Bear Head Energy Green Hydrogen and Ammonia Production, Storage and Loading Facility

Environmental Assessment Registration

Sections 1-3

February 2023

Prepared for:

Bear Head Energy Inc.

Prepared by:

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File: 121431287

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Executive Summary

Bear Head Energy Inc. (BHE) proposes to construct and operate a green hydrogen and ammonia production, storage and loading facility (the Project) at the site of the previously approved, but not fully constructed, Bear Head LNG Project in the Point Tupper Industrial Park on the Strait of Canso (Bear Head Site). BHE is a Nova Scotia-registered company and owner of the previously approved Bear Head LNG Project. In July 2022, Buckeye Partners, L.P. (Buckeye) acquired BHE. Buckeye has one of North America's largest energy midstream portfolios with operations throughout the U.S. and the Caribbean.

The Project will be constructed in multiple phases driven by the availability of renewable power. At full build-out, the Project will be capable of producing 2 million tonnes per annum (mtpa) of green ammonia using renewable energy. The facility would include electrolysis units for green hydrogen production, air separation unit(s) (ASU) for nitrogen generation, Haber-Bosch ammonia synthesis unit(s), ammonia bulk storage tank(s), and a marine terminal. The proposed marine terminal includes a jetty platform, ship berthing and trestle structure, loading facilities and marine offloading facility (MOF) to be developed within the water lot owned by BHE. The design of these marine facilities will be the same as previously approved for the Bear Head LNG Project.

With safety as a priority in project development, BHE has engaged Lloyds Register to develop a code of practice to guide the design, construction, operation and abandonment of the Project. The Code of Practice for Bear Head Ammonia-Hydrogen Production Facilities (COP) supplements applicable requirements in the Gas Plant Facility Regulations and best practice from globally recognized codes and standards associated with hydrogen and ammonia.

The Project will use electrolysis to split water molecules into hydrogen and oxygen. Nitrogen will be generated in the ASU directly from the air. Once nitrogen and hydrogen have been produced, hydrogen is catalytically reacted with nitrogen to form anhydrous liquid ammonia in a Haber-Bosch ammonia synthesis unit. Ammonia carriers will transport liquid ammonia to markets outside the region. Shipping frequency is estimated to be approximately 40 to 60 ships at peak per year on ammonia carriers with a capacity of approximately 50,000 to 80,000 cubic metres (m^3). These are fewer and smaller ships than were proposed for the previously approved Bear Head LNG Project.

Approximately 15 million litres of water/day on average (4 million US gallons of water/day) will be required by the facility and will be supplied to the site via pipeline from the Landrie Lake Water Utility (LLWU). Power supply for the Project will be provided from renewable power via the grid and/or direct power connection from primarily new onshore and/or potential future offshore renewable energy projects. Water supply and energy production and storage will be permitted (as required) separately by the proponent(s) of these utilities/projects.

The Project will generate various wastes, discharges and emissions, including air emissions (dust and criteria air contaminants), lights, and noise during all phases of the Project, and reject process water (from the water purification process) during operations. The green hydrogen and ammonia synthesis process does not generate any GHG emissions. Limited greenhouse gas (GHG) emissions will be generated from fuel combustion associated with site vehicle/mobile equipment and occasional use of a diesel generator for back-up power supply. Reject process water from the water purification process (prior to electrolysis) will be tested and treated as applicable to meet CCME guidance frameworks and regulatory approval requirements prior to discharge to the Strait of Canso. Additional site water discharges include hydrostatic test water used during site testing and commissioning, and surface runoff. Solid and hazardous wastes will include scrap metals, insulation waste, packing/crating materials, paints, oils, lubricants, batteries, and domestic/office waste. Wastes will be managed in accordance with a Waste Management Plan and comply with the Solid Waste-Resource Management Regulations and applicable municipal waste requirements.

This EA Registration document was developed to meet the requirements of a Class I EA Registration under the Nova Scotia *Environment Act* and Environmental Assessment Regulations and reflects the methods and approaches used for the previously approved Bear Head LNG Project (JWEL 2004; SNC Lavalin 2015). Several marine and terrestrial studies conducted at the Bear Head site between 2003 and 2015 were used to help inform this EA Registration. Supplemental baseline studies completed in 2022 included acoustic bat monitoring, a freshwater fish and fish habitat survey, wetland and wildlife reconnaissance surveys, and eel grass survey. Additional wetland and wildlife surveys are planned for 2023.

The EA Registration document focuses on potential interactions with the following Valued Components (VCs):

- Atmospheric Environment
- Groundwater Resources
- Surface Water Resources
- Freshwater Fish and Fish Habitat
- Vegetation and Wetlands
- Wildlife and Wildlife Habitat
- Marine Environment
- Land Use and Communities
- Fisheries, Aquaculture and Marine Harvesting
- Cultural and Heritage Resources

For each VC, Project interactions and potential effects are identified for all Project phases, in consideration of effects pathways. Appropriate mitigation is identified and residual effects (i.e., post-mitigation) are evaluated. Follow-up and monitoring is proposed where there may be a need to verify mitigation effectiveness, validate effects predictions, fulfill regulatory requirements (e.g., compliance monitoring), and/or address stakeholder or Mi'kmaq concerns.

Residual effects from routine Project activities are predicted to be not significant for all VCs (Section 6). A considerable amount of site preparation work has already been performed, with a large part of the Project footprint having been established, thereby limiting the potential for effects on the terrestrial and freshwater environments. No new wetland or watercourse alterations are anticipated to be required for Project development. The development and implementation of an Environmental Management Plan will help to avoid or reduce adverse environmental effects of the Project. Follow-up and monitoring programs are proposed for vegetation and wetlands, wildlife and wildlife habitat, and the marine environment. Ongoing consultation and engagement with the Mi'kmaq of Nova Scotia and stakeholders will help to reduce adverse socio-economic effects and optimize Project benefits.

Accidents and malfunctions were evaluated separately (Section 7) and included consideration of the following scenarios: hydrogen and ammonia releases; failure of water management controls; and fuel and hazardous material spills. Provided that the prevention and response mitigation outlined in the EA Registration document, including adherence to the COP and other applicable codes and standards, is implemented, environmental effects associated with a failure of water management controls and/or fuel and hazardous material spills are predicted to be not significant. As informed by the Quantitative Risk Assessment (Appendix G) and ecological risk assessment, residual environmental effects of an unplanned release of hydrogen or ammonia could potentially result in a significant adverse effect on most of the VCs with the exception being the Cultural and Heritage Resources VC. However, with the implementation of design mitigation to prevent unplanned releases and/or reduce consequences should an unplanned release occur, and emergency response measures to respond to an emergency event, a significant adverse environmental effect is unlikely to occur.

BHE has engaged the Mi'kmaq of Nova Scotia, and regulatory and public stakeholders in order to provide Project information and obtain feedback on potential issues and concerns to be addressed during Project design and planning. Consultation and engagement efforts have included one-on-one meetings, revitalization of the Community Liaison Committee (CLC) previously established for the Bear Head LNG Project, and community open house meetings in local communities. In general there has been considerable support in the region for the Project.

The Project has the potential to remove areas historically or currently used by the Mi'kmaq for traditional purposes, such as hunting, fishing or gathering. Given that the Project Area has been substantially developed already and additional clearing and grubbing will be limited, direct effects on wildlife habitat will be limited, and associated effects to traditional land use are also anticipated to be limited. Mitigation implemented to eliminate or reduce adverse effects on biophysical resources will also serve to reduce adverse effects on Mi'kmaq land and resource use.

BHE will continue to engage the Mi'kmaq of Nova Scotia not only to understand potential concerns and mitigate adverse effects, but also optimize positive effects of the Project. BHE has and will continue to work with Mi'kmaq communities to develop and implement MOUs and benefit agreements for the Project to address protection of Aboriginal Rights and Title, ecological knowledge and traditional use access, procurement and employment opportunities, training and education, and ongoing communications. BHE will also seek opportunities for cross-cultural learning and knowledge exchange with Mi'kmaq communities.

Environmental factors which could potentially affect the Project include climate and climate change; sea ice; sea level rise; seismic activity; wildfires; and security (e.g., vandalism/terrorism) issues. All facility components and operations will be designed to all relevant engineering codes and standards (as referenced in the COP) with the full knowledge of potential environmental conditions on the site including extreme weather events as well as predicted parameters due to changing global climate. Therefore, effects of the environment on the Project are predicted to be not significant and will be managed primarily through engineering design and operational planning (including contingency plans).

The Project represents a commercial scale energy export project that will provide a non-GHG emitting fuel source and allow Nova Scotia to become a leader in the global energy transition. Building the Project to supply green ammonia to the international market provides cost advantages, including increased investment and higher production rates with decreased unit costs. Although the Project will at first produce ammonia to be shipped to world markets versus supplying local energy needs, it may also act as a pillar for the local green hydrogen and ammonia sector and support the transition in Nova Scotia to clean energy. The Project can serve to anchor a growing domestic green hydrogen and ammonia economy in Nova Scotia and potentially act as a catalyst for additional green energy investments in adjacent industries,

Abbreviations

AC CDC	Atlantic Canada Conservation Data Centre
ACI	American Concrete Institute
ANSI	American National Standards Institute
ANSMC	Assembly of Nova Scotia Mi'kmaq Chiefs
API	American Petroleum Institute
ARIA	archeological resource impact assessment
ARUs	autonomous recording units
ASU	air separation unit(s)
BHE	Bear Head Energy Inc.
BHLNG	Bear Head LNG
Ca	calcium
CAAQS	Canadian Ambient Air Quality Standards
CCME	Canadian Council of Ministers of the Environment
CCME WQG-PAL	CCME Canadian Water Quality Guidelines for the Protection of Aquatic Life
CD	chart datum
CLC	community liaison committee
cm	centimeters
CNWA	*Canadian Navigable Waters Act*
CO	carbon monoxide
CO_2	carbon dioxide
COP	Code of Practice
COSEWIC	Committee on the Status of Endangered Wildlife in Canada
Cr	chromium
CSChE	Canadian Society for Chemical Engineering
Cu	copper
CWS	Canadian Wildlife Service
dB	decibels
dBA	A-weighted dB scale

DFO	Fisheries and Oceans Canada
EBSA	ecologically and biologically significant area
ECCC	Environment and Climate Change Canada
ECREG	Eastern Canada Vessel Traffic Services Zone
EDI	electrodeionization
EMP	Environmental Management Plan
ERP	Emergency Response Plan
Fe	iron
FAT	Factory Acceptance Test
FID	final investment decision
FSC	food, social, and ceremonial
FWAL	freshwater aquatic life
GHG	greenhouse gas
GWP	global warming potential
H+	protons
H_2	hydrogen
HADD	harmful alteration, disruption, or destruction
HSSE	health, safety, security and environment
IFM GIF	IFM Investors Global Infrastructure Fund
ISO	International Organization for Standardization
ISQG	Interim Sediment Quality Guidelines
KMKNO	Kwilmu'kw Maw-klusuaqn Negotiation Office
kV	kilovolt
LAA	Local Assessment Area
L_{Aeg}	weighted continuous sound level
L_{dn}	Day-night average sound level
LFA	lobster fishing area
LLWU	Landrie Lake Water Utility
LNG	liquified natural gas
LUB	land-use bylaw
MBA	mutual benefits agreement
MCTS	Marine Communications and Traffic Services

MEKS	Mi'kmaq Ecological Knowledge Study
MKS	Mi'kmaw Knowledge Study
mm	millimetre
MMscfd	million standard cubic feet per day
MOF	marine offloading facility
MOU	memorandum of understanding
MPS	Municipal Planning Strategy
mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt hour
N_2	nitrogen
N_2O	nitrous oxide
Na	sodium
NAFO	Northwest Atlantic Fisheries Organization
NAPS	National Air Pollutant Surveillance
NH_3	ammonia
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NRR	(Nova Scotia) Natural Resources and Renewables
NS ESA	Nova Scotia *Endangered Species Act*
NSCC	Nova Scotia Community College
NSCCTH	Nova Scotia Communities, Culture, Tourism and Heritage
NSECC	Nova Scotia Environment and Climate Change
NSBI	Nova Scotia Business Inc. (now Invest Nova Scotia)
NSPI	Nova Scotia Power Incorporated
NSPW	Nova Scotia Public Works
NTU	nephelometric turbidity units
O_2	oxygen
OH-	hydroxyl ion
OHSA	*Occupational Health and Safety Act*
PCB	polychlorinated biphenyls
PEM	proton exchange membrane

PID	parcel identification
PM	particulate matter
RAA	Regional Assessment Area
RO	reverse osmosis
RoW	right of way
SAR	species at risk
SARA	*Species at Risk Act*
SOCC	species of conservation concern
TERMPOL	Technical Review Process of Marine Terminal Systems and Transshipment Sites
TPM	total particulate matter
TRC	Technical Review Committee
TSS	total suspended solids
VC	valued component
VOC	volatile organic carbons
vpd	vehicles per day
VTS	vessel traffic services
QRA	Quantitative Risk Assessment

1.0 INTRODUCTION

Bear Head Energy Inc. (BHE, formerly Bear Head LNG Corporation; BHLNG) proposes to construct and operate a Green Hydrogen and Ammonia Production, Storage and Loading Facility (the Project) at the site of the previously approved Bear Head Liquified Natural Gas (LNG) Export Facility (Bear Head LNG Project) in the Point Tupper Industrial Park near Port Hawkesbury on the Strait of Canso on Cape Breton Island, Nova Scotia (Figure 1.1).

Following review of an updated Project Description submitted to Nova Scotia Environment and Climate Change (NSECC) on September 1, 2022, the Minister determined that the Project represents a modification of an approved undertaking (Bear Head LNG Project) and that a Class I Environmental Assessment (EA) Registration under the *Environment Act* and the Environmental Assessment Regulations is required.

This EA Registration document has been prepared to evaluate the impacts of the proposed modifications to the Approved Project and satisfy requirements of a Registration of a Class I Undertaking under the Environmental Assessment Regulations.

1.1 IDENTIFICATION OF THE PROPONENT

1.1.1 Proponent Background and Contact Information

BHE, a Nova Scotia-registered company, is the owner of the site, the previously approved Bear Head LNG Project, and related authorizations, permits or approvals. BHE’s team has considerable experience in all aspects of project development, including design, regulatory, commercial and project finance. The majority of the BHE management team worked previously to fully permit the Bear Head LNG Project. BHE is no longer advancing the Bear Head LNG Project and is currently developing the Green Hydrogen and Ammonia Production, Storage and Loading Facility in its place.

Project Area
Highway
Road
Resource Road
Trail
Railway
Waterways (1:10k)

0 0.5 1 Kilometres
(At original document size of 8.5x11)
1:65,000

N

Notes
1. Coordinate System: NAD 1983 CSRS UTM Zone 20N
2. Data Sources: Government of Nova Scotia Natural Resources and Renewables; Nova Scotia Lands, Forests and Wildlife (NSTD)
3. Background: Government of Nova Scotia; Province of New Brunswick, Province of Nova Scotia, Esri, HERE, Garmin, FAO, NOAA, USGS, NRCan, Parks Canada, Esri, USGS, Maxar

Stantec

Project Location Prepared by NW on 2022-11-08
Richmond County, NS
Client/Project 121431287_042
Bear Head Energy
Regulatory Permitting Support
Figure No.
1.1
Title
Project Location

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Proponent contact information is provided below.

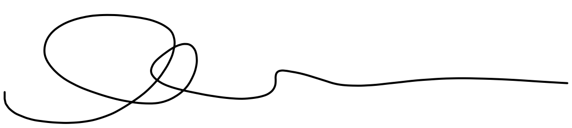
Name of Project
Bear Head Energy Green Hydrogen and Ammonia Production, Storage and Loading Facility

Proponent Contact Information

Name:	Bear Head Energy Inc.
Mailing Address:	1969 Upper Water Street, Suite 1903 Halifax, NS B3J 3R7
Street Address:	as above
Website:	www.bearheadenergy.ca

Company President/CEO:		**Environmental Assessment Contact:**
Name:	John Godbold	Paul MacLean
Official Title:	President and CEO	Chief Operating Officer and Canada Country Manager
Tel:	713-553-6564	902-471-9711
E-Mail Address:	John.godbold@bearheadenergy.ca	Paul.maclean@bearheadenergy.ca

Signature of Authority



Paul MacLean
Chief Operating Officer and Canada Country Manager
Bear Head Energy Inc.

1.1.2 Proponent's Relationship to Buckeye Partners, L.P.

On July 12, 2022, Buckeye Partners, L.P. (Buckeye), fully acquired BHE. Buckeye hired the BHE management team to develop the Project.

Buckeye's history as an owner and operator of energy infrastructure spans almost 140 years back to Standard Oil and the beginnings of large-scale energy distribution. Buckeye has a long history of successfully developing, constructing, owning, and operating large scale energy infrastructure projects. Buckeye is a highly experienced developer of energy infrastructure projects having successfully developed and constructed over CA$4 billion of projects since 2011 with a team of highly experienced development professionals. Buckeye is also a trusted partner in the energy space having worked collaboratively to develop numerous successful platforms with key global energy players including Trafigura, Vitol, Shell, Phillips 66 and Marathon Petroleum. With roughly 5,500 miles of pipelines, 135 inland and marine terminals and over 130 million barrels of tank capacity, Buckeye has one of the largest energy midstream portfolios with operations throughout the U.S. and the Caribbean.

Across every aspect of its business, Buckeye focuses on responsibly providing world-class service to meet the evolving energy needs of its customers. As part of this commitment, Buckeye is advancing several energy transition and decarbonization initiatives beyond the Project described in this proposal. These include opportunities in low-carbon energy sources such as solar, wind, hydrogen, biofuels, and LNG. Buckeye leverages its strengths—focusing on safety and asset integrity, along with its expertise, talent, and capital—to build businesses and offerings that are innovative and responsive to the needs of the future, while continuing to serve the energy needs of its communities today.

Buckeye is 100% owned by the IFM Investors (IFM) Global Infrastructure Fund (IFM GIF) which targets core infrastructure in developed markets and is supported by a seasoned and stable investment team of over 100 infrastructure specialists.

1.2 PROJECT OVERVIEW

The Project involves the construction, operation and decommissioning of a green hydrogen and ammonia production, storage and loading facility. The Project will be constructed in multiple phases driven by the availability of renewable power. At full build-out, the Project will be capable of producing 2 million tonnes per annum (mtpa) of green ammonia (e.g., wind, hydro, tidal, solar) to run the facility. The facility will be located within the footprint of the previously approved, but not fully constructed, Bear Head LNG Project, and would include electrolysis units for green hydrogen production, air separation unit(s) (ASU) for nitrogen generation, Haber-Bosch ammonia synthesis unit(s), ammonia bulk storage tank(s), and a marine terminal plus associated infrastructure. The proposed marine works include a jetty platform, ship berthing and trestle structure, loading facilities and marine offloading facility (MOF) to be developed within the water lot owned by BHE. The design of these marine facilities will be the same as previously approved for the Bear Head LNG Project.

The Project will use electrolysis to split water molecules into hydrogen and oxygen. Nitrogen will be generated in the ASU directly from the air. Once nitrogen and hydrogen have been produced, hydrogen is catalytically reacted with nitrogen to form anhydrous liquid ammonia in a Haber-Bosch ammonia synthesis unit. Specialty marine carriers will transport liquid ammonia to markets outside the region. Shipping frequency is estimated to be approximately 40 to 60 ships at peak per year on specialty carriers with a capacity of approximately 50,000 to 80,000 cubic metres (m^3).

Approximately 15 million litres of water/day on average (4 million US gallons of water/day) will be required by the facility and will be supplied to the site via pipeline from the Landrie Lake Water Utility (LLWU). LLWU currently has regulatory approval for an allowable daily withdrawal limit of 36 million litres per day. Power supply for the Project will be provided from renewable power via the grid and/or direct power connection from primarily new onshore and/or potential future offshore renewable energy projects. Water supply and energy production and storage will be permitted (as required) separately by the proponent(s) of these utilities/projects.

It is estimated that the Project would generate approximately 45 to 70 permanent direct jobs and 175 permanent indirect jobs for 20 years or more and 600 to 700 temporary construction jobs.

1.3 BACKGROUND

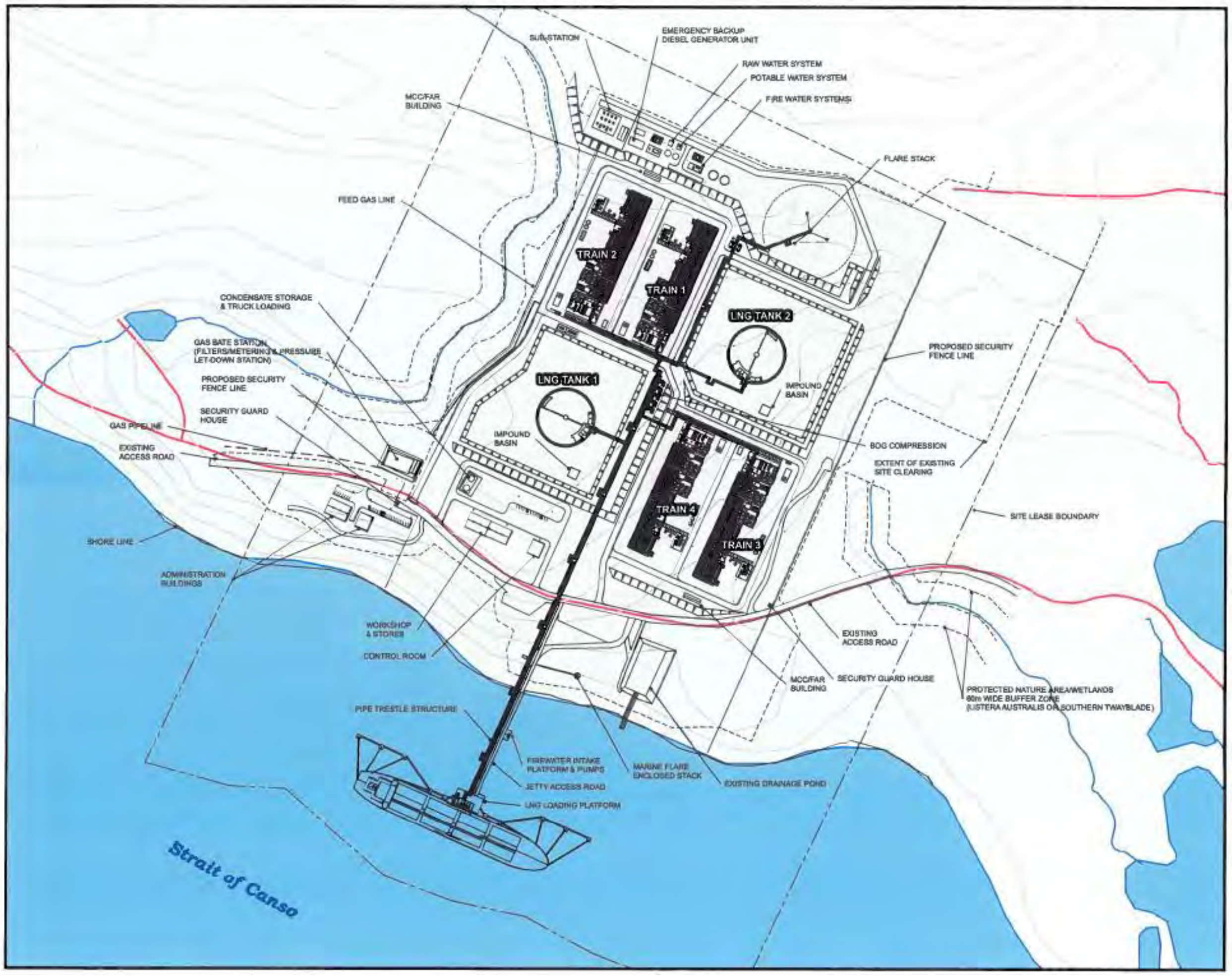
In 2004, BHLNG, wholly owned by Anadarko Petroleum Corporation, proposed to develop a 1,500 MMscfd (million standard cubic feet per day; approximately 11.3 mtpa) LNG import terminal (LNG Import Facility[1]) at full build-out on a site encompassing 101 ha of land and a 27 ha water lot. Both the land and water lots are fully owned by BHE.

Between 2004 and 2007, the LNG Import Facility received the necessary federal, provincial, and municipal approvals to proceed with construction. Construction commenced in 2005 with road building, site preparation and construction of two LNG tank foundations. A considerable portion of the site was cleared and extensively re-graded. Culverts and erosion and sedimentation controls were established to manage surface water runoff from the site and associated access road. The project was put in hot idle in 2007. The site was monitored and maintained by BHLNG and in 2015, BHLNG proposed to resume development of the site for the purpose of exporting 8 mtpa of LNG.

Numerous environmental studies were conducted to inform project planning and support regulatory applications for the Bear Head LNG Project (Table 1.1). These studies were incorporated into a provincial Registration Document for the Bear Head LNG Project filed in 2015. The Registration Document, as well as the Minister's Decision to approve the undertaking pursuant to Part IV of the *Environment Act*, and associated approval conditions, can be found on the provincial EA registry: https://novascotia.ca/nse/ea/bear-head-lng.asp. Figure 1.2 shows the planned layout of the Bear Head LNG Project as approved in 2015. Note the MOF is not depicted in Figure 1.2 as it was added to the Bear Head LNG Project and approved in 2016 following the 2015 EA approval.

In March 2016, BHE acquired additional acreage from NSBI (now Invest Nova Scotia) to provide adequate buffer area for thermal and vapour exclusion zones required for the Bear Head LNG Project. In April 2016, an updated Approval to Construct a Liquified Natural Gas Plant Export Facility was issued pursuant to Part V of the *Environment Act*. However, because of changing energy markets, development of the site was again placed in hot idle in 2019. Figure 1.3 shows the original site boundary including the water lot and additional acreage for the buffer zones which BHE still owns and intends to maintain for the current Project (and which are included in the Project Area).

[1] Previous regulatory applications and approvals refer to the "LNG Marine Terminal" and the "Bear Head LNG Project". To provide clarity and consistency when discussing the evolution of the project and background materials, this document refers to the "LNG Marine Terminal" project as the "LNG Import Facility".



Source: SNC Lavalin 2015

Figure 1.2 Approved Bear Head LNG Project Layout (Marine Offloading Facility not depicted in this Figure)

Table 1.1 Data Sources and Field Studies Completed for the Bear Head LNG Project

Environmental Assessment Component	Date	Source
Noise	2014	SNC Lavalin
Wetlands (including field studies)	2004, 2005, 2014	SNC Lavalin
Freshwater Fish and Fish Habitat (including field studies)	2004, 2014	SNC Lavalin
Bats (desktop)	2014	Search of ACCDC Database
Mammals (field/desktop)	2004	JWEL
Reptiles and Amphibians (field/desktop)	2004	JWEL
Birds (field/desktop)	2004, 2013, 2014	MBBA, ACCDC, JWEL
Plants (field/desktop)	2003, 2004, 2007	JWEL
Terrestrial species at risk (SAR) (field/desktop)	2004, 2014	Search of ACCDC Database
Marine SAR (desktop)	2004, 2014	COSEWIC
Marine Benthic (including sediment sampling)	2003, 2016	JWEL, CBCL
Physiography, Surficial and Bedrock Geology	2004	JWEL
Acid Rock Drainage Potential	2004	JWEL
Water Sources	2014	SNC Lavalin
Climate	1996	Davis & Browne
Ambient Air Quality	2010, 2012	NAPS Station Port Hawkesbury
Physical Oceanography	2004	JWEL
Archaeology (field/desktop)	2004	JWEL
Mi’kmaw Knowledge Study (now referred to as a Mi’kmaq Ecological Knowledge Study)	2004, 2015	CMM

Project Area
Road
Resource Road
Trail
Waterways (1:10k)
Property Parcel

0 100 200 300 Metres
(At original document size of 8.5x11)
1:13,000

N

Stantec

Project Location: Richmond County, NS
Prepared by NW on 2023-01-18

Client/Project: Bear Head Energy, Regulatory Permitting Support
121431287_044

Figure No. 1.3

Title

Project Site Boundaries and Buffer Area (Project Area)

Notes

1. Coordinate System: NAD 1983 CSRS UTM Zone 20N
2. Data Sources: Government of Nova Scotia Natural Resources and Renewables, Bear Head Energy
3. Background: Government of Nova Scotia; Province of New Brunswick, Province of Nova Scotia, Esri, HERE, Garmin, FAO, NOAA, USGS, NRCan, Parks Canada, Esri, USGS, Maxar

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1.4 REGULATORY FRAMEWORK

The Government of Nova Scotia recently announced it is in the process of updating legislation to clarify the regulatory path forward to support the production and use of green hydrogen in Nova Scotia. These updates are expected to include amendments to the *Electricity Act*, *Underground Hydrocarbons Storage Act*, *Pipeline Act* and *Gas Distribution Act* (NRR 2022). Key environmental legislation pertaining to the Project is contained in the *Environment Act* and regulations including the Activities Designation Regulations and Environmental Assessment Regulations. Transportation and storage of hazardous materials will be completed in accordance with the provincial Dangerous Good Management Regulations of the *Environment Act* as well as the federal *Transportation of Dangerous Goods Act* and Regulations. Applicable codes and standards are referenced throughout the EA Registration where relevant.

The Bear Head LNG Project received conditional approval as a Class I Undertaking under the provincial *Environment Act* on May 15, 2015. Following review of an updated Project Description for the current Project, the Minister of Environment and Climate Change determined that the Project represents a modification of an approved undertaking and that a Class I EA Registration under the *Environment Act* and the Environmental Assessment Regulations is required.

An Environmental Screening was conducted under the *Canadian Environmental Assessment Act* in 2004 for the proposed marine wharf associated with the LNG Import Facility. On February 26, 2015, the Canadian Environmental Assessment Agency (the Agency) advised that the Bear Head LNG (Export) Project was not subject to a new federal EA under the *Canadian Environmental Assessment Act, 2012* (CEAA 2012) since the design of the export facility was "substantially the same" as the previously assessed import facility and some construction of the LNG facility had already taken place. Following review of an updated Project Description for the current Project, on January 4, 2023, the Agency concluded since the design for the Project's marine terminal is substantially the same as that assessed in 2004, in accordance with section 185.1(1) of the IAA and section 128(1)(c) of CEAA 2012, the Project is not subject to the *Impact Assessment Act* (refer to Appendix A).

Similarly, recognizing that the works, undertakings, and activities related to the marine terminal and facilities for the updated Project will be the same those previously authorized under *Fisheries Act* Authorization 16-HMAR-00088, Fisheries and Oceans Canada (DFO) has amended the existing authorization to update the approval holder's name (to Bear Head Energy Inc.) and extend the Valid Authorization Period" to December 31, 2031 (Appendix A).

BHE have engaged Transport Canada and will continue to work with them to amend the existing approval for the marine terminal issued under the former *Navigation Protection Act* to update the name of the proponent and any other potential updates (e.g., legislative update to *Canadian Navigable Waters Act*).

Appendix A contains copies of recent regulatory correspondence and existing approvals. Table 1.2 summarizes the additional approvals anticipated to be required for the Project, noting, as applicable, where existing approvals apply.

Table 1.2 Key Regulatory Approvals Required for the Project

Legislation	Regulatory Agency/Department	Requirement	Applicable Project Component/Activity	Permit/Approval	Status/Comments
Provincial					
Environment Act - Activities Designation Regulations	NSECC	"A site with a chemical storage tank system the capacity of which exceeds 2000 L of chemicals in liquid form or 2000 kg of chemicals in solid form", requires a Division IV approval.	Ammonia storage (124,000 m3)	Storage of Dangerous Goods (Division IV Approval)	Although ammonia was proposed to be used in the Bear Head LNG Project and included in the Industrial Approval application, permanent ammonia storage was not included in the previous Industrial Approval to Construct. A new application will be required for the Project and it is anticipated that chemical storage (Division IV approval trigger) will be managed through a new Industrial/Storage of Dangerous Goods Approval.
Environment Act - Activities Designation Regulations	NSECC	"A chemical manufacturing plant in which organic or inorganic chemicals are manufactured" requires a Division V Industrial Approval.	Production of ammonia	Industrial Approval (Division V Approval)	An Industrial Approval to Construct the Bear Head LNG Project was issued on October 30, 2014. A new Industrial Approval will be required for the Project which will include conditions for Project construction, operation and decommissioning.
Environment Act - Activities Designation Regulations	NSECC	Approval required to use or alter a watercourse*, water resource, or wetland. *Some watercourse alterations are exempt from approval and require only notification as per Section 5B or 5D of the Regulations.	Alteration of a wetland and/or watercourse	Division I Water Approval (Watercourse or Wetland Alteration)	A Water Approval to alter wetland habitat was issued on October 6, 2004 prior to site development activities. Work at that time was completed in accordance with the Water Approval. It is assumed that no new disturbance of wetlands or watercourses will be required for the facility on the previously developed site. However, if watercourse or wetland alteration is required, an application for a new Water Approval will be submitted.

Table 1.2 Key Regulatory Approvals Required for the Project

Legislation	Regulatory Agency/Department	Requirement	Applicable Project Component/Activity	Permit/Approval	Status/Comments
Public Highways Act	Nova Scotia Public Works (NSPW)	Activity/work on the roadway or within the highway right-of-way, including installing a driveway or erecting a structure within 100 metres of any highway	Any work within a highway Right-of-Way (RoW) (pipeline, driveway installation)	Work within Highway Right-of-Way Permit	A Breaking Soil of Highways Permit (#21-04-29) was issued in 2004 for civil work associated with the Bear Island site access road. Correspondence in 2014 confirmed no additional permits were required unless there was planned future construction or civic work associated with the site access road. If proposed construction requires civil work within a highway RoW (or installation of driveway or erection of structure within 100 m) then a new application is required. However, given the current Project Description and limited civil work required, this approval may not be required.
Federal					
Fisheries Act	DFO	Authorization for Harmful Alteration, Disruption or Destruction (HADD) of fish habitat	Marine terminal	Authorization under federal *Fisheries Act* for effects to fish habitat (HADD) in 2016 for impacts of marine offloading facility and jetty (infilling).	HADD authorization granted (with conditions) in 2016 for the infilling of fish habitat associated with the combined material offloading facility and tug wharf and approaches to the marine terminal, and habitat alteration associated with operations. Authorized "serious harm" includes "destruction of 6500 m^2 of marine fish habitat during construction and permanent alteration of 1800 m^2 eelgrass habitat during operations, as well incidental mortality of sessile or slow moving species resulting from infilling activities. DFO has amended the existing approval to update the approval holder's name and extend the dates of the "Valid Authorization Period" to December 31, 2031.

Table 1.2 Key Regulatory Approvals Required for the Project

Legislation	Regulatory Agency/Department	Requirement	Applicable Project Component/Activity	Permit/Approval	Status/Comments
Fisheries Act	DFO	Letter of Advice on the HADD of fish habitat	Marine outfall	Letter of Advice	As per the 2004 federal screening, if a marine outfall is constructed, BHE will submit detailed plans to DFO for review and approval.
Canadian Navigable Waters Act (CNWA)	Transport Canada - Navigable Waters Protection	Construction of works in navigable waters	Marine terminal	Canadian Navigation Waters Protection Authorization	Approvals under the *Navigable Waters Protection Act* were received in 2005 and 2006 and amended in December 2016 under the updated *Navigation Protection Act*. The *Navigation Protection Act* was amended and renamed the *Canadian Navigable Waters Act* in 2019. "Existing works" deemed approved under the *Navigation Protection Act* remain approved under the CNWA where terms and conditions remain in effect. With the latest amendment, the conditions on construction start and end dates, validity period, and Technical Review Process of Marine Terminal Systems and Transshipment Sites (TERMPOL) were removed. BHE has met with Transport Canada and has requested confirmation that the existing authorization remains valid and be amended to reflect the change in the name of the approval holder.
Municipal					
West Richmond Planning Area Municipal Planning Strategy and Land Use By-law	Eastern District Planning Commission	Development within the West Richmond Plan Area. Proposed facility is primarily within the Port Industrial (I-2) zone with a smaller portion of the property in Heavy Industrial (I-3) zone.	All project components	Municipal Development Permit and Building Permits	General Municipal Development Permit (#RI-D2014-140) was issued to Bear Head LNG in December 2014 for an LNG facility. Individual components of the facility were subject to development permits as well as building permits at time of actual construction. New proposed development is assumed compatible with current land use zoning but will require new development permit and subsequent building permits.

2.0 PROJECT DESCRIPTION

2.1 PURPOSE AND NEED FOR THE UNDERTAKING

Hydrogen does not emit greenhouse gases (GHGs) when combusted and because of this, hydrogen energy is expected to become a key pillar of global decarbonization efforts. The Project represents a commercial scale energy export project that will provide a non-GHG emitting fuel source and allow Nova Scotia to become a leader in the global energy transition. Hydrogen is difficult to store and transport due to its low energy density so it is often combined with nitrogen to safely produce ammonia for efficient transport. Building the Project to supply green ammonia to the international market provides cost advantages, including increased investment and higher production rates with decreased unit costs. A large-scale export project encourages the development of expertise and experience of local equipment and service providers, facilitating opportunities and growth to service future local markets as they evolve. Although the Project will at first produce ammonia to be shipped to world markets versus supplying local energy needs, it may also serve to anchor a growing domestic green hydrogen and ammonia economy in Nova Scotia and potentially act as a catalyst for additional green energy investments in adjacent industries,

2.2 PROJECT LOCATION

The Project will be located in the Point Tupper Industrial Park near Port Hawkesbury on the Strait of Canso in Richmond County, Cape Breton, Nova Scotia (Figure 2.1). The Strait of Canso is one of the world's deepest ice-free harbors. The Industrial Park is readily accessible to transportation infrastructure through proximity to the Trans-Canada Highway, Strait of Canso, Port Hawkesbury Airport, and Canadian National Railway. The largest residential population centres within 10 km of Point Tupper include the town of Port Hawkesbury, and the town of Mulgrave, located on the opposite shore of the Strait of Canso. A summary of key Project location details is provided in Table 2.1.

Table 2.1 Key Project Location Details

Feature	Details
Address	241 Bear Island Road Point Tupper, Richmond County, Nova Scotia
Owner	Bear Head Energy Inc.
Areal Extent	Land 101.75 ha (251.43 acres) Water Lot 27.70 ha (68.45 acres)
Latitude and Longitude	45°33'30.32" N and 61°18'2.59" W
Parcel Identification (PID) Numbers	Land 75189415, 75215012 Water Lot 75189423
Distance to Great Circle Shipping Route	80 km
Distance to an International Airport	238 km
Distance to a Regional Airport	17 km

Table 2.1 Key Project Location Details

Feature	Details
Distance to Port of Halifax	287 km
Zoning (Port Industrial: I-2)	Heavy Industrial, including Fuel Bunkering and Marine Terminals

The Project is primarily within the Port Industrial (I-2) zone with a small portion of the property in Heavy Industrial (I-3) zone. Land uses for Port Industrial development may include fuel bunkering, marine terminals, and other heavy industrial or port activities. The Project is consistent with this land use designation.

Other tenants within the Point Tupper Industrial Park include Point Tupper Marine Services Co., EverWind Fuels (formerly Nustar Terminals Canada), and Nova Scotia Power Incorporated’s (NSPI, an Emera Company) coal-fired thermal electrical generating station. Existing activities in the business park include power generation, industrial waste management facilities, coal storage and handling, transshipment terminals, storage of dangerous goods and management of bulk petrochemicals.

2.3 PROJECT COMPONENTS AND SITE PLAN

BHE is proposing to construct a green hydrogen and ammonia production, storage and loading facility capable of producing 2 mtpa (2,900,000 m^3) of ammonia, focused on the use of renewable power to run the facility. Hydrogen production is based on an average of 2,860 megawatts (MW) power input with an average of 2,000 MW consumed by the electrolysers and an average of 860 MW consumed in the Haber-Bosch ammonia synthesis unit and balance of the plant at full build-out. The Project will be built in phases based on the availability of renewable power. The facility will be located within the footprint of the approved Bear Head LNG Project and includes the following key components as shown on Figure 2.1:

- Electrical substation(s) – transforms renewable energy and delivers it to the electrolysers, Haber-Bosch ammonia synthesis unit, air separation unit(s), and balance of the plant
- Water purification plant (reverse osmosis [RO] unit) – purifies the water used in the electrolysers to reduce fouling and enhance hydrogen purity
- Electrolysers – Using electricity, electrolysers split water into hydrogen (H_2) and oxygen (O_2) gas
- Air separation unit(s) (ASUs) – cryogenically distills nitrogen in the air effectively separating nitrogen gas from the atmosphere
- Haber-Bosch ammonia synthesis unit(s) – synthesizes ammonia from gaseous nitrogen and hydrogen at high temperatures and pressures
- Ammonia storage tank (s) with a total volume of approximately 124,000 m^3
- High pressure flare and low pressure (marine) flare
- Administration buildings and parking
- Marine facility – transfers ammonia from the storage tanks to marine vessels; includes a MOF and a berth (design of these marine facilities will be the same as previously approved for the Bear Head LNG Project)

Legend

Project Area

0 100 200 Metres
(At original document size of 8.5x11)
1:8,000

N

Notes
1. Coordinate System: NAD 1983 CSRS UTM Zone 20N
2. Data Sources: Bear Head Energy, Government of Nova Scotia
3. Background: Province of Nova Scotia, Esri Canada, Esri, HERE, Garmin, FAO, NOAA, USGS, NRCan, Parks Canada, Esri, USGS, Maxar

Stantec

Project Location — Prepared by NW on 2023-01-12
Richmond County, NS

Client/Project — 121431287_045
Bear Head Energy
Regulatory Permitting Support

Figure No.
2.1

Title
Preliminary Site Plan for Green Hydrogen and Ammonia Facility at Bear Head Site

V:\1214\Active\121431287_NS\03_data\gis_cad\gis\mapping\mxd\general\ArcGIS Pro\Port Richmond BearHeadEnergy\BearHeadEnergy EA 121431287.aprx Revised: 2023-02-09 By: mblackwood

2.4 PROJECT DESIGN AND CODE OF PRACTICE

BHE will design the facility to meet applicable standards, regulations, and codes. As part of the full engineering design, the requisite codes and regulations will be fully identified and documented. BHE proactively engaged Lloyds Register to identify and document the applicable codes and specifications utilized globally and developed a code of practice to guide the design, construction, operation and abandonment of the Project. The *Code of Practice for Bear Head Ammonia-Hydrogen Production Facilities* (COP) has been developed to supplement requirements in the Gas Plant Facility Regulations and best practice from globally recognized codes and standards associated with hydrogen and ammonia The COP is intended for BHE’s initial use and is being reviewed with NSECC to demonstrate compliance with current applicable regulatory requirements and ensure the protection of the public and the environment through the appropriate design, construction, operation and abandonment of the Project. The COP is intended to be applied with reference to other relevant standards and practices specific to hydrogen and ammonia operations. As the Province of Nova Scotia develops its own regulatory standards for hydrogen and ammonia operations, those standards will become the driving set of standards for the Project. The overall outline of the COP is provided below:

- Section 1 – Provides an introduction and overview of the COP
- Section 2 – Describes the relationship of the COP to applicable Acts and Regulations
- Section 3 – Describes permitting requirements
- Section 4 – Provides supplementary information on ammonia
- Section 5 – Provides supplementary information on hydrogen
- Section 6 – Provides supplementary information on oxygen
- Section 7 – Details overall process design requirements
- Section 8 – Provides supplementary information on flare and venting systems
- Section 9 – Details requirements at the Front-End Engineering Design stage
- Section 10 – Details requirements at the Detailed Design stage
- Section 11 – Details personnel safety requirements
- Section 12 – Requirements for Commissioning and Start-up
- Section 13 – Provides details of requirements for operation
- Section 14 – Provides details of requirements for closure and abandonment
- Section 15 – Provides a list of references

2.5 SITE PREPARATION AND CONSTRUCTION

Most of the site preparation work was already conducted for the Bear Head LNG Project, therefore additional civil related construction activities such as land clearing, excavation and grading will be limited and will occur within the previously approved site boundaries (Figure 1.2).

Additional site preparation will be undertaken to enable the installation of temporary facilities, fencing, parking, offices, staging and lay down areas; construction activities will require limited vegetation removal and grading to establish substation(s) and potentially other structures subject to final site planning and engineering. Existing fencing will be upgraded and extended around the entire perimeter of the site.

Further construction will include the installation of foundations, equipment settings, ancillary equipment, piping and structures, and construction of the marine terminal facilities. BHE intends to use existing tank foundations for the Project, but if they are unable to be repurposed, there may also be some demolition required.

Construction of the marine terminal will be as previously approved under the federal *Fisheries Act* and former *Navigation Protection Act* (now *Canadian Navigable Waters Act*) as part of the development of the Bear Head LNG Project and no changes are proposed. No dredging will be required for the construction of the marine facilities or to maintain vessel access during operations.

Marine terminal construction involves construction of a jetty, MOF, berthing and mooring dolphins, pipe trestle, jetty access road, walkways and berthing systems. The MOF and laydown area work surface will be established to facilitate construction of the marine facilities and delivery of Project equipment and pre-constructed modules. The marine jetty will include concrete decking on drilled steel tubular piles. The jetty will consist of reinforced concrete pile caps supported on tubular steel piles (driven down to bedrock), with a steel trestle frame structure in turn supporting pre-cast concrete decking. This provides support for the piping, utilities steel support beams, and one lane of decking for light vehicle traffic. The tubular pile construction minimizes damage to the marine habitat. During construction of the marine facilities, turbidity curtains and other appropriate measures will be deployed, if logistically possible, to protect the marine environment.

Construction to facility commissioning will be conducted over approximately a 36-month period, similar to that planned for the Bear Head LNG Project. This includes approximately six months of site preparation activity and 30 months of construction and installation. However, the Project will be phased driven by the availability of renewable power. Communication with the relevant authorities will be adhered to for on-site inspection and approval in accordance with construction permit conditions.

During fabrication and installation, quality assurance will be maintained by imposing controls such as:

- Specified qualifications for suppliers
- Standards for welding, fabrication, non-destructive examination and auditing
- Designer, fabricator and constructor competency requirements
- Ammonia tank(s) construction, inspection and testing requirements
- Qualifications for welders and quality assurance personnel
- Inspection and testing of piping

2.6 COMMISSIONING

Following completion of pre-commissioning checklists, commissioning can begin. Commissioning is expected to occur over a three to six-month period The following provides key activities during commissioning:

- Commissioning is the on-site process to verify that equipment has not been damaged during shipping since the Factory Acceptance Test (FAT) was completed. All field devices are installed at this point, so field wiring is confirmed to be correct, and a subset of FAT tests are repeated to ensure the equipment can communicate to all field devices and that equipment is calibrated.
- Mechanical commissioning consists of dry commissioning and wet commissioning. Dry commissioning confirms proper function of mechanical systems without process fluids, while wet commissioning adds the process fluids and chemicals to confirm operation.
- Electrical commissioning consists first of pre-energization safety. When equipment is first energized as a system, it may be that construction is still taking place next to equipment currently under test, and it must be ensured that power is safely isolated from any equipment installations. Once isolations are confirmed, equipment racks are powered up and system integration can occur.
- Once all mechanical and electrical components are complete, system commissioning can begin, where all the electrical and mechanical equipment works together as a system for the first time.
- Commissioning checklists are completed and witnessed by specialists and subject matter experts

Detailed commissioning procedures will be established through detailed design.

2.7 OPERATIONS AND MAINTENANCE

2.7.1 Green Hydrogen and Ammonia Process

Figure 2.2 is a schematic showing the overall hydrogen production and ammonia synthesis process, highlighting process inputs and outputs. In addition to having similar project components and site plan, the process flow for green hydrogen and ammonia is similar to the Bear Head LNG Project. Figure 2.3 presents a simplified process diagram of the green hydrogen and ammonia process in comparison to the Bear Head LNG Project. One of the most notable differences between the updated Project and the Bear Head LNG Project is that the green hydrogen and ammonia process involves the use of renewable energy and water. Water will be supplied to the site by the LLWU and renewable energy from wind, solar, hydropower, and/or tidal power sources will be used to power the facility. Neither the hydrogen process electrolysers nor the Haber-Bosch ammonia synthesis unit will produce carbon emissions because no fossil fuels will be burned onsite except during upset conditions where use of a back-up diesel generator may be required.

The electrolysers will use renewable energy to separate hydrogen from deionized water. Nitrogen is generated from the air in an ASU. Once nitrogen and hydrogen have been produced, hydrogen is catalytically reacted with nitrogen to form anhydrous liquid ammonia which will be shipped to market via specialty marine carriers.

A more detailed description of the green hydrogen and ammonia process is provided below by major component. More information on process utilities and outputs (e.g., wastes, discharges and emissions) is provided in Sections 2.10 and 2.11, respectively.

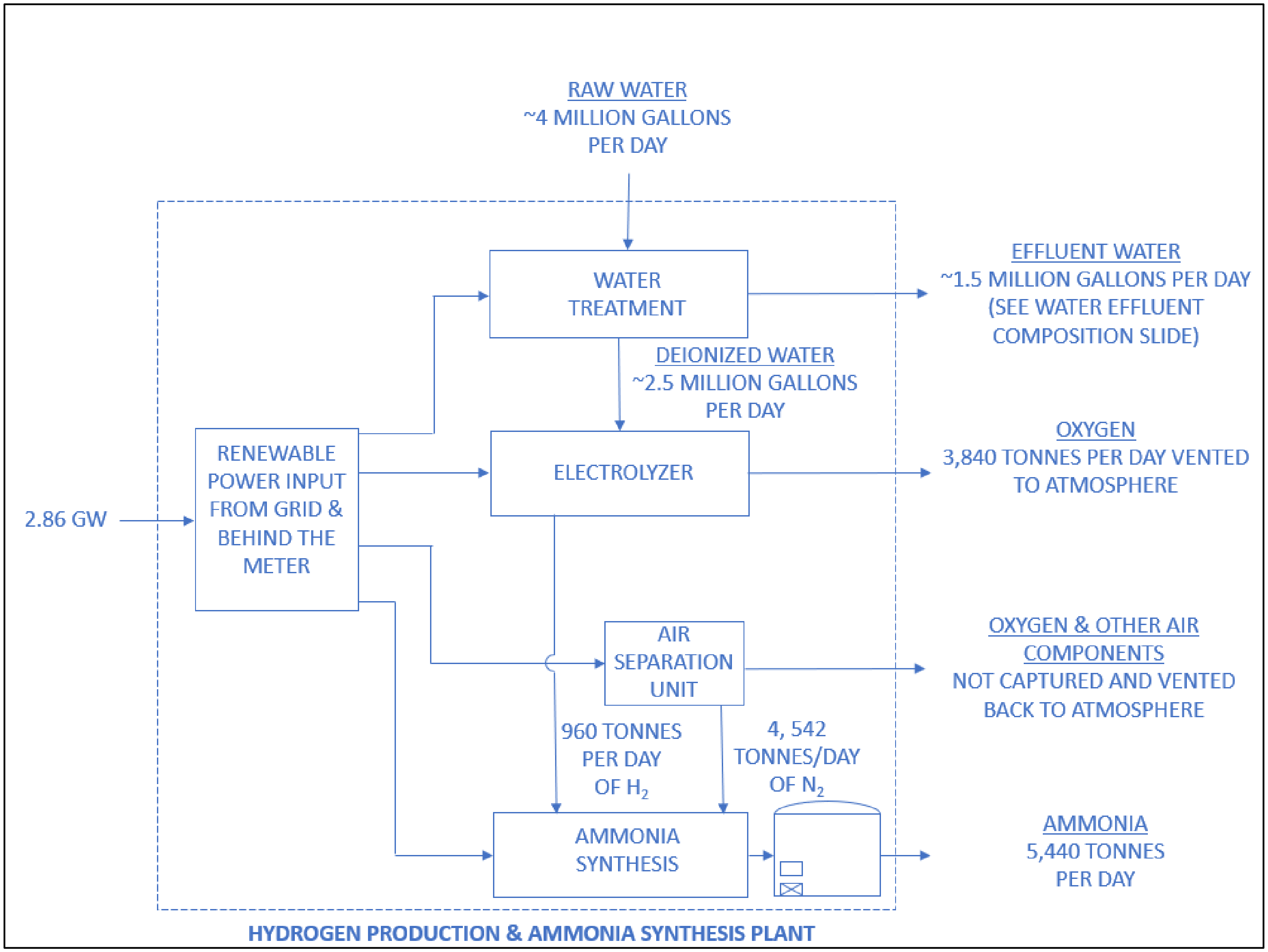

Figure 2.2 Inputs and Outputs for Green Hydrogen Production and Ammonia Synthesis

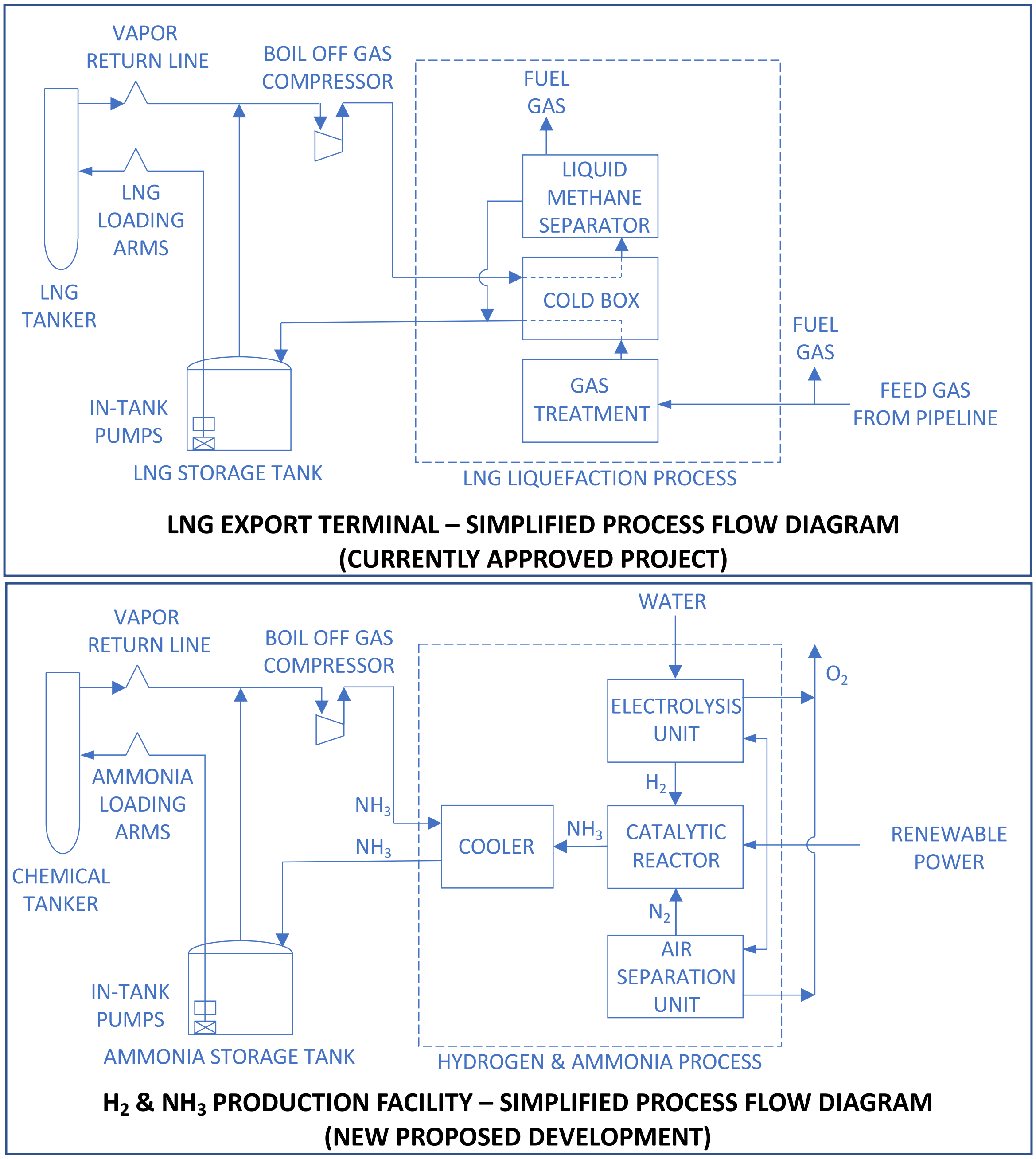

Figure 2.3 Simplified Process Flow Comparison of LNG Export and Green Hydrogen and Ammonia Facility

2.7.1.1 Water Purification (Reverse Osmosis)

Raw water will be supplied to the site by LLWU via pipeline. This water will be treated at the site using a two-stage reverse osmosis (RO) and deionization process prior to being supplied as feedstock for the electrolyser. The exact quality and composition of available water will determine the type and extent of water purification required. LLWU has provided BHE with historic water quality data and in 2022 BHE initiated a frequent water sampling program to characterize the raw water quality and inform detailed design for the water treatment process (refer to Appendix B for historic water quality data). It is often necessary to employ a double pass RO system, where the permeate from the first RO process is filtered again in a secondary RO system. To reach the very low conductivities required by many electrolysers, a final deionization is required. Here, either a mixed bed filter or an electrodeionization (EDI) unit can be used.

2.7.1.2 Electrolysis (Hydrogen Production)

As shown in Figure 2.4, the process uses a direct current to split deionized water into primary components (hydrogen and oxygen) in an electrolyser, which holds an anode and cathode. Currently, BHE plans to use the hydrogen to produce ammonia and to safely vent the oxygen to the atmosphere. However, alternatives for local green hydrogen use and/or storage may be evaluated in the future. Capture and use of oxygen may also be evaluated in the future.

There are various types of electrolysers which function differently depending on the type of electrolyte material utilized. BHE is currently evaluating two types of electrolysers for use: a Polymer Electrolyte or Proton Exchange Membrane (PEM) electrolyser and an Alkaline electrolyser. A comparison of these technologies is presented in Section 2.15.2.3. As new and improved technologies are developed, BHE will evaluate the technologies for future phases.

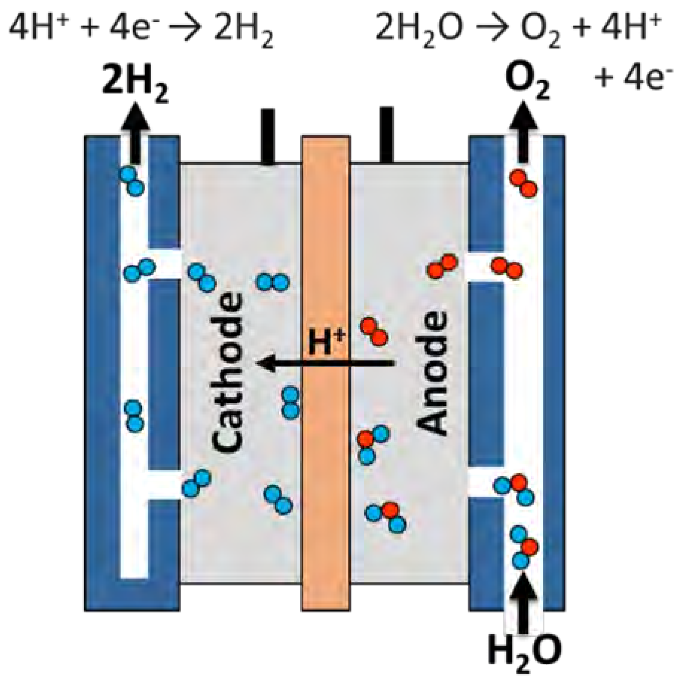

Figure 2.4 Simplified Electrolysis Process[2]

2.7.1.3 Air Separation (Nitrogen Production)

To produce ammonia (NH_3), hydrogen and nitrogen are both necessary components. While the hydrogen is produced in the electrolysis process (Section 2.7.1.2), the nitrogen will be generated in an ASU. Nitrogen is isolated from air by cooling it to a liquid state and then removing the liquid nitrogen. The oxygen and other naturally occurring components of air are then safely vented back to the atmosphere.

Figure 2.5 is a schematic of the ASU process. Air enters an air filter to ensure that particulates (dust and pollen) do not reach the main air compressor of the plant. Removal of these components is necessary to prevent their build up on the compressor impellers. Filtered air is compressed and sent to a direct contact cooler, where it is cooled and washed. Air leaving the direct contact cooler is dust-free but contains water and other impurities that have a potential of freezing in the cold box. Molecular sieves are then used to remove the water and these remaining impurities. The dried clean air is then sent to the cold box, where N_2 and oxygen are separated. The pure N_2 is then sent to the Haber-Bosch ammonia unit, while oxygen can either be captured for use or vented to the atmosphere.

[2] Office of Energy Efficiency and Renewable Energy. https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis.

ASUs are widely used and proven systems which separate atmospheric air into its primary components, typically nitrogen and oxygen, and sometimes also argon and other rare inert gases. The specific design and technology of the units will be further evaluated as engineering progresses to determine the best solution for BHE.

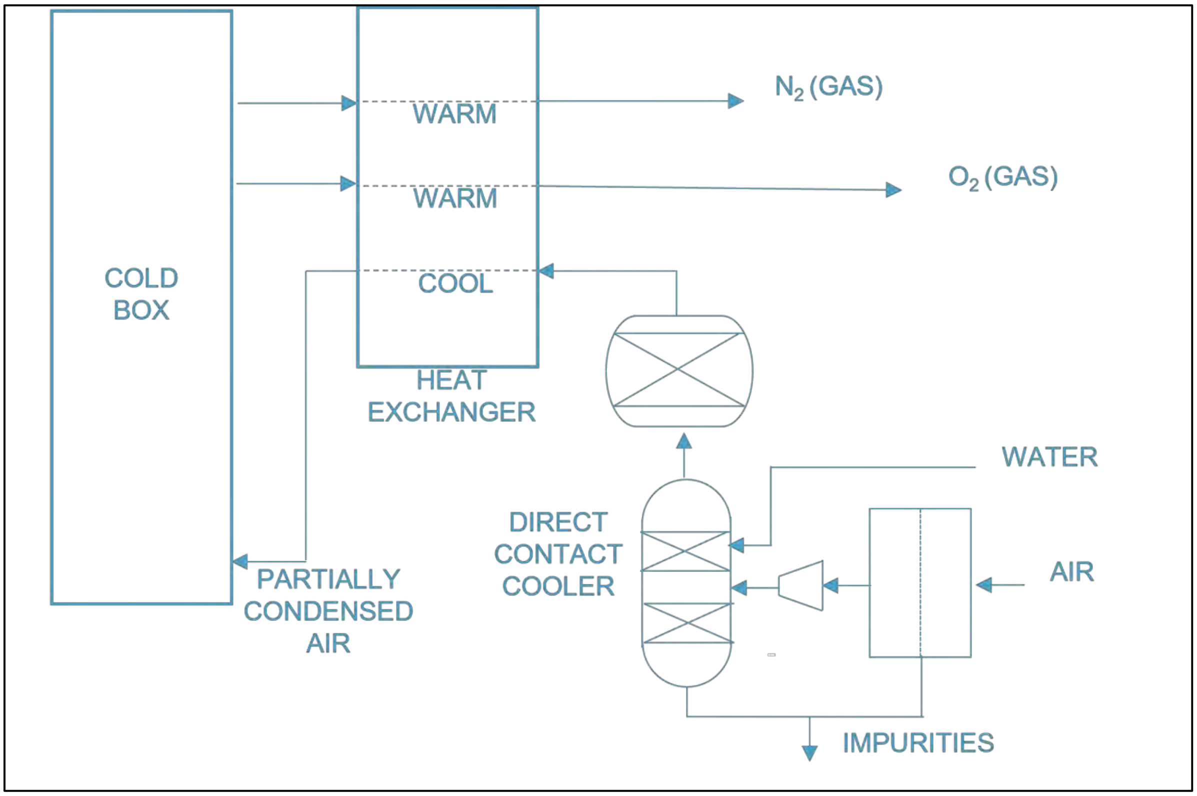

Figure 2.5 Schematic of Air Separation Unit

2.7.1.4 Ammonia Synthesis

Ammonia is synthesized in a processing unit known as a Haber-Bosch ammonia synthesis unit, named for the inventors of the process. A Haber-Bosch ammonia synthesis unit combines hydrogen produced from electrolysers with nitrogen isolated from air. The hydrogen and nitrogen are raised to high temperature and high pressure in the presence of an iron catalyst to form anhydrous ammonia. The reaction to combine H_2 and N_2 is exothermic, therefore a waste heat boiler is utilized to generate steam to drive a steam turbine and produce power. The ammonia is then condensed and sent to storage tanks prior to loading. Figure 2.6 shows a process flow diagram for the ammonia production process.

The Haber-Bosch process is the primary method used globally for producing ammonia. In 2021, the production capacity of ammonia worldwide was 236.4 million metric tonnes per annum (Statista 2022), however almost all of the existing Haber-Bosch ammonia synthesis units obtain the hydrogen from hydrocarbons instead of from electrolysis of water, resulting in extensive carbon emissions. Traditional ammonia production accounts for approximately 1.8% of global CO_2 emissions (The Royal Society 2020). Green ammonia however, is produced completely free of CO_2 emissions.

Like ASUs, catalytic ammonia production uses well-understood and proven systems designed by Haldor Topsoe of Denmark, Thyssenkrupp Industrial Solutions GmbH of Germany, Casale SA of Switzerland and Kellogg Brown & Root of the United States. Similar to the ASU and electrolysis technology and design, BHE will study the various catalytic ammonia technologies to select the optimal solution during full engineering design of the Project.

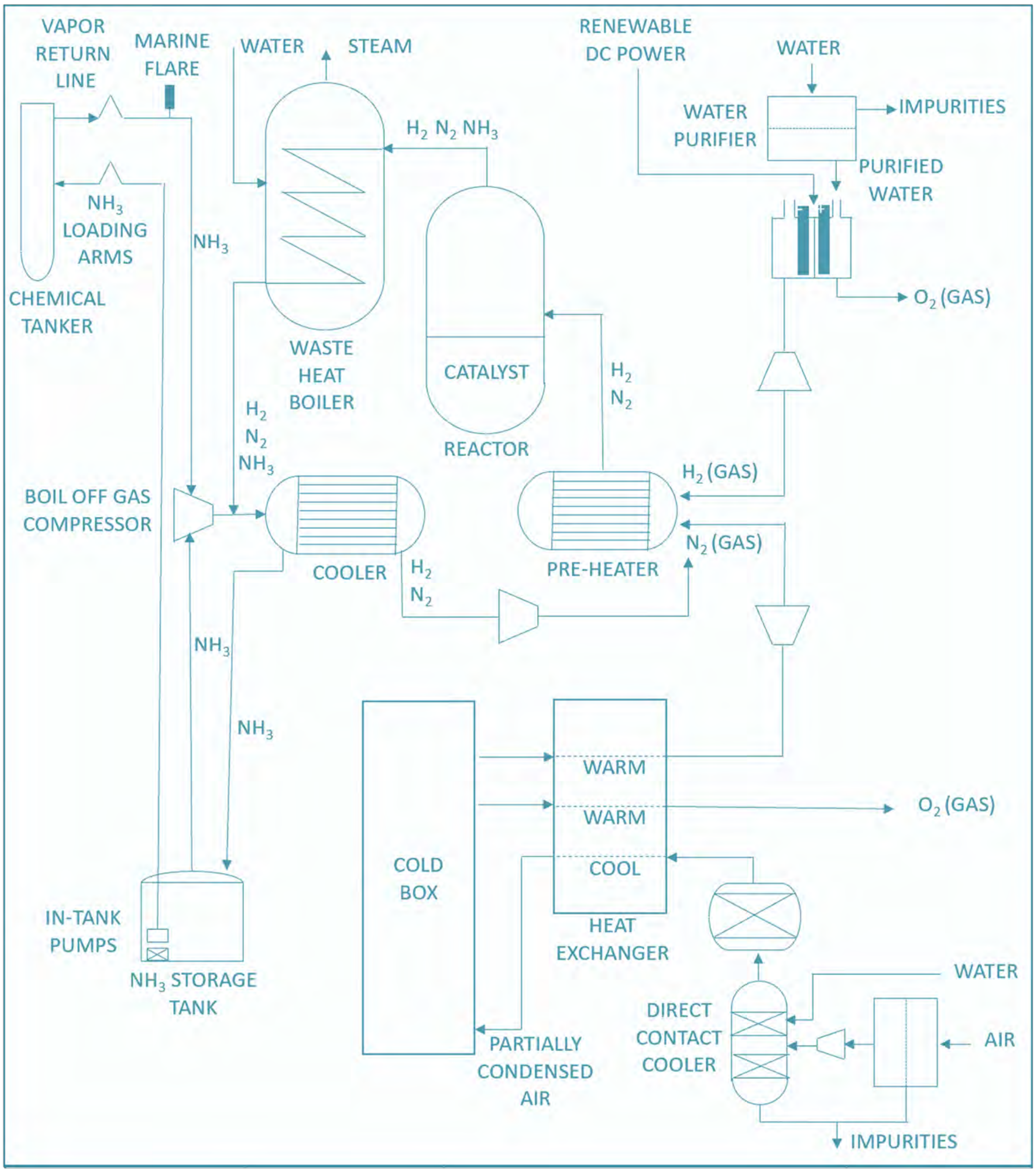

Figure 2.6 Process Flow Diagram for the Green Hydrogen and Ammonia Process

2.7.2 Marine Loading and Shipping

Proposed marine facilities include a jetty platform, a ship berthing and trestle structure, loading facilities, and a MOF, which will all be located within the BHE water lot. The marine facilities were previously approved under the federal *Fisheries Act* and former *Navigation Protection Act* (now *Canadian Navigable Waters Act*) as part of the development of the Bear Head LNG Project and no changes are proposed.

Appendix C contains the design drawings for the marine facilities and Appendix D contains the updated metocean study conducted in 2015 (CBCL 2015) to support the detailed engineering design.

The jetty was initially designed to accommodate LNG vessels with a capacity of up to approximately 267,000 m^3 and drafts up to approximately 15 m. The current generation of specialty chemical carriers which will transport ammonia are smaller than LNG vessels and typically have a storage capacity of 50,000 to 80,000 m^3 (compared to approximately 125,000 to 267,000 m^3/ship for LNG vessels).

Loading of the liquid ammonia will be similar as proposed for LNG transport, using loading arms with vapor recycle. The duration of loading can vary but it is expected to require approximately 12 to 24 hours per vessel.

Shipping frequency is estimated to be approximately 40 to 60 ships per year at peak (reduced from 70 to 135 ships predicted for the Bear Head LNG Project), with specialty carriers being considerably smaller as stated above.

2.7.3 Equipment Inspection and Maintenance

Defined inspection and maintenance procedures for all equipment and components will be developed during detailed engineering prior to operations.

2.8 DECOMMISSIONING AND RECLAMATION

Similar to the Bear Head LNG Project, the Project will be designed for a lifespan of 20 years or more, with opportunities for lifespan extension via ongoing maintenance and scheduled improvements. Decommissioning activities will be similar to construction activities, with the mobilization of equipment and offsite transport of tanks and instrumentation. A decommissioning plan, which will include a site rehabilitation plan, will be developed prior to any decommissioning work and will take into account applicable legislation, codes and standards at that time.

2.9 MATERIAL STORAGE AND HANDLING

Transportation and storage of hazardous materials will be completed in accordance with the provincial Dangerous Good Management Regulations of the *Environment Act* as well as the federal *Transportation of Dangerous Goods Act* and Regulations. All hazardous materials stored on site will be properly labeled and Safety Data Sheets will be available to staff in designated areas. Additional details on materials storage and handling are provided below.

Potential accidental events and emergency response measures associated with ammonia, hydrogen and diesel are addressed in Section 7.0.

2.9.1 Anhydrous Ammonia

The normal operation of the facility will convert all produced hydrogen to anhydrous ammonia which will be stored in liquid form at a refrigerated temperature. Anhydrous ammonia is classified as a Class 2.3 toxic gas, subsidiary Class 8, corrosive, under the *Transportation of Dangerous Goods Act.* Ammonia is a colorless, reactive gas that is lighter than air (approximately half as heavy) which dissolves readily in water. Ammonia has a distinctive, strong smell which can be detected by most people even in small amounts.

As discussed in Section 2.4, BHE has commissioned Lloyds Register to develop a COP for the facility with the objective of protecting the public and the environment through the appropriate design, construction, operation and abandonment of the plant. With respect to ammonia storage and handling, the COP demonstrates compliance with applicable codes and standards including *Occupational Health and Safety Act* (OHSA), American National Standards Institute (ANSI), American Concrete Institute (ACI), and American Petroleum Institute (API) standards. BHE will also accept and incorporate any standards over and above those identified by Lloyds Register to improve safety of all stakeholders.

Current design includes one 124,000 m^3 capacity anhydrous ammonia storage tank to be constructed; further evaluation will be undertaken during the next phase of engineering to determine if multiple smaller tanks are appropriate to decrease risks associated with unplanned releases. The design of the anhydrous ammonia tank(s) will be similar to the previously approved tank design for the Bear Head LNG Project (which was designed for 180,000 m^3 of LNG) and will comply with ammonia storage requirements.

As the site had been previously developed as an LNG terminal, existing tank foundations are available for ammonia storage. The green ammonia is stored in industry standard refrigerated tanks prior to transport (as opposed to cryogenic temperatures for LNG).

Assuming that the foundations have maintained the same bearing capacity that they were originally designed for, the minimum allowable storage capacity of ammonia would have the same mass as the design capacity for LNG. The analysis of the comparative mass of ammonia to LNG indicates that the existing foundations are suitable for the installation of approximately 124,000 m^3 ammonia storage tanks. The actual condition and capacity of the foundations and final capacity of ammonia storage tank will be confirmed by appropriate engineering studies as part of the facility design. A volume of 124,000 m^3 is adequate for storage of 15 days of production at full production rate, thus providing flexibility around shipping schedules. Since the volume of storage is less and the foundation footprint remains the same, the ammonia tank height is expected to be less than the LNG tank height.

Detailed design of the facility will be driven by the COP and other applicable codes and standards and will incorporate applicable design requirements including but not limited to requirements for the components listed below:

- spacing of ammonia storage tank(s)
- location of safety critical systems
- spill and leak control
- impoundment area siting and design
- drainage systems
- pressure relief and venting systems
- piping systems and components

2.9.2 Diesel

Diesel will be required on site for the following applications under emergency or upset (non-routine) conditions:

- A diesel engine generator for emergency power
- Diesel driven water pumps for the facility fire systems
- Diesel engines for the ammonia tank deluge system pumps

The volume of diesel storage required will be determined through detailed design of the facility. Diesel storage requirements will be similar to that previously required for the Bear Head LNG Project.

2.10 UTILITIES

General site utilities (e.g., utility water, firewater and safety systems) and buildings associated with general site utilities (e.g., control room, offices and workshops) will be substantially the same as proposed for the Bear Head LNG Project and will be located within the previous approved footprint of disturbance. Water and energy required for the production of hydrogen and ammonia will be supplied by regulated third-party utility providers or direct power connection to the Project. Permitting and regulation of these utilities is outside the scope of this assessment and will be subject to separate approvals, if required. Additional details are provided below on the water and energy requirements of the Project.

2.10.1 Water Requirements

The electrolysis process requires a fresh water supply as an important feedstock. At full buildout, it is currently estimated that BHE will require up to an average of 4 million gallons (15 million litres) of water daily. The LLWU signed a Memorandum of Understanding on March 25, 2022 to provide the required initial supply water to BHE.

The LLWU draws water from the Landrie Lake watershed to supply water to the Town of Port Hawkesbury as well as several industrial customers in the Point Tupper Industrial Park. Currently, the LLWU draws water from the Landrie Lake watershed to supply water to the Town of Port Hawkesbury as well as several industrial customers in the Point Tupper Industrial Park. In accordance with Water Withdrawal Approval #2005-046169-02, the LLWU has an allowable daily withdrawal limit of 36 million litres per day. In 2020, the maximum daily water withdrawal volume was 13.5 million litres, while the minimum was 4.4 million litres (LLWU 2020). Based on these statistics, the LLWU's current approval will likely allow them to provide BHE with the above noted required water quantities.

Raw water will be supplied to the site by LLWU via pipeline. This water will be treated using a two-stage reverse osmosis and deionization process prior to supply water as feedstock for the electrolyser. The total effluent rate of the water treatment system is approximately 35% of the raw water supply rate (with the remaining 65% of treated water directed to the electrolyser). More information on water requirements and effluent from the water treatment process is provided in Section 2.11.4.

BHE is working with the LLWU to ensure that the amount of water required for the Project will not impact the availability of water to the local residents and industrial users and the related costs for such water. BHE is also working closely with LLWU to have a positive impact on the water resources and delivery of water to all users, including the local residents, through investment in new infrastructure. BHE and LLWU are jointly reviewing options to update LLWU's current infrastructure and rebuild and bring online previously operating infrastructure to enhance the safe yield and increase the deliverability of water to all users.

2.10.2 Energy Requirements

Power supply for the Project will be provided from renewable power via the grid and/or direct power connection from primarily new onshore and/or potential future offshore renewable energy projects. The Project will be constructed in phases driven by the availability of renewable power. At full build out and peak power inflow, the facility could produce 350,000 tonnes of hydrogen and 2 million tonnes of ammonia per year. Peak power at full build out could be as high as 3 gigawatts including 2 gigawatts of electrolyzer capacity.

Hydrogen production is based on 2,860 MW average power input with about 70% of the incoming power (2,000 MW) consumed by the electrolysers and 30% (860 MW) consumed in the Haber Bosch unit, ASU,utilities and balance of the plant. The production of hydrogen requires a total of approximately 50 kW-hr/kg of hydrogen. However, new technologies with efficiency improvements are under development. The resulting total energy requirement for production of green ammonia (including production of hydrogen and nitrogen) is approximately 12 (megawatt hour (MWh)/tonne of ammonia. Detailed power requirements will be further analyzed during the full engineering design of the Project.

Because there will be intermittency in the delivery of the renewable power supplied to the facility, there will be times when excess power produced by high wind can be either stored or delivered to the local power grid for use by local Nova Scotia communities. Likewise, there will be times when additional power will need to be supplied to the site to make up for low winds; this power can be sourced from stored energy, tidal power, solar, or hydropower. Energy production and storage will be permitted separately by the proponent(s) of such independent project(s).

If there is a total loss of power for long durations, the facility will be shut down in an orderly manner using emergency backup power (e.g., diesel generator). Other than emergency backup power, no fossil-fuel-derived power will be used on site.

2.11 WASTES, DISCHARGES AND EMISSIONS

The Project components and activities described above will require electricity, water and nitrogen to create hydrogen which will be converted to ammonia. These processes generate various wastes, discharges and emissions as described below. Figure 2.4 in Section 2.7.1 shows anticipated inputs and outputs of green hydrogen and ammonia production. Table 2.2 summarizes routine Project emissions/effluents; details are provided in subsections below.

Table 2.2 Summary of Wastes, Discharges and Emissions

Type	Project Phase	Source of Emissions/Effluents	Characteristics	Mitigation/Management
Air Contaminants and GHGs	Construction / Decommissioning	Dust	Fine and coarse particulate matter (PM)	• Dust suppression and management • Equipment maintenance • Reduced vehicle and equipment idling • GHG Management Plan • Flaring Plan
		Emissions from equipment exhaust	CO_2, CH_4, N_2O, CO, NOx, SO_2, PM	
	Operation	Combustion processes, fugitive or off- gassing emissions sources and flaring	CO_2, CH_4, N_2O, CO, NOx, SO_2, VOCs, NH_3, O_2 and PM	
Noise	Construction/ Decommissioning	Vehicle/equipment operation	Temporary and intermittent noise from construction vehicle/equipment use	Adherence to Municipality of Richmond County Noise By-law (By-law #65) and provincial *Guidelines for Environmental Noise Measurement and Assessment Criteria.* • Use of appropriate noise muffling equipment • Equipment maintenance • Time of day restrictions to reduce nuisance (with potential for exemptions) • Use of vibratory hammers for jetty pile installation to the extent feasible
	Operation	Vehicle/equipment operation	Long-term, continuous noise from operations	
Lighting	Construction/ Decommissioning	Site and construction equipment lighting	Temporary lighting for the safety of construction activities as required	Adherence to industry standards and safety regulations; use of low intensity, shielded and directional lights where feasible
	Operation	Site lighting for safety and security purposes	Long-term use of lighting for the safety of operators and staff during night operations	

Table 2.2 Summary of Wastes, Discharges and Emissions

Type	Project Phase	Source of Emissions/Effluents	Characteristics	Mitigation/Management
Site Water Discharges	Construction/ Decommissioning	Hydrostatic testing	Raw water from LLWU	Tested and treated as applicable to meet Canadian Council of Ministers of the Environment (CCME) guidance frameworks and DFO/Environment and Climate Change Canada (ECCC) requirements prior to discharge to the Strait of Canso
		Surface runoff	Volumes dependent on rainfall amounts; may contain particulate matter and hydrocarbons	• Site erosion and sediment controls • Stormwater Management Plan
	Operation	Reject process water	Concentrated raw water from LLWU	Tested and treated as applicable to meet CCME guidance frameworks and regulatory approval requirements prior to discharge to the Strait of Canso
		Sanitary wastewater	Wastewater from domestic usage	In-ground disposal (upon approval from NSECC) or tested and treated as applicable to meet CCME guidelines prior to discharge to the Strait of Canso
		Surface runoff	Volumes dependent on rainfall amounts; may contain particulate matter and hydrocarbons	• Site erosion and sediment controls • Stormwater Management Plan
Solid and Hazardous Wastes	Construction/ Decommissioning	Construction and demolition waste	Scrap metals, insulation waste, packing/crating materials, paints, oils, lubricants, batteries, domestic/office waste	• Compliance with *Solid Waste-Resource Management Regulations* and applicable municipal waste requirements • Implementation of a Waste Management Plan • Sorting of waste streams with aim to reuse, recycle and recover wastes at licensed facilities • Dedicated hazardous waste storage area and handling by licensed contractor for disposal
	Operation	Operational waste	Scrap metals, insulation waste, packing/crating materials, paints, oils, lubricants, batteries, and domestic/office waste	

2.11.1 Air Contaminant and GHG Emissions

Releases of air contaminants and GHGs from construction and decommissioning are estimated to be the same or less than predicted for the Bear Head LNG Project, particularly given that site preparation is already substantially complete and the project footprint has already been established. Nevertheless, a variety of equipment will be used on site during Project construction and decommissioning. The operation of this equipment will generate air contaminants and greenhouse gases (GHGs) by burning diesel fuel to finish the construction phase of the work. This will result in the emission carbon dioxide (CO_2), methane (CH_4), nitrogen dioxide (N_2O), sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOCs), and particulate matter. Project-related vehicles and equipment will be maintained in good working order and idling will be reduced to the extent practical to reduce air contaminant emissions. Construction and decommissioning activities will also result in fugitive dust emissions. Dust suppression techniques will be employed as required.

During the operations phase, the air contaminant and GHG emissions for the Project will be virtually eliminated by using renewable energy sources to power the facility. During operations, one of the main constituents / gases that would be released to the atmosphere is oxygen.

The electrolysis process uses renewable electricity to apply an electrical current through deionized water, and split hydrogen and oxygen molecules apart. Hydrogen gas can be captured, purified, and compressed for direct use, storage, or distribution. In the future, storage and distribution of hydrogen and/or oxygen may be evaluated depending on market opportunities. This process produces essentially no carbon emissions. For this project, hydrogen will be captured and used directly to produce ammonia. At peak operations, approximately 3,800 tonnes of oxygen will be produced per day and vented to the atmosphere. Additionally, as part of the nitrogen separation process in the ASU(s), oxygen and other naturally occurring components of air are safely vented back to the atmosphere.

Oxygen is produced during the electrolysis process and to a lesser extent during the air separation (nitrogen production) process. It is anticipated that oxygen will be generated at low pressure in electrolysis processes and will be directly vented to the atmosphere. This Project does not involve collection, storage, handling or export of liquid oxygen.

Oxygen is not toxic nor is it a carcinogen. The natural composition of oxygen in atmospheric air is approximately 20.9%. Enriched levels of oxygen concentration are defined as those greater than 23.5% oxygen. In the presence of fuel and an ignition source, an increase in concentration of atmospheric oxygen can increase the intensity of a fire and change the flammable range of combustible material (i.e., materials become easier to ignite).

The presence of an oxygen-enriched atmosphere or a pressurized enclosure alters the conditions for ignition and dictates the use of special means for prevention and containment of explosions. During the electrolysis process, proper precautions must be in place to prevent hydrogen and oxygen recombination. As included in the COP, venting systems for oxygen dispersal require careful consideration due to the unique properties of oxygen. Project design will abide by applicable codes of practices and standards for oxygen venting systems to avoid internal accumulation of oxygen.

The Project will be designed with the intention of having no ammonia vapor releases. In upset conditions where safety requires the rapid depressurization of the facility, ammonia and hydrogen will be safely combusted in the flaring system. There will be no need for continuous or planned flaring. Like the Bear Head LNG Project, flaring would be necessary only during emergency or upset conditions to ensure the safety of facility personnel and the facility itself.

The Project will have two flares: a high-pressure flare and a low-pressure flare. The high-pressure flare is anticipated to be installed in the same general location and at a similar height as was planned for the Bear Head LNG Project. The high-pressure flare would be used to evacuate the process units, primarily the Haber-Bosch ammonia synthesis unit, if needed. It is estimated that approximately 24 hours of flaring a year would occur from the high-pressure flare. A combination of hydrogen and ammonia would be combusted in the flare. This would occur only under safety-related conditions and only to the extent needed to reduce the pressure in the process units to a safe level. The duration of the flaring and the emissions from flaring will depend upon final design and capacity of the unit. Protocols and methods to minimize the quantities of air contaminants released to the atmosphere during the above events will be considered further during detailed engineering. Contingency planning to minimize the emissions during an event will also be developed in more detail in the detailed engineering design stage.

As there are no hydrocarbons in the system, the emissions from the flare are anticipated to be water vapor and low levels of NO_X produced from the reaction of the ammonia, nitrogen and oxygen. The intent is to use an electronic ignitor for the high-pressure flare, if possible, so that there is no ongoing pilot flame at the flare tip, and so those emissions that would otherwise be continuous are avoided. The flare will be carefully designed to provide sufficient combustion and may require hydrogen to assist combustion. This will be confirmed during the next phase of engineering.

A single low-pressure flare (marine flare) will be installed to service the jetty and, potentially, the ammonia storage tank. This flare will be located in the same general location as previously permitted for the Bear Head LNG Project. This flare will be used in an emergency situation such as interruption of the refrigeration system or an upset during vessel loading and unloading. These events are considered unlikely due to planned redundancy in the equipment, as well as provision for back-up emergency power. Therefore, the operation of the low-pressure flare is likely to be infrequent and estimated to be approximately 5 hours per year. Similar to the high pressure flare, the emissions from the flare are anticipated to be water vapor and low levels of NO_X produced from the reaction of the nitrogen and oxygen (no hydrocarbons in the system). Similarly, the intent is to use an electronic ignitor for the low-pressure flare, if possible, so that there is no ongoing pilot flame at the flare tip, thus avoiding those emissions. The flare will be carefully designed to provide sufficient combustion and may require hydrogen to assist combustion. The final design and configuration of the flaring system will be based on the final Project engineering design.

Flaring events for the Bear Head LNG Project were estimated to be intermittent and occur over a total of approximately 192 hours per year (SNC Lavalin 2015). As noted above, the Project flares are expected to operate at a far lower frequency than those of Bear Head LNG Project (e.g., 29 hours a year) because the BHE Project will consume essentially zero petroleum fuel.

Further, since there are no hydrocarbons in the system, there will be essentially no planned carbon emissions associated with the flaring, if and when it occurs. Additional information on air contaminant and GHG emissions is provided in Section 7.1.

2.11.2 Noise

The noise associated with the construction and operation of the Project will be generally reduced or maintained by the change from LNG to green ammonia. The methods of construction will be generally the same as those previously approved for the Bear Head LNG Project, including marine construction. However, there will be a significant reduction in the quantity and size of heavy equipment being installed which is anticipated to reduce the magnitude and duration of construction noise.

The operation of the green hydrogen and ammonia production, storage and loading facility is expected to produce considerably less noise than the Bear Head LNG Project since approximately half of the primary noise-producing equipment associated with the LNG export facility will be eliminated from the updated facility design (Table 2.3). This includes the gas-fired turbines which were previously the highest noise sources for the Bear Head LNG Project. Also, the mixed refrigerant air coolers for the LNG export facility will no longer be needed for the updated Project. The steam turbines will likely bereduced for the updated design. Depending on the design of the ammonia unit, a reduced number of heat recovery steam generators may be used to optimize the performance of the system.

There will be two new equipment types for the Project: the hydrogen electrolysers and the electrical substation, both of which are low noise emitters compared to the eliminated sources of noise. The electrolysers will be contained in enclosures and operate at very low or no audible levels outside of the enclosure. The electrolysers will be located in the area of the facility previously planned for the liquefaction units. The electrical substation, planned to occupy the same general location as the substation for the Bear Head LNG Project, will be larger than the one previously proposed. High voltage electrical substations such as the 345 kilovolt (kV) station required for the Project, will be designed to meet the sound level criteria at the fence line and receptors.

Table 2.3 Primary Noise Producing Equipment

Bear Head LNG Project	Updated Project
Gas Turbine/MR Compressor Package Gas Turbine Exhaust Once Through Steam Generator Boiler Feed Pumps MR Air Coolers BOG Compressors Ammonia Compressors Steam Turbines Ammonia Air Coolers Air Cooled Condensors Instrument Air Compressors Amine Charge Pumps Amine Air Coolers Miscellaneous Equipment	~~Gas Turbine/MR Compressor Package~~ ~~Gas Turbine Exhaust~~ Steam Generator Boiler Feed Pumps ~~MR Air coolers~~ BOG Compressors Ammonia Compressors Steam Turbines Ammonia Air Coolers Instrument Air Compressors ~~Amine Charge Pumps~~ ~~Amine Air Coolers~~ Miscellaneous Equipment (e.g., piping, inlets, valves) New: Hydrogen Electrolysers Electrical Substations
Note: Strikethrough text signifies equipment that is no longer required for the Updated Project.	

During Project operations, noise emissions will result from the operation of the electrical substation transformers, hydrogen and nitrogen collection, ammonia production and process piping. Acoustic modelling was completed to predict sound levels at nearby receptors due to Project activities. The predicted sound pressure levels were added to measured baseline data and compared to applicable guideline levels to estimate the impact on in sound quality.

The level of marine traffic associated with normal operations will be reduced compared to the Bear Head LNG Project. Ammonia carrying vessels are significantly smaller (50,000 to 80,000 m^3) than those used for transportation of LNG (125,000 to 265,000 m^3), which will result in less marine engine noise. Additionally, the loading of vessels will be less frequent, reducing to 40 to 60 ships per year (previously assumed 70 to 135 ships per year). Therefore, the noise associated with the marine operations is anticipated to be substantially reduced.

Refer to Section 6.1. and Appendix D for more information on the noise assessment.

2.11.3 Lighting

Lighting will be provided at site primarily for the safety of operators and staff during night operations. The over-all lighting design philosophy for the Project will be comparable to the lighting originally permitted for the Bear Head LNG Project and will meet the requirements of the NSI/IES RP-7, “American National Standard Practice for Industrial Lighting” and ANSI/IESNA RP-1, American National Standard Practice for Office Lighting” as required by the Nova Scotia *Occupational Health and Safety Act*. The specifications and design for the lighting required at the two flare structures, will be determined in consultation with Transport Canada.

It is anticipated that the total lighting load for the new facility design will have less impact on the surrounding environment than the previously approved Bear Head LNG Project for the following reasons:

- The mechanical equipment and process units will not be as tall and will require less safety lighting for elevated workspaces. This will reduce the visual impact of the plant from Port Hawkesbury and across the Strait of Canso.
- A large portion of the mechanical equipment, such as the electrolysers, may be enclosed thereby blocking the lighting from night skies and the surrounding environment.
- Advancement of LED lighting will provide more targeted and less invasive lighting by using warm bulbs, shielded light fixtures, and motion sensors where appropriate.
- Lighting associated with marine operations may be reduced due to a decrease in the typical vessel size associated with ammonia transportation when compared to LNG vessels.

2.11.4 Site Water Discharges

Hydrostatic Test Water

As part of the commissioning process, piping and storage tanks will be hydrostatically tested. It is assumed that hydrostatic test water will be supplied by LLWU and will be of acceptable quality for discharge to the Strait of Canso. However, prior to hydrostatic testing, BHE will provide NSECC with a characterization of the hydrostatic water and establish a management plan for spent test fluids for review and approval prior to discharge.

Reject Process Water

As described above in Section 2.3, the production of hydrogen requires deionized water as a feedstock. Approximately 4 million gallons (15 million litres) of water supplied by LLWU will be treated through a two-stage reverse osmosis and deionization process prior to use in the electrolyser. It is estimated that the reject discharge volume from the treatment process will be approximately one-third the volume of the intake water.

Based on predicted water quality of the reject process water (Appendix B), metal concentrations are expected to meet the CCME Water Quality Guidelines for the Protection of Aquatic Life (Marine) (CCME WQG-PAL). However, a marine mixing zone is proposed to be able to meet guideline limits for temperature and salinity since the reject process water will be warmer and lower in salinity than the marine waters in which it is proposed to be discharged.

BHE explored alternatives to marine discharge and use of a mixing zone such as water reuse, evaporation ponds, mixing with freshwater, use of saltwater wells, and seawater intake, but none of these alternatives were technically or economically feasible for the Project. Pre-treatment to cool the temperature and increase salinity of the reject process water would require intensive infrastructure and create new environmental effects. For example, intake of seawater for mixing with the process water discharge would increase the Project footprint and introduce new environmental interactions for the Project related to potential impingement and entrainment of marine organisms and issues in the marine environment. The addition and use of fresh water to reduce the temperature of the process water discharge would require substantially more freshwater supply.

An assimilative capacity investigation and mixing zone assessment in the marine environment was conducted for the discharge of warmer and lower salinity reject process water (refer to Appendix F for more details). This study found that temperature and salinity will reach background levels in 4 to 6 m from the discharge point in the marine environment. BHE will work with NSECC, DFO and ECCC to identify appropriate discharge objectives using the CCME WQG-PAL as a framework to obtain the necessary regulatory approvals prior to discharge.

Sanitary Wastewater

Should site soils and topography support the design an on-site septic system, approval will be sought from NSECC for onsite sewage disposal of domestic effluent generated on the site. If site characteristics preclude the installation of an on-site septic system, discharge to surface water will be required. To permit discharge to surface water, a wastewater treatment system will be installed as required and effluent streams will be treated to acceptable levels prior to discharge.

Surface Runoff

Runoff generated from undeveloped areas of the site will drain via existing natural drainage paths, directing flow to watercourses on the eastern and western site boundaries. Existing site perimeter drains will collect flow discharging from future developed areas and convey the flow to the existing drainage pond south of Bear Island Road. Stormwater runoff will be attenuated in water management pond(s) prior to discharge into the Strait of Canso.

2.11.5 Solid and Hazardous Waste

Solid and hazardous wastes generated will be the similar as predicted for the Bear Head LNG Project and will include:

- scrap metal
- insulation waste
- packing and crating materials
- paints, oils, and batteries
- domestic waste
- solids (i.e., sludge) from the water purification plant (RO unit)

Solid wastes will be sorted into recyclable and non-recyclable waste streams. Efforts will be made to reduce, reuse, recycle and recover wastes at licensed facilities. Waste management procedures will comply with the provincial Solid Waste-Resource Management Regulations and disposal facility requirements. Generated hazardous wastes will be stored on site in a separate and temporary hazardous waste storage area until removal by a licensed contractor for disposal.

2.12 HEALTH, SAFETY AND ENVIRONMENTAL MANAGEMENT

BHE is committed to the development and execution of a detailed Health, Safety, Security and Environment (HSSE) Management system throughout all stages of design, construction, operation and decommissioning. BHE will implement the expertise and experience of Buckeye and leading global engineering and safety compliance organizations to establish a safe and efficient foundation for the Project to succeed while keeping the community safe and minimizing the impact on the environment.

A Risk Management Plan will be developed as a component of the overall HSSE system to identify potential risks, estimate impacts and define response procedures for all phases of the Project. BHE will also prepare an Emergency Response Plan (ERP) for the facility which will include details on emergency procedures to be implemented and coordination with local emergency services and authorities. The Risk Management Plan and ERP will be informed by the COP and other applicable codes and standards (refer to Section 2.4). More information on emergency response is provided in Section 7.

Environmental protection is an important part of the HSSE management system. BHE will develop an Environmental Management Plan (EMP) which may incorporate a variety of environmental protection plans such as:

- Avian Management and Monitoring Plan (will update plan previously developed for the Bear Head LNG Project)
- Air Quality Management Plan
- Flare Management Plan
- Waste Management Plan
- Spill Contingency Plan
- Stormwater Management Plan
- Erosion and Sediment Control Plan
- Archaeological Contingency Plan
- Traffic Management Plan
- Complaint Resolution Plan

A Decommissioning and Reclamation Plan will also be developed prior to Project decommissioning.

2.13 PROJECT SCHEDULE

The overall Project timeline to plant commissioning and first ammonia is approximately 6.5 years starting from 2022 as shown below in Figure 2.7. Final investment decision (FID) is planned by the end of 2024. This schedule is based on other critical elements (e.g., availability and permitting of new renewable power) which may influence the timetable to reach FID. The Project will be constructed in phases driven by the availability of renewable power with first ammonia estimated to occur by mid-2028. The overall duration of the timeline to operations will depend on critical long-lead equipment items such as the electrolysers. The production of electrolysers, and in particular PEM electrolysers is currently very limited. Multiple manufacturers are in the process of expanding production capacity. The ability to reserve production capacity and the delivery of competed units is expected to drive the critical path for the project.

In order to shorten the critical path, the project team may consider starting the long lead procurement items (electrolysers) in advance of FID. Many procurement activities will be performed in parallel with detailed engineering. Site preparation will begin three months following the start of detailed design engineering.

BHE will continue to refine and incorporate incremental detail and specificity to the Project schedule through the various engineering phases.

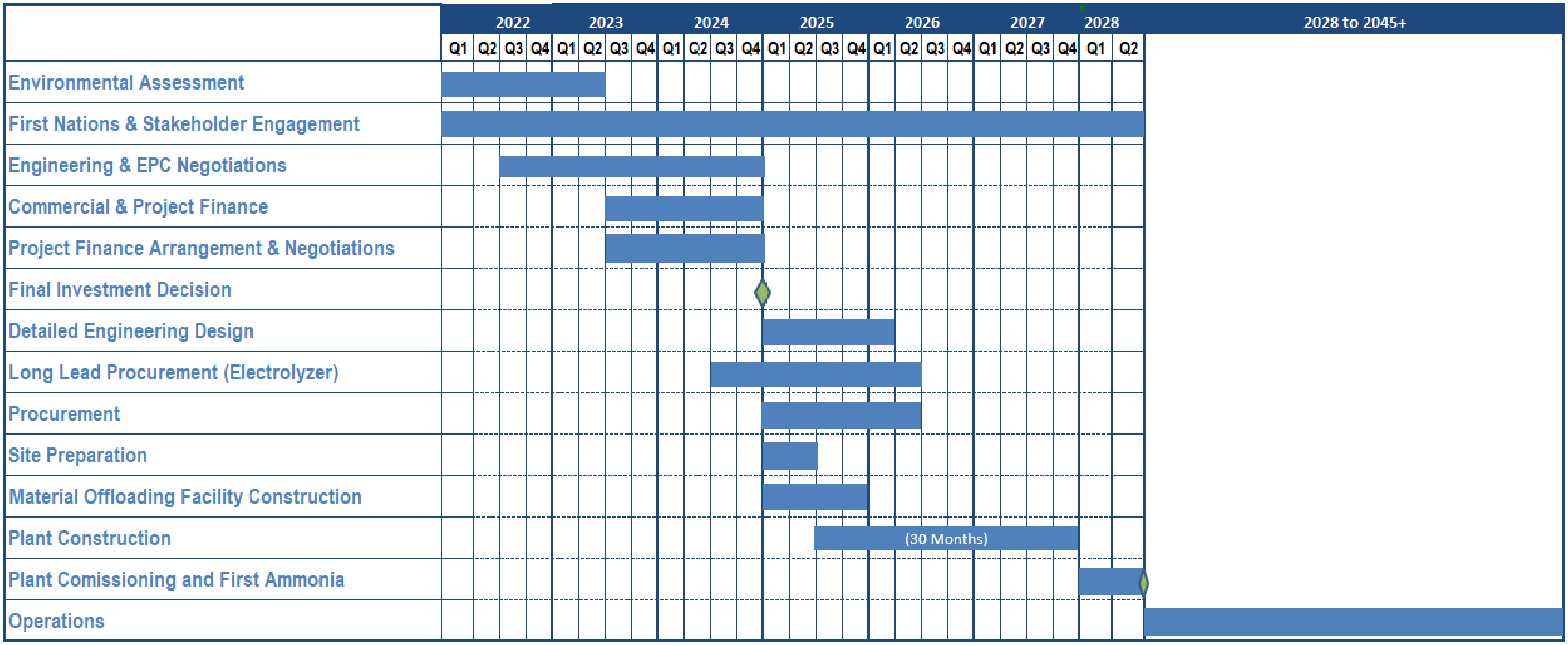

Figure 2.7 Proposed Project Timeline

2.14 ESTIMATED EMPLOYMENT

The estimated employment is the same as predicted for the Bear Head LNG Project, generating approximately 45 to 70 permanent direct jobs and 175 permanent indirect jobs for 20 years or more. Approximately 600 to 700 jobs associated with construction are predicted.

2.15 PROJECT ALTERNATIVES

This section outlines Project alternatives including alternatives to the Project, and alternative means of carrying out the Project.

2.15.1 Alternatives to the Project

The purpose of the Project is to export green ammonia to world energy markets and support global decarbonization efforts. Although the Project will at first produce ammonia to be shipped to world markets versus supplying local energy needs, it may also serve to anchor a growing domestic green hydrogen and ammonia economy in Nova Scotia and potentially act as a catalyst for additional green energy investments in adjacent industries,

In the case that the Project does not proceed, environmental impacts associated with continued development of the Project would be avoided. However, the site has been approved for industrial development and is already substantially developed. If the Project does not proceed, the substantial work that has already gone into developing the Project site would be lost. Of greater significance, however, would be the lost opportunity to advance the energy transition and global decarbonization efforts and the loss of numerous additional Project benefits as outlined in Section 12.

2.15.2 Alternative Means of Carrying out the Project

Alternative means of carrying out the Project include consideration of alternative locations, product transport options, and technology. Each of these alternatives are discussed below.

2.15.2.1 Alternative Locations

The Project Site is considered ideal and was selected over alternative locations for a number of reasons. It is located on the Strait of Canso, which is a natural ice-free harbour that is extremely deep and accommodating to large marine vessels. It is already a major bulk port zoned for industrial/marine terminal use which accommodates approximately 68% of Nova Scotia’s international and domestic cargo tonnage. The Strait of Canso is also central to international shipping routes (Strait of Canso Superport Corporation n.d.) with relatively short shipping distances to key European and U.S. green energy markets. Other regional advantages include proximity to a substantial wind regime capable of providing low cost renewable power and proximity to existing freshwater resources and infrastructure.

The site is also suitable because of the amount of development and work done thus far. As part of previous works related to the Bear Head LNG Project, extensive review and assessment (including field data collection) was undertaken, providing substantive data on the site and its environment. Most importantly, construction was previously started before the LNG Import Facility project was placed in hot idle in 2007. The Bear Head site is therefore substantially developed, greatly limiting the future environmental impacts of Project construction.

Finally, the general public is generally familiar with the Bear Head site being planned for energy development. There is general optimism that the Project's development would attract other investment in the region and serve as a catalyst for future renewable energy development in the province. All of these factors mean that the current location fully meets the needs of the Project, limits environmental impacts and provides positive benefits to the surrounding communities.

2.15.2.2 Product Transport

Currently, the Project's potential market is worldwide and will likely be largely overseas given current limited local market demand. Given hydrogen's low energy density, ammonia is the optimal transportation medium for carrying hydrogen. Since the market is overseas, the only viable option for product transport is by marine vessel transport of ammonia. Transport by roadway or rail can be eliminated and a subseapipeline is not considered feasible at this time.

2.15.2.3 Technology

As new and improved technologies are developed for green hydrogen and ammonia production, BHE will evaluate these technologies for future phases. As noted in Section 2.7.1.2, BHE is currently evaluating different types of electrolysers for use in the Project, including but not limited to, a PEM electrolyser and an Alkaline electrolyser. Alkaline electrolysers operate at extremely caustic conditions with a high concentration of the hydroxyl ion (OH-). When a current is applied to the electrolyser stack, the OH- flows from the negative to the positive side. Conversely PEM electrolysis occurs in acidic conditions with a gradient of protons (H+) flowing from the positive side to the negative side. In both systems, H_2 is generated on the negative side gaining electrons and O_2 on the positive side losing electrons. Alkaline electrolysers have lower installation costs because they don't need the expensive titanium-based materials and noble metal catalysts required in PEM's acidic conditions. The PEM design provides higher electricity conduction, higher efficiency, and higher output pressure with a smaller footprint than alkaline electrolysers. The current site layout in Figure 2.1 is based on the PEM design. However, both of these technologies are feasible and acceptable from an environmental perspective and both will be reviewed during the full engineering design of the Project to select the optimal solution for BHE. Table 2.4 presents a conceptual comparison between the two technologies currently under consideration.

Table 2.4 Comparison of Electrolysers Technologies

PEM Electrolysers		Alkaline Electrolysers	
Pros	**Cons**	**Pros**	**Cons**
Small stack footprint (up to 60%)	Acidic environment and high voltages are very harsh on equipment	Operate very reliably for long periods of time (30+ years)	Porous diaphragm that dissolved O_2 and H_2 can traverse = less product
High quality materials provide stability and optimal conductivity/efficiency	Costly durable titanium materials and noble metal catalysts needed	Cheaper installation cost	Restricted power operating range
Thin membrane diagram reduces resistance increasing efficiency	Sensitive to water impurities: Fe, Cu, Cr, Na, Ca	Simple design and easy to manufacture	Restricted pressure operating levels
Higher current density and operating pressure	High expense makes scaling up harder	Thicker diaphragms can prevent restrictions and traversing gasses	Ohmic resistance increases and efficiency is lower
Strong membrane allows high pressure differentials (1 atm O_2 / 70 atm H_2)	Less mature technology than alkaline (but developing quick)	Very developed commercial electrolysis technology	Operates at low current density

2.15.2.4 Summary

To summarize, Project design, including aspects such as Project location, product transport, and choice of technology are being selected to best meet the needs of the Project while simultaneously meeting operational and safety standards, and reducing the environmental impact of the Project.

3.0 CONSULTATION AND ENGAGEMENT

3.1 CONSULTATION AND ENGAGEMENT FOR THE PREVIOUSLY APPROVED BEAR HEAD LNG PROJECT

The following consultation and engagement activities were undertaken for the previously approved LNG Import Facility and/or LNG Export Facility with engagement dating back to and continuing since the early 2000s:

- A company and project Internet site was established to provide information and updates on project development
- Public open houses were held in Port Hawkesbury, Mulgrave and Goldboro
- Various presentations and information sharing meetings were held with stakeholders including municipal councils, and labour and business groups
- Media announcements were made, and media coverage was tracked
- A Mi’kmaq Ecological Knowledge Study (MEKS) was conducted for the LNG Import Facility in 2004 and another MEKS was conducted for the LNG Export Facility in 2015

Provincial EA Registration documents prepared for both previously approved projects were subject to public review and comment periods.

For the Bear Head LNG Project, BHLNG signed a Memorandum of Understanding (MOU) with the Nova Scotia Community College (NSCC) regarding customized training and skills development. BHLNG also signed an MOU and Mutual Benefits Agreement (MBA) with the Assembly of Nova Scotia Mi’kmaq Chiefs (ANSMC) in 2016 and 2019, respectively.

The consultation and engagement strategy for the updated Project continues to build on previous engagement efforts and includes regulatory agencies, the Mi’kmaq of Nova Scotia, non-governmental organizations and special interest groups (e.g., industry groups), local community business and residents, and the general public. BHE has also reconvened its community liaison committee to facilitate community engagement.

Current Mi’kmaq and stakeholder engagement for the Project is described in Sections 3.2 and 3.3.

3.2 **MI’KMAQ ENGAGEMENT**

BHE initiated meetings on the Project with the Mi’kmaq of Nova Scotia in 2021 and is in the process of finalizing a MOU with the Kwilmu’kw Maw-klusuaqn Negotiation Office (KMKNO) to guide the refinement of the 2019 MBA with the ANSMC. The MBA will facilitate the development and operation of the Project in an efficient, economically sound and environmentally responsible manner and facilitate Project-related economic, employment, business and training opportunities for the Mi’kmaq of Nova Scotia.

Table 3.1 summarizes Mi’kmaq engagement efforts on the Project dating back to June 2021. Unless otherwise indicated in the table (e.g., email), these events represent real or virtual (e.g., Microsoft Teams) meetings.

Table 3.1 Summary of Mi’kmaq Engagement

Organization	Purpose	Date
Indigenous Engagement		
KMKNO	Bear Head - KMKNO Update	June 3, 2021
KMKNO	Bear Head LNG Update	June 23, 2021
KMKNO	Bear Head - KMKNO Meeting	September 14, 2021
KMKNO	Bear Head Update and Benefits Agreement Discussion	December 1, 2021
Waycobah First Nation	Bear Head Energy Update	April 25, 2022
Potlotek First Nation	Bear Head Update and Benefits Agreement Discussion	June 2, 2022
Waycobah First Nation	Bear Head Energy Update	June 13, 2022
Office of L'nu Affairs	Bear Head Energy Introduction (Email)	June 17, 2022
KMKNO	Bear Head Energy Update-Benefits Agreement Amendment	June 28, 2022
Wskijnu’k Mtmo’taqnuow Agency Board	Onshore Wind MOU	September 15, 2022
KMKNO	MOU and MBA Meeting	September 21, 2022
KMKNO	MOU and MBA Meeting	November 7, 2022
Eskasoni First Nation	Bear Head Joint Business Opportunities	December 13, 2022
KMKNO	MOU and MBA Meeting	January 25, 2023

Key issues and concerns that have been raised through meetings with the Mi’kmaq of Nova Scotia relate primarily to water use, jobs and training, and construction camps. In early meetings with the Mi’kmaq of Nova Scotia about the Project, questions were raised about water withdrawal and desalinization of sea water for use in the electrolysis process. The Mi’kmaq specifically expressed concerns about withdrawing water from the Strait of Canso. BHE confirmed that water withdrawal from the Strait of Canso was not a planned activity and that the water supply for the Project would be a freshwater source (supplied by LLWU). Comments were also made that the Mi’kmaq could not support the Project if construction camps were planned. BHE confirmed that no construction camps are planned for the Project. BHE asserts there is an abundance of skilled labour in the region and that no construction or work camps are required to accommodate workers.

BHE is committed to building on relationships that respect Mi’kmaq rights and supports the social, cultural, environmental and educational goals of the Mi’kmaq of Nova Scotia. Since 2015, We’koqma’q First Nation, through First Alliance Safety, has provided security and safety services at the Bear Head Site and will continue to do so.

BHE will continue to engage the Mi’kmaq of Nova Scotia throughout the life of the Project, building on existing relationships to help manage environmental impacts and optimize Project benefits.

3.3 STAKEHOLDER ENGAGEMENT

Since 2021, BHE has met with various local government representatives, regulatory agencies, and public stakeholders to provide updates on the Project and understand potential issues and concerns. In addition to the municipal government, regulatory agency and industry stakeholder engagement summarized in Table 3.2, BHE has reconvened their Community Liaison Committee (CLC), originally established in 2017 (Section 3.3.1), and has held open house meetings in local communities (Section 3.3.2).

Table 3.2 Summary of Stakeholder Engagement

Organization	Purpose	Date
Municipal Government and Utilities		
The Municipality of the County of Richmond County – Warden and Chief Administrative Officer	Bear Head LNG Update with the Municipality of the County of Richmond	April 26, 2021
The Municipality of the County of Richmond County – Warden and Chief Administrative Officer	Bear Head LNG - Taxes and Municipal Project Support - Tax Appeal	May 17, 2021
The Municipality of the County of Richmond County – Chief Financial Officer	Bear Head LNG and Richmond County - Taxes and Payment Planning	May 20, 2021
The Municipality of the County of Richmond County – Chief Financial Officer	Bear Head LNG and Richmond County - Taxes and Payment Planning	July 21, 2021
Town of Port Hawkesbury – Town Engineer and Chief Administrative Officer	Conference Call - Landrie Lake	August 3, 2021
The Municipality of the County of Richmond County (Warden) and Town of Port Hawkesbury (Mayor)	Bear Head and Landrie Lake - MOU	August 13, 2021
The Municipality of the County of Richmond County - Chief Financial Officer	Bear Head Municipal Taxes	January 21, 2022
Municipal Stakeholders – Guysborough, Richmond, Port Hawkesbury	BHE Update Presentation to various municipal leaders and stakeholders	June 21, 2022
Town of Port Hawkesbury Council	Bear Head Project Update	October 4, 2022
Municipality of the District of Guysborough	Bear Head Planning Updates	December 6, 2022
Cape Breton Buildings and Construction Trades Council	Bear Head Project Update	December 8, 2022
Landrie Lake Water Utility	Bear Head Water Transmission	December 14, 2022
Bear Head Energy Community Liaison Committee Meeting	Bear Head Update	December 14, 2022
Landrie Lake Water Utility	Bear Head – Landrie Lake Regulatory Planning	December 20, 2022
Town of Port Hawkesbury Council	Port Hawkesbury Real Estate and Housing Concept	January 3, 2023
Landrie Lake Water Utility	Bear Head Energy Water Supply	January 11, 2023
Landrie Lake Water Utility	Bear Head Energy Water Supply	January 25, 2023

Table 3.2 Summary of Stakeholder Engagement

Organization	Purpose	Date
Nova Scotia Utility and Review Board	Bear Head LNG Update	May 10, 2021
Nova Scotia Utility and Review Board	Bear Head Energy Regulatory Process	August 11, 2021
Nova Scotia Utility and Review Board	Bear Head Energy Update	October 19, 2022
Nova Scotia Utility and Review Board	Bear Head – Landrie Lake Regulatory Planning	December 20, 2022
Provincial and Federal Government Staff and Elected Officials		
Department of Natural Resources and Renewables	Bear Head Energy Update	August 7, 2021
Department of Natural Resources and Renewables	Bear Head Energy Update	September 7, 2021
Department of Natural Resources and Renewables	Bear Head Energy Update	September 17, 2021
Department of Natural Resources and Renewables	Bear Head Energy Update	July 23, 2021
Department of Natural Resources and Renewables	Bear Head Energy Update	June 14, 2022
NSECC EA Branch	Bear Head Energy Update	June 23, 2022
Government of Canada – Member of Parliament and Minister Immigration, Refugees and Citizenship of Canada	Bear Head Energy Update	June 17, 2021
Government of Canada – Member of Parliament and Parliamentary Secretary to the Minister of DFO and Canadian Coast Guard	Bear Head Update	July 19, 2021
NS Department of Finance (Deputy Premier)	Bear Head Energy Update	June 21, 2022
Provincial Public Servants and Cabinet Ministers	Bear Head Energy Update	June 22, 2022
Natural Resources Canada	Bear Head Energy Update	September 22, 2022
NSECC EA Branch	Bear Head EA Process	October 18, 2022
Fisheries and Oceans Canada	Bear Head DFO Authorizations	October 21, 2022
Department of Natural Resources and Renewables NSECC EA Branch	Bear Head Energy Regulatory Changes for Hydrogen and Pipelines	October 28, 2022
Department of Natural Resources and Renewables	Bear Head Project Update	November 1, 2022
Department of Natural Resources and Renewables	Bear Head Site Tour	November 9, 2022
NSECC EA Branch	Bear Head Scoping Session	November 17, 2022
Department of Natural Resources and Renewables	Onshore Wind RFA	December 12, 2022
NSECC EA Branch	Bear Head Scoping Session	December 13, 2022
Department of Natural Resources and Renewables	Hydrogen Sector Infrastructure Planning	January 23, 2023
Transport Canada	Marine Simulations and TERMPOL	January 24, 2023

Table 3.2 Summary of Stakeholder Engagement

Organization	Purpose	Date
Industry Stakeholders		
Nova Scotia Business Inc	Bear Head LNG Update	May 11, 2021
Nova Scotia Business Inc	Discussion re Opportunity	May 11, 2021
Nova Scotia Business Inc	Strait Area Hydrogen Opportunities	May 26, 2021
Bear Head Energy, Cape Breton Building Construction Trades Council	Project Labour Agreement Amendment	September 9, 2021
Nova Scotia Business Inc	Bear Head Hydrogen	September 20, 2021
Nova Scotia Business Inc	Bear Head Energy Utility License Agreement	October 27, 2021
Nova Scotia Business Inc	NSBI (now Invest Nova Scotia) Discussion	October 29, 2021
Nova Scotia Business Inc	Bear Head Land Discussion	November 10, 2021
Strait Area Offshore Wind Task Force (multiple stakeholders)	Strait Area Offshore Wind Monthly Task Force Meeting	March 1, 2022
Nova Scotia Business Inc	Bear Head Lands	March 14, 2022
Bear Head Energy, CLRA and Cape Breton Building Construction Trades Council	Project Labour Agreement Amendment	April 21, 2022
Nova Scotia Business Inc. and Department of Economic Development	Bear Head Energy Update	June 21, 2022
Cape Breton Partnership Investor Summit	Bear Head Project and Labour Needs	October 20, 2022
Nova Scotia Business Inc	Bear Head Road Lead and Land Option	November 1, 2022
Strait Area Offshore Wind Task Force (multiple stakeholders)	Offshore Wind	November 8, 2022
German Ambassador to Canada and Atlantic Hydrogen	Bear Head Project Update	November 17, 2022
Nova Scotia Community College	Nova Scotia Community College MOU	November 24, 2022
Invest In Canada	Bear Head Project Update	December 7, 2022
Strait Area Offshore Wind Task Force (multiple stakeholders)	Bear Head and Offshore Wind	December 21, 2023
Canadian Building Trades Council	The Canadian Investment Tax Credit	December 22, 2022
Nova Scotia Business Inc	Bear Head Lands Update	January 13. 2023
Nova Scotia Business Inc	Bear Head Hydrogen Technology	January 17, 2023
Atlantic Canada Opportunities Agency	Bear Head and Atlantic Canada Market Opportunities	January 20, 2023
Atlantic Hydrogen Alliance	Hydrogen Hubs Working Group Meeting	January 23, 2023

Once submitted to NSECC, this EA Registration document will be posted online for public review and comment, with printed copies also available in the local community, providing stakeholders additional opportunity to learn more about the Project and raise potential questions or concerns for consideration. BHE will continue stakeholder engagement efforts beyond the EA process, throughout the life of the Project, via face-to-face meetings, presentations at industry/community events, website updates, community open houses and CLC meetings.

3.3.1 Community Liaison Committee

BHLNG (now BHE) established a CLC in 2017 with an objective to:

- facilitate open communication with area residents, landowners, Mi'kmaq, municipal representatives and community stakeholders
- bring forward feedback from area stakeholders to BHLNG
- act as a liaison between area stakeholders and BHLNG
- help BHLNG better understand local interests

The CLC has been composed of up to 10 members from the community including representatives of landowners, residents, Indigenous groups, local business, municipal representatives, community/environmental groups.

Meetings were held between 2017 and 2019 and due to project inactivity, was put on hold in 2019. BHE re-engaged the CLC in 2022 with a meeting on December 14, 2022.

During the December 2022 meeting, BHE presented an overview of the history of the project and the current project development plan focused on the production of green ammonia and green hydrogen. Specific topics included history of and investment in the Project site; current ownership and assets of the Project; status of current regulatory approvals and regulatory filing schedule; water supply (feed stock) agreements; communications with the community and First Nations groups to date; and overall Project timelines including final investment decision and construction start. Key messaging from BHE was the focus on safety throughout Project planning. Questions and feedback from the CLC meeting in December 2022 have been summarized with other stakeholder feedback in Section 3.3.3.

3.3.2 Open House Meetings

BHE planned four open house meetings in January 2023, although as noted in Table 3.3, two of these open houses were cancelled due to winter storm conditions. Appendix G contains copies of open house materials that were shared during the Mulgrave and Port Hawkesbury open houses.

Table 3.3 Open House Meetings

Community	Location	Date/Time	Registered Attendees
Mulgrave	Mulgrave Volunteer Fire Department 385 Murry St, Mulgrave NS	January 9, 2023 (3:00-7:00 pm)	31
Arichat	Isle-madame New Horizons Seniors Club 2373 Highway 206 Sampson Cove NS	January 10, 2023 (1:00 - 3:00pm)	Cancelled due to storm
St. Peter’s	United Church Hall 9913 Grenville St St. Peter’s NS	January 10, 2023 (5:00 – 8:00pm)	Cancelled due to storm
Port Hawkesbury	Port Hawkesbury Civic Centre 606 Reeves St Port Hawkesbury NS	January 11, 2023 (4:00 – 8:00pm)	102

The open houses in Mulgrave and Port Hawkesbury were well attended and included participants from neighboring communities. These meetings provided an opportunity for BHE to speak directly with interested participants and gain an appreciation for potential interests, issues and concerns. Overall, attendees were very supportive of the Project occurring in the region and were eager to learn more about potential socio-economic benefits. Questions and concerns raised by attendees are summarized in Section 3.3.3. BHE plans to hold additional community meetings beyond the EA process in order to provide Project updates and obtain stakeholder feedback.

3.3.3 Key Issues and Concerns Raised During Stakeholder Engagement

Table 3.4 summarizes key issues and concerns that have been raised during stakeholder engagement, including the CLC meeting held on December 14, 2022 and the January 2023 open houses. As noted above, most of the stakeholder feedback so far has been in support of Project development with a particular focus on the Project’s potential to help realize numerous local socio-economic benefits.

Table 3.4 Summary of Key Issues and Concerns Raised by Stakeholders

Question/Comment	BHE Response
Project development schedule is aggressive - will need to manage public expectations	The BHE Management team is experienced in large scale project development. BHE will provide regular updates on the Project development schedule through their website and communication with CLC members.
Concern regulatory process could hinder progress	BHE is committed to developing the Project in a safe and sustainable manner and is working closely with regulatory agencies to understand regulatory requirements and reduce risk. BHE is focused on safety over speed and taking the time to develop a safe design for the facility.
Local support for onshore and offshore wind to promote green energy development in region	BHE is encouraged by the local support for the Project and will help establish Atlantic Canada as a global leader in green hydrogen and ammonia production. This Project will help support the development of associated green energy developments such as solar and wind and will also help grew new industry opportunities such as onshore and offshore wind farm and transmission system operations and maintenance, and electrolyser manufacturing and maintenance.

Table 3.4 Summary of Key Issues and Concerns Raised by Stakeholders

Question/Comment	BHE Response
Socio-economic benefits to the region	BHE has commissioned a socio-economic benefits study. Regional benefits will include: diversification of the local economy; capacity building and skills training; increased municipal, provincial and federal tax revenue and jobs and training in the community and region. Up to approximately 700 jobs will be created during construction and up to 70 permanent direct jobs during operations and maintenance. Refer to Section 12 for more information on Project benefits.
Consideration of local training opportunities	BHE is in active discussions with NSCC and the Mi'kmaq of Nova Scotia to initiate training courses so that when we need skilled workers for various jobs, Nova Scotians will be adequately trained for such work.
Status of TERMPOL	A reevaluation of vessel transits will be coordinated with the NSCC Strait Area Nautical Institute (considering the smaller ships and fewer transits). Refer to Section 1.4 and 6.9 for more information TERMPOL.
Significance and implications of “first mover advantage”	The market continues to evolve but BHE is focusing on “safety over speed” to ensure public and ecological safety are a priority throughout Project development and do not consider it a race to market. Refer to Section 2.4 for more information on the Code of Practice that BHE is developing for Project design.
Potential impact on local fishing and marine users	Marine construction will occur within the BHE-owned water lot. Any restriction placed on the movement of vessels in the vicinity of the construction will be promulgated by MCTS in either the Notices to Mariners or Notices to Shipping. Communications will be established with local fishers and the Mi’kmaq of Nova Scotia, (particularly those individual fishers who may fish or harvest resources in the vicinity of the Project Area), and through these discussions, BHE will develop a compensation program to minimize the impact of gear loss or vessel damaged sustained by fishers due to Project-related activities.
Potential impacts on ecotourism	The Project will be developed on a previously developed site zoned for industrial use. The Project is not predicted to interact with existing tourism and recreation in the region.
Impact of Project development on housing market and availability	[BHE has made a commitment to not establish construction camps for the Project. BHE believes there is adequate skilled labour in relatively close proximity to the Project and the influx of additional workers is not expected to add pressure to the current housing market.
Conservation of freshwater resource	At full buildout and operating at full capacity, the facility could require an average of 4 million gallons (15 million litres) of water per day of raw water. BHE is evaluating engineering solutions to reduce the amount of water needed and the ability to limit the effluent water generated through the processing of the raw water to pure deionized water. BHE is also working closely with the Landrie Lake Water Utility to have a positive impact on the water resources and delivery of water to all users, including the local residents, through investment in new infrastructure. BHE is also planning to use air cooling, thereby eliminating substantial water evaporation losses from cooling tower operation. Refer to Section 2.10.1 for more information on Project water use.

Table 3.4 Summary of Key Issues and Concerns Raised by Stakeholders

Question/Comment	BHE Response
Public safety concerns around industrial facility	BHE is taking a safety-first approach to all aspects of facility design, construction, and operations, and we are spending tremendous time and resources in this area. Our team is focused on the development of a safe and well-engineered facility. BHE has worked with Lloyds Register to develop a COP to help guide the design, construction, operation and abandonment of the Project in a manner which will ensure protection of the public and the environment (Section 2.4). We have also conducted a Quantitative Risk Assessment (Appendix H). The QRAwork will continue through the detailed engineering phases and inform our detailed facility design to ensure any risk is minimized and contained within close proximity to the project site and does not impact surrounding communities or businesses. Safety is paramount and one of our core values and will not be compromised for an accelerated schedule or budget. In addition to implementing appropriate preventative measures, BHE will develop and maintain a robust emergency response and contingency plan which will include resourcing appropriate personnel, training and equipment to quickly and effectively respond to any incidents that may occur. Refer to Section 7 for additional information on potential Project risk and safety management.