Module 6

Alternatives Analysis

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Alternatives Analysis

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1 Requirements of the Alternatives Analysis

Pursuant to the National Environmental Policy Act (NEPA), governmental decision makers must consider reasonable alternatives to a proposed action that could result in significant environmental effects. To be reasonable, the alternatives must:

- Satisfy most of a proposed project's basic purpose and need;
- Avoid or substantially lessen any of a project's potential effects; and
- Be feasible from a technical and economic standpoint.

The Maritime Administrator may approve or deny an application for a license under the Deepwater Port Act (DWPA). In approving a license application, the Maritime Administrator may impose enforceable conditions as part of the license. In determining the provisions of the license, the Maritime Administrator may also consider alternative means to construct and operate a deepwater port that meet the points listed above. Identifying and evaluating alternatives helps to ensure that decisions concerning the license are well founded and, as required by the DWPA, are in the nation's best interest, and are consistent with national security, energy sufficiency, and environmental quality policy goals and objectives.

This alternatives evaluation presents a reasonable range of alternatives in accordance with NEPA. As set forth by NEPA, the alternatives evaluation does not consider every possible alternative. The analysis focuses on alternatives that could substantially avoid or lessen significant project effects, even if these alternatives are not within the capability of the Applicant or could be more costly. The alternatives evaluation considers energy system alternatives, as well as siting and technology alternatives. The selected range of alternatives is intended to facilitate meaningful discussion among decision makers and the public regarding the best means to satisfy the need for additional energy supplies for New England.

The adequacy of alternatives analyses performed for other recently proposed liquefied natural gas (LNG) terminal projects, especially for those in the New England region, has been questioned by a number of parties, who have called for a more comprehensive and thorough review by the federal agencies responsible for licensing of these facilities. One of the concerns expressed is that the project's purpose has been so narrowly defined as to artificially constrain the number of reasonable alternatives considered. This alternatives analysis is designed to provide a basis for determining if any reasonable alternatives are environmentally preferable to the proposed action as presented in Module 1 of this document. Neptune has not prematurely eliminated alternatives on the basis of not meeting a very tightly defined purpose; instead Neptune has conducted a comparison of the potential effects of the proposed project with those of alternative means of meeting the proposed need to determine their comparative environmental desirability.

Generally, the alternatives analysis process followed these steps:

- Identification and description of reasonable alternatives;
- Selection of criteria for analysis;

- Evaluation and comparison of alternatives; and
- Selection of preferred alternative.

Only alternatives that are technically and economically feasible and practical were considered. Some alternatives may be impracticable because sites or technology are unavailable and/or because of cost or logistical constraints, which hinder the ability to achieve the overall project purpose.

The analysis focuses on alternatives that may reduce adverse environmental impacts in comparison to the proposed project. Through the application of evaluation criteria and subsequent environmental comparisons, each alternative was evaluated until it was apparent that the alternative was not reasonable or would result in significantly greater environmental impacts that could not be reasonably mitigated. Those alternatives that appear to be the most reasonable and have less than or similar levels of environmental impact are fully evaluated.

In summary, alternatives were identified for further evaluation if they:

- are technically and economically feasible and practical;
- offer significant environmental advantage over the proposed project; and
- capable of satisfying the project objective of providing new capacity for importing LNG from overseas production areas into New England markets.

The types of alternatives that were evaluated and are described in the following sections include the no action alternative, energy system alternatives, regional site alternatives, offshore terminal technology alternatives, terminal site alternatives, pipeline route alternatives, construction alternatives, and LNG vaporization system alternatives. Figure 1 summarizes the sequential process that was used to conduct the alternatives analysis.

2 Need for the Project

According to a report commissioned by the New England Council (NEC), an organization that represents businesses, academic institutions and health organizations throughout New England, there is an economic imperative for additional supplies of natural gas in the region and a critical need to construct new LNG import facilities in the region (NEC 2005). The report entitled *The Economic Imperative for Additional LNG Supplies in New England* states, “Additional supplies of natural gas are needed before 2010. This is a clear and present need, fueled by the convergence of three factors: a growing reliance on natural gas for electricity generation (expected to generate close to 50% of New England’s electricity by 2010); enduring high and volatile natural gas pries, which put the region at a competitive disadvantage; and on peak winter days, the region’s pipeline system is already at 90% capacity and constrained at key points.” The report states that additional LNG infrastructure is necessary to moderate natural gas price volatility, which has forced New England businesses and consumers to spend more than $500 million more for electricity every year since 2001.

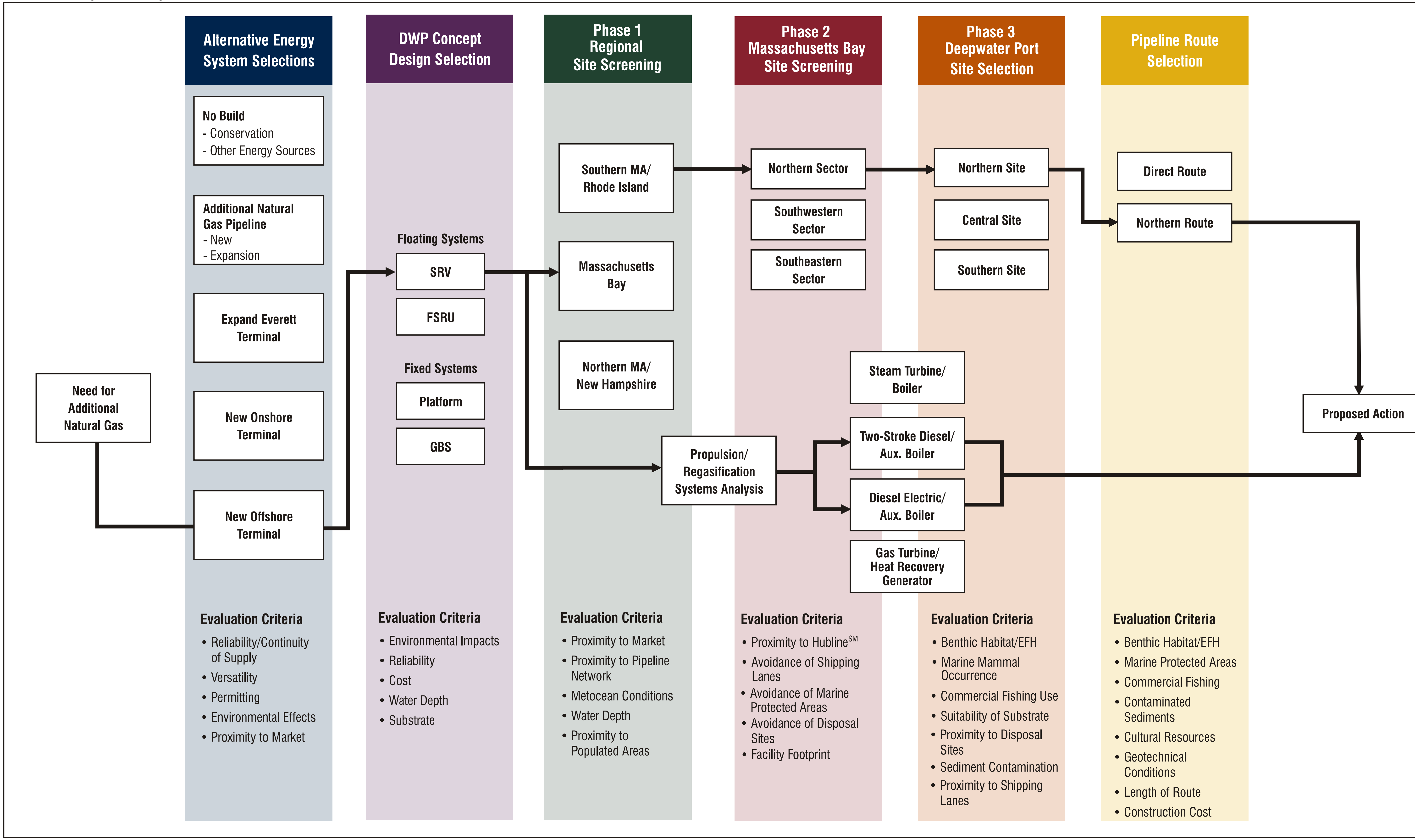

Figure 1 Summary of Alternatives Analysis Process for Neptune LNG

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The analysis conducted by the New England Council is corroborated by a report prepared by the Power Planning Committee of the New England Governors' Conference, Inc.(NEGC) entitled *Meeting New England's Future Natural Gas Demands: Nine Scenarios and Their Impacts* (NEGC 2005). The New England Governors' Conference report emphasizes that the uncertain reliability of natural gas supplies occurs almost exclusively in the winter months when demand for gas increases dramatically and coincides with demand from gas-fired electric generation facilities. The report states, "Even assuming [existing] LNG storage and vaporization capability remains available, if gas demand grows at a rate equal to or higher than recent growth rates, the region's gas delivery infrastructure would be insufficient to deliver all needed gas after 2010. Under these conditions, to avoid leaving some customers without gas for space heat in 2010 and after, additional gas supply infrastructure (either expanded pipeline capacity or expanded LNG storage capacity) or resources that reduce gas demand would have to have been added to the system. Infrastructure expansions or demand reductions would have to be planned and started well before 2010 to help match supply with demand by 2010."

Meeting New England's future gas demands is further complicated by New England's native geology. The New England Governors' Conference report states, "In the past, the use of natural gas in New England was limited to the volume of natural gas that could be delivered to the region by interstate pipeline. New England's native geology does not allow for the development of underground storage caverns that other parts of the country have, where gas is stored in vapor form, mainly in depleted gas and oil wells and salt caverns. Therefore, the only viable means to store gas in New England is in liquid form. Currently, LNG meets approximately 20% of New England's annual gas demand. In periods of winter peak demand, LNG supplies well over 30% of New England's natural gas needs."

The Federal Energy Regulatory Commission (FERC) has determined that, based on regional and local demand projections, the need for additional supplies of natural gas will be required by 2010. They further concluded that this supply should be met both by proposed pipeline projects and by LNG projects (FERC 2003). Both FERC (2003) and NEGC (2005) noted that LNG comes from different natural gas reserves than traditional pipeline sources in eastern and western Canada and the U.S. Gulf Coast, and, therefore, LNG import facilities enable introduction of more sources for supply. Increased fuel source diversity bolsters New England's gas infrastructure by reducing dependencies on specific sources and spreading supply and risk across multiple sources.

Alternative scenarios to address natural gas demand in the New England region were assessed in the New England Governors' Conference Report (NEGC 2005). The report concluded that the region must substantially reduce demand or increase its development of infrastructure before 2010 to ensure reliable delivery of natural gas during peak demand periods. The report also concluded that various demand reduction or resource development scenarios could be pursued, each providing a different degree of success, to meet the region's energy and other public policy goals of reliability of the fuel delivery infrastructure, fuel diversity, price mitigation or reduction, price stabilization, and security. In general, demand reduction scenarios would have limited effect on ensuring long-term reliability of supply during peak demand periods in comparison to development of new natural gas delivery infrastructure.

Demand reduction scenarios include expansion of fuel switching (assuming gas electric generation plants will be able to switch to oil for extended periods for the purpose of serving peak day demand; however, most of the recently constructed gas-fired power plants in New England do not have this capability); expansion of current energy efficiency programs; construction of new renewable electric generation; construction of a new coal gasification plant; and construction of a new nuclear generation plant. The resource development scenarios defined by the report include construction of onshore, in-region LNG expansion projects like the proposed KeySpan LNG Facility Upgrade Project; construction of one or more new onshore, in-region LNG terminals like the proposed Weaver's Cove LNG Project; construction of one or more new offshore, in-region LNG terminal similar to the Northeast Gateway or Neptune LNG projects; and construction of one or more new onshore, out-of region LNG terminals.

Expansion of programs that promote short-term power plant fuel switching (from natural gas to oil), energy efficiency, and renewable energy may be the least expensive way to improve gas supply reliability while improving fuel diversity. Expansion of gas energy efficiency programs may yield even greater reliability enhancements and even lower overall costs than most other scenarios. However, the expansion of LNG delivery and storage terminals would improve reliability of gas supply considerably more than any of the other scenarios (NEGC 2005). The NEGC report identifies reasonable natural gas pipeline and LNG supply systems alternatives that have the potential to satisfy the project objectives.

The proposed Neptune LNG Deepwater Port would expand the New England natural gas infrastructure, and relieve pressure on burdened transportation and storage systems. The Project would increase the supply of natural gas to New England to provide for growing demand and complement the existing gas market by providing fuel supply diversity through global sourcing of LNG. In addition, the proposed Neptune LNG Deepwater Port may also relieve the upward pressure on the reliance and demand for stored gas. Lastly, the Project may help to lower or stabilize natural gas prices in the region.

3 No-Action Alternative

This section discusses the potential effects if the project is not approved. Under the no-action alternative, the demand for natural gas in the New England area would not be satisfied by the project and would have to be met by other natural gas supply options, or by significant energy conservation measures. If projected natural gas demand is not met by the applicants of other proposals, it is likely that shortages of natural gas would occur and natural gas prices would continue to rise.

If the Maritime Administrator denies the license for the Neptune project, the facilities would not be constructed, the objectives of the proposed project would not be met, and Neptune would not be able to provide a new supply of natural gas to the New England market. If this no action alternative were taken, the environmental effects of the proposed project as described in this document would not occur. The resulting effects and actions that would be taken by other suppliers or users of natural gas in the region, as well as any associated direct and indirect environmental impacts, are uncertain. However, since the existing natural gas pipeline system in New England is nearly at capacity during peak use months (FERC 2003) and demand for energy in New England is predicted to increase, customers would have fewer and potentially more expensive options for obtaining natural gas supplies in the near future or could even face shortages of supply. Higher natural gas prices and/or supply shortages could adversely influence the regional economy by reducing realized household incomes and business profits (Greenspan 2003). Higher natural gas prices (or the potential for higher gas prices) and/or natural gas shortages could also lead to alternative proposals to develop natural gas delivery or storage infrastructure, increased efficiency and conservation or reduced use of natural gas, and/or the use of other sources of energy (FERC 2005).

If the no action alternative is selected, there are three likely consequences: (1) adverse economic and environmental effects due to the undersupply of natural gas to the region, (2) proposals for other natural gas transportation infrastructure developments (e.g., land-based pipelines or other offshore or onshore LNG import facilities) to meet the continued demand for natural gas in the region, and/or (3) proposals for new coal-fired power plants (FERC 2005).

3.1 Energy Conservation Alternatives

Energy conservation and increased energy efficiency can contribute to the ability to meet the future energy needs of New England. Since the energy crisis of the 1970s, numerous aggressive energy conservation programs have been implemented throughout New England. As an example, Massachusetts enacted the 1997 Electric Industry Restructuring Act that requires customers of electric distribution companies to pay a charge to support energy efficiency programs. Specifically, these programs include developing and enforcing commercial/residential building codes to ensure that construction meets certain energy standards; Energy Star programs; tax credits for energy efficiency; utility restructuring programs; and regional energy efficiency initiatives. In 2004, the Massachusetts Division of Energy Resources (DOER) reported the following benefits of energy efficiency programs (DOER 2004):

- improved reliability and lowered retail electricity prices through demand reduction by almost $1.2 million in 2002;
- participant savings of over $21.5 million in their 2002 electric bills;
- projected bill savings of an estimated $249,000,000 over the lifespan of the installed measures for an investment of $138 million;
- creation of an estimated 1,778 new jobs, contributing $139 million to the gross state product in 2002; and
- improved air quality in Massachusetts and New England (FERC 2005).

A 2003 report by the American Council for an Energy Efficient Economy (ACEEE) also analyzed projected energy demands in the Northeast. The ACEEE reviewed the national and regional relationship between natural gas price effects of energy efficiency and renewable energy practices and policies (ACEEE 2003). The American Council for an Energy Efficient Economy (ACEEE) found that increased installation of renewable energy generation could affect natural gas price and availability in the Northeast (ACEEE 2003). The report concluded that by 2008 energy efficiency and renewable energy measures could reduce natural gas consumption by 0.9 percent in the northeastern states, which include the New England states, as well as New York, New Jersey, Pennsylvania, Delaware, and Maryland. However, the U.S. Department of Energy's Energy Information Administration (EIA) projects that total gas consumption in New England will increase at an annual average rate of 1.38% between 2004 and 2024. With this projected demand growth rate, energy efficiency measures would not offset the future growth of demand, nor resolve the constraint on meeting current demand. The AFCEE study recognized that energy efficiency and renewable energy are not the only policy solutions required to address the future natural gas needs of the United States and that additional sources of natural gas will be required either from domestic sources or through the importation of gas in the form of LNG (FERC 2005).

3.2 Energy Source Alternatives

In the short term, the no action alternative would lead to natural gas shortages and increased reliance on other fuel sources to meet the overall energy demands of the region. These include conventional energy sources such as other fossil fuels (coal, fuel oil) or nuclear power, as well as renewable sources of energy, like hydropower, wind energy, or solar energy. The feasibility of each of these alternative sources of energy is discussed in the following sections.

3.2.1 Fossil Fuels

Without new natural gas supplies, the region would experience natural gas supply shortages and increased reliance on other types of fossil fuels, such as coal or fuel oil, to cover the shortfall.

The EIA predicts that natural gas consumption between 2005 and 2025 will increase by 1.4 percent per year, consumption of petroleum and coal will increase by 1.0 and 1.1 percent per year, respectively (EIA 2005). With worldwide demand for petroleum products outpacing the discovery and production of additional supplies of crude oil, other petroleum fuels are unlikely to provide a cost-effective option to natural gas in the foreseeable future.

Natural gas is the cleanest burning of the fossil fuels. The combustion of natural gas emits 34 to 52 percent less carbon dioxide per unit of energy than that of other fossil fuels such as coal or oil. In addition, other emissions from combustion of natural gas are significantly lower than those from coal or oil (Table 1). The use of other fossil fuels instead of natural gas would increase air pollution.

Table 1
Estimated Air Emissions by Fossil Fuel Type for Electric Power Generation

Fossil Fuel Type	CO2 (lb/kWh)	SOX (lb/kWh)	NOX (lb/kWh)
Coal	2.1	0.013	0.0076
Oil	1.6	0.011	0.0021
Natural Gas	1.0	0.000007	0.0018

Source: Estimated emissions are based on total emissions and total electrical power production for each fossil fuel type, as reported in USEPA's Annual Energy Review 2003 (USDOE 2003).
Key:
CO_2 = carbon dioxide
SO_X = sulfur oxides
NO_X = nitrogen oxides
lb/kWh = pounds per kilowatt hour

3.2.2 Nuclear

Because of permitting requirements, nuclear waste disposal, cost considerations, and related public concerns, new nuclear power plants are unlikely to be sited in the region in the foreseeable future.

3.2.3 Renewable Energy Sources

Renewable energy sources, including wind, hydropower, municipal solid wastes, wood and other biomass, and solar, are projected to have some role in meeting New England's future energy needs. According to the EIA (2003), several renewable energy sources are being used or have potential to be used in New England, including hydropower; solar energy collected with flat-plate collectors; wind energy, which has good to excellent potential in many areas of New England; and biomass energy in the form of wood from forests or sawmills. The EIA estimates that in 2005, energy consumption in New England from renewable sources such as hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, ethanol, photovoltaic, and solar thermal sources will account for about 9 percent of the region's total energy consumption as compared to estimates of 23 percent from natural gas, 51 percent from petroleum, 6 percent from coal, 10 percent from nuclear power, and about 1 percent from electricity imports. The EIA also predicts that consumption of renewable energy will increase by 1.1 percent a year until 2025, with wind power anticipated to be the primary source of increase (EIA 2005).

However, EIA suggests that nuclear or renewable energies such as hydroelectric, wind, or solar, while important to the overall mix of available energy sources, will not replace the demand for natural gas over the next 20 years (EIA 2005). Furthermore, each of these sources of energy would have project- and site-specific environmental issues such as the disposal of toxic materials, alterations to hydrological/biological systems, and visual impacts.

In summary, alternative sources of energy cannot offset the need for additional gas supply in the New England region, and therefore, are not considered reasonable alternatives to the proposed project.

4 Alternative Natural Gas Supply Systems

Alternative systems of supplying natural gas to the New England market were considered for achieving the project objectives. These include the use or expansion of existing or proposed pipeline or LNG facilities to supply the additional volumes of natural gas that the Neptune LNG deepwater port would deliver. For example, the NEGC report (2005) defined several alternative infrastructure developments that could help to supply the additional natural gas to the New England region, including construction of onshore, in-region LNG expansion projects like the proposed KeySpan LNG Facility Upgrade Project; construction of one or more new onshore, in-region LNG terminals like the proposed Weaver's Cove LNG Project; construction of one or more new offshore, in-region LNG terminal similar to the Northeast Gateway or Neptune LNG projects; and construction of one or more new onshore, out-of region LNG terminals.

This section describes existing pipeline systems and LNG import terminals that serve the region, proposed expansions of those systems, and proposed LNG import terminals, both within and outside the region, that could potentially supply natural gas to the region. These systems are evaluated to determine whether they can satisfy the project purpose and potentially lessen the environmental impacts that would be associated with the proposed Neptune LNG deepwater port project.

4.1 Pipeline System Alternatives

New England is at the end of the eastern U.S. interstate pipeline system, which is primarily fed from natural gas reserves along the U.S. Gulf coast, and is also near the eastern end of the Canadian pipeline system, which has historically transported gas from western Canada reserves. Relatively recent development of reserves in the eastern Maritime Provinces has diversified the available Canadian natural gas supplies for eastern Canada and New England. The major interstate pipelines that serve Massachusetts and the New England region include the:

- Algonquin Gas Transmission (Algonquin);
- Tennessee Gas Pipeline System (Tennessee);
- Portland Natural Gas Transmission System (Portland);
- Maritimes and Northeast Pipeline (Maritimes and Northeast); and
- Iroquois Gas Transmission System (Iroquois) (Figure 2).

The Algonquin and Tennessee systems, which originate from the US Gulf coast region, supply approximately 80% of the region's natural gas that is delivered by pipeline. Portland and Iroquois supply gas from western Canada, whereas the Maritimes & Northeast system transports eastern Canadian gas.

Since 1990, New England's natural gas pipeline system has seen a significant increase in capacity. The total capacity of the New England region's existing natural gas interstate pipeline system is approximately 3.5 Bcf per day (NEGC 2005). Several new projects have been proposed that would increase the capacity of the pipeline infrastructure, but that do not address the need for future supply sources. Neptune LNG's goal is to efficiently exploit the available pipeline transportation capacity and provide a new supply source to the region by developing an LNG import terminal that would minimize environmental impact.

In the sections below, Neptune considered whether the existing pipeline systems that supply New England from traditional continental natural gas production areas, either with or without expansion, could serve the purpose of the proposed project with equal or less environmental impact.

Algonquin

The Algonquin Gas Pipeline transports 1.6 Bcf of gas per day through 1,064 miles of pipeline to points in New Jersey, New York, Connecticut, Rhode Island, and Massachusetts, serving major metropolitan regions such as Boston, Providence, and Hartford. Algonquin connects to Texas Eastern and Maritimes & Northeast (Figure 2). Algonquin's 30-inch-diameter HubLine^{SM} pipeline interconnects with the proposed Maritimes & Northeast Pipeline system in Plaistow, New Hampshire, and includes a 29.4 mile subsea segment from Beverly to Weymouth, Massachusetts. HubLine^{SM} supplies gas for several new power generation projects in eastern Massachusetts, and provides transportation for new supply options from the north. Algonquin is seeking FERC authorization to construct and operate a 16.4-mile subsea lateral pipeline from the proposed Northeast Gateway deepwater port

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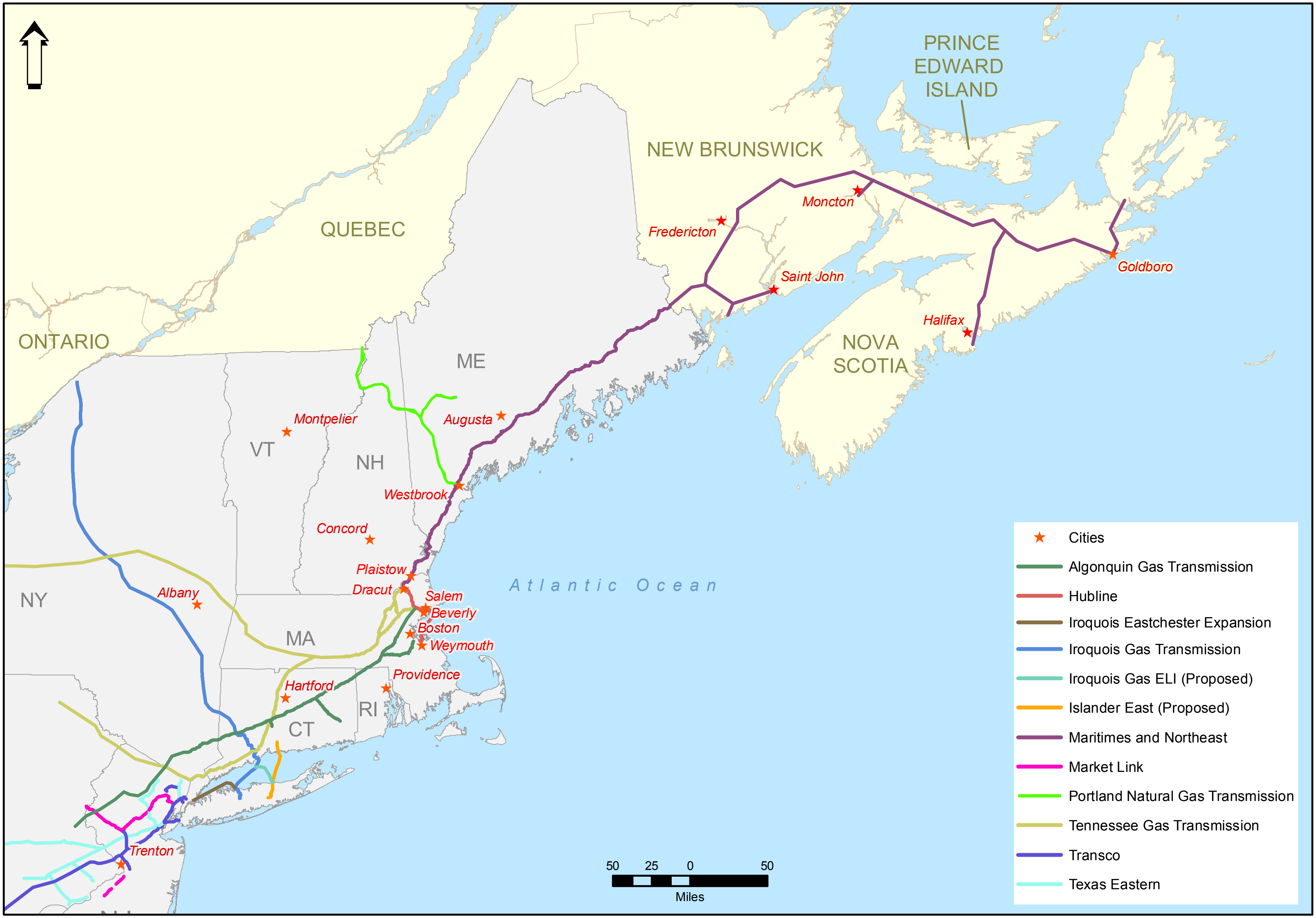

Figure 2
Existing Natural Gas Transmission Pipelines Serving the New England Region

facility in Massachusetts Bay to the HubLine^{SM} pipeline, and to upgrade its existing meter stations in Salem and Weymouth, in order to provide transportation capacity for up to 800,000 dekatherms per day. The Algonquin system, including the HubLine^{SM} pipeline, has open capacity, but is supply constrained. The Neptune LNG project is intended to provide new supply to the Algonquin system from outside the region.

Tennessee Gas Pipeline

Tennessee completed an open season on March 31, 2005, for its proposed Atlantic Supply Expansion project (Figure 2), which would bring additional natural gas supplies into Massachusetts, presumably from LNG import terminals proposed for eastern Canada and Maine. The project, if certificated, would increase capacity at its Dracut, Massachusetts interconnection with Portland and Maritimes & Northeast systems by 250,000 millioin cubic feed per day (mmcfd), and would be completed in 2008. This expansion could not be conducted without an expansion of the Maritimes & Northeast pipeline sufficient to handle the additional gas flow.

Tennessee Gas also recently announced Northeast ConneXion–New England Project, which is proposed to provide an additional 136 mmcfd of natural gas from long-haul sources in Texas and Louisiana (Northeast Gas Association, 2005). The additional volumes would be supplied by increasing compression capacity at existing compressor stations in New York and Massachusetts (FERC 2005).

Portland Natural Gas Transmission System

Portland connects the TransQuebec and Maritimes Pipeline at the Canadian border and the Maritimes and Northeast Pipeline at Westbrook, ME with the Tennessee Gas Pipeline System at Dracut, Massachusetts (Figure 2). It carries a capacity of 210,000 million British thermal units per day (mmBtu/d). The Portland system, was originally designed only to import gas (into New Hampshire), but in 2003 was reconfigured to provide bidirectional service to its customers. The objective of the reconfiguration was to provide shippers of Canadian Sable Island gas, using the Maritimes & Northeast Pipeline system, with an opportunity to redirect some of their gas to markets located in Quebec, which previously had access only to western Canadian gas supplies.

Maritimes & Northeast Pipeline

The Maritimes & Northeast system transport gas from the Sable Offshore Energy Project to markets in both eastern Canada and the northeast United States (Figure 2). This system runs from Goldboro, Nova Scotia, to Dracut and Beverly, Massachusetts, where it interconnects with the Algonquin system. It also interconnects with the Portland and Tennessee pipelines. Currently, the Maritimes & Northeast system appears capable of transporting about 350 mmcfd of natural gas to markets in northern Massachusetts, based on the current throughput. FERC believes that the Maritimes & Northeast system could be expanded to deliver at least another 400 to 500 mmcfd to northern Massachusetts, primarily through the additional compression (FERC 2005). Maritimes & Northeast has recently signed precedent agreements with the developers of proposed LNG terminals in eastern Canada (Bear Head LNG and Canaport LNG, see Section 4.2.3) to transport a total of 1.5 billion cubic feet per day (Bcfd) beginning in 2008. Maritimes & Northeast has begun detailed engineering design and stakeholder consultation for a future expansion of its system

(Maritimes & Northeast 2005). The specific details of a possible pipeline expansion project are not available at this time, although it will presumably require looping of its pipeline system.

Iroquois Gas Transmission System

The Iroquois system delivers more than 1 Bcfd of natural gas from western Canada into the northeastern U.S (Figure 2). Iroquois' Eastchester Expansion pipeline, which extends Iroquois' system 29 miles across Long Island Sound into New York City, was put into service in 2004 and provides an additional 230 MMcf/d of new service into this market.

FERC expects that new pipelines or modifications of existing pipelines will continue to increase the capacity of existing systems delivering natural gas to the New England region (EIA 2003b). Projects such as Tennessee's ConneXion—New England Project will allow access to sources of natural gas outside of the region, including any new LNG import terminals built on the Gulf coast. However, because energy demand in New England is seasonal, pipelines designed to transport natural gas from outside the region during peak demand periods would be underutilized during most of the year. Consequently, FERC believes that the cost of natural gas from outside of the New England region would also generally be higher (FERC 2005).

The use of an existing or proposed source of natural gas outside of the region would require the utilization or expansion of existing pipeline systems to provide an equivalent amount of natural gas to the New England market as that proposed by Neptune. These pipeline systems primarily provide natural gas from production areas in Canada and the Gulf Coast, which are projected to have no growth, or in some instances a decline, in production. Although new supplies of natural gas might become available from other sources, such as new or expanded LNG import facilities along the Gulf and Atlantic Coasts, the interstate pipelines serving New England are operating close to capacity during the winter months (FERC 2005). Continued use and expansion of the existing pipeline network to meet increasing regional demands appears to be an inefficient means of solving seasonal supply problems that can better be met by delivery of imported supplies.

Furthermore, expanding or modifying the existing pipeline systems to deliver the additional volumes of natural gas would result in various environmental impacts, the nature and magnitude of which would depend on the length and design of the proposed projects. Construction of a pipeline of the size that would be required to deliver the proposed throughput would likely incur short- and long-term impacts to water resources, wetlands, upland vegetation, wildlife habitats, roadways, and land use. Operation of new or upgraded compressor stations would also result in long-term noise and air impacts (FERC 2005).

4.2 LNG Terminal System Alternatives

Neptune considered whether existing or proposed LNG terminals, either with or without expansion, could serve the objectives of the proposed project, as well as offer environmental advantages. The only existing LNG terminal that is reasonable to consider as a potential system alternative is the Distrigas LNG facility in Everett, Massachusetts. For reasons explained in Section 4.1, the other existing LNG import terminals on the U.S. Atlantic and Gulf coasts are not considered reasonable system alternatives.

A number of proposed LNG terminals in the northeastern U.S. and eastern Canada are reasonable to consider as system alternatives to the Neptune LNG project (Table 2).

These include the Weaver's Cove Energy project in Fall River, Massachusetts, the KeySpan LNG project in Providence, Rhode Island, the proposed Broadwater Energy and Northeast Gateway offshore terminal projects (in Long Island Sound and Massachusetts Bay, respectively), two LNG projects in Maine near the Canadian border (Quoddy Bay and Downeast LNG), and five terminals in eastern Canada. Although KeySpan's application to modify its existing LNG storage facility to receive LNG imports was denied by FERC in July 2005, KeySpan is requesting a rehearing, and therefore, this facility is also considered as an alternative.

The locations of all of the existing and proposed LNG import facilities in the northeastern United States and eastern Canada region (including terminals not considered as reasonable alternatives) are shown on Figure 2.

4.2.1 Existing LNG Terminals

Everett Terminal

The Distrigas Everett LNG Marine Terminal (the Everett Terminal), which is owned by Suez LNG North America, Inc., the parent company of Neptune LNG LLC, is the only existing source of imported LNG to the New England market. The Everett Terminal began operation in 1971 and is the longest operating LNG terminal in the U.S. The Everett Terminal now meets approximately 20% of New England's natural gas demand (Distrigas of Massachusetts LLC [Distrigas] 2004). The Everett Terminal delivers natural gas and LNG throughout the northeastern U.S. The natural gas is provided to local gas distribution companies, electric generating facilities, natural gas marketers, and industrial end-users and the liquid is supplied to most of the 46 LNG storage facilities located in the northeast through its truck loading facilities at the Everett Terminal.

The Everett Terminal has two storage tanks, with a combined capacity of 3.4 Bcf. The terminal's installed vaporization capacity is approximately 1.0 Bcfd, with a sustainable daily throughput capacity of approximately 715 MMscfd. Its liquid send-out capacity is about one million gallons of LNG per day.

The Everett Terminal is operating close to capacity. In order to significantly expand the terminal to meet the proposed Neptune LNG project's minimum requirement of 400 MMscfd of natural gas send-out, it would require the construction of a new tank for LNG storage and construction of additional vaporization capacity. For economic and environmental reasons, it may not be feasible to expand the Distrigas Everett Terminal storage or vaporization capacity to the levels required to meet the Neptune LNG project objectives.

Table 2
Existing and Proposed LNG Terminals Considered as System Alternatives

Name	Owner	Location	Peak Vaporization Capacity	LNG Storage	Approval Status/ In Service Date
Everett Marine Terminal	Distrigas of Mass./ Suez LNG NA, L.L.C.	Everett, MA	1.0 Bcfd	155,000 m3	Operating
Northeast Gateway	Excelerate Energy, LLC	Massachusetts Bay, MA	0.8 Bcfd	none	In permitting/ Mid-2007
Weaver's Cove LNG	Weavers Cove Energy, LLC and Hess LNG	Fall River, MA	0.8 Bcfd	200,000 m3	Approved/ 2008
Quoddy Bay LNG	Quoddy Bay L.L.C.	Pleasant Point, ME	0.5 Bcfd	none	Pre-permitting/ 2009
Downeast LNG	Kestrel Energy Partners	Robbinston, ME	0.5 Bcfd	160,000 m3	Pre-permitting/ 2010
Broadwater Energy LNG	Shell US Gas and Power LLC and TCPL USA LNG Inc.	Long Island Sound, NY	1.0 Bcfd	350,000 m3	In permitting/ 2010
Rabaska LNG	Enbridge, Gaz Metro and Gaz de France	Lévis, Québec	0.5	TBD	In permitting/ 2009
Gros Cacouna Energy LNG	TransCanada Corp. and Petro-Canada	Riviére du Loup, Québec	0.5 Bcfd	320,000 m3	In permitting/ Late 2009
Canaport LNG	Irving Oil and Repsol YPF	St. John, New Brunswick	1.0 Bcfd	420,000 m3	Approved/ 2008
Keltic LNG	Keltic Petrochemicals, Inc.	Goldsboro, Nova Scotia	0.5 Bcfd	TBD	In permitting/ 2007
Bear Head LNG	Anadarko Petroleum	Point Tupper, Nova Scotia	1.0 Bcfd	360,000 m3	Approved/ Late 2008

4.2.2 Proposed New England LNG Terminals

To meet future demand for natural gas, several new LNG facilities have been proposed in the New England region (Figure 3). These include several projects that have since been rejected and/or abandoned, including Somerset LNG (Brayton Point, Massachusetts), Fairwinds LNG (Harpswell, Maine), and several others at sites along the Maine coast. These projects were not evaluated as potential system alternatives. The following sections describe proposed terminal projects in New England that are in various stages of the permitting process and evaluate the ability of these projects to meet the proposed project need and the comparative environmental impacts.

Weavers Cove Energy (Fall River, Massachusetts)

Weaver's Cove Energy received FERC approval in July 2005 to construct and operate a new LNG terminal on a 73-acre former oil terminal site on the Taunton River in Fall River, Massachusetts. The terminal facilities would include a single docking berth, a 200,000 m^3 full containment storage tank, and vaporization equipment for a normal sendout rate of 400 mmcfd and peak rate of 800 mmcfd, and four truck loading stations. The development of the Weaver's Cove LNG Project would require dredging of about 2.6 million cubic yards (yd^3) from the Mount Hope Bay/Taunton River federal navigation channel and turning basin. The project would also require two pipelines totaling 6.1 miles long that would cross several streams, including the Taunton River.

This terminal could satisfy most of the Neptune LNG project's objectives; however, the project would potentially result in much more substantial environmental and socioeconomic impacts, including the impacts of dredging, which would disturb 191 acres of river and bay bed, and disposal of contaminated sediments, than would the Neptune project. In addition, although it has received FERC authorization, Weaver's Cove Energy must secure a number of other federal, state, and local permits and approvals before the project can proceed, including a dredge and fill permit from the U.S. Army Corps of Engineers, concurrences from the states of Massachusetts and Rhode Island on the project's consistency with the states' respective Coastal Zone Management plans, and concurrence from the U.S. Department of Interior that the project would not have a substantial adverse effect on the Taunton River's potential designation as a Wild and Scenic River. Most of the federal and state agencies with a permitting or advisory role in the project have significant concerns about the project-related dredging impacts on water quality and fisheries habitat in Narragansett Bay, Mount Hope Bay, and the Taunton River. Furthermore, the project has substantial unresolved issues pertaining to the uncertain viability of either of its dredged spoil disposal alternatives (onsite or offshore), the necessary (but currently prohibited) demolition and reconfiguration of the Brightman Street Bridge, and a request by the U.S. Navy for FERC to reconsider its approval of the Weaver's Cove project, because of concern that transits of LNG tankers through Narragansett Bay will disrupt the Navy's testing of underwater vehicles.

Given its multitude of serious environmental shortcomings in comparison to the proposed Neptune project, the Weaver's Cove LNG project is not evaluated further.

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SOURCE: Ecology and Environment, Inc, 2005.

Figure 3 **Existing and Proposed LNG Terminals in the Northeastern United States and Canada**

KeySpan (Providence, Rhode Island)

In 2003, KeySpan announced a plan to convert an existing LNG peak shaving facility in Providence, Rhode Island, into an LNG import terminal (Figure 3). The site currently has a 95,390 m^3 LNG storage tank and truck loading and unloading facilities. The KeySpan LNG Project would involve the installation of a new ship berth, unloading arms, and an indirect-fired vaporizer system adjacent to the Providence River to allow marine ship deliveries of LNG. Additional modifications to the existing facility would include a new indirect fired vaporizer system that would increase the plant's vaporization capacity from 150 mmcfd to 525 mmcfd. In July 2005, FERC denied the license application on the basis that the facility could not meet current construction and safety standards. In early August, KeySpan requested a rehearing on FERC's order. Unless FERC reverses its order and approves a license for this project, this proposed terminal would not be a viable alternative to the proposed project. However, given that the project could be modified to meet current federal regulations, the project was considered and evaluated as a reasonable alternative to the proposed Neptune LNG project.

Because the project would involve construction of limited facilities at an existing industrial site and would not require dredging, FERC's final environmental impact statement found that the KeySpan LNG project would have minimal adverse environmental impacts. Impacts to water quality would be localized and temporary, lasting only for the duration of construction. Impacts to essential fish habitat would not be noticeable or significant. Construction and operation of the facilities would not likely result in adverse effects on wetlands, forest, or wildlife. Although the project-related increase in ship traffic could potentially affect federally listed marine mammals or sea turtles due to vessel strikes, KeySpan committed to complying with applicable speed restrictions for LNG ships if implemented by NOAA Fisheries as part of a strategy being developed to reduce ship strikes of North Atlantic right whales. Commercial and recreational ships and boats and fishermen would be affected by the safety and security zones that would be imposed by the U.S. Coast Guard when an LNG vessel is in transit or berthed at the terminal, primarily in the form of temporary delays as the vessel transits the Providence River, but this impact is not considered significant. The final EIS found that the operational air emissions from the stationary facilities and LNG vessels would not cause or significantly contribute to a violation of an ambient air quality standard. Potential impacts to socioeconomic conditions, historic resources, and noise were found not to be significant.

Based on FERC's conclusions regarding the potential environmental impacts of the proposed project, construction and operation of the KeySpan LNG import terminal would likely result in overall level of environmental impact that would be considered comparable to or less than that of the Neptune LNG project. However, the increased output of the converted facility would be 375 mmcfd, which is slightly less than the baseload capacity of the proposed Neptune LNG facility. Therefore, the proposed KeySpan LNG terminal could be considered a viable alternative means of partially meeting the Neptune LNG Project objectives, if FERC reverses its ruling on the KeySpan application upon rehearing.

Northeast Gateway

The proposed Northeast Gateway (NEG) project would be located in federal waters approximately 10 miles southeast of Gloucester, Massachusetts (Figure 3). The project would utilize the existing HubLine^{SM} pipeline system to deliver anticipated baseload and peak capacities of natural gas of 400 mmcfd and 800 mmcfd, respectively, which would require two vessels operating at full capacity. Two submerged turret buoys with connecting pipelines would transfer natural gas from the LNG carrier vessel to the HubLine^{SM} system. Additional physical structures as well as modifications to existing pipeline facilities would be needed to regulate gas entering the system from the NEG project.

Anticipated navigational safety zones of 1,640 feet are expected to be implemented around each vessel mooring buoy. Additionally, a one-mile diameter "No Anchor Area" and a 2.2-mile diameter "Area To Be Avoided" is expected around each docking buoy.

Northeast Gateway is of the same concept design as that proposed for the Neptune LNG terminal and both projects locations are in the same general area of Massachusetts Bay and have similar proposed routes for the send-out pipeline. Therefore, many of the environmental impacts that are likely to occur are similar for the two projects. However, there are some significant differences in the magnitude of some of the environmental impacts, due to differences between the projects in the specific design of certain project components. The principal differences in design and their associated impacts are:

- Northeast Gateway vessels would use 54 million gallons per day of seawater for ballast and shipboard operations, whereas the Neptune LNG vessels are designed to use 7 million gallons per day. Thus, entrainment and associated mortality of plankton and fish eggs and larvae resulting from seawater use would be 7.5 times greater for the Northeast Gateway project than for the Neptune LNG project.
- At a sendout capacity of 400 mmcfd, Northeast Gateway's project is expected to emit close to 365 tons per year of NOx in connection with regasification operations, whereas Neptune LNG's estimated NOx emissions rate is 62 tons per year. Both the Neptune LNG and Northeast Gateway deepwater ports would be new major stationary sources of NOx emissions and, therefore, both are subject to EPA's Lowest Achievable Emissions Rate (LAER) requirements. While Neptune LNG has designed both its proposed deepwater port facility and the facility's operations specifically to meet these requirements, Northeast Gateway, whose regasification vessels were designed for operation in the Gulf of Mexico within an ozone attainment area, apparently has taken the position that its facility and operations would not be subject to them.
- The proposed pipeline route for Northeast Gateway Lateral is 16.4 miles, which is 5.6 miles longer than the pipeline proposed by Neptune. Consequently, pipeline installation for the Northeast Gateway would result in a longer construction period and a 50 percent greater area of marine habitat disturbance compared to that of the Neptune LNG pipeline.
- Northeast Gateway's terminal is sited within approximately one mile of the Boston Harbor Shipping Lane, whereas Neptune's terminal is located approximately 5 miles north of the shipping lanes. The Neptune LNG terminal location offers a larger safety buffer between the terminal and shipping traffic than does the Northeast Gateway's site, with lesser risk of collision from wayward vessels from the established shipping lane.

- Furthermore, the Northeast Gateway terminal site is located within an area proposed for relocating the Boston Harbor shipping lane, a proposal intended to reduce the potential of vessels striking marine mammals. If the Northeast Gateway project was approved, it would foreclose the option of shifting the shipping lanes in order to reduce marine mammal injuries and deaths.

The Northeast Gateway project does not offer environmental advantages to the proposed project, but potentially poses substantially greater environmental impacts than the Neptune project. Therefore, the Northeast Gateway project is not evaluated further.

Broadwater

The proposed Broadwater project is located within Long Island Sound approximately 10 miles off the coasts of New York and Connecticut (Figure 3). The offshore terminal would be capable of delivering 1 Bcfd into the existing Iroquois pipeline system. The Broadwater project would employ the use of a floating storage and regasification unit (FSRU, see Section 6), which is a floating storage facility that can store approximately 350,000 m^3 of LNG. The FSRU will also be able to regasify the LNG, act as a docking facility to LNG carriers, and transport the natural gas into a pipeline system. A 25-mile long pipeline would be constructed to link the Broadwater FRSU to the Iroquois pipeline system.

The Broadwater project will avoid sensitive onshore coastal habitats such as beaches and salt marsh by avoiding the need for onshore construction. Dense population centers are also avoided from construction and operation due the offshore location of the project. Conversely, most anticipated environmental issues are associated with the marine community, including aesthetics, water quality, marine biological communities, and socioeconomics associated with fishing and lobstering. The nature of these impacts to the marine environment is very similar to that posed by the Neptune LNG project, although the magnitude of the impacts may differ.

Construction of the submarine pipeline and installation of the FSRU anchoring and mooring system would result in disturbances to the seafloor. The seafloor disturbances could cover epibenthos, smother sessile invertebrates, and affect eggs and juvenile bottom-dwelling finfish. The impacts incurred will depend on the specific differences in the nature of the sediments and habitats traversed and period of construction, but given that the pipeline is more than twice the length of the proposed Neptune LNG send-out pipeline (25 miles vs.10.9 miles), the levels of impact to water quality, benthic habitats, and fisheries due to pipeline construction are expected to be greater than that due to construction of the Neptune LNG pipeline.

The Broadwater LNG terminal would generate air emissions due to the FSRU's use of submerged combustion vaporizers, which burn natural gas to warm and vaporize the LNG, as well as LNG carrier operations. Because the terminal would be located within a nonattainment area for ozone, the project may be subject to Lowest Achievable Emission Rate (LAER) control technologies and possibly have to comply with Prevention of Significant Deterioration (PSD) regulations. Furthermore, emissions that do not fall under the air permit would have to conform to the state implementation plan. Due to the Broadwater terminal having a greater proposed throughput than the Neptune LNG facility (1.0 vs. 0.4 Bcfd) and having two vessel sources during operations (the FSRU and unloading LNG carrier) compared to the single SRV for the Neptune LNG project, the Broadwater LNG facility would be expected to have greater air emissions, and potentially greater impacts on local air quality than those from the Neptune project.

The USCG is expected to establish restrictive zones around the FSRU which will inhibit recreational boating and fishing operations from occurring within the area. In addition, incoming and outgoing LNG carrier vessels may also temporarily have restrictive zones, possibly creating minor delays in other marine traffic in Long Island Sound.

The FSRU will rise approximately 75 to 100 feet above the water and include operational lighting as necessary. This could potentially impact the offshore viewshed, but due to the distance offshore (>9 miles) the FSRU and the LNG carrier vessel would resemble a conventional ship. Only necessary lighting will be used to operate the FSRU and LNG carrier in a safe manner.

FERC has concerns about the proposed ability of Iroquois pipeline system to accommodate 1,000 mmcfd. Currently, FERC understands that the capacity of the Iroquois system is 500 mmcfd. Given this information, the Iroquois system may need to be upgraded to transport necessary natural gas demands to affected markets. Consequently, there may be additional environmental impacts associated with upgrade projects, such as added compression, if any are needed.

The Broadwater project is designed to supply natural gas to the metropolitan New York City area and therefore, would not directly serve the target market area. However, because it would provide an additional supply of gas to the Iroquois system to serve demand in the nearby New York market, the project is expected to result in greater available supplies for the Connecticut and other upstream customers. However, this relief on upstream supplies would not necessarily result in reliable delivery of gas to upstream customers within the primary Massachusetts market area, especially during peak demand periods. Thus, although the Broadwater project would result in generally similar environmental impacts as would the Neptune LNG project, the Broadwater facility would not be able to meet some of the primary objectives of the Neptune LNG project. Therefore, Broadwater was not further evaluated as an alternative.

Quoddy Bay (Pleasant Point, Maine)

Over the last 2 years, several companies have evaluated or are currently evaluating construction and operation of LNG import terminals along the coast of Maine. Proposals for facilities in Harpswell, Sears Island, Cousins Island, Hope Island, and Corea appear to have been abandoned, because the project developers could not obtain control of property suitable for an LNG import terminal. Although in the early stages of development, Quoddy Bay, L.L.C. and Downeast LNG, appear to be the only developers moving forward with plans to construct and operate LNG import terminals in Maine.

Quoddy Bay's proposal includes developing an LNG import terminal in cooperation with the Passamaquoddy Indian Reservation at Split Rock in Pleasant Point, Maine (Figure 3). The tribe and the developer signed a land lease agreement in May 2005, and the Bureau of Indian Affairs approved the land lease in July 2005. The proposed Pleasant Point Energy Facility, which would be located on a 15-acre site, would not have any LNG storage capacity, but would regasify the LNG as it is pumped off the ship (LNG Express 2005).

The Pleasant Point Energy Facility would interconnect with the Maritimes & Northeast pipeline system via a new 36- to 42-mile-long sendout pipeline. The new LNG import terminal would have a sendout capacity of 500 mmcfd (average) to 1,000 mmcfd (maximum) (FERC 2005).

The proposed Quoddy Bay project would satisfy most of Neptune's commercial objectives, but whether the project would have equal or less environmental impacts is not certain, as no impact assessment has been conducted for the project and/or made public. Therefore, the project was further evaluated.

The Quoddy Bay project would have a gas send-out rate similar to that of the proposed Neptune LNG project, however, the terminal site is located far from Neptune's intended market in Massachusetts. Assuming that the LNG supply and regasification could be secured for the same price as for the Neptune project, natural gas supplied to the Massachusetts region from the Quoddy Bay terminal would incur a higher transportation cost and therefore, would not be as competitively priced. Although the Bearhead LNG terminal may be considered as a reasonable system alternative to the proposed Neptune LNG project, Neptune LNG believes that the cost of transportation would be approximately four times as high as that which could be provided by Neptune, which would result in higher gas prices for the consumers in central New England. Also, given the early stage of the project's planning and permitting, it is unlikely that the facility could be in operation by the target date of 2010. Furthermore, the project's proposed send-out pipeline could cause significant environmental impacts given its greater length (3 to 4 times as long as Neptune's pipeline) and the pristine region that it would traverse.

Downeast LNG (Mill Cove, Maine)

A new LNG import terminal is proposed for an 80-acre site at Mill Cove in Robbinston, Maine (Figure 3), according to an announcement by representatives of Downeast LNG in July 2005. The site is located near the confluence of the St. Croix River with Passamaquoddy Bay, on the Canadian border. The facility would have a single 160,000 m^3 LNG storage tank and a send-out capacity of 500 mmcfd, and would receive about one ship per week. Downeast LNG conducted a regional site selection study that considered 27 sites for LNG import terminals between Connecticut and Maine, including nearly all sites that have been proposed or evaluated by other proponents (Downeast LNG 2005). No application has been filed with FERC, but the developers estimate that the permitting will take 1.5 to 2 years.

The Downeast facility is in the early planning and design stages and, therefore, project design details needed to assess environmental impacts are not available. However, it is clear that the terminal would require a 3,500- or 4,350-foot pier to be constructed in Mill Cove and that a 20- to 30-mile-long pipeline would be required. Of three alternative pipeline routes shown in Downeast LNG's planning study, all would traverse Moosehorn National Wildlife Refuge (Downeast LNG 2005). Like the Quoddy Bay terminal, this may be considered a reasonable system alternative, but because of its distant location from the Massachusetts market and early stages of planning, it could only partially satisfy the project's commercial objectives and would incur a higher transportation cost.

4.2.3 Proposed Canadian LNG Terminals

Natural gas could be supplied to New England from new sources of LNG in eastern Canada. Five LNG import terminals are proposed in eastern Canada, including two that have been approved. For any of these potential new sources of gas to reach the New England market, additional capacity would have to be added to the Maritimes & Northeast Pipeline. The Maritimes & Northeast system can deliver 350 to 400 mmcfd of natural gas to markets in New England, based on current throughput. However, as discussed in Section 4.1, Maritimes has signed new precedent agreements to transport another 1.5 Bcfd and has begun work on a future expansion of its system to meet this additional capacity (Maritimes & Northeast 2005).

Bearhead LNG

Anadarko Petroleum began preparations for construction on its proposed Bear Head LNG import terminal, located near Point Tupper, Nova Scotia, in late 2004, and expects the terminal to be in-service by November 2007; however, construction of major components had not begun as of August 2005. The proposed terminal will include two 180,000 m^3 storage tanks, with space available for adding a third tank. A jetty will be constructed to allow unloading of 70 to 135 LNG ships per year. Because the jetty will be constructed out to a depth of 59 feet, significant dredging to allow access for LNG ships will not be necessary. The Bear Head facility will be able to initially vaporize and send out about 1.0 Bcfd of natural gas to the Maritimes & Northeast system with a potential future expansion up to 1.5 Bcfd. The Bear Head LNG terminal is being constructed on a 160-acre tract designated for heavy industrial development. An analysis of the environmental impacts associated with construction and operation of this facility was prepared by Access Northeast Energy, Inc., prior to the project's acquisition by Anadarko in August 2004. Given that Anadarko recently signed an agreement with Maritimes & Northeast to transport 750 mmcfd of gas from its Bearhead LNG terminal and that the terminal should be in service by late 2007, this facility could serve at least a portion of the need for additional gas in New England. However, Neptune LNG believes that the cost of transportation would be substantially higher than that which could be provided by Neptune LNG, resulting in higher gas prices for New England customers.

Canaport LNG

Canaport LNG, a company formed by partners, Repsol YPF and Irving Oil, will build, own, and operate an LNG import terminal in St. John, New Brunswick, with a delivery capacity of 1.0 Bcfd of natural gas. The proposed LNG terminal will include three 160,000 m^3 single containment storage tanks. The project has been licensed and the terminal is expected to be operational during 2008. Repsol YPF will provide all of the LNG and will hold the capacity of the terminal. Irving Oil will market the gas in Atlantic Canada and Repsol YPF will market gas elsewhere in Canada and the United States. The front-end engineering design for the terminal is nearly completed, and proposals for engineering, procurement and construction (EPC) contracts were solicited in July 2005. Under agreements signed in July 2005 by Repsol YPF, the Canaport LNG terminal will transport natural gas into the United States on the Maritimes & Northeast Pipeline (Maritimes & Northeast), which recently announced a planned expansion. Similar to Neptune LNG's conclusion in considering the Bearhead LNG terminal, the Canaport LNG project may be considered as a reasonable system alternative to the proposed Neptune LNG project. However, Neptune LNG believes that the cost of transportation would be substantially higher than that which could be provided by Neptune LNG, resulting in higher gas prices for New England customers.

Keltic LNG

Keltic Petrochemicals, Inc., is proposing to construct an LNG terminal at Goldsboro, Nova Scotia, as part of an integrated project consisting of a world-class petrochemical plant, an LNG receiving terminal and regasification facility, demethanizing units, power and steam co-generation up to 200 MW, and related utility systems. The LNG terminal, with a throughput of 0.5 Bcfd of natural gas with a future expansion to 1.9 Bcfd, will provide feedstock to the petrochemical plant and natural gas to the Maritimes & Northeast system, which originates in Goldsboro. The amount of natural gas for delivery into the Maritimes & Northeast system and ultimately into the Massachusetts market is unknown. The project has been in development since 2000 and is now in the environmental permitting stage. Few other details about this project are currently available; however, assuming that a significant portion of the initial 0.5 Bcfd throughput would be used as feedstock for the petrochemical plant, the project would not be able to supply a sufficient volume of gas to central New England to substitute for the Neptune LNG project, until such time that the throughput is expanded, which would be too late to meet the proposed delivery date. Therefore, the Keltic LNG terminal was not considered a viable alternative to the proposed project.

Gros Cacouna Energy LNG

TransCanada Corporation and Petro-Canada are proposing the Gros Cacouna LNG terminal at an existing deepwater port on the St. Lawrence River, near Riviére du Loup, Québec. An environmental impact study for the project was filed with the Canadian Environmental Assessment Agency in June 2005. The terminal is designed with a storage capacity of 320,000 m^3 and a throughput of 0.5 Bcfd with the intent to supply natural gas markets within Québec. The interconnection of the terminal with the existing pipeline network is currently uncertain, but the most likely connection will be a terminus of the existing TransQuébec and Maritimes (TQM) pipeline system at St. Nicholas, near Québec City (Cacouna Energy 2005). Although an interconnection with the Maritimes & Northeast system in New Brunswick is possible, it is likely that such an interconnection would be for the purpose of transporting natural gas from New Brunswick into Québec. Thus, this proposed terminal, if approved and constructed, is unlikely to be a future source of natural gas for the New England market. Furthermore, this project was designed to serve the eastern Canadian markets and Neptune LNG believes that it is not commercially viable for serving the New England market. Therefore, the potential environmental effects of this project were not evaluated.

Rabaska LNG

A 0.5 Bcfd capacity LNG import terminal with a storage capacity of 320,000 cubic meters is proposed at Ville Guay, Québec, on the St. Lawrence River, by a partnership of Gaz Metro, Enbridge, and Gaz de France. The terminal, whose approval is pending at Canadian and provincial agencies, is anticipated to be in service in first quarter of 2009. The Rabaska LNG project is designed to supply natural gas to Quebec and Ontario markets and is not expected to tie into pipeline systems serving the New England area, nor would the project be able to supply natural gas to the New England market at a competitive price. Thus, this project is not considered as a viable alternative system and was not evaluated further.

4.2.4 Proposed Gulf Coast LNG Terminals

As stated in the Weaver's Cove FEIS (FERC 2005), FERC believes that the proposed Gulf coast LNG terminals that have recently been approved by FERC and the MARAD are too far from the New England region to competitively supply the volumes of natural gas that can be provided by an LNG import terminal in the New England region. Furthermore, such a scenario would require substantial expansion of the trunkline pipelines serving the northeast, which would have significant environmental impacts.

5 LNG Terminal Alternatives

Prior to identifying potential LNG terminal alternatives for further consideration and evaluation, Neptune established four basic commercial criteria that must be met for the project to be commercially and economically feasible:

- Provide a new LNG import capacity to deliver natural gas to the central New England market (Massachusetts and adjoining metropolitan areas) at competitive prices;
- High reliability for continuous throughput during winter (period of peak demand), when weather conditions are typically adverse;
- Economically viable at low to medium send-out rates, and ability to vaporize at varying send-out rates to match the seasonality of the market demand; and
- Ability to be in service by 2010 (relatively rapid project development schedule).

If an LNG terminal alternative could not meet these commercial criteria, then it was not considered any further in the alternatives analysis process.

5.1 Onshore Terminal Alternatives

Neptune considered options for siting an LNG terminal at an onshore location in the New England region. The minimum criteria used to identify suitable sites for an onshore LNG terminal were proximity to market and availability of a suitable site within an existing deepwater port. Neptune specifically desired a port location that is located in the central New England region (Rhode Island to New Hampshire), would not require dredging, would not require LNG vessel transits beneath bridges, and contained a tract of available land sufficiently large to site LNG storage tanks in accordance with federal siting criteria. Based on a desktop analysis using these criteria, Neptune determined that there were no sites that met the company's established selection criteria. Therefore, Neptune concluded that an onshore terminal is not a feasible or practical alternative.

5.2 Offshore Terminal (Deepwater Port) Alternatives

Neptune considered deepwater port concept designs or technologies in concert with screening of suitable locations within coastal waters of the region. There are four basic deepwater port concept designs that have been developed by industry and are currently considered commercially available for use as an offshore LNG import terminal: (1) gravity-based structure (GBS), (2) platform-based unit, (3) floating storage and regasification unit (FSRU), and (4) shuttle and regasification vessel (SRV). All four terminal concepts include use of subsea natural gas pipelines to transport regasified LNG from the port to the existing onshore pipeline system.

Although there is some adaptability of design in each of the four concepts, there are inherent features of each that are most compatible with certain environmental conditions and that lend themselves to specific business models. Neptune originally considered all four technologies and their suitability or adaptability for use in the region and their compatibility with Neptune's business model. A site was not eliminated solely because a single pre-selected type of terminal design was not suitable for conditions present at that site. Likewise, a design was not eliminated prior to considering whether that design would be the most suitable for the most preferred site.

6 Offshore Terminal Concept Design Alternatives

The following are descriptions of each port concept design alternative.

Gravity-Based Structure Design (GBS)

GBS consists of a large concrete structure that contains integrated storage tanks and sits on the seafloor. The GBS would be built at an onshore graving dock using well-proven construction methods and then floated, towed to the site, and installed on the seabed. This port concept has been commonly and successfully used in the offshore oil and gas industry for decades. LNG could be offloaded from conventional LNG ships, placed in storage tanks, and then vaporized for delivery as natural gas to the onshore market via an undersea pipeline. Given the expense associated with constructing and operating a GBS, it appears that these facilities are only economically feasible for projects with relatively large LNG storage (e.g., 327,000 to 432,000 yd^3 [250,000 to 330,000 m^3] and natural gas send-out volumes (e.g., 800 to 2,000 mmcfd [22.7 to 56.6 million m^3 per day]). ChevronTexaco has been approved to build a facility of this design in the Gulf of Mexico.

Platform-Based Unit

The platform-based unit design would consist of constructing or converting an existing offshore platform with docking facilities and LNG unloading arms, storage, and vaporization equipment. Because these platforms are or would be anchored using fixed-tower structures, they could be located in a broader range of water depths than a GBS. Similar to the GBS design, LNG could be unloaded from a conventional LNG ship, vaporized at the platform, and sent as natural gas to the onshore market via an undersea pipeline. Depending on the specific design, the use of an offshore platform may not include significant offshore storage of LNG. Crystal Energy, L.L.C. has proposed using an existing platform as a terminal to import LNG into California and the Main Pass Energy Hub Project would develop a deepwater LNG terminal on a series of existing connected platforms about 16 miles off the coast of southeast Louisiana.

Floating Storage and Regasification Unit (FSRU)

An FSRU is a purpose-built floating ship-like vessel without a propulsion system, based on LNG carrier technology and components of floating production, storage and offloading (FPSO) systems, which are widely used in the offshore oil and gas production industry. LNG storage tanks with at least twice the capacity of a typical LNG carrier would be integrated within the hull, and regasification and unloading equipment would be located on deck. These units would be permanently anchored offshore of the proposed market area where conventional LNG ships could dock next to and unload LNG to the FSRU and connected to an external turret, which would allow high-pressure gas to be sent out through a riser to the subsea pipeline. While the FSRU could be spread moored (i.e., on a constant heading), a weathervaning turret-mooring would most likely be used, unless a very sheltered location was available. Depending on the vaporizers and the size of the send-out pipeline, FSRU's could have a natural gas send-out capacity ranging from 700 to 1,500 mmcfd (19.8 and 42.5 million m^3 per day). Companies are currently proposing to use this design to import natural gas to markets in California (Cabrillo Port) and New York (Broadwater Energy).

Shuttle and Regasification Vessel (SRV)

This concept is significantly different from the other three technologies, because it does not involve any permanent storage or regasification facility. Instead, a fleet of specially designed LNG carriers, each containing onboard LNG vaporization equipment, would be built. The vessels would be moored at the offshore terminal site with a permanently installed single-point or submerged turret unloading buoy. After mooring, LNG would be vaporized onboard the vessel and discharged via the unloading buoy and a flexible riser into the subsea pipeline. Because the LNG would be vaporized with the SRV's onboard equipment, no permanent fixed or floating storage or vaporization facilities would be required. Unlike standard LNG carriers, which offload LNG in 18 hours or less, SRVs offload natural gas (i.e., regasified LNG) and inject it into a subsea natural gas pipeline at standard pipeline pressures. As a result, this process can take six days or more to discharge a full cargo of LNG, and continuous off-loading operations are essential to minimize fluctuations in the throughput of natural gas. In March 2005, Excelerate Energy's Gulf Gateway Project began delivering natural gas using this approach.

6.1 Evaluation of LNG Terminal Concept Design Alternatives

The LNG port concept alternatives were evaluated based on environmental factors, technical considerations, and commercial objectives.

Environmental Effects

The installation of a GBS would generally result in a much greater loss of benthic and fish habitat than would the other concept designs (≥ 10 acres). The other port designs have a relatively small bottom footprint and, therefore, would potentially result in significantly less of an effect on fish and marine communities. Because of the significant material needs, the GBS option is generally only economically viable when located in water depths less than 85 feet. A GBS design also can involve significant coastal impacts (e.g., wetland loss, dredging) because it requires construction of a graving dock and sufficient nearshore water depths for floating the GBS to deeper water. Additionally, because of its maximum depth limitations, use of a GBS would generally prevent the ability to site the port to avoid sensitive shallow water habitats and fisheries. It also could result in the facility being sited in nearshore areas where the majority of recreational boating and fishing activity takes place and where it creates potential safety and aesthetic concerns. Furthermore, GBS, as well as platform-based facilities, are permanent fixed structures that stand taller than the floating designs, resulting in greater visual effects or being visible further from shore.

On the other hand, GBS and platform-based units would each serve as artificial reefs, providing a significant amount of hard substrate for the development of new encrusting and fouling communities. As has been demonstrated by other permanent offshore oil and gas structures, such facilities have a potential to support significant, diverse fish and shellfish communities.

Water Depth

Due to the requirements for an appropriate water depth for safe navigation of the LNG vessel and considerations of their construction cost, GBS ports are generally limited to water depths between 45 and 85 feet (13.7 and 25.9 meters). Other types of stationary structures, such as platform-based units, may be located in deeper water. FSRUs and SRVs require a permanently installed anchoring system and sufficient water depth (generally greater than 200 feet) to accommodate mooring lines and a flexible riser connection between the unit and the subsea pipeline.

Substrate

GBS structures must be located in areas where the seafloor is relatively level, lacking in geologic hazards, and with satisfactory substrate characteristics to support the structure's foundation and weight. Platform-based units also require avoiding areas with geologic hazards. The FSRU and SRV concept designs have more flexibility on seafloor conditions, because alternative anchoring methods are available to accommodate different types of substrate.

Reliability

Platform-based units are normally designed for intermittent supply of natural gas and present more operating limitations than GBS structures or floating systems under severe weather conditions. The FSRU would remain on location for longer periods of time (10 to 20 years or more) and would not leave the site for hurricanes or other severe weather such as northeasters. On the other hand, since an LNG carrier would be equipped for traditional side-by-side unloading, diversion of LNG carriers to other ports also would be possible under extreme weather conditions.

The FSRU option would result in greater downtime due to prevailing weather conditions at the planned deepwater port. The side-by-side unloading from LNG carriers should be limited to 2.0-meter significant wave heights for approximately 24 hours for each scheduled offloading from the LNG transport carriers to the FSRU. On the other hand, an SRV can be moored to the specially designed unloading buoys in 3.5-meter significant wave heights. Table 3 compares the approximate percentages of time that wave heights greater than 2.0-meter and 3.5-meter occur in the project area.

As noted in Table 4, the FSRU option is more sensitive to weather conditions, with increased risks for interruption of the delivery of natural gas to New England. The sensitivity is based on weather effects on mooring and unloading of LNG carriers, but also on the FSRU's processing operations due to LNG sloshing in tanks and other motion-related effects on fluid mechanics. This risk is further aggravated by the fact that the greatest weather downtime would occur between January and April, which is the period of greatest demand for natural gas.

Table 3
Percentage of Occurrence of Wave Heights

Wave Heights (meters)	January – April	May – August	September – December	Annual Average
> 3.5	1%	0%	1%	1%
< 3.5	99%	100%	99%	99%
> 2	13%	2%	9%	8%
< 2	87%	98%	91%	92%

Table 4
Equivalent Days of Downtime

Operations	Significant Wave Heights	January – April	May – August	September – December	Annual Average
SRV Weather Down Time	> 3.5m	2	0	1	3
SRV Weather Up Time	< 3.5m	120	122	120	362
FSRU Weather Down Time	> 2m	15	2	11	28
FSRU Weather Up Time	< 2m	106	120	111	337

Key:
FSRU = Floating, storage, and regasification unit.
SRV = Shuttal regasification vessel.

Cost

An FSRU requires equipment for tying an LNG carrier alongside it, as well as the unloading arms and other ancillary equipment to unload the LNG from the carrier. Only one vaporization system would likely be required in a FSRU, but for redundancy purposes, this system would likely have three vaporizers. Conventional LNG carriers would be used for transporting/delivering LNG to the FSRU. Since a FSRU could be towed to a location, propulsion equipment may not be included. Although an SRV and unloading buoy system may be more costly than a conventional LNG carrier due to the required vaporization and buoy mating systems, the total capital cost of an FSRU system that would meet this project's supply conditions would likely be larger, mainly due to the increased costs to accommodate floating storage needs.

Table 5 compares the relative estimated capital expenditures for an FSRU and two LNG carriers for transport of the LNG to the planned deepwater port, versus the SRV and unloading buoy system with three dedicated SRVs equipped with vaporization systems and outfitted to moor the SRV to one of two unloading buoys.

Table 5
Estimated Capital Cost Comparison

Description	Quantity	FSRU ($ Millions)	Quantity	SRV ($ Millions)
180,000-cubic meter LNG Storage Vessel	1	400	0	0
140,000-cubic meter LNG Carriers	2	400	3	600
Vaporization System	1	30	3	75
Trunk and Mating Cone for Unloading Buoys	0	0	3	30
Unloading Buoys	1	40	2	65
Side-by-side Mooring System	1	3	0	0
Conventional Loading Arms	3	7	0	0
Approximate Total Costs		**880**		**770**

Key:
FSRU = Floating, storage, and regasification unit.
LNG = Liquefied natural gas.
SRV = Shuttle regasifcation vessel

6.2 Selection of Preferred LNG Terminal Concept Design Alternative

The SRV was selected as the preferred deepwater port design concept alternative. The Applicant believes, as explained below, that this system presents the best combination of environmental, operational, technical, and economic advantages. An FSRU design was also considered acceptable from an environmental impact minimization standpoint, although the FSRU concept has deficiencies in its ability to meet the project's commercial and operational goals. Nonetheless, the FSRU design was carried through the site screening process to identify potential locations that might be more suitable for an FSRU than a SRV, i.e., an alternative in which an FSRU is capable of achieving lower environmental impacts than a SRV.

A platform-based unit is likely to have more frequent interruptions of gas supply due to more operational limitations during heavy weather conditions. A platform-based unit would not be able to contain sufficient LNG storage to unload the entire cargo from an LNG carrier, and thus regasification would have to be performed directly as LNG is unloaded from the moored LNG carrier. If a vessel is unable to moor alongside the fixed structure due to high winds and wave conditions, then the throughput would be interrupted. Essentially, a platform-based system has more limited operational ability to moor, connect, and unload LNG compared to an SRV during bad weather conditions. Thus, the level of reliability and continuous throughput required for the commercial viability of the project may not be achieved using the platform-based system.

Although a GBS port would have high reliability for continuous delivery of supply, it has several significant disadvantages because it must be sited in shallow waters, where it presents a source of impact to areas of high marine productivity, potential conflict with nearshore fisheries, its proximity to nearshore recreational boating and fishing areas, and a permanent visual obstruction on the horizon. These shortcomings, coupled with high capital and construction costs, make the GBS design less preferable than the SRV, which has a minimal environmental footprint, can be located far from populated areas, and relatively low installation costs. Neptune LNG determined that a GBS was not practical for the proposed project because large storage and send-out volumes are not required, and the design may lead to potentially significant impacts on shallow water marine habitats. Therefore, sites suitable for GBS port designs were not considered in the analysis of alternative locations.

The FSRU has nearly the same level of environmental impacts as the SRV, but has several economic, operational, and technical disadvantages in comparison to the SRV design for meeting the proposed project objectives. These include reduced offloading availability during severe weather conditions due to mooring and unloading arm operational and safety limitations. Furthermore, severe weather conditions require additional engineering design efforts to mitigate the adverse operational effects induced by cryogenic liquid sloshing in the LNG storage tanks, which could reduce the ability to meet the in-service date. The FSRU, due to its storage tanks and its purpose-built, site-specific design and associated cost, is economically suited for large send-outs and long distance shipping; thus the SRV design, which is based on a business model of low to medium send-out capacities and short to medium shipping distances, is more economically competitive than the FSRU concept. In areas within sight of shore, the FSRU would be a permanently visible structure, whereas the SRV design would only be visible when a vessel is connected to one of the buoys.

7 Offshore Terminal Location Alternatives

Neptune used a phased process to identify and evaluate potential locations for an offshore LNG import terminal considering the opportunities and constraints posed by each of the deepwater port concept designs available (as discussed in Section 6). The alternatives analysis used a screening and site selection process that began with the entire central New England coastal region and progressively narrowed the geographic range of locations where it is reasonable and feasible to site an offshore LNG facility (Figure 1). The three steps of this siting process are summarized below and the analyses are then discussed in the subsequent sections.

Phase 1 - Regional Site Screening. The first phase of the alternatives evaluation process was a screening of the central New England region, including Massachusetts Bay and adjacent areas of New Hampshire and Rhode Island to select a feasible area or areas within the region for siting a DWP LNG import facility. Feasible areas were defined based upon the following criteria: suitable proximity to market, proximity to existing gas transmission pipeline networks, required operational water depths, metocean conditions, and proximity to populated areas. The primary screening process compared the suitability of various DWP concept designs at alternative areas to eliminate those areas where it is not reasonable or feasible to locate a deepwater LNG port facility. One sub-region (Massachusetts Bay) was selected for further analysis.

Phase 2 – Suitable Area Analysis. The secondary screening process compared the advantages and disadvantages of the alternative locations within the feasible area identified in Phase 1 to eliminate those locations where it is not reasonable or feasible to locate a deepwater LNG port facility. The selection criteria used were: sufficient facility footprint area, distance to regional commercial shipping lanes, and proximity to or potential effects to marine protected areas and important marine resources. Three sectors were identified for further evaluation.

Phase 3 – Site Specific Analysis. During Phase 3, specific alternative DWP sites were identified within the preferred area identified in Phase 2. The third and final phase of the evaluation process consisted of developing specific evaluation criteria to allow for a more detailed examination and comparison of potential alternative locations within the area to narrow down to a preferred port facility location. These criteria consist of site attributes that affect the environmental, economic, safety, and operational suitability of the project.

In identifying a potential site for this project, Neptune considered USCG guidelines (Title 33 CFR Section 148.720) for siting deepwater port LNG terminals. According to these guidelines, an appropriate site for a deepwater port:

- optimizes location to prevent or minimize detrimental environmental effects;
- minimizes the space needed for safe and efficient operation;
- locates offshore components in areas with stable sea-bottom characteristics;
- locates onshore components where stable foundations can be developed;
- minimizes the potential for interference with its safe operation from existing offshore structures and activities;
- minimizes the danger posed to safe navigation by surrounding water depths and currents;
- avoids extensive dredging or removal of natural obstacles such as reefs;
- minimizes the danger to the port, its components, and tankers calling at the port from storms, earthquakes, or other natural hazards;
- maximizes the permitted use of existing work areas, facilities, and access routes;
- minimizes the environmental impact of temporary work areas, facilities, and access routes;
- maximizes the distance between the port and its components and critical habitats including commercial and sport fisheries, threatened or endangered species habitats, wetlands, floodplains, coastal resources, marine management areas, and essential fish habitats;
- minimizes the displacement of existing or potential mining, oil or gas production or transportation uses;
- takes advantage of areas already allocated for similar use, without overusing such areas;
- avoids permanent interference with natural processes or features that are important to natural currents and wave patterns; and
- avoids dredging in areas where sediments contain high levels of heavy metals, biocides, oil, or other pollutants or hazardous materials and in areas designated as wetlands or other protected coastal resource.

7.1 Phase 1 - Regional Site Screening

This analysis considered various scenarios for locating a deepwater LNG import terminal at a location that would allow access to Neptune's target market. The first phase (regional site screening) was to determine the general region within the central New England coast with the greatest potential to meet all of Neptune's environmental, regulatory, technical, operability, and commercial requirements. The selected region would also need to meet all of the DWPA requirements as specified in Title 33 CFR Section 148.720 (listed above).

One of the primary challenges of the regional site screening process is to identify sites that balance the primary environmental, economic, operational, and safety criteria, all of which are directly or indirectly related to the site's distance from shore. Sites in inshore waters tend to have the best metocean conditions and are closest to the existing pipeline network, however, inshore areas are generally more heavily used for recreational activities and commercial fishing than areas more distant from shore. Sites located further offshore also tend to lessen perceived aesthetic effects and safety concerns, but increase the overall impacts to marine resources due to construction of a longer pipeline.

The screening criteria to select the most reasonable and feasible alternative area in the central New England region to locate the deepwater port include the following:

- **Proximity to Market.** Because Massachusetts comprises half of all natural gas consumption among all the states of New England, the target market is primarily Massachusetts and adjoining metropolitan areas, Therefore, deepwater port location alternatives within the central New England region include three offshore coastal areas: Southern Massachusetts/Rhode Island, Massachusetts Bay, and Northern Massachusetts/New Hampshire.

- **Proximity to Pipeline Network.** Neptune considered the proximity of regional natural gas transmission pipeline networks, such as the Algonquin Gas Transmission system, Maritimes & Northeast Pipeline, Tennessee Gas Pipeline Company, Iroquois Gas Transmission System, and Portland Natural Gas Transmission System, that has adequate capacity to receive natural gas from the DWP and deliver to the target market. The maximum feasible distance from a DWP facility to pipeline connection locations was determined based on technical/economic constraints on pipeline construction. Areas within 20 linear miles of pipelines with adequate capacity were deemed acceptable locations within which to site a deepwater port.

- **Metocean Conditions.** A primary goal in siting any LNG terminal, either offshore or onshore, is to maximize the duration of port availability and minimize interruptions of operations. Existing long-term meteorological and ocean data from NOAA's National Data Buoy Center (NDBC) were examined from various data buoys within the region to determine frequency of occurrence of wave heights and wind velocities that could prevent or interfere with docking/mooring and unloading operations. Areas with higher frequencies of metocean conditions which exceeded acceptable operational thresholds were eliminated.

- **Suitable Water Depth.** As discussed in Section 6.2, suitable water depths vary with the type of deepwater concept design. GBS ports were eliminated from consideration, partially because of their depth limitation, which would significantly constrain feasible offshore areas.

Floating moorings typically involve a buoy with associated anchoring systems to connect a pipeline to the LNG carrier. The floating mooring and delivery systems for use on SRV offloading buoys have a recommended minimum operational depth of 200 feet, which is required to accommodate the flexible riser between the buoy and the subsea pipeline. Therefore, only locations with a minimum depth 200 feet were considered suitable for locating the proposed deepwater LNG port facility.

- **Proximity to Populated Areas.** One of the primary purposes for locating an LNG terminal offshore is to remove facilities from the proximity of populated areas. The benefits of this remoteness are two-fold: public concerns about the consequences of an accidental LNG release are diminished and the visual obstruction posed by large LNG carriers and storage tanks is significantly reduced or eliminated.

Based upon the regional site screening evaluation, the only area within the region where it is reasonable and feasible to locate a SRV or FSRU facility is within the Massachusetts Bay area. Advantages of the Massachusetts Bay coast include:

- Proximity to the major market (Massachusetts),
- Proximity to an existing offshore pipeline, which could preclude the need to construct a connecting pipeline through sensitive coastal resources, and
- Offshore areas with protected waters that provide suitable meteorological and ocean (metocean) conditions needed to assure continuity of operation and reliability of supply.

7.2 Phase 2 - Massachusetts Bay Site Screening

A secondary screening process was designed and used to identify potential areas in the Massachusetts Bay area that would satisfy the basic engineering and environmental constraints required for development of a viable project. The selection criteria regarding potentially suitable areas are listed below.

- **Proximity to HubLine^{SM} Pipeline.** The existing 30-inch HubLine^{SM} pipeline is an offshore 29.4-mile-long pipeline that connects the Maritimes and Northeast Pipeline in Beverly to the Algonquin mainline in Weymouth, Massachusetts. It is the only subsea gas transmission pipeline in the area that can provide adequate throughput capacity to the regional natural gas supply network. Because connecting to the HubLine^{SM} Pipeline would offer the unique advantage of avoiding a landfall and onshore pipeline to connect to other points on the regional pipeline network, Neptune considered the proximity to the HubLine^{SM} Pipeline as a primary criterion in identifying suitable locations for the proposed deepwater port.
- **Avoidance of Shipping Lanes.** Interference of LNG deepwater port operations with designated shipping fairways is prohibited. Therefore,

only locations within the Massachusetts Bay area located outside the boundaries of the Boston Harbor Traffic Lanes, including precaution areas, are acceptable as potential areas for the proposed deepwater LNG port facility. The evaluation also considered potential interference with traffic to and from the designated dredge disposal sites in the vicinity of the port facility, and proposed modifications or additions to the Boston Harbor Traffic Lanes. The Port Operations Committee is considering a proposal to rotate the Boston Harbor Traffic Lanes 7 degrees to the north to minimize the risk of vessel collisions with North Atlantic right whales.

Potential sites must be located in areas that are accessible by LNG carriers from commercial shipping lanes in the area. However, the port must also be located a sufficient distance from shipping traffic to minimize the risk of vessel collisions while the SRVs are stationed at the unloading buoy.

- **Avoidance of Marine Protected Areas.** Several state and federal marine sanctuaries occur in Massachusetts Bay, including the Stellwagen Bank National Marine Sanctuary, the South Essex Ocean Sanctuary, and the North Shore Ocean Sanctuary. It was assumed that construction of the deepwater port or associated gas transmission pipeline within the sanctuary would be prohibited.
- **Avoidance of Disposal Sites.** It is assumed that construction of the deepwater port terminal will not be possible within the location of the Massachusetts Bay Ocean Dredged Material Disposal Site (ODMDS), the Industrial Waste Site and the Interim Dredged Material Disposal Site).
- **Sufficient Area to Contain the Facility Footprint.** The potential sites must have sufficient surface area available for placement of the required deepwater port configuration. Under Neptune's commercial objectives for the project, two unloading buoys are required to enable continuous throughput of natural gas. Each unloading buoy and associated riser pipelines and anchor moorings require a minimum circular footprint of 5,900 feet in diameter. In addition, the unloading buoys must be separated by a distance of 2 nautical miles in order to ensure safe navigation of LNG carriers to/from one unloading buoy, while another LNG carrier is moored and regasifying LNG at the other buoy. Therefore, the port facility itself would require an approximate rectangular footprint of 1.1 miles by 3.4 miles.

Massachusetts Bay Sector Evaluation

Figure 4 shows the results of the screening process. In stepwise progression, these figures indicate acceptable locations for a DWP facility in the Massachusetts Bay area by superimposing the spatial domains of each individual criterion defined above. The intersection of all these domains defines the area that is reasonable and feasible for siting a DWP facility.

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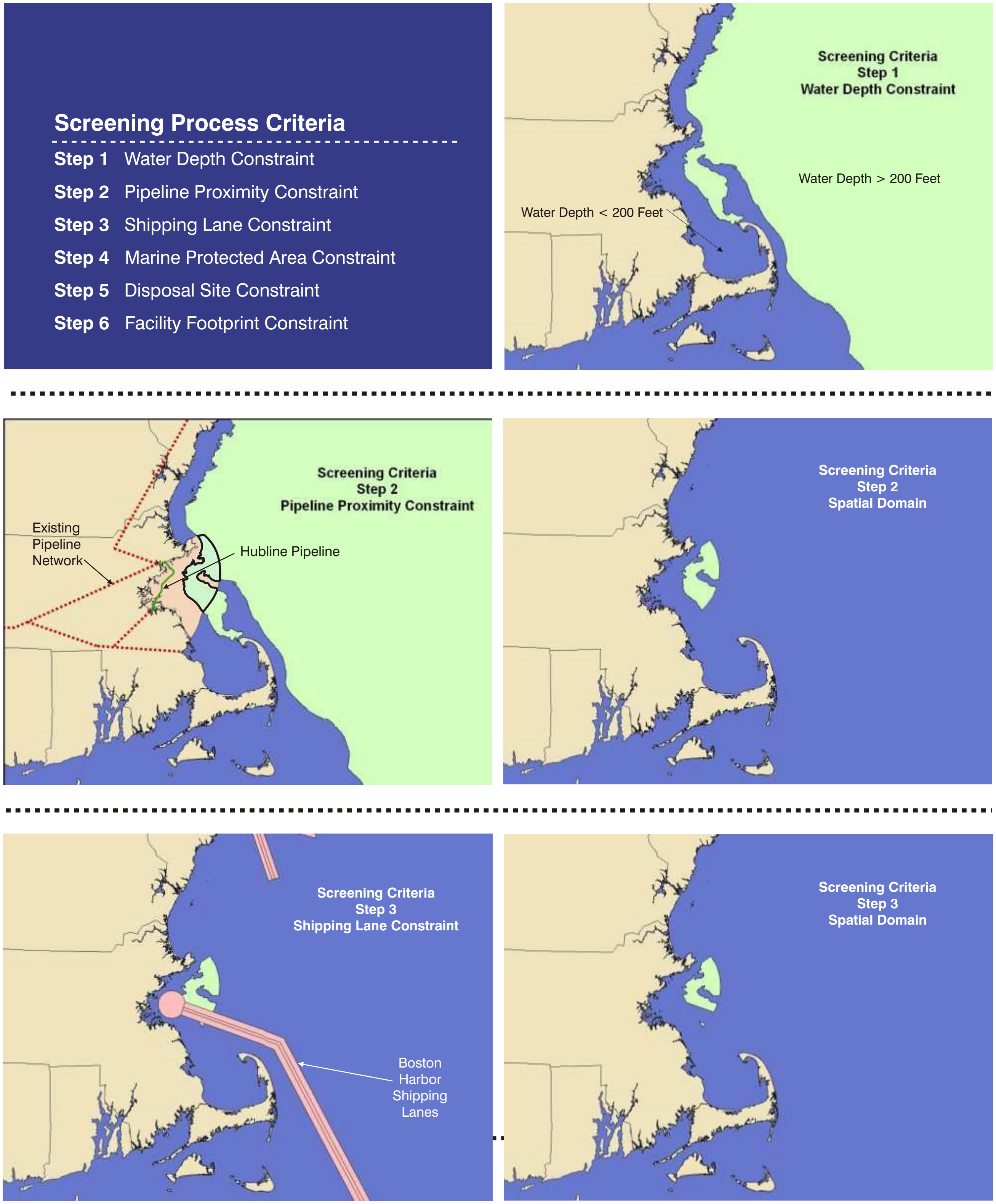

Figure 4 Regional Site Screening Process for Neptune LNG

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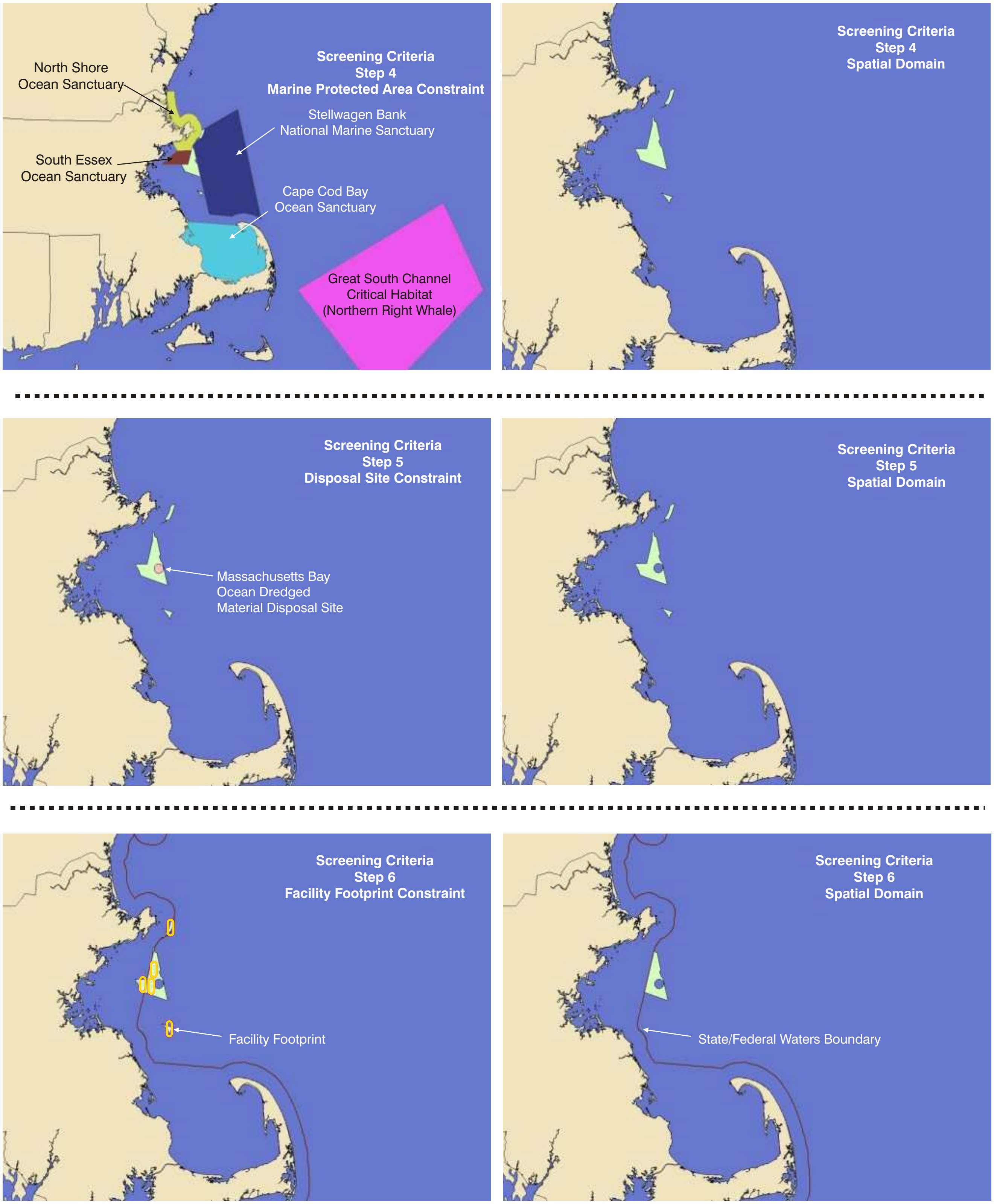

Figure 4 Regional Site Screening Process for Neptune LNG

7.3 Phase 3 – Deepwater Port Site Selection

The primary and secondary screening processes resulted in the selection of an area within Massachusetts Bay that is most feasible and reasonable for the siting of an LNG deepwater port facility. The preferred alternative area is a triangular-shaped area in northeastern Massachusetts Bay to the north of the Boston Harbor Traffic Lanes and between the boundaries of the Stellwagen Bank National Marine Sanctuary and the South Essex Ocean Sanctuary (referred to as the Northeast Sector). In addition, based on constraints from the required size of the facility footprint, and the location of historic and active waste dumps in the area, there are only three alternative sites within the Northeast Sector where it would be reasonable and feasible to site the proposed facility. These three locations, referred to as the North, Central and South alternative sites, are shown on Figure 5.

Northern Terminal Site. The proposed Northern alternative site is located in the northern portion of the northeast sector. The site is located 1.25 miles west of the Stellwagen Bank National Marine Sanctuary, east of the South Essex Ocean Sanctuary, northwest of the Massachusetts Bay spoil dumpsites mapped by the United States Geological Survey (USGS), and approximately 5 miles north of the Boston Harbor Traffic Lanes (Figure 5).

Central Terminal Site. The proposed central alternative site is located on the western side of the northeast sector. The site is located 2.5 miles west of the Stellwagen Bank National Marine Sanctuary, 1 mile east of the South Essex Ocean Sanctuary, 1 mile west of the Massachusetts Bay spoil dumpsites mapped by the USGS, and approximately 1.9 miles north of the Boston Harbor Traffic Lanes (Figure 5).

Southern Terminal Site. The proposed south alternative site is located in the southern portion of the northeast sector. The site is located approximately 1.25 miles west of the Stellwagen Bank National Marine Sanctuary, 2 miles southeast of the South Essex Ocean Sanctuary, 0.75 mile south of the Massachusetts Bay spoil dumpsites mapped by the USGS, and approximately 1 mile north of the Boston Harbor Traffic Lanes (Figure 5).

The North, the Central, and the South alternative DWP locations within the Northeast Sector were compared relative to the following evaluation criteria.

Benthic Habitat/Essential Fish Habitat

Field studies were undertaken to assess benthic habitat at the three alternative terminal sites, including video surveys to determine habitat types and sediment profile imaging (SPI) to assess the sediment conditions and nature and health of infaunal assemblages. The northern terminal area has a predominance of low complexity sandy mud bottom and a general lack of more complex hard bottom habitat, as compared to the central and southern terminal site alternatives. Species typically associated with hard bottom habitats have longer recovery times once disturbed when compared to those species that would typically frequent the predominantly sandy mud bottom of the northern terminal areas.

The results from the SPI survey revealed a low-energy, depositional environment with a relatively uniform sediment (primarily silt-clay with varying degrees of fine sand) over the entire area surveyed, except for three hard bottom locations. The mooring anchors can be sited at all three terminal sites to avoid impacts to the hard bottom areas due to anchor installation or anchor line scouring.

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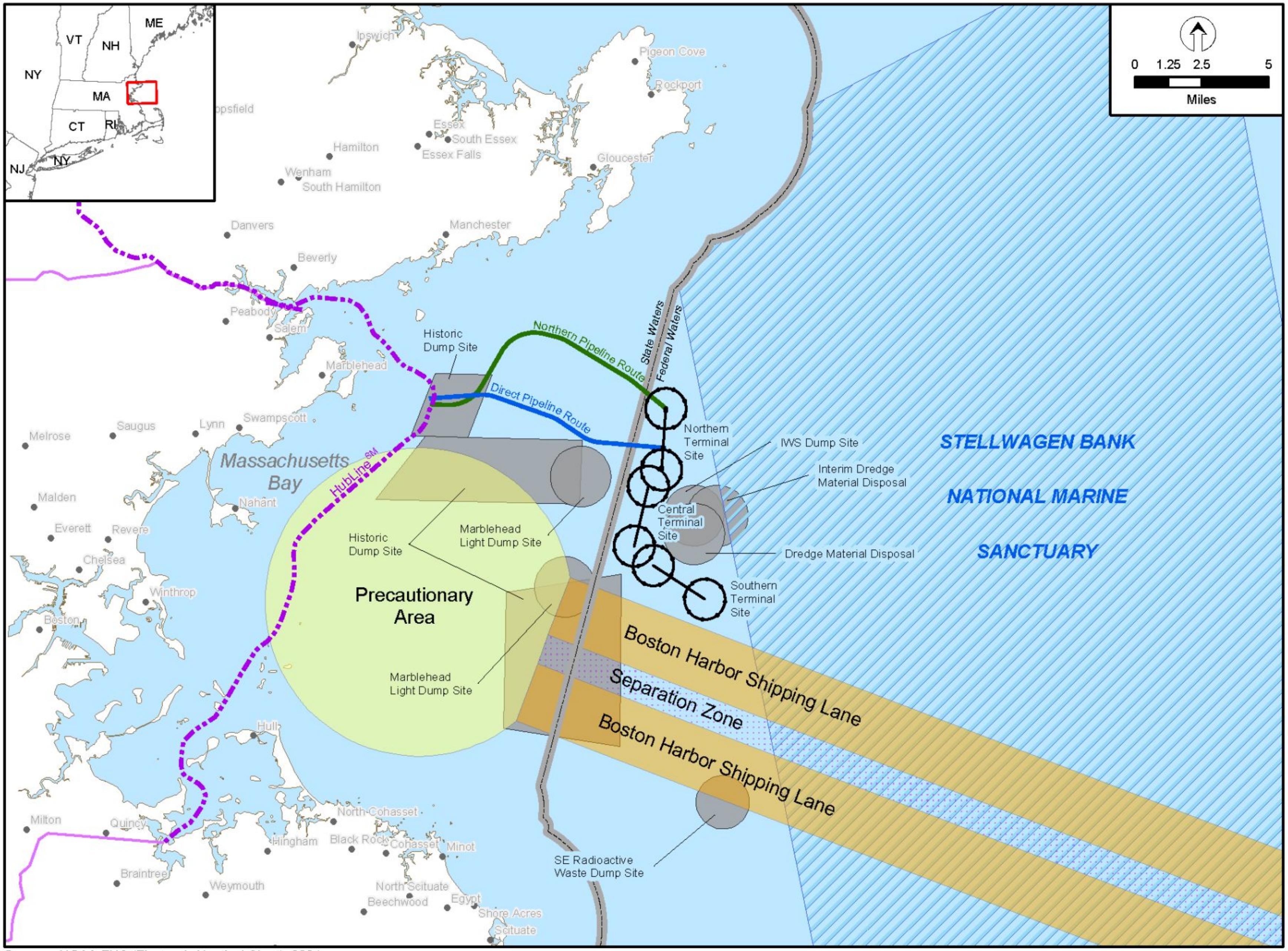

Sourece: NOAA ENC (Electronic Nautical Chart) 2004

Figure 5
Proposed Alternative Terminal Sites and Pipeline Routes for the Neptune LNG Project in Massachusetts Bay

The primary difference in potential benthic habitat impacts between the three alternative terminal sites is the amount of area that would be disturbed by the proposed pipeline installation, if the northern pipeline route alternative is selected. (The northern pipeline route, which is 10.9 miles long, is the preferred route; see Section 8.) The central and southern terminal sites would require 3 and 6 miles, respectively, of additional pipeline, than would the northern terminal site. Thus, the central and southern terminal sites would disturb 27 percent and 55 percent, respectively, more benthic habitat than would the northern terminal.

Marine Mammal Occurrence

The distribution of marine mammal sightings within the three terminal areas was compared using sighting data provided by Stellwagen Bank National Marine Sanctuary for the period 1979 to 2002. Sightings of right whales are not reported in any of the three alternative terminal sites. Fin whales and humpback whale sightings were reported at all three alternative sites, but the number of sightings of both species at the southern terminal site is slightly less than at the central and northern sites. This apparently less frequent occurrence of fin and humpback whales near the southern site, just north of the existing Boston Harbor Shipping Lanes, is part of a larger corridor of lower frequency sightings that extends across Stellwagen Bank, and is the stimulus for the proposed northern shift in the shipping lanes to lessen the risk of vessel strikes of marine mammals. Although the southern terminal site may appear to be a more desirable location than the central or northern terminal sites with regard to the apparent frequency of occurrence of some species of marine mammals, locating the port at this location would foreclose the opportunity to relocate the Boston Harbor Shipping Lanes to take advantage of this observed difference in marine mammal presence. Given that the deepwater port would generate about two vessel transits per week and the average traffic along the shipping lanes is hundreds of vessels per week, siting the port at the southern terminal would have the potential to increase the risk of vessel collisions with marine mammals, if it prevents the future relocation of the shipping fairway, as currently proposed.

Commercial Fishing Use

A comparison of the proposed terminal sites with respect to the potential effects of terminal construction and operation is difficult because of the lack of site-specific information on fishing effort and catch. Catch data reported to the government is compiled for large areas, and fishermen are loathe to provide specific information on the locations of their preferred fishing grounds or landings from such areas. Thus, the comparison must be conducted using indirect information, such as presence of target species, suitable habitat, and fishing gear, such as lobster traps. This type of information was gathered during the field surveys conducted during the summer of 2005, but this information represents only a limited period and season.

The geophysical surveys documented extensive trawling activity (as evidenced by shallow parallel, linear scour marks in the sediment, which were visible on sidescan sonar charts) throughout most of the soft bottom areas at all three terminal sites. The bottom substrate and habitats are very homogenous throughout all three sites, and therefore, fishery landings and value is expected to be similar between the three sites. Thus impacts due to exclusion of fishing during operation of the terminal would be nearly the same at all three alternative terminal sites. However, the presence of short-dumped debris within the Central and Southern Terminal Sites may provide some artificial habitat. In addition, because the Central and Southern sites would require additional pipeline lengths of 3 and 6 miles, respectively, in comparison to the Northern Site, disturbances to the soft bottom habitat from pipeline installation would affect much less fish habitat if the Northern Site was selected than if either of the other two terminal sites were constructed. Therefore, construction impacts to commercial important fish species would be anticipated to be less for the Northern Site than for the Central or Southern sites.

Furthermore, the duration of pipeline construction within the terminal area is expected to be shorter for the Northern Site than the Central or Southern sites due to the shorter pipeline required. Thus, closure of fishing areas to avoid conflicts with construction vessels and activities during pipeline construction would be shorter for the Northern Site and, presumably, have less of a negative effect on commercial fishing activities than would the Central and Southern terminal sites.

Suitability of Substrate

The terminal area is generally level with soft soils (clays) over bedrock or glacial till. The depth of soils varies from 25 to 95 feet. There are a number of bathymetric highs related to sub-cropping and outcropping of hard ground. In these areas the soft sediment is either thin or absent. Except for these areas where hard ground is at or close to the seafloor, the soils are of sufficient composition and depth to provide suitable conditions for use of suction piles, which are the preferred type of anchor for the proposed anchoring/mooring system. The areas of shallow sediment and/or outcroppings are sparsely distributed throughout all three alternative terminal sites such that they do not pose constraints for anchor installation in any of the cases. The flexibility in selection of exact anchor placement locations will enable these outcrops/thin sediment areas to be avoided, regardless of which site is selected. Therefore, substrate suitability does not act as a differentiating criterion in the comparison of the three alternative terminal sites.

Proximity to Disposal Sites

All three alternative terminal sites are located near to the Massachusetts Bay Ocean Dredged Material Disposal Site (ODMDS) and two historical dump sites (Industrial Waste Site and the Interim Dredged Material Disposal Site), which overlap the ODMDS and are located east of the Central Terminal site. The Central and Southern Terminal sites contain extensive debris fields, sonar targets, and magnetic anomalies, which are interpreted as being material intended for the designated dump sites that was either dumped outside of the designated areas or redistributed by trawling. The Central Terminal site contains over 700 magnetometer contacts and 190 sonar contacts. Less distinct debris piles are scattered between the major debris areas, suggesting that the waste material has been buried, mixed, and redistributed throughout much of the terminal site. The Southern Terminal site also has debris scattered throughout the site (440 magnetometer contacts and 150 sonar contacts), with especially abundant piles in the northwestern section of the site, closest to the dump site. Numerous linear trails and patches of the most recent spoil/debris suggest that the material was probably “short dumped” by vessels destined for the disposal site northeast of the Southern terminal site.

The proximity of the terminal site to the disposal area could also affect navigation. The precautionary area surrounding the terminal when an LNG vessel is present would potentially require vessels transporting dredged material to the active disposal site to divert from a direct course. However, each of the three alternative terminal sites could pose as a navigation obstruction for dump barges, depending on the originating port and the course followed by the vessels. Therefore, this aspect of proximity to the dump site does not appear to be a relevant selection criteria in the comparison of terminal site alternatives.

Sediment Contamination

Some contaminants were detected at all three proposed terminal sites. However, the types and levels of contaminants detected should not pose any limitations to the project. The proposed northern terminal alternative has the lowest occurrences/levels of contaminants, predominately due to its distance from known and recently identified (through the Phase II geophysical surveys) disposal areas.

Proximity to Shipping Lanes

The proximity of the port to the regional commercial shipping lanes is a primary consideration of safety. The closer a site is located to the commercial shipping lanes, the greater the risk of collision from vessels that may stray from the designated shipping lanes. The northern port location alternative is the most distant of the three sites from the commercial shipping lanes (i.e., the Boston Harbor Traffic Lanes), at a distance of 5.0 miles. Although the central and southern terminal sites are viable locations for the port, the northern terminal site provides the greatest buffer with commercial vessel traffic and, therefore, the largest margin of safety.

Furthermore, if the proposed shift in the location of the Boston Harbor Traffic Lanes occurs (a 7 degree rotation to the north), the southern terminal site would be located within the new traffic lanes, and the central terminal site would be located only about 1 mile from the northern boundary of the shipping lane. In either case, the northern terminal site would be the preferred location in terms of proximity to shipping lanes.

Conclusion

The Northern Site alternative was determined to be the least environmentally damaging alternative and was selected as the preferred terminal site for the following primary reasons:

- Because the Northern Site would require 3 and 6 miles, respectively, less pipeline length than the Central or Southern sites, the Northern Site would result in 20 to 30 percent less area of disturbance to benthic habitats and less interference with fishing activities during construction;
- The majority of the Northern Site is located further from the existing and former disposal sites and the site contains significantly less documented debris (from offsite dumping) than either of the other two alternative sites; and
- The Northern Site has the largest safety buffer from the Boston Harbor Shipping Lanes of the three alternative sites and would not be compromised by a proposed shift in the shipping lanes.

8 Alternative Pipeline Routes

Two alternative pipeline route corridors were identified from the preferred Northern Terminal location to the HubLine^{SM} tie-in point: the Direct Route and the Northern Route (Figure 5). The routes were evaluated and compared to determine which is the preferred route for the sendout pipeline, based on the following evaluation criteria.

Effects on Benthic Habitat / Essential Fish Habitat

The SPI survey documented distinct differences in both sediment type and faunal characteristics between the proposed Northern versus the Direct Route. While both routes have mature benthic communities that show little signs of stress from prolonged or frequent disturbance, and both routes display the general trend of a gradual fining of sediment from west to east proceeding from shallow to deeper water (medium to fine sand transitions into silt/clay facies with increasing depth), the sediments along the Direct Route were much more variable and included numerous bands of rock or till outcrops (as clearly identified in the geophysical survey) interspersed between the sandy and muddy areas.

The results of the benthic video survey confirm that the benthic habitats along the Northern Route, which are predominantly low complexity sandy mud bottom, are less valuable than the pebble/cobble and partially buried or dispersed boulder habitat, which comprises approximately 1.3 miles (15 percent) of the habitat along the Direct Route. Species typically associated with hard bottom habitats have longer recovery times once disturbed when compared to those species that would typically frequent the predominantly sandy mud bottom of the Northern Route. In addition, commercial lobsters and scallops were observed more often along the Direct Route than along the Northern Route.

Based on the benthic surveys conducted, the area traversed by the Direct Route appears to be a more valuable resource for fish habitat than that traversed by the proposed Northern Route, both in terms of potentially available prey as well as structural habitat diversity.

Effects on Marine Protected Areas

Each pipeline route would traverse state marine sanctuaries, which are unavoidable by any pipeline route from outside state waters to the HubLine^{SM} pipeline. The Northern Route would traverse 2.8 miles of the North Shore Ocean Sanctuary and 7.1 miles of the South Essex Ocean Sanctuary. The Direct Route would cross 7.7 miles of the South Essex Ocean Sanctuary. Thus, the Direct Route would traverse 2.2 miles less of a state marine protected area than the Northern Route.

Effect on Commercial Fishing

A comparison of the proposed routes with respect to the potential effects of pipeline construction and operation is difficult because of the lack of site-specific information on fishing effort and catch. Catch data reported to the government is compiled for large areas, and fishermen are loathe to provide specific information on the locations of their preferred fishing grounds or landings from such areas. Thus, the comparison must be conducted using indirect information, such as presence of target species, suitable habitat, and fishing gear, such as lobster traps. This type of information was gathered during the field surveys conducted during the summer of 2005, but this information represents only a limited period and season.

The geophysical surveys documented extensive trawling activity (as evidenced by shallow parallel, linear scour marks in the sediment, which were visible on sidescan sonar charts) throughout most of the soft bottom areas on both alternative routes. Although the Northern Route contains more soft bottom than the Direct Route, and therefore, may be used more extensively for trawling, the greater presence of hard bottom habitats along the Direct Route, as documented by both the geophysical and benthic surveys, provides more suitable habitats for lobster and groundfish. Furthermore, disturbances to the soft bottom habitat from pipeline installation would have shorter term effects on habitats and prey than on hard bottom habitats, which take longer to repopulate. Therefore, impacts to commercial important fish species would be anticipated to be less for the Northern Route than for the Direct Route.

Due to the soft, more easily plowed sediments that predominate more of the Northern Route than the Direct Route, the duration of construction is expected to be shorter for the Northern Route (even though it is 1.9 miles longer than the Direct Route). Thus, closure of fishing areas to avoid conflicts with construction vessels and activities during pipeline construction would be shorter for the Northern Route and, presumably, have less of a negative effect on commercial fishing activities than would the Direct Route.

Contaminated Sediments

The adverse impacts to sediment and water quality could differ between the alternative pipeline routes, depending on the degree to which contaminated sediments are potentially disturbed during pipeline construction. These potential effects were assessed by the distance that the proposed routes traverse historic dumping areas and areas of potentially contaminated sediment, based on results of geophysical surveys and laboratory analyses of sediment cores.

Both alternative pipeline routes traverse a historical waste disposal site near their proposed interconnection points with the existing HubLine^{SM} Pipeline. Furthermore, there is a debris field within the proposed corridor for the Direct Route (see Module 5, Figure 1-3 for location), which could represent waste material. Sediment cores taken along the Northern Route were found to have fewer kinds and lower levels of contaminants than cores collected along the Direct Route, probably due to their respective distances from known disposal areas and disposed material identified by the geophysical surveys. However, none of the types and levels of contaminants detected in sediments along either route should pose any limitations to the project.

Effect on Cultural Resources

Based on remote sensing data from the geophysical surveys, two wrecks were identified along the Northern Route within the anchoring corridor for the pipeline lay barge (see Module 5, Figure 1-4 for location). These features can be avoided during construction, by implementing barge anchor plans. Two wrecks were also identified within the proposed pipeline corridor along the Direct Route (see Module 5, Figure 1-3 for location). The Direct Route was adjusted to avoid these resources by a minimum of 500 feet. Construction and operation of the pipeline along either alternative route should not result in effects to cultural resources.

Geotechnical Conditions

The Direct Route passes through a restricted corridor that passes between morphological highs, where bedrock and or glacial tills outcrop. The predominant soils encountered within the upper 6 feet are very soft clays within the eastern section of the route and fine sands to the west (adjacent to HubLine^{SM}). Approximately 3.1 miles (34%) of the route, primarily near the western end, pass through areas where the surficial soils are less than 5 feet thick. Within these areas, reworked glacial deposits would be encountered. This unit is likely to comprise poorly sorted sand gravels and cobbles in a silt/clay matrix. Boulders, stiff clay and dense sands also may be encountered. A specialist review based on the Phase I geophysical and geotechnical survey results confirmed that the Direct Route is trenchable. However, there is a risk that, as with previous projects in Massachusetts Bay, trenching and backfilling problems may be encountered, which could lead to schedule delays and extensive remedial works.

The surficial soils along the Northern Route are predominantly fine marine silts and clay grading to fine sands inshore. The depth to bedrock or tills is generally greater than 20 feet. Due to the predominance of soft soils, trenching and backfilling of the Northern Route is expected to be up to twice as fast as for the Direct Route. A further advantage of the Northern Route is that a straighter connection between the Northern Terminal Flowline and the Northern Pipeline Route can be achieved. This would avoid a 'T'-connection, which would be required for the Direct Route, providing improvements to pipeline constructability and system commissioning. The Northern Route parallels the existing Hibernia fiber optic telecommunications cable for a significant length (5.2 miles within 1,640 feet and 0.7 miles within 300 feet), while the Direct Route does not parallel the cable. Both routes cross the cable.

Pipeline Length

The Direct Route alternative is 1.86 miles or 17 percent shorter than the Northern Route. The length of the pipeline has a direct effect on the duration and costs of construction, as well as the magnitude and areal extent of environmental effects. In addition, any increase in the length of the pipeline also requires additional pipeline pressure to meet the operational requirements of the receiving pipeline, and this translates into increased costs for operation of LNG pumps on the SRV and a concomitant increase in air emissions due to the additional energy needs. The effect of pipeline length on the duration and cost of construction and on benthic habitat are addressed in other sections. The 17 percent difference in length would not appreciably change the economics of operation of the project due to increase pumping or compression, nor would the incremental increase in air emissions appreciably change the impacts or permitting of the project. Thus, these effects of the pipeline length are not considered significant factors in deciding the preferred pipeline route.

Construction Cost

The main cost differences between the two alternative pipeline routes are due to the greater length of the Northern Route as compared to the Direct Route (10.85 miles vs. 8.99 miles) and the varying soil conditions within the respective areas of each route.

The 20% greater pipeline length of the Northern Route would result in 20% greater material costs than for the Direct Route.

The Direct Route crosses an area with stiff soils, boulders and areas of shallow bedrock/glacial till which contrasts with the substrate along the Northern Route, which has a 10-foot minimum thickness surface layer of silt, sand, or soft clays. Therefore, the Direct Route would be slower to trench, and this would result in greater costs for installation (Table 6).

Table 6
Comparison of Pipeline Construction Costs
Between Route Alternatives

Item	Northern Route	Direct Route
Materials	$44,282,000	$38,088,000
Installation	$43,260,000	$46,935,000
Total Cost	$87,542,000	$85,023,000

There may be areas along the Direct Route that require a second pass of the plow and possibly additional protection in the form of artificial backfill or mattresses where designed cover depths are not achieved. This would add additional cost to the project in terms of vessel time and possible schedule delay. If an anchored barge is used to lay and trench the pipeline, there could also be more delays along the Direct Route due to the anchoring difficulties in hard soils.

Conclusion

The Northern Route alternative was determined to be the least environmentally damaging alternative and was selected as the preferred pipeline route for the following primary reasons:

- The Northern Route, although 1.86 miles longer than the Direct Route, traverses only soft bottom (clay and sand) habitats, as compared to the Direct Route, which crosses approximately 1.3 miles of hard bottom (gravel with cobbles). Given that soft bottom habitats generally support fewer commercially important species and are more resilient to disturbance than hard bottom habitats, the impacts to fish and marine communities would be less if the pipeline were constructed along the Northern Route than the Direct Route;
- Construction along the Northern Route would take less time due to the complete avoidance of gravel, cobble, and other hard substrates and lack of thin surficial sediment layers as compared to the Direct Route, and would have less risk of incurring trenching and/or burial problems; therefore, the duration that the unburied pipeline would obstruct lobster movement or trawling would be less than for the Direct Route; and
- Although both routes traverse a historical disposal site, the Direct Route is located near two other former disposal sites and some documented areas of debris. Although levels of contamination from collected sediment cores along both routes are not cause for concern, the Northern Route sediment samples generally had fewer and lower levels of contaminants than did the Direct Route samples. Thus, installation of the pipeline along the Northern Route is less likely to disturb or disperse contaminated sediments.

9 Alternative Construction Methods

Neptune LNG considered numerous means of mitigating the potential detrimental environmental impacts of the project, including alternative methods for constructing the proposed facilities. A number of these alternative mitigation measures that were considered and evaluated will be addressed in the consequences analysis section of the revised Deepwater Port Application (in the Environmental Evaluation) and are not discussed here. This section describes the alternatives analysis for two primary aspects of construction, which were the subject of comments from the agencies who reviewed the original Deepwater Port Application submitted for the Neptune LNG project. These alternative construction methods, which are described in the following two subsections, address the anchoring system to be used for the mooring/unloading buoys and the seasonal timing of facility construction.

9.1 Alternative Anchoring Methods

Installation of the mooring anchors for the two proposed offloading buoys is one of the primary activities associated with construction of the proposed deepwater port that has the potential to cause environmental damage. There are a variety of available anchoring systems, each with its own suitability for varying environmental (e.g., seafloor, water depth, metocean) conditions, that also differ in the nature of their potential adverse impacts to marine resources associated with their installation. Table 7 identifies the four types of systems identified and evaluated by Neptune LNG for application to the proposed project and their primary characteristics.

Table 7
Alternative Types of Anchors for the Buoy Mooring System

Alternatives	Considerations	Characteristic
Embedment Anchors	Soils Impact Decommissioning	Versatile and accommodates wide range of soils Temporary environmental impact following installation Recoverable on decommissioning
Suction Piles	Soils Impact Decommissioning	Sensitive to variations in soil type Small area of disturbed seabed Recoverable on decommissioning
Driven Piles	Soils Impact Decommissioning	Designed to suit as-found soil conditions Small area of disturbed seabed, noise impact during installation Usually abandoned on decommissioning
Gravity Anchors	Soils Impact Decommissioning	Versatile, accommodate most soils Obstruction during lifetime of deepwater port Recoverable on decommissioning

The criteria used to evaluate the four anchoring alternatives are suitability of substrate, area of bottom disturbance, noise generated during installation, and decommissioning. From an engineering design standpoint, the type of soils or substrate is usually the major deciding factor in determining the most suitable anchor. However, because of the potential presence of marine mammals in the project area and the susceptibility to adverse impacts from loud noise, the noise generated by anchor installation is considered of primary importance in the selection of the preferred anchoring system.

Driven piles are the most versatile anchoring system, being effective in almost any type of soil condition, and they have the smallest area of bottom disturbance of the four alternatives. However, the repetitive hammer blows needed to drive the piles into the sediment create significant sound pressure waves that have been demonstrated to cause behavioral changes and physiological damage to marine mammals' hearing ability, depending on the proximity to the site and the magnitude of the noise. Because of the significance of the marine mammal population in the project area and the proposed terminal site's proximity to Stellwagen Bank National Marine Sanctuary, Neptune determined at an early stage that the precise terminal site should be selected to avoid pile driving, if possible, and that pile driving would only be used as an anchoring method of last resort.

Suction piles require specific depths and types of soils, but disturb a limited bottom area. They are installed by placement on the seafloor and drawn into the soft sediments by lowering the pressure beneath them. They require a minimum of 25 feet of surficial soils, but are highly reliable. Once installed, suction piles do not protrude above the seafloor.

Gravity anchors are massive concrete objects that provide a stable anchor by their weight rather than by embedment in the seafloor. These are rapid and easy to install, as well as recover at the time of facility decommissioning, but create a large obstruction on the seafloor for the life of the project.

Embedment anchors are also versatile and accommodate a wide range of soil types. As implied by the name, this anchor type is embedded in the soil by dragging them with heavy pull tugs. Thus, their installation involves disturbance of the seafloor to a greater degree than any of the four alternatives, with impacts to benthic communities and water quality as well as the noise generated by tugs during installation. Embedment anchors can be recovered upon decommissioning of the terminal.

The suction piles were selected as the preferred anchoring system because of its superior performance and the suitability of soil conditions, as determined by the project-specific geophysical and geotechnical surveys. Suction piles are also the least environmentally damaging alternative because their installation does not create any impulse or other significant noise that could be harmful to marine mammals, and their installation minimizes the impact area on the seafloor and generation of turbidity.

More extensive geotechnical studies must be conducted before the anchoring system selection and final design can be completed. Until the detail design stage of the project is reached, Neptune LNG intends to preserve the other types of anchors as potential alternatives. However, as noted, the driven pile alternative would only be used if the other three types were determined to be infeasible or impractical.

9.2 Alternative Construction Schedules

As recommended by EPA and other agencies, Neptune has considered alternative construction schedules to the winter time construction period proposed in the original application. Neptune is currently considering a construction schedule that would commence in mid- to late May and conclude in November. Neptune has developed a construction schedule that includes contingencies for weather delays and has created construction contingency plans that address contingencies for equipment mobilization, installation sequence, weather, and offshore construction problems. Neptune intends to consult federal and state resource agencies to incorporate time-of-year restrictions and develop necessary mitigation measures to ensure that impacts due to construction that can not be avoided by timing restrictions are otherwise minimized.

Neptune considered the timing of construction based on design and construction preferences and weighing the potential impact to marine animal species, fishing, and other uses of the project area. The environmental considerations include weighting the importance of species (economically important and protected species), the potential for impact, and the degree of impact and ability to mitigate impact.

Sequence of Construction

The sequence of construction would be to start laying the pipeline from the southernmost buoy through the terminal area and continuing westward (i.e., offshore to inshore) toward the HubLine^{SM} tie-in. Separate components that would be installed in conjunction with the pipelay would be the two terminal manifolds, the Hibernia cable crossing, and the HubLine^{SM} hot tap.

Under ideal conditions, the pipeline would be laid in 3 to 5 weeks (3 week with dynamically-positioned (DP) pipelaying vessel, 4 to 5 weeks if using conventional anchoring lay vessels). Plowing of the trench and burying the pipeline would follow the laying of the pipeline, and would require approximately 2 weeks (1 week each to cut the trench and backfill the trench/installed pipeline). Using sequential laying and plowing of the pipeline would mean that any given segment of the pipeline would be laying on the seafloor (i.e., creating an obstruction) for approximately 3 weeks.

Installation of the terminal anchors would probably begin soon after the pipelaying vessels/activity have cleared the terminal area. Sixteen anchors will be installed, one at a time, taking approximately 1 day per anchor. The installation of the risers, buoys, and umbilicals would occur following anchor installation, during the time the pipeline is being installed. Under ideal conditions, the total duration of the terminal construction/installation and commissioning would be approximately 4 months; however, a two-month contingency should be built into the schedule to allow for schedule delays.

Primary Environmental and Socioeconomic Criteria

The primary environmental and socioeconomic concerns relevant to the timing of construction are fishing activity (primarily lobster and bottom fish), marine mammals (northern right whale, humpback and fin whales), and spawning of fish.

Bottom fishing and gillnetting. Some or all of the project area is closed to bottom trawling and gillnetting during the months of April to June and October to November (NOAA Rolling Closure Areas; Figure 6). Fishermen have indicated that if there is temporary exclusion of fishing due to construction, they would prefer to have construction occur during the rolling closures when the area to be affected by construction is already closed to bottom trawling and gillnetting.

Lobster/lobster fishing. Information from lobstermen and from the benthic video survey indicate that most of the project area has few to no lobsters (and lobster fishing gear) during the month of July, when most lobsters (and lobstering activity) have moved in shore. Lobsters generally move from deep water into shallow inshore waters as the water warms; therefore, a pipeline installation sequence from offshore to inshore during June and July coincides well with respect to avoiding lobsters.

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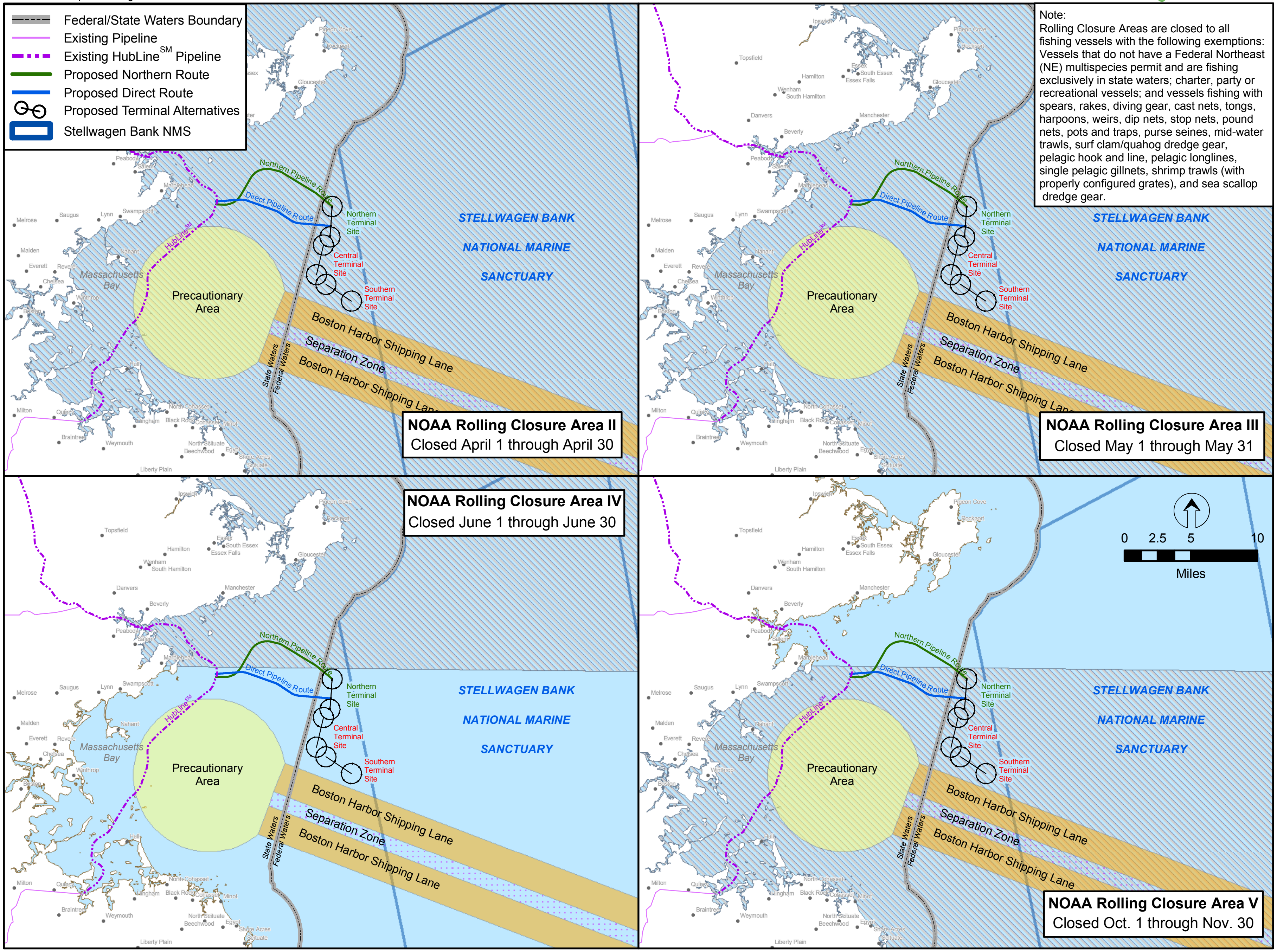

Source: National Oceanic and Atmospheric Administration (NOAA) Fisheries Northeast Region, 2004

Figure 6
NOAA Rolling Closure Areas in the Project Vicinity

Mid-water trawling. There is no significant commercial fishing for tuna and menhaden in the project area. Commercial fishing operations for herring should not be affected by construction, unless there is an unusual concentration of herring that occurs in the project area. Although there are only two local mid-water trawlers that fish for herring, if major schools developed in the project area, there may be a need to stop construction during the period that trawlers are active in the construction area.

North Atlantic right whale/humpback whales. Although North Atlantic right whales have been sighted in every month of the year, they are primarily present in Massachusetts Bay during February through May. There are very few right whale sightings after mid-May. (Fin and humpback whales are present from March/April through November and cannot be avoided unless construction occurs in the winter.) Humpback whale numbers begin to increase on Stellwagen Bank waters in or about June and normally persist throughout the summer to early fall period.

Fish spawning. Some species of fish spawn in Massachusetts Bay in every month of the year, so timing construction to avoid spawning periods of all fish is impossible. However, the suitability of spawning habitat along the pipeline route would dictate whether impacts to spawning grounds would be affected by construction if it took place during the respective spawning periods.

Whale-watching and recreational fishing. Other commercially important activities besides commercial fishing, such as whale-watching, charter and head boat fishing, and recreational boating may be adversely affected by summertime construction (primarily by exclusion from areas where construction activities are occurring). Measures other than seasonal timing of construction, such as sequencing or overlapping construction activities to reduce the duration of construction in a given area, can be used to mitigate adverse effects of construction on these activities.

Summer Construction Schedule Alternative

A summertime construction schedule is shown on Figure 7. Scheduling construction of the project between mid-May and mid-September would minimize or avoid adverse impacts to the most critically imperiled species and the most important commercial fishing activities better than any other time of the year. Although the duration of construction activities is conservatively estimated, this schedule does not include any buffer for contingencies. Therefore, an alternative schedule that incorporates potential weather or equipment delays was developed (Figure 8). This contingency schedule adds approximately 2.5 months to the construction schedule, resulting in a late November completion rather than mid-September. Neptune LNG intends to plan and design the project construction process to meet the schedule shown in Figure 7, but conduct its environmental consequences analysis and request permits based on the contingency schedule presented on Figure 8.

Therefore, construction would be completed between mid-May and the end of November. During this period:

- Few if any right whales are likely to occur in the project area during this period.
- Lobsters and lobster fishing appear to be at their lowest levels of the year in the project area for most of this period. Pipeline construction would be completed prior to lobsters and lobstering activity moving back into the pipeline area.

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Neptune Construction Schedule

Activity Description	Orig Dur	Early Start	Early Finish
Construction Plan Schedule	118*	18MAY09	12SEP09
Surveys	107*	18MAY09	01SEP09
Debris Survey (Gas Trans/Flowline/Buoys)	8	18MAY09	25MAY09
Post-lay Gas Transmission/Flowline Surveys	8	23JUN09	30JUN09
As-Built Anchor Position Surveys	8	25AUG09	01SEP09
Gas Transmission Line / Flowline	76*	25MAY09	08AUG09
Install Dead Man Anchor / Lay Flowline	6	25MAY09	30MAY09
Install Deadman Anchor/Lay Gas Transmission	22	30MAY09	20JUN09
Trench Flowline	5	20JUN09	24JUN09
Trench Gas Transmission Line	10	25JUN09	04JUL09
Backfill Flowline	5	04JUL09	08JUL09
Backfill Gas Transmission Line	10	09JUL09	18JUL09
Install Manifolds / Field-Fit Spools	15	18JUL09	01AUG09
Perform System Hydrotests	8	01AUG09	08AUG09
Buoys	36*	08AUG09	12SEP09
Install Anchors / Chains	15	08AUG09	22AUG09
Install Buoys	8	22AUG09	29AUG09
Install Risers	8	29AUG09	05SEP09
Perform Buoy System Tests	8	05SEP09	12SEP09
Hot-Tap	30*	04JUL09	02AUG09
Excavate at Hot-Tap Location	8	04JUL09	11JUL09
Perform Hot-Tap	15	12JUL09	26JUL09
Install Field-Fit Spool	8	26JUL09	02AUG09
Facility Protection	91*	26MAY09	24AUG09
Concrete Mattresses on Hibernia Cable	8	26MAY09	02JUN09
Post Installation Concrete Mattresses	22	03AUG09	24AUG09
Arrival of 1st LNG Carrier	0		26SEP09

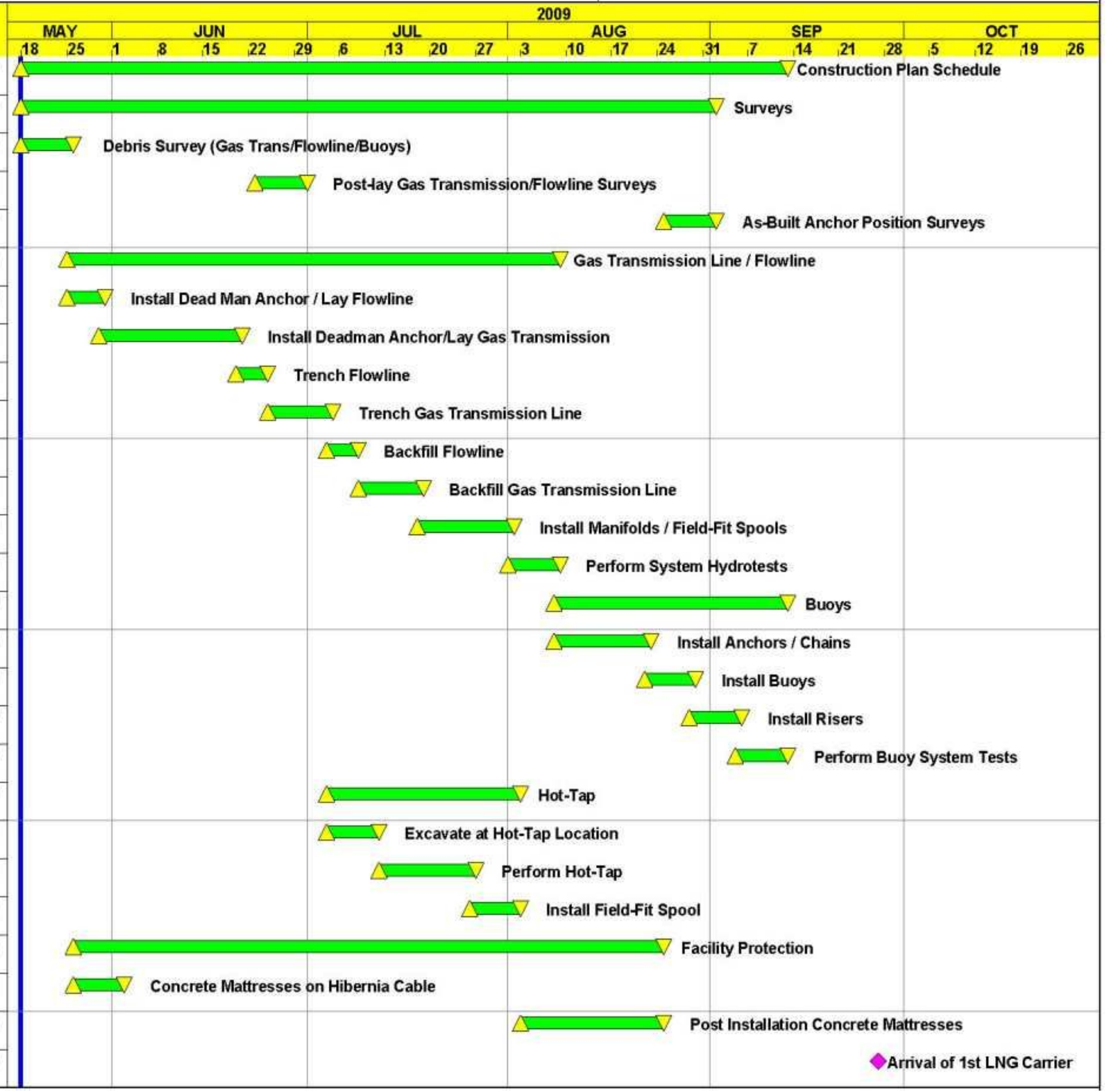

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Figure 7 Summer Construction Schedule

- Bottom fishing and gillnetting would be prohibited in most of the project area for at least a portion of the construction period.
- Construction would occur during peak spawning periods for several species of commercially important fish, but the soft substrates along the Northern Pipeline Route are not preferred egg deposition habitat for these fish species. Furthermore, sediment suspension caused by pipeline trenching would be minimized by use of a plow, which would significantly restrict the area and duration of bottom disturbing activities in comparison to dredging or jetting.
- The best weather of the year occurs in the summer months. Thus, the duration of construction is least likely to be delayed due to bad weather than at any other season of the year. Completing the construction in the shortest possible time is the best strategy for minimizing adverse environmental effects.

Neptune considered lessons learned by the HubLine^{SM} construction experience. HubLine^{SM} scheduled construction from March 2002 to December 2002 including pipeline laying, plowing, and backfilling, and experienced significant delays due to unexpected difficulties in trenching, pipelaying, and backfilling; unworkable weather conditions; and unforeseen equipment problems. The primary lessons are:

- Implement thorough and rigorous construction planning and meticulous execution;
- Conduct thorough geophysical and geotechnical surveys and confirm the results to ensure that proposed construction equipment and methods will work as planned;
- Recognize that geologic, sediment, metocean, and other marine environmental conditions in the New England area differ from the Gulf of Mexico, where most pipeline contractors are experienced in working, and that construction equipment, procedures, techniques and working conditions may have to be adapted to suit the local conditions;
- Minimize the duration of construction, in order to minimize impacts to marine resources, by using the most efficient and effective construction equipment and methods available, even if costs are substantially higher;
- Build in contingency periods in the construction schedule and ensure permits for these contingencies are secured and are prepared to address the need for additional mitigation and monitoring if these contingencies are implemented;
- Have standby equipment and personnel available to respond to unforeseen problems and/or need to compensate for delays and stay within restricted work windows.

Neptune LNG also recognizes that, although the projects are both located in Massachusetts Bay, there are important differences between the HubLine^{SM} pipeline and the Neptune LNG project locations, including the geological conditions, water depth, distribution of marine habitats, predominant marine communities, seasonal timing of fishing, etc. Thus, Neptune LNG has developed its proposed approach to construction based on spatial and

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Neptune Contingency Schedule

Activity Description	Orig Dur	Early Start	Early Finish
Contingency Plan Schedule	196*	18MAY09	29NOV09
Surveys	138*	18MAY09	02OCT09
Debris Survey (Gas Trans/Flowline/Buoys)	8	18MAY09	25MAY09
Potential Weather or Equipment Delays	10	26MAY09	04JUN09
Post-lay Gas Trans/Flowline Surveys	8	30JUL09	06AUG09
Potential Weather or Equipment Delays	10	07AUG09	16AUG09
As-Built Anchor Position Surveys	8	25SEP09	02OCT09
Potential Weather or Equipment Delays	10	03OCT09	12OCT09
Gas Transmission Line / Flowline	150*	07JUN09	03NOV09
Install Dead Man Anchor / Lay Flowline	6	07JUN09	12JUN09
Potential Weather or Equipment Delays	10	13JUN09	22JUN09
Install Deadman Anchor/ Lay Gas Transmission	22	23JUN09	14JUL09
Potential Weather or Equipment Delays	15	15JUL09	29JUL09
Trench Flowline	5	30JUL09	03AUG09
Potential Weather or Equipment Delays	5	04AUG09	10AUG09
Trench Gas Transmission Line	10	11AUG09	24AUG09
Potential Weather or Equipment Delays	5	25AUG09	29AUG09
Backfill Flowline	5	30AUG09	03SEP09
Potential Weather or Equipment Delays	5	04SEP09	10SEP09
Backfill Gas Transmission Line	10	11SEP09	24SEP09
Potential Weather or Equipment Delays	5	25SEP09	29SEP09
Install Manifolds / Field-Fit Spools	15	30SEP09	14OCT09
Potential Weather or Equipment Delays	10	15OCT09	24OCT09
Perform System Hydrotests	10	25OCT09	03NOV09
Potential Weather or Equipment Delays	5	04NOV09	08NOV09
Buoys	79*	26AUG09	12NOV09
Install Anchors / Chains	15	26AUG09	09SEP09
Potential Weather or Equipment Delays	15	10SEP09	24SEP09
Install Buoys	8	25SEP09	02OCT09
Potential Weather or Equipment Delays	15	03OCT09	17OCT09
Install Risers	8	18OCT09	25OCT09
Potential Weather or Equipment Delays	10	26OCT09	04NOV09
Perform Buoy System Tests	8	05NOV09	12NOV09
Potential Weather or Equipment Delays	8	13NOV09	20NOV09
Hot-Tap	51*	31AUG09	20OCT09
Excavate at Hot-Tap Location	8	31AUG09	07SEP09
Potential Weather or Equipment Delays	10	08SEP09	17SEP09
Perform Hot-Tap	15	18SEP09	02OCT09
Potential Weather or Equipment Delays	10	03OCT09	12OCT09
Install Field-Fit Spool	8	13OCT09	20OCT09
Potential Weather or Equipment Delays	8	21OCT09	28OCT09
Facility Protection	168*	05JUN09	19NOV09
Concrete Mattresses on Hibernia Cable	8	05JUN09	12JUN09
Potential Weather or Equipment Delays	8	13JUN09	20JUN09
Post Installation Concrete Mattresses	22	29OCT09	19NOV09
Potential Weather or Equipment Delays	10	20NOV09	29NOV09
Arrival of 1st LNG Carrier	0		30NOV09

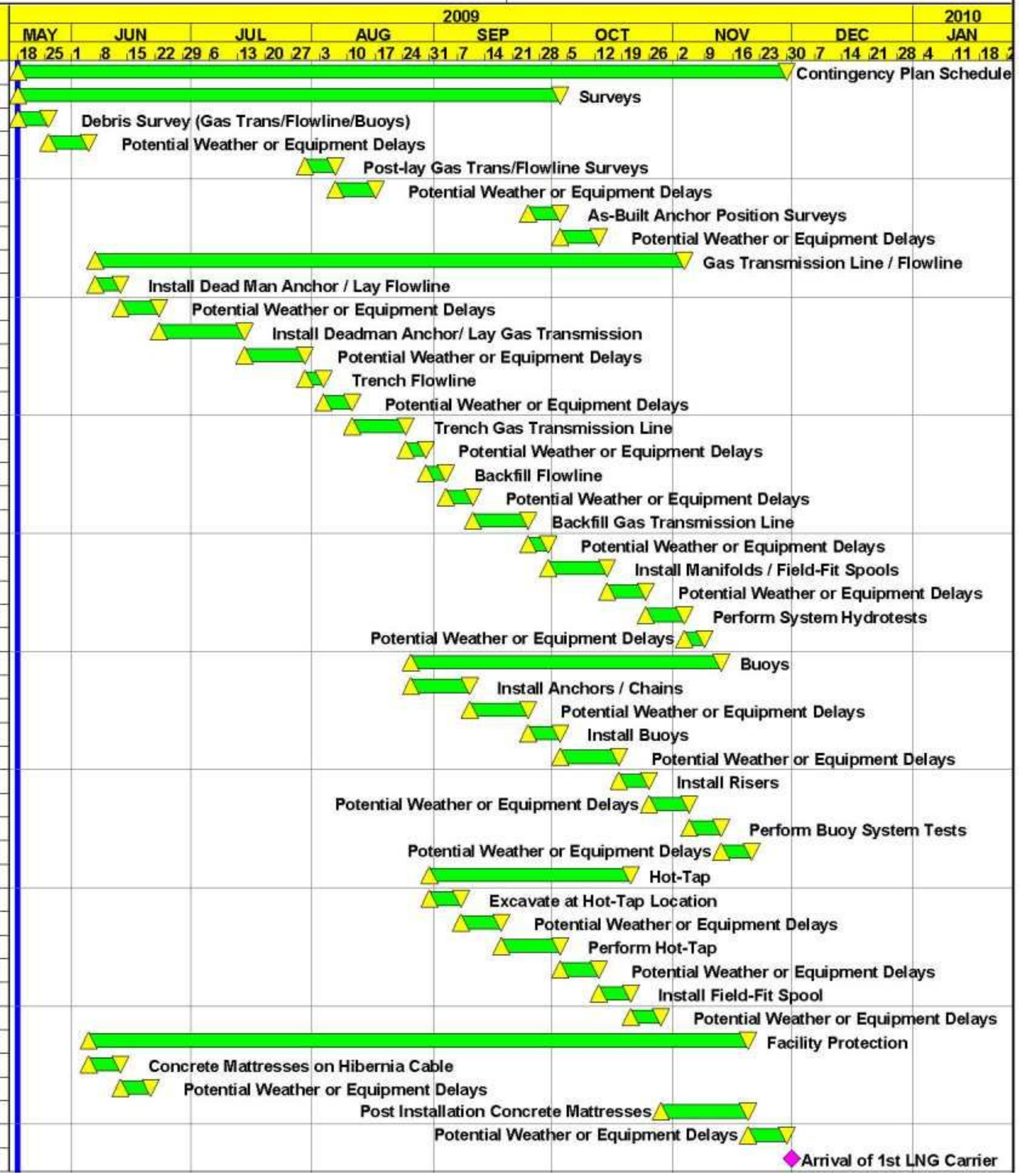

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Figure 8 Summer Construction Contingency Schedule

temporal variations in valued resources unique to the project area. As mentioned above, a draft Construction Contingency Plan has been developed and will be refined as the project design proceeds. The Plan describes equipment mobilization, schedule, weather, and offshore construction contingencies in the event that problems occur during the intended construction period. The construction contingency schedule is based on predicted delays for each type of contingency and the associated response actions as defined in the Plan.

Winter Construction Schedule Alternative

A winter construction schedule is considered an alternative to a summer construction period. Duke Energy is proposing to construct the Northeast Gateway Lateral pipeline project (associated with the Northeast Gateway deepwater port) in Massachusetts Bay between September and May, with pipelaying, plowing, and backfilling occurring between November 1 and mid-February.

Neptune's proposed summer construction duration, including additional time to cover contingencies, would be 6 months. However, a winter construction period would incur additional weather delays that would significantly extend the construction period, and therefore, the 9-month period proposed by Duke is reasonable. Consequently, Neptune LNG considered a winter construction schedule using the Northeast Gateway Lateral construction schedule as the specific period (September to the end of May).

Advantages of this construction period would include:

- Construction would avoid the summer peak occurrence of, and fishing for, several pelagic fish species, such as bluefin tuna, Atlantic herring, bluefish, and Atlantic mackerel.
- Bottom fishing and gillnetting would be prohibited in most of the project area for 4 of the 9 months of construction (October to November and April to May), avoiding potential conflicts with fishing activities during almost half the construction period.
- Disadvantages of a winter construction schedule include:
- Peak occurrence of North Atlantic right whales, in February through April, which could result in construction-related impacts due to vessel strikes and noise.
- Lobsters and lobster fishing in the project area would be near their maximum levels during the fall (October and November) and spring (April and May) months. Although pipelaying and installation would only overlap these peak months during November, other construction activities occurring during these months would create potential impacts to lobsters and conflicts with lobster fishing activities.
- Although peak spawning periods for several species of commercially important fish (hake, silver hake, witch flounder) would be avoided, the period coincides with spawning of many others (Atlantic cod, haddock, winter flounder, and pollock).
- Severe storms occur frequently during this period. Thus, construction delays due to bad weather would be significantly greater than a summer construction schedule.

Conclusion

- In conclusion, construction during the period September through May appears to conflict with the peak occurrence and/or spawning of many important species of marine mammals, fish, and shellfish. Furthermore, the winter construction period would extend the duration of construction due to weather delays, which conflicts with Neptune's goal of completing the construction in the shortest possible time, in order to minimize adverse environmental effects.
- Therefore, Neptune LNG determined that the summer construction period is the least environmentally damaging alternative and selected mid-May through November as the preferred construction schedule.

10 Alternative Propulsion / LNG Vaporization Technology Systems

Several LNG carrier propulsion alternatives were evaluated in combination with LNG vaporization technologies. The evaluation considered:

1) life cycle costs
2) environmental impacts to air and water, and
3) operational, reliability, and safety considerations.

Two of the propulsion alternatives considered were dual purpose; i.e. the propulsion system equipment served to meet the LNG vaporization needs as well. The first alternative considered was gas-fired propulsion steam boilers which provide steam to turbine generators to propel the vessel and to heat the LNG in the vaporizer heat exchangers. The boiler steam would also be expanded through turbo generators to make electricity to run the LNG pumps and to meet ship hotelling requirements. The second dual purpose alternative was gas-fired turbines to propel the vessel and the waste heat would be recovered to vaporize LNG and meet the ship electrical requirements as above. The steam boiler propulsion system is proven technology and used on many classes of vessels throughout the world. The gas turbine propulsion system is considered a novel concept and is not proven for this LNG carrier application.

The two other propulsion system alternatives considered require separate LNG vaporization systems. In these cases, there is no integration between systems. Both of these propulsion alternatives are dual fuel (DF) diesel engine-based (burning 99% gas and 1% marine diesel oil (MDO)), one being a slow speed diesel and the second, diesel electric. In both cases the heat required to vaporize LNG would be supplied by gas-fired auxiliary marine boilers and the electrical requirements would be supplied by dual fuel (DF) power generation engines.

Open Loop vs. Closed Loop Vaporization

Closed loop LNG vaporization systems were the only viable alternatives considered for this facility. Open loop systems which utilize seawater as the heating medium were not considered viable for several reasons. First, the year round seawater temperature averages 50.5°F, and varies from a low of 37.4°F to a high of 65.1°F. For only a few months a year would seawater be viable as the sole source of heat to vaporize LNG, without some form of supplemental heating by burning fuel. Thus, in the northeastern U.S. winter marine environment, a hybrid system employing both seawater and supplemental fuel combustion would be required to vaporize LNG. This hybrid system would have greater overall impacts to the marine environment and atmosphere than would the closed system which impacts only the atmosphere. The seawater circulating water flow would remain the same and the supplemental heating would result in additional air impacts. (Because of the LNG carriers' space constraints, air vaporization is not technically feasible for supplemental heating and would not work in the colder winter months when ambient air temperature is at its coldest).

Secondly, and more importantly, open loop systems would create far greater marine impacts than closed systems. Based on seawater throughputs for open rack vaporizers used by Gulf Gateway in the Gulf of Mexico of 76 MGD, an open system would require an intake of at least the same volume for LNG heating purposes, during the summer months (when peak water temperatures in Massachusetts Bay approach average Gulf of Mexico winter temperatures). This water is then discharged at a temperature 20°F to 30°F cooler than ambient. Marine organisms (eggs and larvae) would be entrained in the once through system. None are expected to survive due to the anti-fouling agents applied to the circulating engine cooling water system to retard marine growth. Secondary biological affects are fish impingement on intake screens and cold water discharge plume from the open loop system.

It was also recognized that from several agency consultations and other on-going reviews of deepwater port applications in the Gulf of Mexico, closed systems are preferred over open loop systems. It has been Neptune's objective to minimize marine impacts by employing LNG carrier technology to reduce seawater intake requirements to the minimal levels reasonably achievable. Open loop systems would not support meeting this objective.

In summary, closed vaporization systems were selected for further evaluation in combination with or separate from the ship's main propulsion system. The following section discusses the advantages/disadvantages of several propulsion and vaporization systems and the rationale for selecting the preferred propulsion/vaporization alternative.

Selected Propulsion / Vaporization Alternative

As described above, four propulsion/vaporization alternatives were evaluated. Two of the alternatives combine propulsion systems with vaporization systems (i.e. the oversized steam boilers/steam turbine generators option and the gas turbine/heat recovery steam generator option). At first glance, combining systems seems to be the most efficient use of energy and hardware, however, after detailed economic and environmental (LAER/BACT) studies, it was determined this is not the case. The two diesel engine options evaluated resulted in far less air emissions and seawater consumption (with corresponding less marine impact) than the two combined propulsion/vaporization systems. In addition, the life cycle costs (which include capital and operating expenses) were less for the two diesel options. Life cycle costs include fuel and maintenance for propulsion (round trip to and from LNG loading terminals) and fuel for vaporization. With the exception of the gas turbine propulsion system, the other three systems would provide an equivalent level of reliability and safety and have been used in some type of marine application. The gas turbine option was dropped from further evaluation because of the reliability issue and furthermore, it was the most costly alternative evaluated. Table 8 illustrates the significant environmental and cost differences among the three remaining alternatives considered:

Table 8
Significant Environmental and Cost Differences Among Alternatives

Propulsion/Vaporization Alternative	Annual NO_x Tons/year	Seawater Intake MGD	Life Cycle Cost $ Million – Delta NPV
Steam Boiler/ST	99.9	40	0
Slow Speed Diesel	62	7	-58
Diesel Electric	62	7	-36

Note: Net Present Value (NPV) was calculated over a 20 year period at an 8% discount factor.

As shown in the table above, either of the diesel alternatives will generate less impact to the air and marine environment than the steam boiler alternative. Both diesel alternatives are also less costly than the steam boiler option after a life cycle analysis was performed. Neptune is seeking bids from several shipyards for both diesel options, however, preliminary indications are that the diesel electric propulsion and auxiliary marine boiler alternative would be the preferred system for the Neptune project. In either case, the environmental impacts would be identical for either diesel option.

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