesel Oxidation Catalysts (DOCs), and Electrostatic Precipitators (ESPs).
- **Section 7: BACT for NOX and PM Emissions** – This section synthesizes the findings and identifies the most effective and feasible emission control technologies for the ACT.
- **Section 8: References** – This section provides a list of sources and literature reviewed in the preparation of this report.

Each section is designed to build upon the previous one, providing an assessment of emission impacts and control technologies for the proposed ACT.

1.4 Regulatory Framework

The regulatory framework for BACT in Newfoundland and Labrador is primarily governed by two key pieces of legislation: the Air Pollution Control Regulations, 2022 under the Environmental Protection Act and the Management of Greenhouse Gas Regulations under the *Management of Greenhouse Gas Act* (Newfoundland and Labrador, 2018a).

1.3.1 Air Pollution Control Regulations

According to Section 6 of Regulation 11/22 (Newfoundland and Labrador, 2022):

(1) An owner or operator who installs a new or modified emission source shall employ the best available control technology.

(2) Notwithstanding subsection (1), an owner or operator may install a new or modified emission source which does not comply with that subsection with the written approval of the minister.

(3) Notwithstanding subsection (1), best available control technology shall not apply to

   a. routine maintenance, repair and parts replacement;
   b. normal increases in production rates unless otherwise prohibited;
   c. increases in hours of operation unless otherwise prohibited; or
   d. use of an alternative cleaner fuel or raw material.

(4) Best available control technology shall be acceptable to the department and shall, in that particular circumstance, be

   a. the most effective emission control device or technique;
   b. the most stringent emission control device or technique;

c. proven reliable in comparable processes; and

d. economically feasible as determined by the minister in light of industry standards after consultation with the particular owner or operator.

However, exceptions are allowed for routine maintenance, minor production increases, and the use of cleaner fuels, provided these do not undermine overall emission control standards. Written approval from the Minister is required if an emission source does not comply with the prescribed BACT standards.

1.3.2 Management of Greenhouse Gas Regulations

In addition, Regulation 116/18 outlines (Newfoundland and Labrador, 2018b) the specific requirements for industrial facilities under the *Management of Greenhouse Gas Act*. The Project is expected to emit 15,000 tonnes of carbon dioxide equivalent or more of greenhouse gas. According to Section 4 of *the Act*, the Project is subject to *the Act* and is required to submit BACT information at the time of registration or project description submission to ensure compliance with emission control standards. According to Section 12.1 (4) of the Regulations: An industrial facility is considered to meet the best available control technology requirements where the Lieutenant-Governor in Council is satisfied that the combination of machinery and equipment in the industrial facility

a) has the most effective greenhouse gas emissions control;

b) has proven performance and reliability in comparable industrial facilities;

c) is economically feasible, based on consultation with the operator; and

d) complies with an Act or regulation relating to air pollution, occupational health and safety and fire and life safety.

Ultimately, the regulations aim to mitigate environmental impacts by enforcing the adoption of the most advanced and reliable control technologies while maintaining economic feasibility and regulatory compliance.

2 ENVIRONMENTAL IMPACTS OF THE EMISSIONS

2.1 ENVIRONMENTAL IMPACTS OF NO_X

Nitrogen oxides (NO_X) are a group of gases primarily composed of nitric oxide (NO) and nitrogen dioxide (NO_2). They are mainly produced during high-temperature combustion processes when the nitrogen in the air and fuel reacts to form NO and NO_2. The higher the combustion temperature, the greater the formation of NO_X. This process is significant in both natural and anthropogenic emissions, with recent studies highlighting that non-thermal sources, such as photochemical reactions, also play an increasing role in NO_X formation, particularly in urban areas with low-emission vehicles and alternative fuels. Additionally, alternative fuels like biofuels can also contribute to NO_X emissions, albeit at different levels compared to traditional fossil fuels (EPA, 2020; Zhang et al., 2021).

Emissions of nitrogen oxides have significant adverse effects on human health and the environment. Health impacts include increased incidence of respiratory diseases such as asthma and bronchitis, as well as cardiovascular issues, particularly from long-term exposure to NO_X and associated fine particulate matter ($PM_{2.5}$) (Brook et al., 2019). NO_X is also a precursor to ground-level ozone, which contributes to smog and has harmful effects on air quality and public health. On the environmental side, NO_X emissions contribute to acid deposition, eutrophication of water bodies, and visibility degradation. Recent studies have shown that NO_X emissions continue to cause eutrophication in both freshwater and coastal ecosystems (Holland et al., 2020). Although significant reductions in acid rain have been achieved in regions like North America and Europe due to emissions controls, NO_X remains a threat to ecosystems in parts of the world that are not yet experiencing such reductions (Davidson & Seitzinger, 2019). Furthermore, NO_X -related aerosols play a role in both warming and cooling the atmosphere, contributing to the complex dynamics of climate change (Liu et al., 2020).

2.2 ENVIRONMENTAL IMPACTS OF PARTICULATE MATTER

Particulate matter (PM) refers to a mixture of solid particles and liquid droplets found in the air, which vary in size, composition, and source. PM is typically classified by its size, with PM10 representing particles with a diameter of 10 micrometers or less, and $PM_{2.5}$ referring to particles with a diameter of 2.5 micrometers or less. $PM_{2.5}$ particles are of particular concern because they can penetrate deep into the lungs and even enter the bloodstream, posing significant health risks. These fine particles originate from combustion sources, including vehicles, power plants, industrial processes, and residential heating. Non-combustion sources such as dust, construction activities, and wildfires also contribute to PM levels.

Exposure to PM, especially $PM_{2.5}$, is associated with a wide range of adverse health effects, including respiratory and cardiovascular diseases, cancer, and premature death (Brook et al., 2019). The World Health Organization (WHO) has classified $PM_{2.5}$ as a human carcinogen due to its ability to penetrate deep into lung tissues and reach the bloodstream, causing both short-term and long-term health effects (WHO, 2021). Studies have shown that long-term exposure to $PM_{2.5}$ is linked to an increased risk of stroke, heart attacks, and lung diseases such as chronic obstructive pulmonary disease (COPD). In addition to health impacts, PM also has significant environmental consequences, contributing to visibility impairment and acid deposition. PM can alter the atmospheric radiation balance, influencing climate change by both cooling and warming the atmosphere depending on the composition of the particles (Matsuki et al., 2020). Recent research has also shown the role of PM in eutrophication and its impact on aquatic ecosystems, further highlighting its widespread environmental effects (Baker et al., 2020).

3 NOX EMISSION FROM TURBINES

Large quantities of NO_X are formed in most combustion processes, primarily due to high-temperature reactions between nitrogen (N_2) and oxygen (O_2) in the air. The formation of NO_X involves the dissociation of molecular nitrogen and oxygen into their atomic forms, which then react to produce various nitrogen oxides, including NO, NO_2, NO_3, N_2O, N_2O_3, N_2O_4, and N_2O_5. Among these, NO, N_2O, and NO_2 are the most prevalent and environmentally significant compounds, responsible for most of the regulatory and air quality concerns.

NO_X formation occurs through three primary mechanisms: thermal NO_X, fuel NO_X, and prompt NO_X.

- **Thermal NO_X:** Thermal NO_X is the most common and significant type of NO_X produced in high-temperature combustion processes. It occurs when N_2 from the combustion air reacts with O_2 at very high temperatures, typically above 1,300°C. At these elevated temperatures, the strong molecular bonds of nitrogen break, allowing the free nitrogen atoms to combine with oxygen and form nitrogen oxides. The Zeldovich mechanism describes this process through a series of reactions that result in the formation of NO and NO_2. Since the formation of thermal NO_X is highly temperature-dependent, the hotter the flame, the more NO_X is produced. This makes controlling flame temperature and optimizing the air-to-fuel ratio critical for reducing thermal NO_X emissions. Technologies like low- NO_X (LNBs) burners and Dry Low Emission (DLE) burners are commonly used to manage and minimize this type of NO_X.

- **Fuel NO_X:** Fuel NO_X is generated from the oxidation of nitrogen compounds that are chemically bound in the fuel itself, such as coal, oil, and some heavy hydrocarbons. During combustion, as the fuel breaks down, the nitrogen it contains is released and reacts with oxygen to form NO_X. Fuel NO_X formation tends to happen at lower temperatures compared to thermal NO_X and depends on the nitrogen content of the fuel, combustion temperature, and oxygen availability. There are two primary pathways for fuel NO_X production: the conversion of volatile nitrogen released in the early stages of combustion and the oxidation of nitrogen remaining in the char after devolatilization. Fuel NO_X is often controlled using techniques like low- NO_X burners (LNBs) and fuel pre-treatment processes that lower the nitrogen content in the fuel.

- **Prompt NO_X:** Prompt NO_X forms through a less common but still important mechanism, especially in fuel-rich combustion environments. It results from the rapid reaction of atmospheric nitrogen with hydrocarbon radicals (like CH and CH_2) present early in the combustion process, before the flame reaches its peak temperature. This mechanism is most noticeable in fuel-rich flames and low-temperature combustion zones. The hydrogen cyanide produced in these initial reactions is subsequently oxidized to form NO. While prompt NO_X usually contributes a smaller share of overall NO_X emissions compared to thermal and fuel NO_X, it can become significant in specific types of burners or industrial processes where fuel-rich conditions are present.

3.1 PARAMETERS INFLUENCING NO_X EMISSIONS

The level of NO_X formation, and thus NO_X emission, in a turbine depends on the combustor design, the types of fuel being burned, ambient conditions, operating cycles and the power output level (as a percentage of the rated full power output of the turbine).

3.1.1 Combustor Design

The combustor design is a critical factor in NO_X formation in diesel-fired turbines. Thermal NO_X formation is primarily influenced by flame temperature and residence time. Combustion parameters, such as equivalence ratios and the introduction of cooling air, have a significant impact on thermal NO_X emissions. Incomplete fuel/air mixing can create local fuel-rich zones and hot spots, leading to higher thermal NOx production. Thermal NO_X formation is highly sensitive to flame temperature (Nussbaumer, 2003).

3.1.2 Type of Fuel

The type of fuel used in diesel-fired turbines greatly affects NO_X emissions. Diesel fuel typically contains higher carbon content than gaseous fuels, leading to higher flame temperatures and increased NO_X emissions. Fuels with higher sulphur content can also contribute to the formation of sulphur-based aerosols, which may indirectly affect NO_X emissions. Conversely, using lower-sulphur diesel or alternative fuels may help reduce NO_X formation by lowering flame temperatures (Hassan et al., 2005).

3.1.3 Ambient Conditions

The new CTs are located on the coast, where humidity levels are higher. Therefore, it is important to examine the effect of ambient conditions on emissions. Ambient conditions, particularly humidity, temperature, and pressure, influence NO_X formation in diesel turbines. Water vapour acts as an inert substance, reducing flame temperature and thereby decreasing NO_X emissions. At low humidity, NO_X emissions increase with higher ambient temperatures. However, at high humidity, the effect of temperature on NO_X emissions varies: at low ambient temperatures, NO_X emissions rise with increasing temperature, while at higher temperatures (above 10°C or 50°F), NO_X emissions typically decrease (Vogt et al., 2008) (Berkowicz et al., 1997).

3.1.4 Operating Cycles

In diesel-fired turbines, NO_X emissions are primarily determined by the combustion process, not by downstream conditions. In simple and cogeneration cycles, NO_X emissions are similar because they are formed only in the combustor. In regenerative cycles, NO_X emissions do not increase, as the firing temperature remains constant despite reduced fuel usage due to the higher inlet temperature in the combustion chamber (Perry et al., 2010).

3.1.5 Power Output Level

NOx emissions in diesel turbines are correlated with the power output level. At lower power outputs, the flame temperature is reduced, leading to lower NO_X emissions. Conversely, at higher power outputs, increased flame temperatures lead to higher NO_X emissions (Ferguson et al., 2016a).

3.2 Uncontrolled Emission Factors

The uncontrolled NO_X emission factors for diesel-fired turbines typically range between 300 and 800 ppmv, depending on the manufacturer, turbine design, and power output levels (U.S. EPA, 2004; Li et al., 2017). The emissions factors are generally applicable to internal combustion engines and combustion sources, including both diesel engines and turbines. However, they are not specifically focused solely on diesel-fired turbines but rather encompass broader combustion technologies, including diesel engines and stationary combustion sources.

3.3 Regulation

In the United States, the proposed federal New Source Performance Standards (NSPS) under 40 CFR Part 60, Subpart KKKK, established by the U.S. Environmental Protection Agency (EPA), sets emission standards for stationary combustion turbines, including those firing diesel fuel. For diesel-fired turbines with a heat input between 50 MMBtu/h and 850 MMBtu/h, the NO_X emission limit is 74 ppmv at 15% O_2. These standards reflect the higher NO_x emissions typically associated with diesel combustion compared to natural gas. (U.S. EPA, 2024).

In Canada, the Canadian Council of Ministers of the Environment (CCME) established the National Emission Guidelines for Stationary Combustion Turbines in 1992, outlining recommended nitrogen oxides (NO_X) emission limits for stationary natural gas turbines (CCME 1992). These guidelines specify output-based limits measured in grams per gigajoule (g/GJ) of energy output, which can be converted to concentration-based limits expressed in ppmv at 15% O_2. For non-peaking stations with a power output between 9 MW and less than 50 MW, the guideline sets a NO_x emission limit of 0.20 g NO_x/GJ, approximately equivalent to 55 ppmv at 15% O_2.

While CCME guidelines apply to stationary natural gas turbines irrespective of fuel type, diesel-fired turbines face unique challenges in meeting NO_X emission limits due to higher baseline emissions. Natural gas turbines and diesel turbines differ significantly in their emissions of NO_X, primarily due to differences in combustion technology and fuel characteristics.

Newfoundland and Labrador's Air Pollution Control Regulations primarily focus on ambient air quality standards, setting limits for PM, $PM_{2.5}$, and NO_X concentrations in the surrounding environment. Rather than specifying exhaust gas concentration limits for combustion sources like diesel turbines, the regulations emphasize maintaining overall air quality. The Air Pollution Control Regulations, 2022 require the application of BACT for emission control from regulated sources, as outlined in Section 1.3.

The Project is expected to emit 15,000 tonnes of carbon dioxide equivalent or more of greenhouse gas and according to Section 4 of the Act, it is subject to the Act and is required to submit BACT information at the time of registration or project description submission to ensure compliance with emission control standards.

4 PM EMISSION FROM TURBINES

For diesel-fueled turbines burning regular diesel, PM emissions consist mainly of two components: soot particles and sulfate particles. Soot is formed from the incomplete combustion of diesel fuel, while sulfate particles result from the oxidation of sulphur compounds in the fuel. The proportion of these particles varies based on sulphur content, combustion efficiency, and operating conditions. Diesel turbines emit higher amounts of PM and $PM_{2.5}$ compared to natural gas turbines due to the nature of diesel combustion, which generates more carbonaceous and sulfate particles. The sulphur content in the diesel fuel plays a crucial role in determining the quantity and composition of these emissions (U.S. EPA, 2024).

4.1 PARAMETERS INFLUENCING PM AND $PM_{2.5}$ EMISSIONS

Several parameters influence both the quantity and composition of PM emissions. These factors are described in the following section.

4.1.1 Diesel Sulphur Content

The use of Low-Sulphur Diesel (LSD) and Ultra-Low-Sulphur Diesel (ULSD) significantly reduces PM and $PM_{2.5}$ emissions compared to regular diesel with higher sulphur content. This reduction occurs because high sulphur content contributes to the formation of sulfate particles during combustion. With ULSD (≤15 ppm sulphur), even greater emission reductions are possible.

The impact on soot particles, which are primarily composed of elemental carbon from incomplete combustion, is less direct. While lower sulphur content reduces sulfate-based PM, it does not directly decrease soot formation.

4.1.2 Combustion Efficiency

The efficiency of the combustion process plays a significant role in determining PM and $PM_{2.5}$ emissions. Incomplete combustion, which occurs at lower combustion temperatures or with insufficient oxygen, results in the formation of soot particles. High combustion temperatures typically result in fewer emissions due to more complete oxidation of the fuel. However, excessive combustion temperatures can also lead to the formation of ultrafine particles via nucleation processes. Therefore, maintaining an optimal combustion temperature and sufficient oxygen supply is crucial for minimizing particulate emissions (Nussbaumer, 2003).

4.1.3 Turbine Design and Engine Load

The design of the diesel turbine, including its operating parameters such as pressure, temperature, and speed, significantly affects the formation of PM. High-pressure and high-temperature environments facilitate the nucleation and agglomeration of particles. As the engine load increases, the combustion temperature rises, which can lead to higher formation of ultrafine particles. Under low load conditions, engines may not reach sufficient temperatures for complete combustion, leading to higher soot formation (Tian et al., 2013).

4.1.4 Fuel Injection and Quality

Diesel fuel properties, such as its sulphur content, viscosity, and cetane number, have a direct impact on PM emissions. Higher sulphur content contributes to the formation of sulfate aerosols through the oxidation of sulphur compounds in the exhaust. Fuel quality is a key factor influencing the size and composition of particulate emissions, as lower-quality fuels tend to produce higher amounts of soot (Hassan et al., 2005). The use of alternative low-sulphur fuels or biodiesel blends can help mitigate PM emissions, as they generally produce fewer particulate pollutants compared to conventional diesel fuel (Baumgardner et al., 2006).

4.1.5 Ambient Conditions

The new CTs are located on the coast, where humidity levels are higher. Therefore, it is important to examine the effect of ambient conditions on PM emissions. Atmospheric conditions such as temperature and humidity influence both the nucleation and growth of $PM_{2.5}$ particles. For instance, higher humidity can lead to the condensation of water vapour onto particles, increasing their size and weight. This can contribute to higher levels of secondary PM, especially sulfate aerosols, when sulphur compounds in the exhaust interact with water vapour (Vogt et al., 2008). In case of LSD or ULSD use, this effect is negligible.

5 OPTIONS FOR NO_X CONTROL

NOx emissions from combustion processes can be controlled through a variety of technologies, broadly categorized into dry combustion controls, dry post combustion controls, and wet controls. As the CTs primary fuel is diesel, the emission control technologies discussed in this section are specific to turbines burning diesel fuel.

- Dry combustion control technologies focus on minimizing NO_X formation during the combustion process by altering the combustion environment. LNBs are one of the most common methods in this category, reducing NO_X emissions by 40–60% through precise control of air-fuel mixing and limiting peak flame temperatures (World Bank Group, 1998; CIMAC, 2008). DLN combustors take this a step further by pre-mixing air and fuel, achieving up to 90% NO_X reduction and producing emissions as low as 9 ppmv in some advanced systems (U.S. EPA, 2000; Schorr & Chalfin, 2022). Ultra-Low NO_X burners (ULNBs) represent a further advancement, providing significant NO_X reductions by ensuring thorough pre-mixing and optimized combustion (Sargent & Lundy, LLC, 2022). Some of ULN technologies use catalytic oxidation to reduce flame temperature and NO_X and CO formation.
- Dry post combustion control technologies primarily include post-combustion treatments designed to chemically reduce NOx emissions. Selective Catalytic Reduction (SCR) is one of the most effective and widely used techniques in this category, achieving over 90% NOx reduction by injecting ammonia or urea into the exhaust stream and passing it through a catalyst (Richards & Schell, 2000; U.S. EPA, 1993; Smith, 2022). Although highly efficient, SCR systems require substantial capital investment and ongoing operational costs (RTP Environmental Associates Inc., 2015).
- Wet control technologies lower NO_X emissions through water or steam injection. These technologies are applicable to both natural gas and diesel-fired turbines. These technologies work by lowering the peak combustion temperature, which reduces thermal NO_X formation regardless of the fuel type. This approach typically achieves 40–60% NOx reduction, though it may increase carbon monoxide (CO) emissions as a trade-off (U.S. EPA, 2000; World Bank Group, 1998). The effectiveness of water and steam injection depends on factors such as the water-to-fuel ratio and combustion system configuration (Sargent & Lundy, LLC, 2022; U.S. EPA, 1993).

In practice, selecting the appropriate NOx control technology depends on various factors, including fuel type, combustion system design, emission reduction goals, and economic considerations. While SCR remains the gold standard for maximum NOx reduction, advancements in combustion control technologies like DLN and ULN offer efficient alternatives with lower capital costs and operational complexity.

5.1 DRY COMBUSTION CONTROL TECHNOLOGIES

5.1.1 Low NOx Burners (LNB)

LNBs reduce NOX emissions primarily by using staged combustion, where the fuel and air are introduced in separate zones to control flame temperature and reduce the formation of thermal NO_X. In the first stage, fuel-rich combustion occurs at a lower temperature, and in the subsequent stages, additional air is introduced to complete combustion. This process limits the peak flame temperature and reduces oxygen availability during the hottest part of the burn, both of which are key contributors to NO_X formation. LNBs can be applied to both natural gas and liquid-fired turbines, including diesel, making them a more flexible but somewhat less effective option for NO_X control.

5.1.2 Dry Low Emissions (DLE) and Dry Low NO_X (DLN) Burners

Dry Low Emission (DLE) and Dry Low NO_X (DLN) are essentially the same in principle, but the terminology varies slightly depending on the manufacturer and context. DLN is the term commonly used by General Electric (GE), while DLE is used more broadly by other manufacturers like Siemens, Solar Turbines, and Mitsubishi. DLE and DLN burners represent advanced low-NOx combustion technologies that use lean premixed combustion technology, specifically designed for natural gas turbines. These systems reduce NOx emissions by carefully managing the air-fuel mixture and maintaining lower flame temperatures during combustion (U.S. Environmental Protection Agency, 2000). Unlike older systems that rely on water or steam injection for NOx control, DLE and DLN systems achieve substantial emission reductions without additional cooling agents, enhancing efficiency and reducing operational costs (Schorr & Chalfin, 2022).

DLE systems primarily use lean premixed combustion, where fuel and air are thoroughly mixed before ignition. This creates a more uniform and cooler flame, significantly minimizing NOx formation. As a result, DLE systems often achieve NO_X emissions in the range of 9–25 parts per million (ppm) without the need for water or steam injection. These systems are widely used in aeroderivative turbines such as the GE LM6000, Solar Mars 100, and Siemens SGT-800 (Smith, 2022). In contrast, DLN systems—GE's proprietary technology for their heavy-duty natural gas turbines—employ staged combustion. By burning fuel in multiple zones, DLN technology carefully controls temperature and NOx production, often achieving NOx levels as low as 9 ppm without external cooling (U.S. Environmental Protection Agency, 1993).

DLE and DLN technologies are primarily developed for and widely used in natural gas turbines, where lean premixed combustion can be effectively implemented. These technologies are technically feasible for diesel-fired turbines; however, their application would require significant modifications to the burners.

5.1.3 Ultra-Low NOx Burners (ULNB)

Ultra-Low NOx Burners (ULNB) are advanced combustion systems designed to minimize NO_X emissions by optimizing the air-fuel mixture and controlling the combustion temperature. Unlike traditional burners, ULNBs use techniques like staged combustion, flue gas recirculation, and lean premixed combustion to achieve more complete and efficient fuel burning, which significantly reduces the formation of NO_X. These systems are particularly effective in industrial natural gas turbines and large-scale power generation applications, often achieving NOx emission levels as low as 9–15 parts per million (ppm) when firing natural gas (U.S. EPA, 1993). ULNBs offer several advantages, including improved thermal efficiency and reduced greenhouse gas emissions compared to conventional combustion systems. Additionally, they eliminate the need for water or steam injection, avoiding the operational complexities, increased water demand, and potential maintenance issues associated with wet NOx control technologies (CIMAC, 2008). By combining low emissions with efficient performance, ULNBs are increasingly becoming the preferred choice for meeting stringent environmental regulations in both simple- and combined-cycle power plants. Similar to DLE and DLN, this technology is technically feasible for diesel-fired turbines; however, its application would require significant modifications to the burners.

5.1.4 Catalytic Combustion

Catalytic combustion is an advanced emission control approach that uses catalysts to promote cleaner and more efficient fuel combustion, significantly reducing Nox Emission. XONON, developed by Mitsubishi Power, a subsidiary of Mitsubishi Heavy Industries, is an example of catalytic combustion technology specifically designed for natural gas turbines. This technology uses a proprietary catalyst to convert NOx into nitrogen and water vapour and CO into carbon dioxide. Although XONON offers high emission reduction efficiency and operational simplicity, considerations such as catalyst longevity, operational costs, and compatibility with existing turbine systems are important when assessing its suitability.

Notably, XONON is designed for natural gas turbines and is not typically applied to diesel turbines, which often require different emission control technologies tailored to their unique combustion processes.

5.2 WET CONTROL TECHNOLOGIES

5.2.1 Water or Steam Injection

Water or steam injection is a well-established method for controlling NO_X emissions in GE LM6000 gas turbines, commonly used in both simple-cycle and combined-cycle power plants operating on diesel or natural gas. NOx formation in natural gas turbines primarily results from the high combustion temperatures where nitrogen and oxygen from the air react to produce NOx. In turbines like the GE LM6000, water or steam is injected directly into the combustor's flame zone to reduce peak combustion temperatures by absorbing heat. This also increases the mass flow rate through the turbine without additional fuel input, further cooling the flame and slowing the rate of NOx production. Steam injection, in particular, can enhance power output and efficiency because the steam expands through the turbine like combustion gases. This technique can lower NOx emissions by up to 70% to 90%, depending on the water-to-fuel ratio and system configuration (CIMAC, 2008). However, these benefits come with trade-offs, including increased demand for high-purity water, potential efficiency losses due to energy used in heating and vaporizing water, and higher maintenance requirements resulting from the risk of corrosion and deposits caused by added moisture. The efficiency losses from water injection can be notable, contributing to lower efficiency levels compared to dry low-emissions systems (CIMAC, 2008).

5.2.2 Single Annular Combustion (SAC)

Single Annular Combustion (SAC) is a burner design, not an emission control method. It features a ring-shaped combustion chamber with fuel injectors and flame zones arranged in an annular configuration. Since SAC designs do not inherently support lean premixed combustion, they are often paired with water or steam injection systems to control NO_X emissions by lowering flame temperatures. While SAC technology is proven and capable of handling a wide range of fuels, it has drawbacks, including high water demand, increased operational costs, and maintenance issues related to potential corrosion and deposits from water injection (CIMAC, 2008). SAC systems also typically exhibit lower efficiency because of the energy required to vaporize water. In contrast, DLE systems achieve combined-cycle efficiencies as high as 56% without the need for water or steam injection (OSTI, n.d.), making them more attractive for reducing both emissions and operational complexity.

5.2.3 Factors Affecting the Performance of Wet Controls

The water-to-fuel ratio (WFR) is the most important parameter affecting the performance of water or steam injection systems. Higher WFRs generally lead to greater NOx reduction efficiency, with reductions of 70% to 90% commonly achieved. Water is a more effective heat sink than steam because it absorbs additional energy during vaporization, so higher levels of steam than water must be injected to achieve the same NOx reduction. Combustor geometry and the design of the injection nozzles also play a critical role in performance. Proper atomization and a well-distributed spray pattern are essential to ensure a homogeneous mixture of water droplets and fuel, which prevents localized hot spots that could lead to increased NOx emissions. Additionally, the fuel type impacts emission performance, with lower NOx levels typically achieved when using gaseous fuels compared to liquid fuels (CIMAC, 2008).

5.2.4 Achievable NOx Emissions Levels Using Wet Controls

Guaranteed NOx emission levels provided by natural gas turbine manufacturers for wet controls typically range around 25 to 42 ppmv for most natural gas turbines and 42 to 75 ppmv for most oil-fired turbines, depending on system configuration and water-to-fuel ratios (WFR). The actual percent reduction in NOx emissions using water or steam injection generally ranges from 70 to 90 percent, depending on the turbine's uncontrolled emission levels and the specific injection method applied (CIMAC, 2008).

Emission test data for water injection on natural gas turbines indicate NOx emissions ranging from approximately 20 ppm to 105 ppm, with WFRs between 0.16 and 1.32. These tests cover a wide range of turbine sizes, from 2.8 MW to 97 MW, demonstrating that water injection is effective across various natural gas turbine models. NOx emission levels consistently decrease as the WFR increases, though the extent of reduction also depends on factors like turbine design, efficiency, firing temperature, and the extent of combustion controls incorporated into the combustor design.

For steam injection, NOx emission test data show emissions ranging from approximately 40 ppm to 80 ppm, with WFRs between 0.50 and 1.02. These results are based on turbines firing natural gas with power outputs ranging from 30 MW to 70 MW. Steam injection not only reduces NOx emissions but can also improve turbine efficiency and power output by expanding through the turbine like combustion gases (CIMAC, 2008).

Water injection can reduce NO_X emissions in diesel-fired turbines by approximately 50–70%, which is comparable to the reduction efficiency observed in natural gas turbines on a percentage basis. However, due to the inherently higher baseline NO_X emissions in diesel combustion—often ranging from 300 to 800 ppm—the absolute post-injection NO_X levels in diesel turbines tend to remain higher than those in g natural gas units. While extensive emission test data exist for natural gas turbines, data specific to diesel-fired turbines are limited, though available studies and guidance documents (CIMAC, 2008, U.S.EPA) suggest similar relative performance in NO_X reduction using water injection.

5.2.5 Impact on Hydrocarbon and Carbon Monoxide Emissions

Wet control technologies, such as water or steam injection, primarily target NO_X reduction in gas turbines, but they can also influence hydrocarbon and CO emissions. In diesel-fired turbines, the injection of water or steam lowers the peak combustion temperature, which reduces NOx formation but often results in incomplete combustion. This incomplete combustion can lead to an increase in hydrocarbons and CO emissions, as the cooler flame temperature may prevent the complete oxidation of fuel (CIMAC, 2008). As a result, while NOx emissions are significantly reduced—often by 70 to 90 percent—the trade-off is a potential rise in unburned hydrocarbons and CO, which can affect overall air quality and compliance with emission standards. The impact of water or steam injection on hydrocarbon and CO emissions is generally similar for both natural gas- and diesel-fired turbines, but the effect can be more significant in diesel turbines due to less efficient combustion.

5.2.6 Impact on Turbine Performance:

The use of water or steam injection in diesel-fired turbines also impacts turbine performance, particularly in terms of efficiency and power output. Steam injection can enhance power output and thermal efficiency because the injected steam expands through the turbine alongside combustion gases, contributing to increased mass flow and mechanical work (OSTI, n.d.). However, water injection generally results in a slight decrease in thermal efficiency, as energy is diverted to vaporize the water, reducing the available energy for power generation. Despite these performance impacts, wet controls remain a widely used NOx reduction strategy due to their proven effectiveness and operational flexibility in various turbine configurations.

5.2.7 Impact on Maintenance Requirements:

Wet control systems in diesel-fired turbines introduce additional maintenance challenges due to the presence of moisture in the combustion system. The continuous injection of water or steam increases the risk of corrosion and deposits in the hot section of the turbine, particularly around the combustor and turbine blades (CIMAC, 2008). The need for high-purity water to avoid mineral buildup adds complexity to water treatment and supply systems, increasing operational costs and requiring frequent inspections and cleaning. Furthermore, erosion of turbine components can occur over time, potentially reducing equipment lifespan and increasing downtime for maintenance.

The U.S.EPA (U.S.EPA 1993) summarized the maintenance impacts provided by some turbine manufacturers. These impacts are shown in Table 5-1. The table shows that the maintenance impact, if any, varies from manufacturer to manufacturer and model to model. Some manufacturers stated that there is no impact on maintenance intervals associated with water or steam injection for their turbine models. Data were provided only for operation with natural gas. There is no information regarding the effect of injection of steam on the maintenance of the natural gas turbines firing fuel oil.

Table 5-1: Impacts of Wet Controls on Natural Gas Turbine Maintenance

	NO_x Emissions, ppmv at 15% O_2			Inspection Interval, Hours		
Manufacturer/ Model	**Standard Combustor**	**Water Injection**	**Steam Injection**	**Standard Combustor**	**Water Injection**	**Steam Injection**
General Electric						
LM1600	133	42/25	25	25,000	16,000[a]	25,000
LM2500	174	42/25	25	25,000	16,000[a]	25,000
LM5000	185	42/25	25	25,000	16,000[a]	25,000
LM6000	220	42/25	25	25,000	16,000[a]	25,000
MS5001P	142	42	42	12,000	6,000	6,000
MS6001B	148	42	42	12,000	6,000	8,000
MS7001E	154	42	42	8,000	6,500	8,000
MS7001F	179	42	42	8,000	8,000	8,000
MS9001E	176	42	42	8,000	6,500	8,000
MS9001F	176	42	42	8,000	8,000	8,000
Asea Brown Boveri						
GT10	150	25	42	80,000[b]	80,000[b]	80,000[b]
GT8	430	25	29	24,000	24,000	24,000
GT11N	400	25	25	24,000	24,000	24,000
GT35	300	42	60	80,000[b]	80,000[b]	80,000[b]
GT24	25[e]	NA[d]	25[e]	24,000[b]	NA[d]	24,000[b]
Siemens Power Corp.						
V84.2	212	42	55	25,000	25,000	25,000
V94.2	212	55	55	25,000	25,000	25,000
V64.3	380	75	75	25,000	25,000	25,000
V84.3	380	75	75	25,000	25,000	25,000
V94.3	380	75	75	25,000	25,000	25,000
Solar Turbines, Inc.						
T-1500 Saturn	99	42	NA[c]	NA[d]	NA[d]	NA[c]
T-4500 Centaur	150	42	NA[c]	NA[d]	NA[d]	NA[c]
Type H Centaur	105	42	NA[c]	NA[d]	NA[d]	NA[c]
Taurus	114	42	NA[c]	NA[d]	NA[d]	NA[c]
T-12000 Mars	178	42	NA[c]	NA[d]	NA[d]	NA[c]
T-14000 Mars	199	42	NA[c]	NA[d]	NA[d]	NA[c]

Allison/ General Motors						
501-KB5	155	42	NA[c]	25,000	17,000	NA[d]
501-KC5	174	42	NA[c]	30,000	22,000	NA[d]
501-KH	155	42	25	25,000	17,000	20,000
570-K	101	42	NA[c]	20,000	12,000	NA[d]
571-K	101	42	NA[c]	20,000	12,000	NA
Westinghouse						
251B11/12	220	42	25	8,000	8,000	8,000
501D5	190	25	25	8,000	8,000	8,000

Notes: Details of steam injection maintenance intervals are subject to confirmation with each manufacturer.

[a] Applies only to 25 ppmv level. No impact for 42 ppmv.

[b] This interval applies to time between overhaul (TBO).

[c] Steam injection is not available for this model.

[d] Data not available.

[e] No NO_x reduction quoted for steam injection

5.3 DRY POST COMBUSTION CONTROL TECHNOLOGIES

5.3.1 Selective Catalytic Reduction (SCR)

SCR is a proven post-combustion technology used to reduce NO_X emissions from diesel-fired turbines. SCR systems convert NO_X into nitrogen and water by introducing ammonia (NH_3) or ammonia-producing compounds like urea into the exhaust stream in the presence of a catalyst. These systems typically operate within a temperature range of 200°C to 400°C (392°F to 752°F), depending on exhaust conditions, with catalyst materials like base metals (e.g., titanium or vanadium oxides), noble metals, or zeolites providing high surface area and minimal obstruction to flue gas flow (CIMAC, 2008b).

For diesel-fired turbines, the primary NO_X reduction reactions involve the conversion of NO NO_2 with ammonia. Given that NO makes up the majority of NO_X emissions, the efficiency of this reaction is critical. However, the presence of sulphur in diesel fuel introduces additional complexity. Sulphur dioxide (SO_2) in the exhaust can oxidize to sulphur trioxide (SO_3), which reacts with ammonia to form ammonium bisulfate and ammonium sulfate at lower temperatures. These byproducts can lead to fouling, increased backpressure, and corrosion of downstream equipment, particularly in heat recovery systems (CIMAC, 2008c).

SCR systems can be applied to diesel-fired turbines across various configurations, but their effectiveness depends on exhaust temperature, fuel composition, and operational conditions. Diesel turbines often operate with variable exhaust temperatures, which can fall outside the optimal range for catalyst performance. Base-metal catalysts typically function best between 260°C and 400°C (500°F to 800°F), while zeolite catalysts extend this range up to 590°C (1100°F), offering more flexibility in high-temperature applications (CIMAC, 2008b).

5.3.2 Factors Affecting SCR Performance

The performance of SCR systems in diesel-fired turbines depends on several factors. Catalyst material and condition play a key role, with base metals like vanadium and tungsten oxides and zeolites being the most commonly used. These materials offer varying resistance to degradation caused by contaminants in diesel exhaust, such as sulphur compounds and particulates. Over time, the catalyst's efficiency may decrease due to masking, poisoning, or sintering, resulting in reduced NO_x conversion rates (CIMAC, 2008a).

Maintaining the reactor temperature within the catalyst's optimal operating range is also crucial, as deviations can lead to lower NO_x reduction efficiency and increased ammonia slip—where unreacted ammonia escapes into the atmosphere as a secondary emission (U.S. EPA, 1999).

Space velocity, defined as the volumetric flow rate of exhaust gas divided by the catalyst volume, further influences SCR performance. Lower space velocities allow for longer residence times of gases within the catalyst, enhancing NO_x reduction efficiency but necessitating larger catalyst volumes (CIMAC, 2008b). The NH_3/NO_x ratio is equally important, with a typical operating ratio of around 1.0 to balance effective NO_x reduction with minimal ammonia slip. Deviations from this stoichiometric balance can either compromise emission control efficiency or lead to excess ammonia emissions (CIMAC, 2008c).

5.3.3 Achievable NO_X Emission Reduction Efficiency Using SCR

Most SCR systems achieve NO_x reduction efficiencies typically between 70% and 95%, with ammonia slip levels reported as high as 20–25 ppm (CIMAC, 2008b; U.S. EPA, 1999). When combined with technologies like water or steam injection and DLN combustors, SCR can reduce NO_x emissions to as low as 2.5–4.2 ppmv for natural gas and 4.2–11.0 ppmv for oil fuels (U.S. EPA, 1999).

5.3.4 Application and Challenges of SCR for Diesel Turbines

SCR is one of the most widely used post-combustion technologies for controlling NO_X emissions from combustion engines, including diesel turbines. However, its application in diesel-fired turbines faces several technical and environmental challenges. Diesel turbines often burn heavier fuels, leading to higher levels of PM and sulphur oxides (SO_X), which can foul the SCR catalyst and reduce its efficiency and lifespan (CIMAC, 2008a). In contrast, natural gas turbines typically use cleaner fuels like natural gas, producing fewer contaminants and allowing SCR systems to operate more efficiently over longer periods (CIMAC, 2008b).

A significant challenge lies in the exhaust temperature characteristics of diesel turbines. SCR systems require exhaust temperatures between 250°C and 450°C for optimal ammonia-NO_x reactions. Diesel turbines often operate at lower exhaust temperatures, which can fall outside this optimal range, requiring additional preheating or system modifications to maintain performance (CIMAC, 2008c). This adds complexity and increases operational costs and energy consumption.

Despite these challenges, SCR is used in large stationary diesel turbines where strict NO_x regulations apply, particularly in power generation and industrial co-generation applications. Advanced filtration systems like Diesel Particulate Filters (DPFs) or Electrostatic Precipitators (ESPs) are often installed upstream of the SCR system to reduce particulate load and protect the catalyst, helping maintain SCR efficiency but requiring significant investment in equipment and maintenance (OSTI, n.d.).

5.3.4.1 Environmental and Operational Considerations

SCR systems, while effective at reducing NO_x emissions, introduce their own environmental and operational challenges. Ammonia, the reducing agent used in SCR systems, is a toxic substance requiring special handling and permitting. The risk of leakage or accidental release during delivery adds environmental hazards, and ammonia slip — the release of unreacted ammonia — is regulated as a toxic emission in most jurisdictions (U.S. EPA, 1999). Ammonia slip can also lead to the formation of secondary pollutants like ammonium sulfate or ammonium nitrate, increasing operational complexity (CIMAC, 2008b). Managing ammonia slip requires precise control and monitoring systems, adding to maintenance requirements.

SCR catalysts often contain toxic metals like vanadium and tungsten, which are classified as hazardous waste at the end of their operational life. Proper disposal requires adherence to stringent hazardous waste management protocols, increasing both environmental impact and cost (CIMAC, 2008c). Failure to manage spent catalysts responsibly can lead to soil and water contamination.

Fuel quality also significantly impacts SCR performance in diesel turbines. High-sulphur diesel fuels increase SO_3 formation, leading to ammonium salt deposition and catalyst fouling. This results in more frequent maintenance, reduced efficiency, and potential damage to exhaust components. Ammonia slip exacerbates this issue by accelerating salt buildup (CIMAC, 2008c).

Retrofitting SCR systems on diesel-fired turbines can be challenging and costly. Simple-cycle diesel turbines often require additional heat exchangers to bring exhaust temperatures within the catalyst's effective range, while combined heat and power (CHP) systems may require significant modifications to existing heat recovery equipment (CIMAC, 2008a). These capital and operational costs often make SCR less feasible for smaller or mobile diesel turbine applications, limiting its use to larger, stationary installations where strict emission standards justify the investment (OSTI, n.d.).

Recent advancements in SCR technology have focused on improving catalyst durability, expanding effective temperature ranges, and integrating emission control systems. Enhanced catalysts with higher thermal stability and resistance to poisoning have extended operational lifespans and maintained efficiency in varying conditions (CIMAC, 2008b). Modern diesel-fired turbines increasingly adopt combined emission control systems, integrating SCR with Exhaust Gas Recirculation (EGR) and particulate filters. This approach effectively addresses multiple pollutants, including NO_x, SO_x, and PM, ensuring compliance with evolving emission standards (U.S. EPA, 1996).

5.3.4.2 Technical and Measurement Challenges

Beyond environmental and cost considerations, SCR systems face technical challenges related to emission measurement and system performance. Achieving single-digit NO_x levels (below 9 ppmv) can be difficult due to variability and uncertainty in current measurement methodologies. Factors such as exhaust flow calculation errors, ambient atmospheric conditions, and measurement instrument variability can introduce significant uncertainty, sometimes as high as 50% (CIMAC, 2008a). These issues complicate the enforcement of ultra-low NO_x limits and require advanced monitoring systems to ensure compliance.

The efficiency and reliability of SCR systems can also be compromised by the mechanical and operational demands of diesel turbines. Aggressive emission targets often lead to combustor oscillations, adversely affecting energy conversion efficiency and increasing wear on turbine components (OSTI, n.d.). Maintaining both low emissions and high operational reliability requires careful balancing of system design and performance parameters.

5.3.5 SCONOX

SCONOX is a catalytic air pollution control technology originally designed for natural gas turbines. It reduces NO_X and CO emissions without using ammonia, offering high efficiency and dual pollutant control. However, its sensitivity to sulphur and particulate matter makes it technically impractical for diesel-fired turbines, which typically burn higher-sulphur fuels and generate more PM. As such, SCONOX is not suitable for diesel applications without extensive fuel and exhaust treatment.

5.3.6 Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR) is a post-combustion technology that reduces NO_X emissions by injecting NH_3 or urea into the flue gas within a specific temperature range, typically between 870°C and

1,200°C (1,600°F to 2,200°F). Within this range, NH_3 reacts with NO_X to form nitrogen and water without the need for a catalyst. The optimal temperature window is crucial; injecting NH_3 above 1,200°C can lead to increased NO_X formation, while temperatures below 870°C result in reduced reaction efficiency. Introducing hydrogen (H_2) alongside NH_3 can lower the effective temperature window to 700°C (1,300°F), enhancing flexibility in various applications (U.S. EPA, 2016a).

Despite its economic advantages over SCR due to the absence of catalyst costs, SNCR faces challenges when applied to natural gas turbines. According to manufacturers data, both diesel and Natural gas turbine exhaust temperatures typically do not exceed 600°C (1,100°F), which is below the effective range for SNCR reactions. Additionally, the required residence time for the reaction is approximately 0.3 to 1 second, which is relatively long given the high flow velocities in natural gas turbine operations. These factors limit the practicality of SNCR in both diesel and natural gas turbine applications (U.S. EPA, 2016b).

5.4 SUMMARY OF NO_X CONTROL TECHNOLOGIES

Table 5-2 Summary of Feasible and Viable NO_X control technologies for diesel turbines.

Table 5-2: Feasible and Viable NO_X control Technologies for Diesel Turbines

Emission Control Technology	NO_X Reduction Efficiency	Why It's Feasible for Diesel Turbines	Key Considerations
Selective Catalytic Reduction (SCR)	80% to 95%	Most effective NO_X reduction, works well with ULSD	Requires ammonia or urea injection; sensitive to sulphur and PM; catalyst maintenance necessary
Dry Low NO_X **(DLN) Combustors**	50% to 75%	Achieves low NO_X without water/steam injection; improves efficiency	Not compatible with water/steam injection; requires stable high-temperature operation. DLN uses premixed air and fuel mixture. Water or steam injection will interfere with the accurate control of burners.
Water or Steam Injection (SAC)	50% to 70%	Simple and widely used; effective in reducing combustion temperature	High water demand; increased maintenance from corrosion and deposits
Selective Non-Catalytic Reduction (SNCR)	30% to 60%	Lower-cost alternative to SCR; no catalyst required	Requires precise temperature control (900°C to 1100°C); less effective at lower exhaust temperatures
Ultra-Low NO_X **Burners (ULNB)**	75% to 90%	Advanced prevention-based technology; reduces NO_X during combustion	Requires specific turbine design; high initial cost but lower operational complexity

6 OPTIONS FOR PM AND $PM_{2.5}$ CONTROL

Controlling PM and $PM_{2.5}$ requires efficient aftertreatment technologies tailored to the unique characteristics of diesel turbine exhaust, including high flow rates, variable temperatures, and the potential for increased sulphur and soot content. Three primary technologies used for PM control in diesel-fired turbines are DPFs, Diesel Oxidation Catalysts (DOCs), and ESPs, each with distinct mechanisms, efficiencies, and operational considerations. Besides DPFs, DOCs, and ESPs, several other control technologies can be applied to reduce PM emissions from diesel turbines. Each has its own advantages and limitations based on efficiency, cost, operational conditions, and compatibility with diesel turbine exhaust characteristics.

6.1 DIESEL PARTICULATE FILTERS (DPF)

DPFs are highly effective in capturing and reducing PM emissions by physically trapping soot and fine particles within a porous ceramic or metal filter structure. Wall-flow DPFs can achieve up to 98% efficiency for soot removal, with some tests showing solid particulate removal rates around 98.9% (Ferguson et al., 2016b). These filters use regeneration methods to burn off accumulated soot, minimizing backpressure and maintaining engine efficiency.

6.1.1 Regeneration Methods:

- Active Regeneration: Involves raising exhaust temperatures through engine throttling or fuel injection to oxidize soot. This process can increase fuel consumption and operational complexity. In the case of peaking operation of diesel turbines, it presents challenges. In diesel-fired turbines, active regeneration of Diesel Particulate Filters (DPFs) involves increasing the exhaust temperature to oxidize accumulated soot, typically by injecting additional fuel upstream of the DPF and combusting it using a Diesel Oxidation Catalyst (DOC). This process raises the exhaust temperature to approximately 600–700°C, allowing soot to be burned off and preventing excessive backpressure. Unlike engines, turbines operate more steadily, enabling more predictable regeneration cycles, though careful system design is needed to manage high exhaust flowrates and avoid turbine performance degradation. Active regeneration systems for turbines must also accommodate the turbine's sensitivity to pressure drops and thermal stress (U.S. EPA, 2002; Johnson Matthey, 2018).
- Passive Catalyzed Regeneration: Uses catalysts like cerium to lower the temperature needed for soot oxidation, enabling regeneration at around 300°C.
- Continuously Regenerating Trap (CRT): Combines oxidation catalysts with the DPF, promoting soot oxidation at lower temperatures and reducing PM emissions by 50–70%.

Despite their high efficiency, DPFs are less common in diesel turbines due to several technical challenges. Diesel turbines produce high exhaust flow rates and variable exhaust temperatures, often falling below the 350°C needed for passive regeneration. This can lead to soot buildup, clogging, and increased maintenance. Additionally, high pressure drop across a DPF reduces the efficiency of diesel turbines by increasing backpressure, which lowers power output and raises fuel consumption. This can lead to more frequent regeneration cycles, higher operating and maintenance costs, and potential performance derating—especially problematic during peaking operations where efficiency is critical.

6.2 DIESEL OXIDATION CATALYST (DOC)

DOCs reduce PM emissions by oxidizing the volatile organic fraction of PM, hydrocarbons, and CO over a catalytic surface (typically platinum or palladium). DOCs are more effective at addressing the soluble organic portion of PM rather than solid soot, making them suitable for applications where hydrocarbon reduction is a priority.

6.2.1 DOC Efficiency and Performance:

- PM Reduction: 20% to 40% in diesel internal combustion engines (ICEs) and 10% to 25% in diesel turbines.
- Optimal Temperature Range: 200°C to 500°C, aligning well with the steady-state operation of diesel ICEs but less effective in variable-load diesel turbines.
- Pressure Sensitivity: DOCs impose low backpressure, which is manageable in ICEs but can significantly affect turbine efficiency.

In diesel turbines, DOCs face challenges such as high exhaust flow rates, temperature variability, and lower soluble organic fractions in PM. These factors limit DOC efficiency and increase maintenance needs due to catalyst fouling from soot and sulphur content. DOCs are more common in stationary diesel turbines with consistent high exhaust temperatures and ULSD fuels.

6.3 Electrostatic Precipitators (ESP)

ESPs are well-established technologies for removing PM from industrial exhaust streams. ESPs use an electric field to charge and capture PM on collection plates, achieving high filtration efficiency without significant pressure drop.

6.3.1 ESP Efficiency and Performance:

- PM Removal Efficiency: Over 95% (U.S. Environmental Protection Agency, 2021).
- Applicability: Effective for large-scale stationary diesel turbines and industrial facilities with high exhaust flow rates.
- Maintenance: Requires periodic cleaning of collection plates but offers long operational life with minimal backpressure impact.

Compared to DPFs and DOCs, ESPs provide a non-contact method for PM removal, avoiding issues like pressure buildup and soot clogging. They are particularly suitable for diesel turbines operating under variable loads and temperatures, where passive regeneration of DPFs is less reliable.

6.4 Baghouse (Fabric Filters)

Baghouse filters offer excellent PM control efficiency, often exceeding 99%, including for fine and ultrafine particles. However, their high-pressure drop can significantly affect diesel turbine efficiency, making them less practical for turbine applications. Additionally, the large size and maintenance needs of baghouses make them more common in industrial boilers and stationary combustion systems than in diesel-fired turbines, where space and efficiency are critical considerations.

6.5 Wet Scrubbers

Wet scrubbers use water or chemical solutions to capture PM and soluble gases from exhaust streams, achieving PM removal efficiencies between 80–95%. They are more commonly used in systems where both PM and acidic gases (like SO_X) need control. For diesel turbines, their high-water consumption, wastewater treatment requirements, and potential for corrosion make them less common.

6.6 SUMMARY OF PM AND M2.5 CONTROL TECHNOLOGIES

Table 6-1 Feasible PM and $PM_{2.5}$ Control Technologies for Diesel Turbines.

Table 6-1: Feasible PM and $PM_{2.5}$ Control Technologies for Diesel Turbines

Emission Control Technology	PM Reduction Efficiency	$PM_{2.5}$ Reduction Efficiency	Why It's Feasible for Diesel Turbines	Key Considerations
Diesel Particulate Filters (DPFs)	80% to 98%	80% to 98%	Highly effective; captures fine particles; works with low-sulphur fuel	High-pressure drop; requires consistent high exhaust temperatures for regeneration. Simple cycle generator data from manufacturers show lower exhaust temps and would need catalyst to reach regeneration temperature.
Electrostatic Precipitators (ESPs)	90%+	90%+	Ideal for high exhaust flow rates; minimal pressure drop	High capital and operational costs; large space requirement
Diesel Oxidation Catalysts (DOCs)	20% to 40%	10% to 25%	Reduces volatile PM fraction; low backpressure	Limited $PM_{2.5}$ control; more effective on soluble organic fraction than solid soot
Wet Scrubbers	80% to 95%	80% to 95%	Effective for both PM and sulphur-based aerosols	High-water demand; wastewater treatment required; potential for corrosion

7 CAPITAL AND OPERATING COSTS OF CONTROL TECHNOLOGIES

This section presents an analysis of the capital and operational costs associated with NO_X and PM control technologies for diesel turbines. The cost data is primarily sourced from the U.S. EPA Control Cost Manual (U.S. EPA 1996), ensuring a standardized basis for comparison. While cost-effectiveness is a common metric in industrial applications where large quantities of pollutants are removed, it is less relevant for turbines due to their relatively low emissions volumes. Instead, capital and operating costs provide a more meaningful indicator for decision-making.

It should be noted that the capital and operating costs of some technologies not commonly used in diesel turbines are very limited and carry significant uncertainty. As such, the information presented in this section is intended to provide a general understanding and a high-level analysis for the selection of BACT technology. In addition, the cost implications resulting from lower power generation efficiency and increased emissions of other contaminants are not discussed due to the lack of accurate cost information.

7.1 NOx Control Technologies

7.1.1 Water or Steam Injection

- Capital Cost: The U.S. EPA Control Cost Manual estimates capital costs for water injection systems at approximately $12,000–$25,000 per MW, depending on system complexity and water treatment requirements.
- Operating Cost: Operating costs primarily include water consumption, which ranges from 1.2 to 2.5 gallons per MMBtu of fuel burned, and potential efficiency losses of 1–3%, leading to increased fuel costs. The additional maintenance costs due to corrosion and deposits in the combustion system are estimated at $1,000–$3,000 per year per MW.

7.1.2 SCR

- Capital Cost: The EPA estimates SCR capital costs for turbines at $40,000–$100,000 per MW, depending on system size, catalyst material, and integration complexity.
- Operating Cost: Costs include ammonia or urea supply, catalyst replacement, and maintenance. Ammonia costs range from $0.50–$1.50 per lb of NOx removed, while catalyst replacement costs $50,000–$100,000 every 3–5 years.

7.2 LNB, DLE, ULNB Combustion

- Capital Cost: LNB systems range from $5,000–$15,000 per MW. DLE and ULN systems, if applicable, range from $15,000–$30,000 per MW.
- Operating Cost: Minimal for LNB; higher for DLE/ULN due to tighter control requirements and potential flame instability issues.

7.3 PM Control Technologies

7.3.1 DPFs

- Capital Cost: Data on DPF costs for turbines is scarce, but for stationary diesel engines, capital costs range from $5,000–$25,000 per MW.

- Operating Cost: Maintenance costs can be high due to filter cleaning or replacement, estimated at $2,000–$5,000 per year per MW. Fuel penalties due to backpressure may lead to efficiency losses of 1–2%.

7.3.2 ESPs

- Capital Cost: $75,000–$200,000 per MW, varying with system design and size.
- Operating Cost: $0.003–$0.005 per kWh, including energy consumption, maintenance, and periodic cleaning of collection plates.

7.4 DOCs

- Capital Cost: $5,000–$15,000 per MW.
- Operating Cost: Low; includes minimal maintenance and periodic catalyst replacement.

A summary of control technology costs is provided in Table 7-1and Table 7-2 for NO_X and PM, respectively.

Table 7-1: NOx Control Technologies

Technology	Capital Cost ($/MW)	Operating Cost
Water/Steam Injection	$12,000–$25,000	$1,000–$3,000/year + water costs
SCR	$40,000–$100,000	$0.50–$1.50/lb NO_X removed + maintenance
LNB	$5,000–$15,000	Minimal
DLE/ULN	$15,000–$30,000	Moderate (control systems)
SNCR	$30,000–$60,000	$0.002–$0.004/kWh

Table 7-2: PM Control Technologies

Technology	Capital Cost ($/MW)	Operating Cost
DOC	$5,000–$15,000	Low
DPF (Active Regeneration)	$5,000–$25,000	$2,000–$5,000/year
ESP	$75,000–$200,000	$0.003–$0.005/kWh

8 BEST AVAILABLE CONTROL TECHNOLOGIES FOR NO_X AND PM EMISSIONS

It is important to note that ACTs use LSD or ULSD as fuel and operate as peaking units, with a typical annual run time of 270 hours and a worst-case contingency scenario of up to six weeks per year.

Accurate fuel–air ratio, effective operating controls, and regular maintenance are critical for minimizing emissions in diesel-fired turbines. Proper fuel–air mixing ensures complete combustion, reducing the formation of NO_X, and unburned hydrocarbons. Advanced control systems help maintain optimal combustion conditions across varying loads, while routine maintenance prevents issues like fouled injectors or degraded components that can increase emissions.

When low-sulphur diesel fuel is used in diesel-fueled turbines, emission control challenges related to catalyst poisoning are significantly reduced. This reduction minimizes the risk of catalyst fouling and lowers maintenance requirements, making it possible to adopt a broader range of emission control technologies.

Key considerations for selecting feasible and viable NO_X control technologies for diesel turbines are:

- SCR remains the most efficient NO_X control for diesel turbines but faces challenges with ammonia slip, sulphur content, and catalyst fouling — making it best suited for large stationary applications (25 MW and above) with low-sulphur diesel. Limited space availability poses technical challenges for using this technology, and capital and operational cost poses challenges for economic feasibility of this technology given that the ACTs are used as peaking units with typical annual run time of 270 hours and a worst-case contingency scenario of less than six weeks per year.
- ULNB and DLN combustors provide high efficiency and NO_X control without the water demand of SAC, but they require optimized air-fuel mixing and cannot operate alongside water/steam injection. Water injection is incompatible with DLN because it interferes with the carefully controlled lean premixed combustion process, risking flame instability, increased emissions, and operational challenges. DLN is designed specifically to avoid the need for water or steam injection.
- Water/Steam Injection (SAC) is widely used but brings increased maintenance and lower efficiency due to corrosion and water handling. However, it provides an economically and technically viable solution for diesel turbines.

  In addition, Newfoundland and Labrador Hydro has significant experience with the operation of SAC technology at its facilities.

When low-sulphur diesel fuel is used in diesel-fueled turbines, emission control challenges related to PM and SO_X emissions are significantly reduced. This reduction minimizes the risk of catalyst fouling and lowers maintenance requirements, making it possible to adopt a broader range of emission control technologies.

As previously explained, particulate emissions from turbines are influenced by the design of the combustion system, fuel characteristics, and operating conditions. In some jurisdictions, sulfuric acid and liquid unburned hydrocarbons may also be classified as particulate matter. Feasible control options for particulate emissions are generally limited—particularly for peaking units that operate less than six weeks per year. With the exception of smoke, most particulate components are managed through fuel composition control. While smoke emissions are also influenced by fuel type, they are primarily minimized through advanced combustor design. For turbines fired with light oil, smoke is typically not a concern and, when it does occur, is usually limited to startup or shutdown periods.

Modern turbines incorporate advanced combustor designs that result in minimal particulate emissions when using low-sulfur diesel or ultra-low-sulfur diesel. Post-combustion particulate control systems are not commonly applied to simple-cycle turbine installations.

Key considerations for selecting feasible and viable PM and $PM_{2.5}$ control technologies for diesel turbines are:

- DPFs and ESPs are the most effective for PM control, with ESPs being preferable for high-flow, variable-load diesel turbines due to their lower pressure drop. The space limitations and cost implications are important factors. ESPs, while highly effective for PM removal, are impractical for ACTs due to their large footprint, which is incompatible with the space limitations in the turbine generator area. ESPs also require significant energy input and complex maintenance, making them less attractive for a peaking project focused on efficiency and reliability with typical annual run time of 270 hours and a worst-case contingency scenario of less than 6 weeks per year.
- DPF pressure drop poses a significant drawback for diesel turbine applications.
- DOCs are more effective at reducing hydrocarbons than solid PM, making them a supplementary but not primary PM control method for diesel turbines. However, it features low capital and operating cost.
- Wet scrubbers offer very high PM control but are less practical for diesel turbines due to space requirements, pressure drop, and operational complexity.

Given the constraints and considerations provided above, as well as the cost information provided in Section 7, BACT for NO_X in diesel turbines is mostly achieved through:

- Water or Steam Injection (SAC): Reduces peak flame temperature, lowering thermal NO_X formation; still compatible with diffusion flame combustion used in diesel turbines. Newfoundland and Labrador Hydro has significant experience with the operation of SAC technology at its facilities.
- Use of ULSD: Minimizes sulphur content, which can indirectly help reduce NO_x and prevent damage to any downstream emissions control devices.
- Good Combustion Practices: Optimized air-fuel ratios, advanced fuel injection, and regular maintenance to ensure clean, complete combustion.

Given the constraints and considerations provided above, as well as the cost information provided in Section 7, BACT for PM in diesel-fired turbines is most commonly achieved through:

- Use of ultra-low sulphur diesel (ULSD) to minimize PM formation at the source.
- Good combustion practices, including proper turbine tuning and maintenance to optimize fuel–air mixing and reduce PM generation.
- High-efficiency DOCs may be considered a supplementary technology for reducing organic PM (e.g., soluble organic fraction), provided proper catalyst maintenance is ensured. However, since ACTs are peaking units with a typical annual run time of 270 hours and a worst-case contingency scenario of up to six weeks per year, DOCs may not be considered BACT, as the incremental emission reductions come at a cost that is not economically feasible.

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