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2.0 PROJECT DESCRIPTION

2.1 Project Overview

ANEI proposes to use a portion of the Bear Head area to construct an LNG import terminal capable of unloading LNG ships with a capacity up to 250,000 m^3, and providing an average sendout capacity of 1,000 MMscfd with a future expanded capacity of 1,500 MMscfd. The proposed facility will receive and offload LNG ships, store the LNG in storage tanks, vaporize the LNG, and then deliver the gas at a point of interconnection with facilities to be constructed, owned and operated by Maritimes and Northeast Pipeline (M&NP). The point of interconnection will be located either at the boundary of the plant site or on the site. The natural gas will be transported by M&NP to markets located in Canada and the northeast United States.

The main product of the facility will be natural gas. In some instances, the high heating value and other constituents of the LNG may be above the natural gas pipeline specifications as specified in the Maritimes & Northeast Limited Partnership Gas Tariff. In this event, the natural gas will be injected with nitrogen prior to sendout to the pipeline. ANEI is also evaluating the opportunity for onsite extraction of natural gas liquids (NGLs) to meet the pipeline specifications. The recovered NGLs can be marketed as feedstock to interested petrochemical companies. The proposed design includes, as an option, facilities and operations necessary to perform this function.

Warm seawater can be used as a heat source for the vaporization of the LNG. Two options are being considered to obtain this heat source. Discussions are ongoing with Nova Scotia Power Inc. (NSP) to establish a closed loop system that would circulate waste heated seawater from the NSP cooling water discharge at the nearby Point Tupper power plant to the LNG facility for use in the vaporization process. The cooled seawater from the LNG facility would then be returned to NSP for use in the cooling system, thereby eliminating the discharge of heated chlorinated water from the power plant into the Strait, and increasing the efficiency of the power plant cooling water system. This would involve the construction of a closed loop system between the two facilities. The alternative option is to have an independent system that uses seawater to provide the heat needed for this process through a seawater intake and discharge system at the ANEI facility.

The site layout (Figure 1.1) is designed to meet requirements of internationally accepted codes and to facilitate Project construction and operation. LNG facilities layouts are designed to comply with the siting requirements of Canadian Standards Association (CSA) Z276-01 “Liquefied Natural Gas (LNG) - Production, Storage, and Handling” and the National Fire Protection Association (NFPA) Standard 59A, “Standard for Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants”. The site was also selected to minimize interaction with sensitive environmental features (*e.g.*, streams, wetlands).

The Project includes the following major components:

- LNG ship berthing facility with LNG unloading arms (including three liquid arms, one vapour return arm and space for an additional arm for future expansion);
- Two LNG storage tanks, each with a gross volume of 180,000 m^3, with space provided for future installation of the third tank;
- LNG Shell & Tube (STV) vaporizers, using a primary closed loop methanol-water system heated using hot seawater from the existing NSP power plant and circulation pumps, or seawater from the jetty seawater pumps and backup heat provided by direct fired heaters;
- In-tank LNG pumps;
- External second-stage sendout pumps;
- Vapour handling system including boil-off gas (BOG) compressors and a BOG booster pump for returning vapour during ship unloading;
- Nitrogen injection system which includes both liquid and gaseous nitrogen capabilities;
- Potential for ethane and heavier components (NGL) extraction unit to provide LNG of the proper composition and heating value;
- Three natural gas fired heaters (plus one spare) as backup heat source to vaporize LNG to natural gas;
- Various supporting utilities and safety systems required for safe operation of the terminal; and
- Infrastructure (*e.g.*, roads, fencing, buildings and power supply).

All components will be operated in accordance with governing federal, provincial, and industry regulations and standards.

A photo of a similar LNG facility is included in Appendix B.

2.2 Project Infrastructure and Activities

2.2.1 Construction

The Project will require the construction of three main areas: marine berthing facilities; storage tanks; and supporting facilities. The supporting facilities portion of the work will include installation of: all roads; permanent drainage; equipment; piping; permanent buildings; and the internal control systems for the facilities. The storage tank portion of the work will include an engineering, procurement, and construction (EPC) contract for the installation of the LNG storage tanks, complete with foundation, external piping, electrical, instrumentation, power and control, paint, and insulation. The berth would include: an unloading platform; breasting and mooring dolphins; walkways; and the electronic berthing aid system.

2.2.1.1 Site Preparation

Initial construction work will consist of: site clearing, grading and levelling; establishing road bases, including surface drainage; and the installation of temporary facilities (*e.g.*, fencing, parking, offices, staging, and laydown areas necessary for construction). Local supplies will be used where feasible during construction of the terminal, including potable and raw water, crushed rock and sand, and wood products.

2.2.1.2 Onshore Facilities

Phase I of the Project will include the construction of the two LNG storage tanks, installation of vaporizers, nitrogen injection system, NGL extraction unit (if necessary), and construction of the jetty and ship berthing facilities. During the future expansion phase of the Project (Phase II), installation of the third LNG storage tank, additional NGL extraction unit, and additional vaporizers will be completed.

Environmental protection during land based construction activities will address management of hazardous materials, dust control, and erosion and sedimentation control. Hazardous material management is discussed in Section 2.5. A stormwater management plan will be developed to prevent sediment-laden runoff from the facility from entering streams or the marine environment during the operations phase. This plan will be designed to meet all provincial requirements for surface runoff quality (*e.g.*, suspended solids < 25mg/L). Erosion and sediment control features may include, as applicable: proper grading of slopes; placement of granular materials; rapid vegetation of exposed soils; properly sized settling ponds; and filter drains. The site will be maintained in accordance with the NSDEL "Erosion and Sedimentation Control Handbook for Construction Sites" (NSDOE 1988). Curbs will be incorporated in parking and process areas to allow for stormwater from these areas to be drained to a collection area equipped with a sump where runoff can be checked prior to release.

2.2.1.3 Offshore Facilities

Proposed marine works (Appendix B, Figure 1) include: construction of a jetty platform; ship berthing and trestle structure; dolphins; and unloading facilities. The marine jetty design will consist of a concrete decking on drilled steel tubular pile structures and will accommodate LNG vessels with a capacity of up to 250,000 m^3, with a ship draft of approximately 13.5 m. Given the depth of the Strait of approximately 18 m (10 fathoms) at the jetty, it is not anticipated that dredging will be required for the construction of the marine works. The pier and berthing facilities for the proposed project would consist of a trestle approximately 45.7 m long and a berth designed to accommodate liquefied gas carriers up to 250,000 m^3 in capacity. The trestle would provide the structural support for the cryogenic piping and utility lines from the shore to the berth, and would also accommodate one lane for light vehicles. The trestle would be an open structure composed of steel or concrete elements resembling a highway bridge. Fill material would not be necessary for this method of construction. Silt curtains and debris booms will be deployed, if feasible and necessary, during jetty construction to minimize siltation and turbidity in the marine environment.

Depending upon final contractor selection, either concrete or structural steel would be used for the main trestle components. The trestle will likely have two steel pipe piles per bent with a concrete or structural steel cap forming a frame. The pipe piles will be on the order of 30 to 36 inches in diameter and approximately 31 to 37 m long. Precast/prestressed concrete beams or steel girders will be used to span the 18.2 m distance between the beams. A cast in place concrete deck will provide containment for the piping as well as form a roadway.

The berth would include an unloading platform supporting the liquid product transfer lines and unloading arms. The berth would also include four breasting dolphins equipped with fenders and quick release hooks, and five mooring dolphins equipped with quick release hooks would also be provided to safely moor the vessel. Walkways would also be included between the dolphins and the platform for personnel access. A gangway would ease the transfer of personnel between the vessel and the berth structures. An electronic berthing aid system would be installed at the berth to assist berthing operations.

During normal terminal operation (when no ship is unloading), a 10-inch line will recirculate LNG to the main header at the end of the pier. A total of four marine unloading arms will be installed on the unloading platform, two for liquid delivery to the storage tanks, one liquid or vapour (hybrid) arm, and one for use in vapour return to the ship. The unloading arms are designed with swivel joints to provide the required range of movement between the ship and the shore connections. Each arm will be fitted with powered emergency release coupling valves to protect the arm and avoid spillage of its liquid contents. Each arm will be operated by a hydraulic system and a counterbalance weight will be provided to reduce the deadweight of the arm on the shipside connection and to reduce the power required to manoeuvre the arm into position.

2.2.2 Commissioning

The final stage of construction is the start-up and commissioning of the facilities. With completion of all control systems testing, the units will be purged of oxygen using nitrogen gas. Various terminal units will then be checked for pressure leaks via pressurizing and depressurizing over approximately three days. The terminal will then begin cool-down operations using either LNG or liquid nitrogen. This process will start with the tanks where LNG will accumulate via the addition of a small, continuous flow. Gradually the cool-down will continue with the piping and other equipment. All vapours are vented during this cool-down period, which lasts approximately 8 to 12 days for two tanks. An additional 8 to 12 days will be required for Phase II expansion.

In order to commission a storage tank, the following steps are followed:

1. Purge with dry nitrogen to a dew point of 10 °C to prevent perlite insulation in the annular space from absorbing moisture while tank awaits final purge and cool-down.

2. Displace the air in the tank with dry nitrogen in order to reduce the oxygen below the flammable limit when later displaced with natural gas.

3. Complete tank dryout to an acceptable dew point, if step 2 has not already accomplished adequate dryout.

4. Cool the tank with either LNG or liquid nitrogen.

5. Establish a liquid level in the tank.

During cool-down of the tank, a cool-down spray ring or distribution header is provided to uniformly spray either LNG or liquid nitrogen into the tank for initial cool-down. The tank vendor establishes the criteria for cool-down that includes the maximum rate of cool-down, temperature differences between adjacent temperature points and maximum temperature differences across the entire structure. In most situations LNG is employed as the cool-down media, especially for storage tanks associated with liquefaction plants. However, some storage tanks for LNG receiving terminals employ liquid nitrogen for the initial cool-down; this occurs primarily when the terminal owner desires to train operators and proof test the instrumentation and piping contraction due to cool-down of the system prior to the arrival of the first LNG ship. This action will significantly reduce the time period the expensive ship must remain at the terminal. In this situation liquid nitrogen is preferable to LNG cool-down because it is often readily available. The primary disadvantage for liquid nitrogen cool-down is that it is very expensive. For a typical 100,000 m^3 tank the liquid nitrogen requirement is about 685,000 kg as compared to 418,000 kg for LNG. At several LNG receiving terminals, the cost of the LNG and liquid nitrogen were equivalent on a per kg basis. Thus, nitrogen cool-down is more expensive. The selection of cool-down method will be determined during detailed engineering based on further discussion with the tank vendors.

2.2.3 Operation

Once commissioned, the facility will begin receiving LNG from several export facilities world-wide and begin the primary activities including: unloading LNG from LNG ships to the storage tanks; LNG storage; regasifying the LNG with vaporizers; and the final sendout of natural gas. A simplified process flow diagram is presented in Figure 2.1.

2.2.3.1 Marine Facilities

LNG will be transported to the receiving terminal via specialized LNG ships. A wide range of LNG ships are available to bring LNG from various parts of the world. The LNG berth will be designed to handle LNG ships that have a capacity range of up to 250,000 m^3, with a ship draft of approximately 13.5 m (refer to Appendix B for photos of a typical LNG ship). The marine facilities are sited to provide the LNG ship with an uncongested, ice-free seaward approach, which is unrestricted from tidal and most weather related concerns. The jetty is to be located at 18 m depth with a wide turning basin and unrestricted egress from the terminal.

The marine jetty design will consist of concrete decking on drilled steel tubular pile structures. LNG is unloaded by the ship's pumps at an average rate of 12,000 m^3/hr. Based on the unloading rate and preliminary shipping studies, there will be approximately 70 to 135 ships per year. The unloading system is designed to unload the entire contents of a ship within 12 to 14 hours. During the unloading mode of operation, LNG is transferred from the LNG ship to the onshore LNG storage tanks via cryogenic lines located along the trestle. Onboard ship pumps will deliver the LNG to the LNG storage tanks.

The marine facilities have been designed to provide safe berths for the receipt and support of LNG ships and to ensure the safe transfer of LNG cargo from the ships to onshore storage facilities. Design will be in accordance with applicable codes and standards, including but not limited to Oil Companies International Marine Forum, and Society of International Gas Tanker and Terminal Operators. All LNG ships arriving at ANEI terminal will be constructed according to structural fire protection standards contained in the International Convention for Safety of Life at Sea. This will be completed under the review and approval procedures of the Canadian Coast Guard and other applicable regulatory bodies.

The proposed terminal is located in an area of compulsory pilotage under the federal *Pilotage Act,* Atlantic Pilotage Authority Regulations; this means that pilots are required for navigation into the Strait.

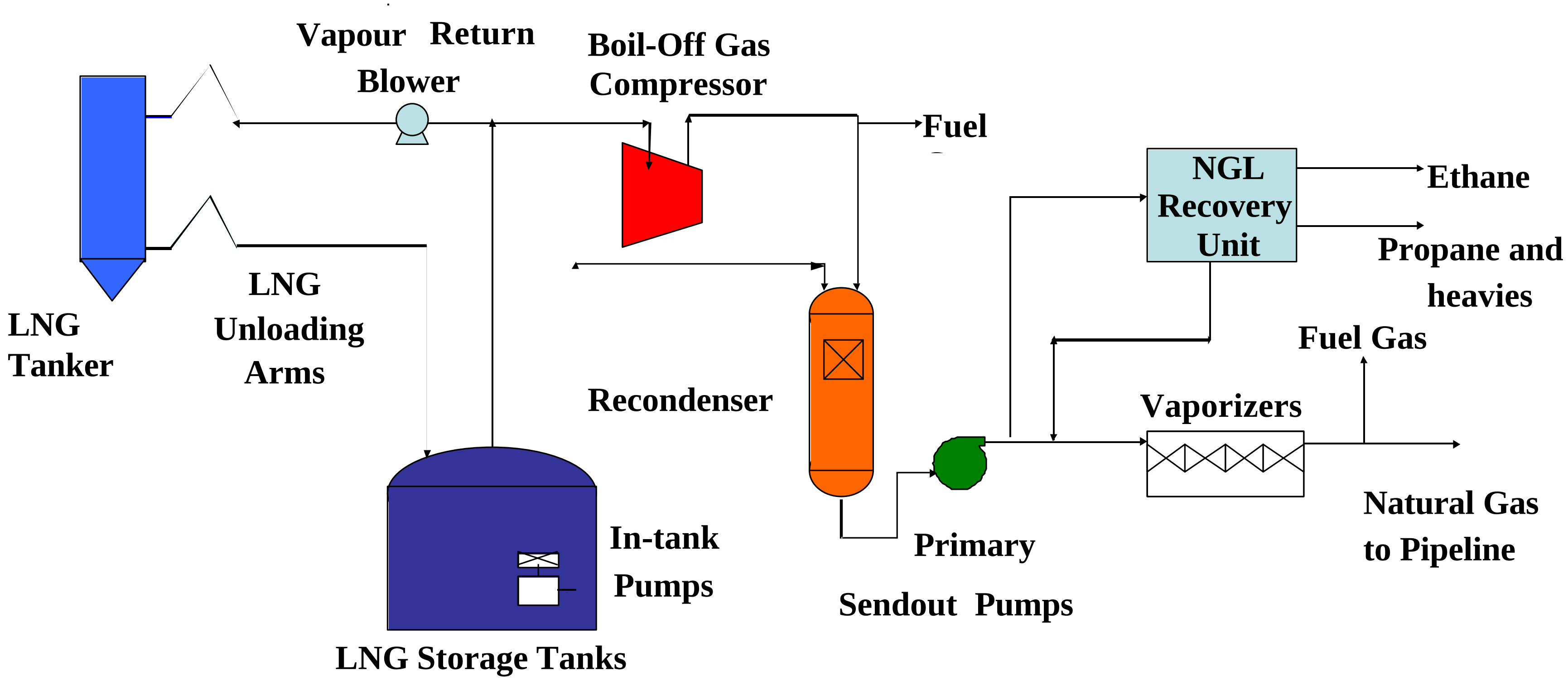


Figure 2.1 Simplified Process Flow Diagram

2.2.3.2 Storage

Phase I includes two 180,000 m^3 LNG storage tanks, which have the double wall steel tank design. These specialized cryogenic tanks are constructed so that only the inner tank wall, made of 9% nickel steel, comes in contact with LNG and has the mechanical properties to contain cryogenic liquid. The outer carbon steel tank wall has the primary functions to contain warm methane vapour, provide support for the roof, and to resist wind and normal external loadings, and additionally functions as an insulation container. The tanks will be surrounded by an impoundment sized in compliance with provincial regulations and Canadian Standards Association (CSA) code requirements to contain any possible LNG spills or leaks.

The diameter of the outer container will be approximately 78 m and the height of the top of the dome is approximately 55 m. The space between the inner container and outer container will be insulated with expanded perlite that will be compacted to reduce long term settling. This insulation will allow the LNG to be stored at a temperature of -168°C while maintaining the outer container at near ambient temperature. The insulation under the inner container's bottom will be a cellular glass, load-bearing insulation. The outer container above the approximately 4.6 m high thermal corner protection system is lined on the inside with carbon steel plates. This carbon steel liner will serve as a barrier to moisture migration from the atmosphere reaching the insulation inside the outer container. This liner also forms a barrier that prevents vapour from escaping from inside the tank during normal operations. To increase the safety of the tank, there will be no penetrations through the inner container or the outer container sidewall or bottom below the maximum liquid level. All piping into and out of the tank will enter from the top of the tank.

Detailed design of the LNG storage tanks will be completed during the detailed engineering phase of the project.

2.2.3.3 Boil-off Gas Handling System

There are two basic modes of operation for the Terminal: 1) ship unloading; and 2) plant holding. During plant holding mode, when no ship is being unloaded, send-out of natural gas continues uninterrupted. During ship unloading, LNG is transferred from an LNG ship into the onshore storage tanks, while send-out from the facility is maintained. The terminal is designed such that all cryogenic piping is maintained at cold temperatures by a continuous circulation of LNG.

From the unloading arms manifold, LNG is delivered via unloading pipelines located along the trestle to the LNG storage tanks. During normal operation (plant holding mode) ambient heat input into the LNG will cause a small amount of LNG to be vaporized, called boil-off gas (BOG). Some vaporization of LNG will also be caused by other factors such as barometric pressure changes, heat input due to pumping, and ship flash vapour. The vapour handling system will condense the BOG and combine it back with the LNG. BOG from the LNG storage tank will be compressed by the BOG compressors and then passed to the recondenser system where it will be condensed into the outgoing LNG prior to being pumped to pipeline pressure in the high-pressure pumps. During the unloading mode, a portion of the BOG generated is returned to the ship via the vapour return line to maintain pressure in the ship tanks (refer to Figure 2.1).

2.2.3.4 Control of High Heating Value

In order to control the high heating values (HHV) of the sendout gas, a nitrogen injection system is provided and options for an NGL recovery system are being considered during future expansion in order to meet the heating value specifications of the natural gas send-out pipeline.
A nitrogen injection package will be provided including gaseous and liquid nitrogen generators. The nitrogen would then be injected into the natural gas prior to being sent to the send-out pipeline. These facilities and the related operations are included as a design option as part of this assessment.

Alternatively, a portion of the LNG components may need to be removed in order for the resultant natural gas to meet market specifications (btu and gas quality). If the LNG received does not meet these specifications, it can be routed through the optional NGL recovery unit. The LNG is first sent to the preheaters to be heated prior to being sent to the demethanizer. The demethanizer is a trayed fractionation column, where liquid flows down the tower and is stripped of methane by warmer vapours rising through the column. The vapour from the demethanizer is condensed by heat exchange with incoming LNG and sent to the secondary booster pumps.

The demethanizer bottoms (liquid) will contain ethane and heavier components (C_2+), such as propane and butane. This C_2+ stream will then be delivered at a point of interconnection with facilities to be constructed, owned and operated by others (*i.e.*, not ANEI). The point of interconnection will be located either at the boundary of the plant site or on the site.

2.2.3.5 Gasification/Vaporizer

LNG can be vaporized or regasified by heating it with fuel, water, or a combination of both. Shell and tube intermediate fluid vaporizers (STV) are used as the primary vaporizer for normal operation using the warm seawater from the existing local power plant heating a closed loop heat transfer fluid (HTF) system containing methanol-water mixture that is passed through the STVs and NGL extraction unit reboilers. This heat is used to vaporize the LNG to natural gas and send it to the sendout gas pipeline (see Figure 2.2). As backup, direct fired heaters are provided to heat the HTF when the heated seawater from the power plant is not available. For the future expansion, additional STVs will be required.

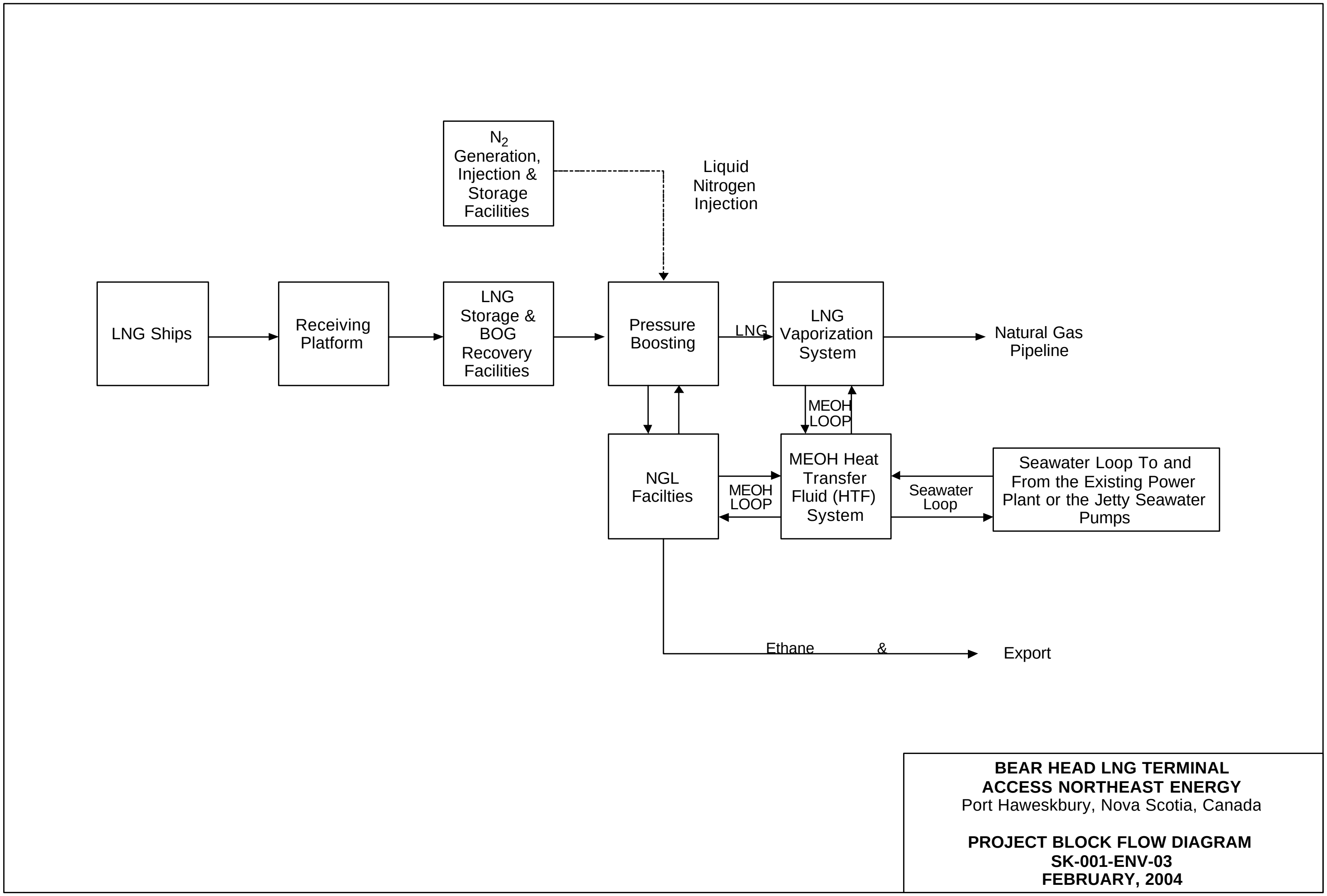


Figure 2.2 Project Block Flow Diagram

As discussed in Section 2.1, construction of a closed loop system between NSP and the LNG facility will provide the required water. The alternative option considered is an independent system that uses seawater to provide the heat needed for this process; this will require construction and operation of a seawater intake and outfall (refer to Figure 1.1).

During scheduled maintenance of the NSP power plant, if jetty seawater temperature is too low and/or during upset conditions, three direct fired heaters plus a spare will be utilized to provide the necessary heat for LNG vaporization. During future expansion, if the option of NGL extraction is installed then the backup heaters will also be utilized to provide the additional necessary heat. The hot flue gases are used to heat the closed-loop HTF which is then passed through the reboilers and STVs to vaporize the LNG. As a worst case, the heaters could be used 100% to provide heat for vaporization, if the power plant water or the seawater is not available or unusable.

2.2.3.6 Sendout System

Following vaporization, the LNG is sent to the gas metering station for gas pipeline delivery. The metering system will be a dedicated fiscal gas metering station provided for custody transfer of sendout gas. The system will be supplied as a complete pre-engineered package including the flow measurement skids, associated instrumentation, analyzers and flow computers.

2.2.3.7 Utilities

Facilities will be installed to provide the following utilities to support Project operations:

- closed loop HTF (15% methanol-water mixture) for the exchange of heating and cooling water from NSP power plant to the Project and back, or a seawater intake, outfall and pumping system as an alternative heat source for vaporization;

- direct fired heaters burning natural gas to provide backup heat to the HTF system;

- firewater and fire-fighting equipment and systems including a foam system;

- fuel gas which can be taken from several points within the facility including from the vaporizer outlet, from the BOG compressor discharge, and “back-flowed” gas from the pipeline;

- plant and potable water;

- plant and instrument air provided through instrument air compressors;

- nitrogen production system (gaseous and liquid) to be used for nitrogen injection into the natural gas prior to sendout as well as various other uses during pre-commissioning and project start-up such as drying out and purging activities;

- emergency power generation, provided by an internal combustion diesel engine to generate approximately 1 MW capacity;

- effluent treatment, including sanitary and contaminated storm runoff;

- diesel oil supply for firewater pumps and emergency generator; and

- imported power for operations.

Fresh water will be obtained from the municipal supply, and power will be supplied from the nearby NSP facility, as will heating water for revaporization of the LNG (preferred option). Domestic sewage will be treated through an on-site collection and treatment system. Fuel gas required for operations will be extracted from the plant.

2.2.3.8 Vent/Flare System

During normal operation any excess vapours are routed to the LNG storage tanks' vapour header system to be recovered and recycled to the sendout gas or to be used as fuel gas via the BOG compression system. An emergency relief system is provided to gather and safely dispose of discharges from control valves, vents, drains, thermal and pressure relief devices during upset conditions. Vapour from the LNG storage tanks is collected and sent to the BOG compressors through a vapour collection header. If the tank pressure rises too high, a pressure safety valve opens and relieves the vapour to the vent. The storage tanks are further protected from over pressure by relief valves discharging directly to the atmosphere.

During an emergency upset condition, the vapour handling system may not be sufficient to handle the quantity of vapour generated. In this case, the vapours will be routed to a vent or flare for proper disposal. The only continuous point source emissions are from the combustion of natural gas used in the two flare pilots sized for approximately 150,000 btu/hr capacity each and from flare header sweep gas. The flare tip will be elevated to approximately 61 m (200 feet). Given an estimated diameter of 0.91 m (36 inches) and a flare header sweep gas velocity of 0.03m/sec (0.1 ft/sec), the flare header sweep gas volumetric rate will be approximately 72 m^3/hr (2,545 ft^3/hr). If natural gas is used as sweep gas, this would result in approximately 732.5 kWh (2,500,000 btu/hr) (LHV) of heat release. The continuous heat release from the flare thus totals 820.4 kWh (2,800,000 btu/hr). The exact height and dimension of the flare system and composition of the sweep gas will be determined during front end engineering design.

2.2.4 Decommissioning

The terminal will be designed for a life span of 20 years. As is common in the industry, facility life could be extended beyond 20 years with appropriate technical and maintenance activities. Decommissioning and abandonment of the Terminal facilities will be undertaken in accordance with the regulatory requirements applicable at the time of such activities. In the event the facility is dismantled/decommissioned, an abandonment plan and, if required, a site restoration plan, would be developed.

At a minimum, an abandonment plan would include a schedule for equipment decommissioning and disassembly. The plan would indicate the approximate time required to remove and dispose all abandoned installations, structures, and buildings for which onsite reuse is not possible, and to reinstate the site to a quality necessary for subsequent industrial land use.

Decommissioning planning will be developed in consideration of environmental goals for the area. Activities that support such planning may include a review of baseline and follow up monitoring data; thorough record keeping; adherence to applicable standards and guidelines during Project operations; documentation of potential influencing factors; and development of a rehabilitation plan.

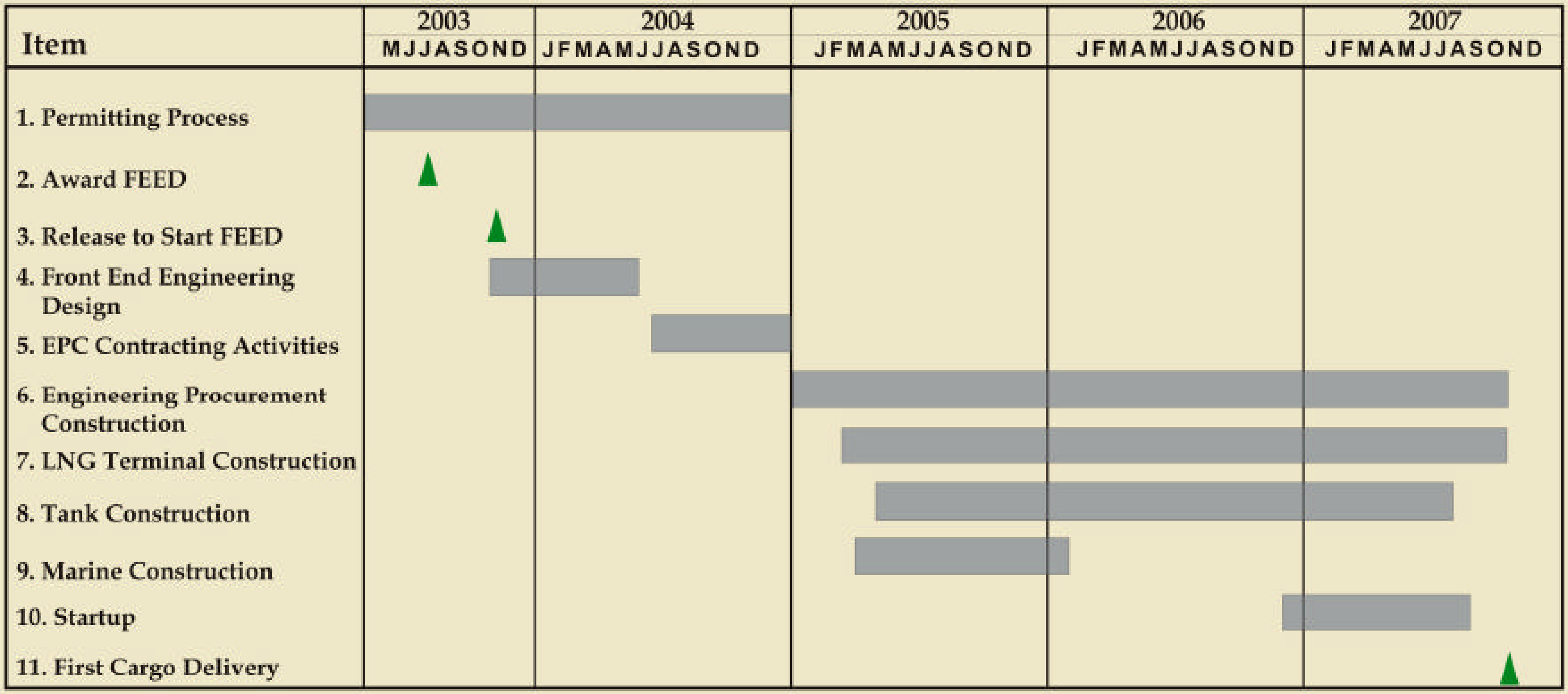
Disposal of waste will be conducted in accordance with NSDEL waste management regulations and guidelines. Removal of buildings or structures is expected to have similar effects and considerations as construction and will be conducted in accordance with regulatory requirements applicable at the time of removal.

2.3 Project Schedule

The Project is currently in the Front End Engineering Design (FEED) phase. The FEED phase of the Project, anticipated to take approximately seven months to complete, will be followed by detailed engineering and procurement. Project construction is scheduled to last approximately 32 months with Project operations expected to begin in late 2007. The operational life of the Project could continue indefinitely with good operation and maintenance. The overall Project schedule is presented in Figure 2.3.

Normal operating hours are 24 hours per day, 365 days per year. This is accomplished with the use of spare equipment and a regular maintenance program.

Figure 2.3
Overall Project Schedule



2.4 Emissions and Waste Discharges

The Project will meet or improve upon the compliance standards outlined in applicable regulations or standards with respect to emissions and waste management. Where no standards exist, best industry practices will be adopted where feasible. ANEI will minimize to the extent practical, volumes of wastes and concentrations of contaminants entering the environment. A Waste Management Plan (WMP) will be developed for all phases of the Project. The objective of this plan is to minimize waste discharges and emissions and identify appropriate waste reduction and other mitigative measures.

Estimated quantities of wastes, discharges and emissions that will be generated during Project construction, commissioning and operation are summarized in Table 2.1. The table also includes summary descriptions of the characteristics of the waste discharges and disposal procedures to meet regulatory compliance standards. The Project will employ good engineering practices and standard industry controls to minimize the environmental impact from construction and operation.

2.4.1 Air Emissions

2.4.1.1 Construction/Commissioning

Air quality impacts associated with construction activities are generally related to the generation of dust and routine emissions from the operation of construction equipment. Control measures, such as use of dust suppression techniques, will be used in construction zones as required to minimize the impacts from fugitive dust. The air emissions from the construction equipment will be localized and temporary, lasting the duration of construction activities. Routine inspection and maintenance of construction equipment will minimize exhaust fumes.

Prior to startup and upon completion of control systems testing, the units will be purged of oxygen using nitrogen gas. Various terminal units will then be checked for pressure leaks by pressurizing and depressurizing over an approximate three day period. The terminal will then begin cool-down operations using LNG or liquid nitrogen. In this process, a small, continuous flow of LNG or liquid nitrogen will accumulate in the tanks. The cool-down will gradually continue with piping and other equipment. All vapours are vented during this cool-down period, which lasts approximately eight to twelve days.

Table 2.1 Routine Project Emissions/Effluents				
Type	**Emission/Effluent**	**Estimated Quantity**	**Characteristics**	**Disposal Standard/Comments**
		Construction/Commissioning		
Atmospheric Emissions	Generator, engine and utilities exhaust	Temporary, minor	CO_2, NO_x, SO_2, TSP	Atmospheric emissions will comply with the NS Air Quality Regulations and Ambient Air Quality Objectives (*CEPA*).
	Cool-down Operation	Temporary (one time only, approximately 6,500 metric tons over a period of approximately 10 days)	Natural gas components or Liquid Nitrogen	Atmospheric emissions will comply with the NS Air Quality Regulations and Ambient Air Quality Objectives (*CEPA*).
Liquid Effluent	Hydrotesting of LNG storage tanks	Temporary (one time only, approximately 108,000 m^3 used to test one tank and then transferred to test second tank during Phase I)	Seawater used for hydrotesting with wash down of small quantity of fresh water, no additives; discharged to the ocean	The discharge of hydrotest fluids will require pre-approval from Environment Canada. Hydrotest water will be tested prior to discharge to determine any need for treatment.
	Sanitary	Portable sanitary units used during construction (peak construction 1,625 workers)	Sanitary waste (no food wastes)	Provincial and municipal standards for sewage management.
Solid Waste	Miscellaneous solid wastes	As required	Construction materials, packaging and shipping materials, damaged containers, and refuse associated with construction	Wastes will be sorted and disposed according to Nova Scotia Solid-Waste Resource Management Regulations and municipal requirements. Metals will be salvaged.
Stormwater	Stormwater runoff	Based on rainfall in the region	Water with some particulate matter and possible hydrocarbon contamination from small equipment spills	Stormwater management plan will be developed and implemented; EPP to outline erosion and sedimentation control plans including use of silt curtains, etc., and establishing new vegetation in the project area after construction will minimize impact during construction (*i.e.*, <25mg/L TSS); spill prevention and cleanup.

Table 2.1 Routine Project Emissions/Effluents				
Type	**Emission/Effluent**	**Estimated Quantity**	**Characteristics**	**Disposal Standard/Comments**
		Operation		
Atmospheric Emissions	Backup direct fired heaters	Intermittent backup, See Tables 2.2 through 2.4	NOx, CO_2, SO_2, CO, TSP	Only used when power plant heated seawater or jetty seawater is not available to warm up the HTF to vaporize LNG and if NGL extraction option is selected; assume 100% use of heaters as worst case. Atmospheric emissions will comply with the NS Air Quality Regulations and Ambient Air Quality Objectives (*CEPA*).
	Testing of emergency power generator	Intermittent, See Tables 2.2 through 2.4	NOx, CO_2, SO_2, CO, TSP	Only used for periodic maintenance testing of emergency equipment (0.5 hours/week) per code requirements. Atmospheric emissions will comply with the NS Air Quality Regulations and Ambient Air Quality Objectives (*CEPA*).
	Testing of emergency firewater pumps	Intermittent, See Tables 2.2 through 2.4	NOx, CO_2, SO_2, CO, TSP	Only used for period maintenance testing of emergency equipment (0.5 hours/week) per code requirements. Atmospheric emissions will comply with the NS Air Quality Regulations and Ambient Air Quality Objectives (*CEPA*).
	Flare pilot	Continuous flare pilot emissions, See Tables 2.2 through 2.4	NOx, CO_2, SO_2, CO, TSP	Emergency flare is part of the emergency vapour handling system and will be used during upset conditions. Flare pilots will operate continuously burning natural gas.
Liquid Effluent	Treated sanitary wastewater	Total employees during operation is approximately 35 with an estimate volume of 50 gpm per person per day.	Treated onsite in a package treatment unit	Treated effluent will meet NS and Environment Canada water quality requirements before being discharged to the ocean.
	Once-through seawater (if used) for LNG vaporization	33,000 m^3/hr (145,000 gpm) for at least 6 months of the year. Backup fired heaters are used when the seawater temperatures are low and can not provide the necessary heat.	Seawater discharge that is cooled to approximately 7°C below ambient and contains less than 0.5 ppm of chlorine	Seawater will be injected with sodium hypochlorite as biocide and will comply with discharge regulations. Outfall will be designed with to assist rapid dispersion of the chlorine and warm the seawater to 3°C temperature difference with ambient within approximately 100 m radius from point of discharge.

Table 2.1 Routine Project Emissions/Effluents

Type	Emission/Effluent	Estimated Quantity	Characteristics	Disposal Standard/Comments
	Stormwater	Average annual rainfall	Minimal particulate matter with rainfall; minor amounts of hydrocarbon from small spills	Stormwater management plan will be developed and implemented. TSS will be less than 25 mg/L. Process equipment areas will be paved and curbed to minimize contact with stormwater. Effective spill prevention and cleanup will be achieved by water testing prior to discharge, if necessary.
	Water for testing seawater firewater pumps	Testing 0.5 hours/week per safety code requirements; capacity of pumps to be determined during detailed engineering	No additives; seawater will be pumped through the pumps and then back to the ocean	Disposal without any treatment.
Solid Waste	Miscellaneous solid waste	As required	Domestic waste, packaging, minor construction/maintenance waste	Wastes will be sorted and disposed according to Nova Scotia Solid-Waste Resource Management Regulations and municipal requirements. Metals will be salvaged.
Hazardous Waste	Skimmed oil and oily sludge from oil/water separator (if required)	Intermittent	From potential spills of lubricating oils used for equipment maintenance	Process areas will be paved and curbed to avoid contaminating stormwater. If necessary, the first flush (15 minutes) of rainfall will be collected and sent through the oil/water separator to remove any oils from potential spills. The effluent from the oil/water separator will be vacuum trucked offsite by a licensed local service provider.

The cool-down procedure to be followed depends on the availability of cold gas. In receiving terminals, warm gas should be introduced first. This will prevent “undercooling” that may take place. The inert gas should be vented via the tank and vent pressure control system. The vented gas should be analyzed periodically to measure the purge gas and hydrocarbon concentrations until the required end point has been reached. Tank pressure should be maintained by means of the pressure control system and by adjustment of the incoming flow of gas. When the hydrocarbon concentration of the vented gas to the flare is above 90% volume, the cooling will be started by introduction of liquid through the cool-down spray ring. When the composition of the vented gas reaches the design value, the boil-off compressor should be lined up and taken into operation. The pressure control of the tank should be adjusted to its normal operating level.

The cool-down rate will be monitored and, in the case of an exceedance, the flow of liquid will be temporarily halted. When the temperature intervals on the inner tank bottom reach the normal storage temperature, accumulation of liquid on the inner tank bottom will start. Liquid will be introduced through the main inlet line and the cool-down will be completed.

2.4.1.2 Operation

LNG receiving terminals have very few potential sources of pollution, as these facilities serve and function as a storage and transfer system for LNG. The LNG Terminal will handle liquefied natural gas that is comprised mainly of methane with decreasing fractions of ethane, propane, butane and longer-chain hydrocarbons.

The only emission sources of significance for the project emission inventory during normal operations include:

- continuous emissions from flare pilots and the combustion of flare header sweep gas;

- intermittent emissions from backup direct fired process heaters for heating the intermediate heat transfer fluid (HTF) (15% methanol-water mixture);

- intermittent emissions from routine testing of diesel engine driven emergency generator for backup power;

- intermittent emissions from routine testing of diesel engine driven emergency firewater pumps;

- intermittent emissions from ships while docked at the unloading berth, normally referred to as hotelling emissions; and

- continuous piping equipment fugitive emissions.

The only continuous point source emissions are from the combustion of natural gas used in the two flare pilots sized for approximately 150,000 btu/hr capacity each and from flare header sweep gas. The flare tip will be elevated to approximately 61 m (200 feet). Given an estimated diameter of 0.91 m (36 inches) and a flare header sweep gas velocity of 0.1 ft/sec, the flare header sweep gas volumetric rate will be approximately 72 m^3/hr (2,545 ft^3/hr). If natural gas is used as sweep gas, this would result in approximately 2,500,000 btu/hr (LHV) of heat release. The continuous heat release from the flare thus totals 2,800,000 btu/hr. The exact height and dimension of the flare system and composition of the sweep gas will be determined during FEED.

During normal operations, the closed loop HTF system that is used to vaporize the LNG and provide heat to the NGL extraction unit reboilers will be heated in a heat exchanger with a warm seawater stream from a local existing power plant or alternatively by seawater from the jetty seawater pumps. As a backup to this system, three direct fired heaters plus a spare heater are provided to heat the closed loop HTF methanol-water mixture system.

The HTF heater models will be similar to hot-oil type or glycol-water type heater designs in that they are not intended to boil the process fluid, only to heat it within a certain prescribed temperature range. The fuel utilized for the heaters is supplied by the terminal's internal fuel gas system and is composed of vaporized natural gas from cargo receiving operations and LNG vaporization and boil-off gas operations.

The process capacity of each water heater is rated at approximately 350 Million British Thermal Unit (MMbtu) per hour for the process heat rate of absorption or delivery (Qabs, MMbtu/hr – low heating value (LHV)). Accounting for these heaters' 92% fired fuel to Qabs efficiency during their normal run-times between maintenance turn-around results in these heaters being defined as ~380 MMbtu/hr (LHV) actual firing rate heaters (350/0.92 = 380 MMbtu/hr). For environmental permitting activities, where firing is defined on a high heating value (HHV) basis, these heaters fired rating are ~418 MMbtu/hr (HHV) given HHV:LHV ratio of ~1.1:1 (380x1.1 = 418 MMbtu/hr).

It is assumed the backup heaters will be used during the time when the warm water is unavailable from the power plant (3 weeks/year) or the seawater from the jetty is unusable due to low temperatures (approximately 6 months/year). While the backup heaters will only be used during an upset condition when the heat from the water sources is not available (as worst case scenario) and if the NGL extraction option is selected, the backup heaters would potentially be used 100% of the year as necessary to provide heat. Thus the preliminary emission estimates provided in Table 2.2 include emissions for three heaters operating 365 days/year as a worst case scenario, as well as the preferred alternative, where three weeks operation would be required to sustain operation while the power plant is shut down for maintenance.

One diesel engine is used for emergency power generation of approximately 1000 kWe and two diesel engines are expected to be used for emergency firewater pumps. The two diesel engine driven seawater firewater pumps are located on the jetty. All of the diesel engines will be tested weekly for about 30 minutes, and the emissions associated with the testing are considered to be normal operating emissions. During FEED, the exact size and capacity of the generator and firewater engines will be finalized.

Table 2.2 Air Emission Inventory

	Power	Load Factor	USEPA AP-42 Emission Factor- Note C 1b/hp hr	Operating Emission Rate 1b/hr	Operating Emission Rate g/s	Duty Cycle	Annual Emission ton/yr	Annual Emission tonne/yr
NO_x								
HTF Heaters - note B				37.87	4.78			
Preferred Backup				37.87	4.78	3 wk/yr	10	9
Optional half-time				37.87	4.78	6 mos/yr	83	76
Optional full-time				37.87	4.78	Full time	166	151
Flare Pilot and Purge				0.21	0.03	Full time	0.920	0.836
Diesel Genset	1500	0.25	0.024	9	1.14	30 min/wk	0.117	0.1066
Fire pump driver	510	0.25	0.031	3.9525	0.50	30 min/wk	0.052	0.0468
Fire pump driver	510	0.25	0.031	3.9525	0.50	30 min/wk	0.052	0.0468
Ship Hotelling- Note A	310	1	0.031	4.969	.63	135 days/yr	8.0	7.31
Total - note D								17.0
CO								
HTF Heaters - note B				46.71	5.89			
Preferred Backup				46.71	5.89	3 wk/yr	12	11
Optional half-time				46.71	5.89	6 mos/yr	103	93
Optional full-time				46.71	5.89	Full time	205	186
Flare Pilot and Purge				1.16	0.15	Full time	5.1	4.6
Diesel Genset	1500	0.25	0.00550	2.063	0.260	30 min/wk	0.027	0.0244
Fire pump driver	510	0.25	0.00668	0.852	0.107	30 min/wk	0.011	0.0101
Fire pump driver	510	0.25	0.00668	0.852	0.107	30 min/wk	0.011	0.0101
Ship Hotelling	310	1	0.00668	0.6	0.08	135 days/yr	1.0	0.89
Total - note D								16.2
CO_2								
HTF Heaters - note B				149,368	18,837			
Preferred Backup				149,368	18,837	3 wk/yr	37,641	34178
Optional half-time				149,368	18,837	6 mos/yr	127,340	247,225
Optional full-time				149,368	18,837	Full time	654,680	594,449
Flare Pilot and Purge				369.0	46.54	Full time	1617.3	1468.5
Diesel Genset	1500	0.25	1.16	435.0	54.9	30 min/wk	5.67	5.15
Fire pump driver	510	0.25	1.15	146.6	18.5	30 min/wk	1.91	1.74
Fire pump driver	510	0.25	1.15	146.6	18.5	30 min/wk	1.91	1.74
Ship Hotelling	310	1	1.15	2608.0	328.9	135 days/yr	4225.0	3836.3
Total - note D								39491.2
SO_2								
HTF Heaters - note B				17.78	2.24			
Preferred Backup				17.78	2.24	3 wk/yr	4	4
Optional half-time				17.78	2.24	6 mos/yr	39	36
Optional full-time				17.78	2.24	Full time	78	71
Flare Pilot and Purge				0.04	0.01	Full time	0.2	0.2
Diesel Genset	1500	0.25	0.00809	3.034	0.383	30 min/wk	0.040	0.0359

Table 2.2 Air Emission Inventory								
	Power	**Load Factor**	**USEPA AP-42 Emission Factor- Note C 1b/hp hr**	**Operating Emission Rate 1b/hr**	**Operating Emission Rate g/s**	**Duty Cycle**	**Annual Emission ton/yr**	**Annual Emission tonne/yr**
Fire pump driver	510	0.25	0.00205	0.261	0.033	30 min/wk	0.003	0.0031
Fire pump driver	510	0.25	0.00205	0.261	0.033	30 min/wk	0.003	0.0031
Ship Hotelling	310	1	0.00405	31.800	4.01	135 days/yr	51.5	46.8
Total - note D								51.0
Note: Use 5000 ppm (0.5%) S in diesel								
3.5% S in diesel for Ship hotelling								
PM10								
HTF Heaters - note B				9.41	1.19			
Preferred Backup				9.41	1.19	3 wk/yr	2	2
Optional half-time				9.41	1.19	6 mos/yr	21	19
Optional full-time				9.41	1.19	Full time	41	37
Flare Pilot and Purge				0.023	0.00	Full time	0.1	0.1
Diesel Genset	1500	0.25	0.00070	0.263	0.033	30 min/wk	0.003	0.0031
Fire pump driver	510	0.25	0.00220	0.281	0.035	30 min/wk	0.004	0.0033
Fire pump driver	510	0.25	0.00220	0.281	0.035	30 min/wk	0.004	0.0033
Ship Hotelling	310	1	0.00072	0.009	0.001	135 days/yr	0.015	0.013
Total - note D								2.3
Methane								
HTF Heaters - note B				2.85	0.36			
Preferred Backup				2.85	0.36	3 wk/yr	1	1
Optional half-time				2.85	0.36	6 mos/yr	6	6
Optional full-time				2.85	0.36	Full time	12	11
Flare Pilot and Purge				0.007	0.00	Full time	0.0	0.0
Diesel Genset	1500	0.25	0.00071	0.001	0.033	30 min/wk	0.000	0.0031
Fire pump driver	510	0.25	0.00000	0.000	0.000	30 min/wk	0.000	0.0000
Fire pump driver	510	0.25	0.00000	0.000	0.000	30 min/wk	0.000	0.0000
Ship Hotelling	310	1	0.00072	0.003	0.028	135 days/yr	0.0	0.3288
Fugitive Losses				7.13	0.90	Full time	31.3	28.4
Total - note D								39.7
Commissioning cool-down (one-time)						10 days	7159	6500.0

Note A
Ship Emission Basis:
Ship typically use LNG fuel to generate steam used in the steam turbines to generate electricity and for propulsion. While docked and unloading LNG, they switch to heavy fuel oil (HFO). Ship emission presented here is based on 8% LNG use and 92% HFO use during hotelling for a boiler capacity of 342.2 mmbtu @ 84% efficiency

Note B
The preferred alternative would use power plant waste heat for all but the 3 weeks per year for power plant shutdown. The alternatives are full-time (*i.e.*, year round) use of the HTF heaters for vaporization energy, or half-time use of the HTF heaters and heat pumping from seawater for the remaining 6 months

Note C
AP-42 emission factors are taken from the online version URL http://www.epa.gov/ttn/chief/

Note D
Totals refer to the preferred alternative, with HTF heaters in backup mode, i.e., 3 weeks/year.

Emissions from the LNG ships while hotelling at the unloading berth were also evaluated. Table 2.2 lists the peak daily and annual emission rates of the criteria pollutants. Hotelling of each LNG ship will typically require 24 hours including activities such as: customs and immigration; servicing/provisioning; connecting arms; gauging and purging lines; ramp pumping; full pumping; ramp down pumping;

purging the lines; disconnecting the arms; and gauging. The annual emissions inventory accounts for a maximum of 135 LNG ship arrivals, which is equivalent to one arrival approximately every 2 to 3 days.

The preliminary summary of air emissions during normal operations based on an LNG terminal of similar size including fugitive emissions is provided in Table 2.2.
The following are potential start-up, shutdown, maintenance, upset, and emergency air emissions:

- emergency flare;
- LNG or nitrogen from initial cool down operations during startup of the facility, (LNG or liquid nitrogen could be used for cool-down operations, to be determined during detailed engineering phase);
- natural gas from pressure relief valves on the LNG storage tanks, and process equipment; and
- products of combustion from diesel engine drivers used during emergencies for the emergency power generator and the two firewater pumps.

During the initial cool down operations for start-up of the facility, liquid nitrogen or LNG could be used to purge and cool-down the facility. If LNG is used for cool-down operations, approximately 6,500 metric tons of natural gas could be released over a period of 10 days. This is a one-time release amount for startup from all of the facility's empty equipment.

LNG Terminal Vapour Handling Facilities

Design Overview

During normal operation, BOG is generated in the cryogenic storage tanks and unloading lines as a result of heat leaking in from the surroundings and the heat of pumping LNG for recirculation. The amount of BOG generated in a terminal depends on several factors such as mode of operation (ship unloading status), equipment capacity, operating pressure and temperature of the LNG storage tank, and amount of boil-off vapours returned to the ship. While unloading, some of the BOG is returned to the ship to maintain pressure in the ship tanks. Excess vapours will be routed to the BOG compressor, then to the recondenser, and finally to the vaporizers for sendout (refer to Figures 2.4 and 2.5)

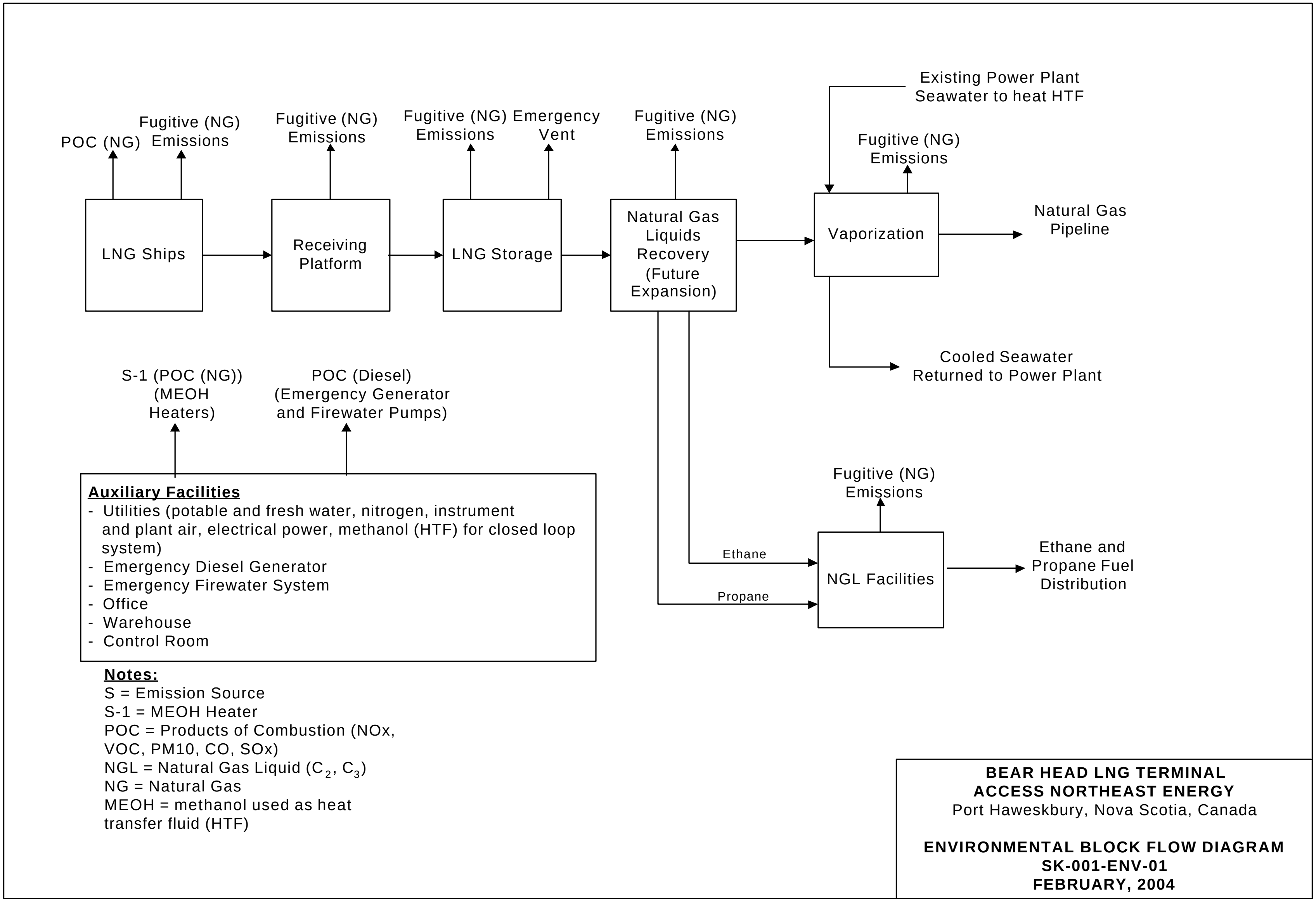


Figure 2.4 Environmental Block Flow Diagram

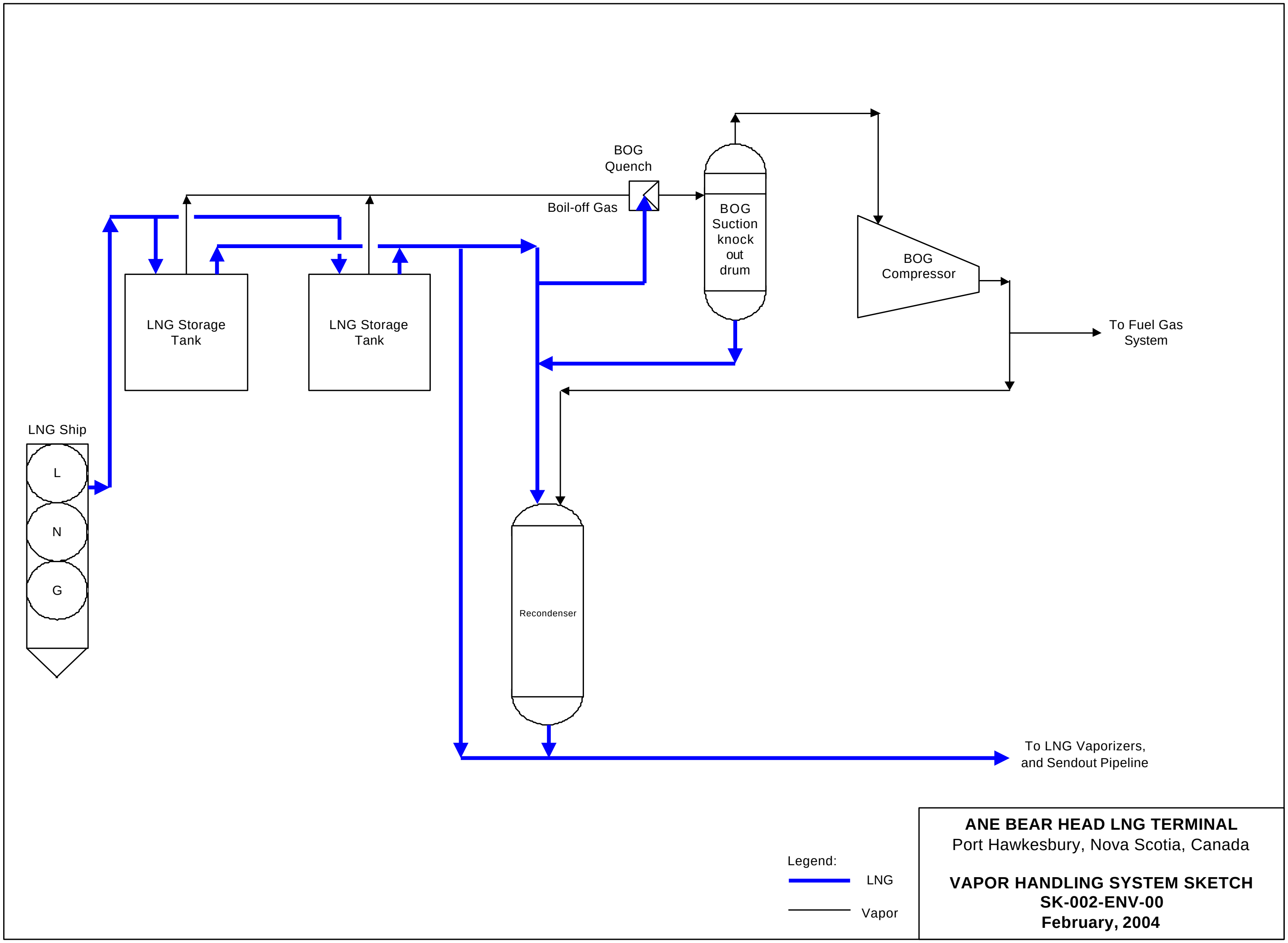


Figure 2.5 Vapour Handling System Sketch

Engineered Provisions

The LNG terminal design has the following engineering provisions to handle expected normal daily variations and potential upset conditions without releasing gas to the relief system:

- extra LNG storage tank capacity;
- LNG storage tanks set with a design pressure that is lower than the actual operating pressure;
- BOG compressor and recondenser to condense the vapour into LNG and send to the vaporizers for continued gas sendout;
- BOG compressor quench system to help cool any vapours and condense them prior to the BOG compressor inlet;
- BOG compressor capacity at the level needed for ship unloading to assure extra capacity for normal operation; and
- Emergency Shutdown (ESD) System.

Environmental Controls

In addition to conservative equipment specifications and spare equipment included in the design to handle the BOG, a pressure relief system consisting of a vent/flare system is provided for emergency situations and startup. The emergency gas release system would only allow natural gas components to escape to the atmosphere in an emergency or transient operating scenario such as an overpressure of the storage tanks or connected processing systems. Example emergency scenarios include: rapid over pressurization of equipment; no sendout of natural gas to the pipeline due to a blocked valve or unavailability of the pipeline; rapid barometric pressure drop during ship unloading; or power outage for a long period of time. No such emergency has occurred in the modern operating record of LNG receiving terminals in the United States. Engineering provisions are being provided both in equipment and control systems to minimize the potential for any such occurrences.

Detailed emissions estimates will be developed during FEED, which is currently underway.

Potential impacts to air quality will be minimized by strict adherence to applicable federal and provincial standards and conditions of approval. Other control and mitigation efforts will include:

- using low NO_x burner on the heaters to reduce the quantity NO_x emissions generated by the heaters;
- monitoring to ensure that equipment are continually operating as close to optimum conditions as practicable; and
- proper maintenance and monitoring program to control leaks, spills and fugitive emissions of hydrocarbons during operation.

2.4.1.3 Air Emissions Modelling

In order to predict the dispersion and subsequent effect of air emissions from the Project, a simulation was conducted using a mathematical computer model of atmospheric transport. This method provides quantitative results and enables direct comparison of the simulated project effects with regulatory criteria. Table 2.3 provides a summary of the Environment Canada and Nova Scotia Air Quality Objectives that will be met by the Project. Dispersion Model results and analysis of air quality impacts are presented in Section 8.1.2.

Table 2.3 Nova Scotia Air Quality Regulations *(Environment Act)* and *Canadian Environmental Protection Act* Ambient Air Quality Objectives

Pollutant and units (alternative units in brackets)	Averaging Time Period	Nova Scotia	Canada			
		Maximum Permissible Ground Level Concentration	Canada Wide Standards (pending) Wide Standards (pending)	Ambient Air Quality Objectives		
				Maximum Desirable	Maximum Acceptable	Maximum Tolerable
Nitrogen dioxide	1 hour	400 (213)	-	-	400 (213)	1000 (532)
µg/m³ (ppb)	24 hour	-	-	-	200 (106)	300 (160)
	Annual	100 (53)	-	60 (32)	100 (53)	-
Sulphur dioxide	1 hour	900 (344)	-	450 (172)	900 (344)	-
µg/m³ (ppb)	24 hour	300 (115)	-	150 (57)	300 (115)	800 (306)
	Annual	60 (23)	-	30 (11)	60 (23)	-
Total Suspended Particulate Matter (TSP)	24 hour	120	-	-	120	400
µg/m³	Annual	70	-	60	70	-
PM2.5 µg/m³	24 hour, 98th percentile over 3 consecutive years	-	30 (by 2010)	-	-	-
PM10-2.5 µg/m³		-	Recommended in 2003	-	-	-
Carbon Monoxide	1 hour	35 (31)	-	15 (13)	35 (31)	-
mg/m³ (ppm)	8 hour	15 (13)	-	6 (5)	15 (13)	20 (17)

Table 2.3	**Nova Scotia Air Quality Regulations *(Environment Act)* and *Canadian Environmental Protection Act* Ambient Air Quality Objectives**					
		Nova Scotia	**Canada**			
			Canada Wide Standards (pending)	**Ambient Air Quality Objectives**		
Pollutant and units (alternative units in brackets)	**Averaging Time Period**	**Maximum Permissible Ground Level Concentration**	**Wide Standards (pending)**	**Maximum Desirable**	**Maximum Acceptable**	**Maximum Tolerable**
Oxidants – ozone	1	160 (82)	-	100 (51)	160 (82)	300 (153)
μg/m^3 (ppb)	8 hour, based on 4th highest annual value, averaged over 3 consecutive years	-	128 {by 2010} -65	-	-	-
	24 hour	-	-	30 (15)	50 (25)	-
	Annual	-	-	-	30 (15)	-
Hydrogen sulphide	1 hour	42 (30)	-	-	-	-
μg/m^3 (ppb)	24 hour	8 (6)	-	-	-	-

2.4.2 Wastewater Discharges

Construction/Commissioning

Construction of marine facilities (*i.e.*, jetty, berthing facility and, if necessary, seawater intake and outfall structures) will involve disturbance and re-suspension of some marine sediment. There is also potential for erosion and sedimentation of marine and freshwater systems associated with land based construction activities. An Environmental Protection Plan (EPP), including plans for erosion and sediment control measures will be developed prior to commencement of construction activities and implemented to minimize impacts to water quality from construction activities. These measures will include:

- programming site activities to minimize the disturbance of the project surface area;
- avoid maintaining open excavations for prolonged periods and compact loose materials;
- compacting soils as soon as excavations, filling, or levelling activities are complete;
- installing silt fences, hay bales, etc. to minimize the transport of silts;
- implementing measures to control against sedimentation and erosion, and to ensure that construction personnel are familiar with these practices and conduct them properly; and
- control of runoff during the construction phase.

The only wastewater expected to be discharged during construction is the storage tank hydrotest water. Standard operating procedures and monitoring of the effluents will minimize any impacts to the quality of near shore waters.

The LNG storage tank inner container will be hydrotested in accordance with American Petroleum Institute (API) 620. During hydrotesting, the Project will have temporary seawater pumps to pump seawater to the first storage tank of approximately of 108,000 m^3. No chemicals will be added to the test seawater. Water will be pumped into the tank at rates not exceeding the limitation set by API 620 and piped into the inner container through the manhole in the outer container roof. Residence time in the tank will be limited to approximately seven weeks from start of filling to completion of emptying, although some final mopping out and drying will take a short while longer. It is proposed that the test water will be transferred between each tank and ultimately discharged to the ocean. Test water will be sampled and tested for suitability prior to use and prior to discharge. If treatment is necessary, procedures will be developed for treating the water prior to discharge.

Operation

The following wastewater will be generated during Project operations:

- treated sanitary wastewater discharged to the ocean;
- once-through seawater discharge to the ocean (if used for LNG vaporization); and
- stormwater runoff.

Sanitary wastewater generated from Project operations will be treated, as necessary, to comply with the regulatory requirements prior to discharge. Sanitary wastewater will be treated onsite using a packaged sanitary wastewater treatment unit approved under relevant regulations and guidelines.

If the second alternative to use seawater from the jetty pumps is used, the basis of this system is to deliver a maximum of 33,000 m^3/hr (145,000 gpm) of seawater to heat exchangers to heat up the HTF. This is based on a maximum allowable design temperature drop of 7°C from ambient. The actual water requirements may vary according to the system design and will be confirmed during detailed engineering and the selection of the equipment vendor.

Seawater intake will pass through a series of screens to remove marine debris and then enter the intake basin. Raked bar screens are provided at the inlet to the intake basin to remove floating debris and provide protection for the seawater and firewater pumps in the basin. The intake screening system will be designed according to DFO Revised Fish Screening Guidelines (DFO 1986) to minimize entrainment of marine organisms. The basin will ultimately be designed for vertical seawater pumps. The pumps are located in individual isolatable bays within the intake basin. At the inlet of each seawater pump bay, a travelling band screen is provided for removal of suspended solids to prevent blockage or damage to the vaporizers. The number of pumps and their capacity will be determined during detailed engineering.

Sodium hypochlorite solution from the electro-chlorination units will be injected into the seawater at the inlet to the intake basin at a normal dose of 2 ppm as a biocide to control marine growth in the system. Provisions will also be made to provide capabilities for shock dosing of the individual pump bays with sodium hypochlorite solution to give a maximum chlorine level of 10 ppm within the water.

The seawater from the heat exchangers will be collected in a sump and directed into a channel to be routed back, via gravity, to the cooling water outfall channel. At the discharge outfall the maximum residual chlorine level will be compliant with regulatory standards. Total residual chlorine (TRC) levels will be monitored. Environment Canada will be consulted during the FEED regarding lowest practical levels of TRC allowable under CEPA and practical alternatives to chlorination. The preferred method is the closed loop system using heated water from the NSP power plant which would decrease the use of chlorinated cooling water currently discharged from the power plant. The outfall will be designed to help disperse the water temperature to within 3 °C of ambient seawater temperature within 100 m of the discharge point.

Process areas will be curbed to contain any potential spills and direct the runoff to the stormwater system through an oil/water separator prior to discharge. A Stormwater Management Plan will be developed to prevent silt-laden runoff from the facility from entering streams or the Strait. This plan will be designed to meet all provincial requirements for surface runoff quality (*e.g.*, suspended solids < 25mg/L).

Groundwater

There are no public or private wells within the LNG terminal area. No groundwater withdrawals will be required for the construction, operation, or maintenance of the Project. Water will be supplied to the facility through the local municipal water supply. The terminal facilities will contain non-permeable surfaces and secondary containment as necessary, thus protecting from spills onto unpaved surfaces.

ANEI will assure that the construction of the foundations for the LNG tanks will not allow for contamination of aquifers in this area. This will be accomplished, if necessary, through the use of driven piles, which do not create an opening to cross the aquifer.

Spills, leaks, or accidental releases of potentially hazardous materials during construction or operation of the proposed terminal could adversely affect water quality including groundwater. A Spill Management Plan and Emergency Response and Contingency Plan will be developed and implemented to minimize the chances of any spill reaching any waterbody including groundwater, and also include mitigation measures to minimize impact if a spill does occur and reach a waterbody. Potential Project impacts on groundwater are evaluated in Section 8.1.1.

2.4.3 Noise Emissions

Project construction noise will be intermittent, as equipment is operated on an as needed basis and mostly during daylight hours.

Noise emissions generated during facility construction and operations will not exceed the provincial guidelines at the property boundaries of the site:

65dBA	0700-1900 hours;
60 dBA	1900-2300 hours; and
55 dBA	2300-0700 hours.

Typical noise emissions from construction equipment are presented in Section 8.1.3.3. Noise emissions estimated from a similar LNG facility are also included in Section 8.1.3.4 as well as the evaluation of potential noise impacts.

2.4.4 Lighting

In general, high mast lighting for area lighting is proposed, including around the tanks. These lights will likely not be as tall as the tanks, however, some additional local lighting will be added at the top of the tanks. This lighting is necessary so that the closed circuit television (CCTV) cameras can view the in-tank pump connections, relief valves, and vents. All area lighting will most likely be photocell controlled. In all cases, the lights will be pointed downward wherever practical. All fixtures will be approved for the area classification in which they are installed. Preliminary consultations with Transport Canada indicate that aviation obstruction lighting will not be required for the tanks as currently designed (S. McDonough, pers. comm. 2004).

2.4.5 Solid and Hazardous Waste

Potential sources of nonhazardous or solid wastes generated by Project activities include scrap metals, insulation waste, packing/crating materials, and domestic wastes. These wastes will be segregated as recyclable and nonrecyclable, with recyclable material collected and transported to a licensed recycling facility using authorized local services. An effort will be made to minimize the amount of waste generated by application of 4-R principals (reduce, reuse, recycle, recover) to the extent practical. Waste management procedures will comply with provincial solid waste management regulations as well as additional municipal and disposal facility requirements. Non-recyclable wastes will be transported offsite to a permitted landfill.

Hazardous waste that is expected to be generated from Project construction and operation sources will be minimal and includes small quantities of waste oils. Hazardous waste will be stored onsite in a separate temporary hazardous waste storage area provided with full containment. Hazardous wastes will be removed from the site by a licensed contractor and disposed at an approved facility. Other control measures for hazardous waste include developing and implementing Spill Management Plan and Emergency Response and Contingency Plan to avoid impacts from release of potentially hazardous materials.

2.5 Hazardous Materials

Hazardous materials will be in use at the Project facilities. All Project staff will be appropriately trained in the handling, storage, and disposal of hazardous materials. Chemical storage and handling will be done in accordance with the manufacturer's recommendations and federal and provincial regulations, where applicable. Hazardous materials anticipated to be in use throughout the life of the Project include:

- LNG;
- sodium hypochlorite used as a biocide in seawater (if necessary for alternate heat source for vaporization);
- 15 % methanol-water mixtures used as HTF to provide heat to the vaporizers and NGL extraction unit reboilers; and;
- lubricating oils and fuels (diesel fuel, natural gas, etc.).

Transportation and storage of hazardous materials will comply with the Nova Scotia Dangerous Good Management Regulations and *Transportation of Dangerous Good Act* and Regulations. Only provincially licensed haulers will be used. To minimize, contain, and control any potential releases of hazardous materials, a site-specific Spill Management Plan and Emergency Response and Contingency Plan will be developed.

2.6 Environmental and Safety Protection Systems

Potential environmental hazards associated with LNG releases are generally minor because LNG released into the environment vaporizes into natural gas, which is lighter than air and evaporates completely. Other than flammability, methane is essentially non-reactive. There will be no process releases of either LNG or natural gas during normal operations. Potential spills of lube oil and diesel fuel are possible at the LNG terminal. Small amounts of these materials are used only for equipment and emergency power generation and are not handled as a product. Spills of such substances will be minimized through development and application of a Spill Management Plan and Emergency Spill

Response and Contingency Plan. Workers will be trained in the Spill Management Plan and appropriate clean up materials will be kept on site.

LNG terminals, by the nature of materials handled, have the possibility of creating hazards that may affect public safety. Impacts on public safety, however, are minimized by strict facility siting/design criteria (*e.g.*, CSA Z276-01) and operational measures to reduce both the probability and consequences of a potential release. The effects of natural hazards such as extreme waves, earthquakes, tornadoes, or hurricanes are incorporated into the design, construction, and operational considerations of the LNG terminal facilities in compliance with the applicable codes and standards.

During the operating history of all LNG terminals, there have been no LNG-related safety incidents where LNG was spilled or otherwise mishandled that resulted in impacts to the public or the environment. A complete risk assessment conducted for this project has been prepared and included as Appendix C and summarized in Section 3.

2.6.1 Equipment Inspection and Maintenance

The LNG industry has a long and outstanding safety record. The industry has been able to maintain this excellent record because of the effort that has been devoted to development and implementation of: safe designs; operating procedures; safety features such as spill prevention, automatic hazard detection and emergency isolation and shutdown provisions; and fixed and mobile equipment for vapour dispersion, fire control and extinguishment.

The principal standards used in LNG terminal design are the CSA Z276-01 "Liquefied Natural Gas (LNG) - Production, Storage, and Handling" and NFPA Standard 59A, "Standard for Storage and Handling of Liquefied Petroleum Gases at Utility Gas Plants". Industry codes and standards specify, among many other details, the basis for minimum distances to shipping lanes, public meeting places, bridges, and residences. These codes are continually being updated to reflect new concerns and technology advancements.

Periodic inspection and preventative maintenance are among the most important functions that can be performed in an LNG facility, or any process plant, to prevent a hazardous material being accidentally released; comprehensive inspection and maintenance procedures will therefore be developed. Emergency procedures will also be prepared after careful study of potential hazards and a careful evaluation of the best way to handle each hazard. These procedures will be contained in an Emergency Response and Contingency Plan.

2.6.2 Hazard Mitigation and Fire Protection Measures

During the FEED phase of the Project, a detailed hazard analysis will be conducted to ensure that all standard and code requirements are met and that appropriate hazard prevention, mitigation and protection systems are properly included in Project design.

The CSA standard requires that all areas that have a potential for combustible gas concentrations due to leakage of LNG or flammable refrigerants be monitored for combustible gas concentrations. Control and monitoring of the Project will be performed by an integrated programmable logic controller (PLC) control system consisting of packaged units with local control panels, numerous field mounted instruments connected to remote input/output (I/O) cabinets and operator interface stations located in the control rooms. An independent Safety Instrumented System (SIS) will be installed to allow the safe, sequential shutdown and isolation of rotating equipment, fired equipment, and LNG storage facilities.

2.6.2.1 Land-Based Facilities

The LNG facility will typically include a wide range of "passive" and "active" hazard mitigation features and provisions to afford thorough protection for the facility and employees. Passive features generally include those that do not require human intervention; for example: spill drainage and containment systems; ignition source control; and fireproofing. Active provisions normally require some action by an operator. Active spill and fire control systems and equipment to be deployed will normally consist of:

- a looped, underground firewater distribution piping system serving hydrants, firewater monitors, hose reels, water spray (deluge) and sprinkler systems, properly valved to minimize system impairment due to maintenance or repair;
- fresh water and seawater firewater pumps;
- fixed high expansion foam system;
- fixed dry chemical systems;
- portable and wheeled fire extinguishers employing dry chemical and CO_2, the latter intended primarily for energized electrical equipment;
- audible and visual alarms;
- closed-circuit television system monitors installed in the security office, main control room, main gate, and the marine unloading berth to provide selectable remote views for the operators;

- fire protection in buildings, generally consisting of smoke detectors and portable fire extinguishers; and,

- sprinkler systems may be installed on a select basis.

Process instruments will routinely monitor conditions such as pressure, flow and temperature, which can give an early indication of a potentially hazardous condition. Specialized automatic hazard detection and alarm notification devices are normally installed to provide an early warning of a hazardous release or a fire condition. Automatic hazard detectors are designed to sense a variety of conditions including combustible gas and low temperature (indicating a leak or LNG spill), and heat and flame (indicating a fire).

Hazard detection is designed on the following strategies:

- visual monitoring;
- automatic detection (combustible and toxic gas, fire, flame, smoke, and low temperature);
- centralized alarm system; and
- emergency shutdown system.

In the event of an accidental leak or spill of LNG to the environment, hazard control provisions immediately go into operation. The first provisions are passive spill drainage and containment features. It is important that the leak or spill be contained and confined to minimize the impact on the surrounding area. The hazardous release is quickly detected and audible and visible alarms are registered at key locations.

2.6.2.2 Marine Facilities

The marine facilities will be designed to provide safe berths for the receipt and support of LNG ships and to ensure the safe transfer of LNG cargo from the ships to onshore storage facilities. Design will be in accordance with applicable codes and standards, including but not limited to Oil Companies International Marine Forum (OCIMF), and Society of International Gas Tanker and Terminal Operators (SIGTTO). All LNG ships arriving at the terminal will be constructed according to structural fire protection standards contained in the International Convention for Safety of Life at Sea (SOLAS).

Protection of the LNG ship during navigation, berthing and unberthing, and while docked and unloading is a major design consideration. Safety measures include: emergency shutdown systems; powered emergency release coupling (PERC) valves; spill containment; and provisions to protect piping from the effects of transient pressure surges.

The operating and safety record of LNG ships has been outstanding. To date, LNG vessels have made about 38,000 voyages and safely transported over 1.5 billion m^3 of LNG without releases of any LNG cargo. No incident has resulted in the release of LNG cargo outside of the ship or in any LNG release fires. The few incidents that have occurred on LNG ships are typical of the incidents of all types of ships (*i.e.*, not related to either the LNG cargo or the fact that the ship was an LNG carrier). Several of the incidents would have been more serious if the ship had not been an LNG carrier. Incidents have included minor piping leakage (non-LNG) and an occasional venting of a tank. These types of incidents, however, have not affected the safety record of LNG ships. Refer to Section 3 and Appendix C for detailed risk assessment information for LNG ships.

All LNG ships used to deliver LNG to the Project will have double-hull construction (double bottoms and sides). Double hull construction increases the structural integrity of the hull and provides protection of the cargo tanks in the event of an accident. The International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code) regulations require that LNG ships meet a Type IIG standard of subdivision, damage stability, and cargo tank location. This design ensures that the LNG ship could withstand flooding of any two adjacent compartments without any adverse effect upon the stability of the ship. Most large LNG ships have a distance of 1.5 to 2.4 m between the outer hull and the cargo tank. As a result, grounding incidents severe enough to case a cargo spill on a single-bottom oil tanker would not penetrate both the inner and outer hulls of an LNG tanker.

Ships delivering LNG to the terminal will likely be either the spherical or membrane design, as an equal number of the LNG ships in use are of either type. The spherical tank design uses spherical aluminum alloy tanks (usually 3 to 5) insulated with polyurethane panels. In the membrane tanks system, the ship's hull makes up the outer wall, with an inner tank membrane separated by insulation. The membranes are separated and supported by rigid insulation panels which also separate the composite section from the inner hull. Membranes used are either stainless steel, as in the Technigaz membrane, or Invar in the Gas-Transport membrane type. Membrane tanks have the advantage of making more efficient use of the space within the hull.

The LNG ships used to transport LNG to the terminal would be fitted with an array of cargo monitoring and control systems. These systems will automatically monitor key cargo parameters while the ship is at sea and during the unloading of LNG at the terminal. The LNG ships will also be outfitted with navigation and communications systems, including: Automatic Radar Plotting Aids (ARPA); Automatic Identification of Systems (AIS); LORAN-C receivers; and echo depth finders.

While approaching and leaving the jetty, vessels will be under the jurisdiction of Canadian Coast Guard and subject to mandatory pilotage requirements. All normal federal safety standards and any additional standards for LNG carriers will apply.

2.6.2.3 Emergency Response and Contingency Plan

A project-specific Emergency Response and Contingency Plan for unplanned discharges or spills will be prepared. A Spill Management Plan will also be developed to prevent and respond to smaller spills. In the case of an accidental release of materials from the facility, reporting and clean-up procedures will follow provincial emergency spill regulations as required. Lubricants and other petroleum products will be stored and waste oils will be disposed of in accordance with provincial regulations. Small spills will be contained by on site personnel using spill kits kept at the site.

Typical elements of the Emergency Response and Contingency Plan will include the following information:

- purpose and scope of plan coverage;
- general facility identification information (e.g., name, owner, address, key contacts, phone number);
- facility and locality information (e.g., maps, drawings, description, layout);
- discovery/initial response;
- sustained action;
- termination and follow-up actions/prevention of recurrence;
- notification (internal, external, and agencies);
- response management system (e.g., incident commander, safety, liaison, evacuation plan);
- assessment/monitoring, discharge or release control, containment, recovery, and decontamination;
- logistics – medical needs, site security, communications, transportation, personnel support, equipment maintenance and support, emergency response equipment (*e.g.*, PPE, respiratory, fire extinguishers, first aid);
- incident documentation (accident investigation and history);
- training and exercises/drills;
- plan review and modification;

- prevention; and
- regulatory compliance.

The Emergency Response and Contingency Plan will also reference the CAN/CSA Z731-03 “Emergency Preparedness and Response” standard to supplement code requirements as applicable in the development of the Emergency Response and Contingency Plan.

The capacity of local fire and/or ambulance services to respond to incidents will be evaluated. ANEI will work closely with related agencies on the issue of public and marine safety. All staff will complete Workplace Hazardous Materials Information System (WHMIS) training. ANEI will develop a comprehensive EHS system that encompasses internal requirements for employee safety and environmental reporting.

2.7 Employment

The proposed facility will provide a significant number of construction jobs. It is anticipated that approximately 400-600 full-time equivalent positions will be created on average over the 32-month construction period. At the peak of construction, the number employed will reach approximately 700-1,000.

During operation, it is anticipated that 32 full-time equivalent positions will be required, involving a payroll of approximately $2.1 million per year.