3.0 ALTERNATIVES

In considering KeySpan LNG's and Algonquin's applications, the FERC will review both the environmental and non-environmental record in deciding whether to issue any authorization for the project. In accordance with NEPA and Commission policy, we have evaluated a number of alternatives to the proposed LNG and pipeline facilities to determine if any are reasonable and environmentally preferable to the proposed actions. Alternatives described in the following sections include no action or postponed action alternatives, system alternatives, LNG terminal site alternatives, marine berth alternatives, and pipeline route alternatives.

The evaluation criteria for selecting reasonable and potentially environmentally preferable alternatives include whether they:

- are technically and economically feasible, and practical;
- offer significant environmental advantage over the proposed action; and
- meet the project objectives of:
  - providing 375 MMcfd of new, firm, reliable baseload supply of natural gas to meet the increasing energy demand in Rhode Island and the New England region in the near future, and
  - augmenting the supply of LNG to fill regional storage capacity via truck deliveries.

With respect to the first criterion, it is important to recognize that not all conceivable alternatives are technically and economically feasible and practical. Some alternatives may be impracticable because they are unavailable and/or incapable of being implemented after taking into consideration costs, existing technologies, and logistics in light of the overall project purpose. In conducting a reasonable analysis, it is also important to consider the environmental advantages and disadvantages of the proposed action and to focus the analysis on those alternatives that may reduce impacts and/or offer a significant environmental advantage.

Through the application of evaluation criteria and subsequent environmental comparisons, each alternative was considered to a point where it was clear if the alternative was not reasonable or would result in significantly greater environmental impacts that could not be readily mitigated. Those alternatives that appeared to be the most reasonable with less than or similar levels of environmental impact are reviewed in the greatest detail.

3.1 NO ACTION OR POSTPONED ACTION

The Commission has three alternative courses of action in processing applications under sections 3 and 7 of the NGA. It may: 1) deny the requested authorizations; 2) postpone action pending further filings or study; or 3) grant the authorizations with or without conditions.

If the Commission denies the authorizations or postpones action on the applications, the short- and long-term environmental impacts identified in this EIS would not occur. If the Commission selects the no action or postponed action alternative, however, the objectives of the proposed project would not be met and KeySpan LNG would not be able to provide a new supply of natural gas to the New England region in the near future. The existing KeySpan LNG facility would likely continue to function as a peak

shaving operation receiving LNG by truck, providing 150 MMcfd to NEGC, and distributing LNG (by truck) to other peak shaving facilities in the area.

Other than considering the existing, proposed, or announced projects, it is purely speculative to predict the resulting effects and actions that could be taken by governments and other suppliers or users of natural gas in the region as well as any associated direct and indirect environmental impacts. However, because 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 (FERC, 2003; EIA, 2005b), customers would have fewer and potentially more expensive options for obtaining natural gas and LNG supplies in the near future. Higher natural gas prices could adversely influence the regional economy by reducing realized household incomes and business profits (Greenspan, 2003). Higher natural gas prices (or the threat of higher gas prices) could also lead to either alternative proposals to develop natural gas delivery or storage infrastructure, increased efficiency and conservation, reduced use of natural gas, and/or the use of other sources of energy.

Alternative Natural Gas Infrastructure Proposals

The adoption of the no action alternative could result in the need for other LNG facilities or additional pipeline capacity to meet the increasing demand for natural gas in the New England region (FERC, 2003). This might include constructing or expanding regional pipelines as well as LNG import and storage systems. Any construction or expansion work would result in specific environmental impacts that could be less than, similar to, or greater than those associated with the KeySpan LNG Project. We have conducted and included in this EIS an analysis of what appear to be the most reasonable natural gas and LNG system alternatives that have the potential to meet the project objectives. Section 4.13 includes additional discussion of the need for natural gas in the region as well as the potential impacts on natural gas infrastructure if one or more LNG projects are (or are not) built.

Conservation

Denying or postponing a decision on KeySpan LNG's application could limit access to new supplies of natural gas in the future, which could in turn contribute to higher natural gas prices. Higher prices could potentially result in customers conserving or reducing the use of natural gas.[1] There is no doubt that both conservation and increased efficiency have an important role to play in the future energy needs of New England. Beginning during the energy crisis of the 1970s, numerous aggressive energy conservation programs have been developed in the New England region. 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 (MADOER) reported several benefits of energy efficiency programs (MADOER, 2004). These benefits included:

- 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;

[1] This effect has been noted in other market studies. For example, as discussed in the draft EIS the DOE/EIA's Annual Energy Outlook 2004 with Projections to 2025 Report revised projections for gas demand downward and projections for coal, nuclear, and renewable energy upward from the previous year's report, due in part to higher natural gas prices.

- 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.

A 2003 report by the American Council for an Energy Efficient Economy (ACEEE) also analyzes 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 report found that increased installation of renewable energy generation could affect natural gas price and availability. The report concluded that energy efficiency and renewable energy measures could reduce natural gas consumption in the northeastern states, which includes the New England states as well as New York, New Jersey, Pennsylvania, Delaware, and Maryland, by 0.9 percent by 2008. However, the study also 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. The DOE/EIA study, which considers renewable energy as well as other energy sources, supports this conclusion and 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, 2005a). Furthermore, each of these forms of energy involves environmental issues such as the disposal of toxic materials, alterations to hydrological/biological systems, and visual impacts.

Other Sources of Energy

Denying or postponing a decision on KeySpan LNG's application could also force potential customers of the natural gas provided by the project to seek regulatory approval to use other forms of energy. These other forms might include renewable sources of energy, nuclear power, or other fossil fuels.

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 (2003a), 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 DOE/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 around 1 percent from electricity imports. The DOE/EIA also predicts that consumption of renewable energy will increase by 1.1 percent a year until 2025. The majority of the increase in renewable energy generation is expected to come from wind power. The DOE/EIA predicts that natural gas consumption will increase over the same period by 1.4 percent per year, that consumption of petroleum and coal will increase by 1.0 and 1.1 percent per year, respectively, and that there will be virtually no increase in consumption of energy from nuclear power (EIA 2005b). In addition, each of these alternative forms of energy involves significant environmental issues such as alterations to hydrological/biological systems and visual impacts.

The issue of natural gas demand and scenarios to address this demand were assessed in the recent Governors Conference Report (Power Planning Committee, 2005). The report concluded that the region must accomplish a substantial amount of demand reduction or infrastructure development before 2010 to ensure reliable delivery of natural gas in the winters beyond 2010 (see more discussion of this topic in section 1.2). 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. The demand reduction scenarios evaluated in the report included expansion of fuel switching (this scenario assumes gas electric generation plants will be able to switch to oil for limited periods for the purpose of serving peak day demand); expansion of energy efficiency programs beyond those currently in place; 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 included construction of onshore, in-region LNG expansions like the proposed KeySpan LNG Project; construction of one or more onshore, in-region LNG terminals like the proposed Weaver's Cove LNG Project (see section 3.2.1); construction of one or more offshore, in-region LNG terminals similar to the Northeast Gateway or Neptune LNG Projects (see section 3.2.2.1); and construction of one or more onshore, out-of-region LNG terminals (see section 3.2.3) The report found that expansion of fuel switching (power plants engaging in short-term switching from natural gas to oil), energy efficiency, and renewable energy programs may be the least expensive ways to improve gas supply reliability while improving fuel diversity. The expanded investments in gas energy efficiency programs, in particular, may yield even greater reliability enhancements and even lower overall costs than most other scenarios. The expansion of LNG delivery and storage terminals, however, would provide considerably greater improvements to gas supply reliability than any of the other scenarios.

The Governors Conference Report does not identify or evaluate the likelihood of funding or market support for the various scenarios, nor does it critically evaluate the timeframes for passing legislation, planning, permitting, or constructing the necessary facilities for each scenario. The report also does not critically evaluate the likelihood of obtaining permits or approvals for each scenario. In our view, any proposal for a coal gasification or nuclear plant would generate considerable public opposition and would likely take longer to plan, study, and construct than the report indicates. It is also significant that the Governors Conference Report did not consider the environmental impact of any of the nine scenarios. Fuel switching for example would result in the combustion of a fossil fuel other than natural gas.

Compared to other fossil fuels such as coal or oil, natural gas is a relatively clean and efficient fuel that can reduce the emission of regulated pollutants (e.g., nitrogen oxides, sulfur dioxide, and particulate matter) or unregulated greenhouse gases (e.g., carbon dioxide). Given that there are emissions associated with producing, processing, transmitting, and distributing natural gas and other fossil fuels, it is difficult to accurately quantify the impact of an LNG import project on air quality. However, credible estimates of air emissions can be developed based on reasonable assumptions regarding burning natural gas delivered by the project compared to burning fossil fuels that would likely be utilized if the gas from the project was not available. Table 3.1-1 lists the emissions that would result from the KeySpan LNG Project assuming it provides about 375 MMcfd of additional natural gas to the market and the corresponding emissions that would result if an equivalent amount of energy were generated using coal or fuel oil in place of natural gas. It is clear from the table that the use of either fuel oil or coal would increase emissions significantly. Additionally, to comply with current air emission regulations, emission control technologies could be required that could limit the economic viability of any new oil- or coal-fired facility.

TABLE 3.1-1

Comparison of Air Emissions from Burning Fossil Fuels [a/]

Fossil Fuel	SO_2 (tpy)	NO_x (tpy)	PM_{10} (tpy)	CO_2 (tpy)	C (tpy)
Natural Gas	41	6,208	497	6,875,000	1,875,000
Fuel Oil	32,491	12,417	704	9,968,750	2,718,750
Coal	86,919	43,460	1,925	13,062,500	3,562,500

[a/] The emissions generated by coal, fuel oil, and natural gas were estimated using recent Best Available Control Technology (BACT) analyses identified on the EPA Reasonably Available Control Technology/BACT/Lowest Achievable Emission Rate Clearinghouse for boilers with heat input ratings between 100 and 250 million Btus per hour. The emissions from each fuel source are estimated based on a total annual fuel use of 136,875,000 million Btus per year (375 million cubic feet per day, 365 days per year, 1,000 Btus/cubic foot).

SO_2 sulfur dioxide
NO_X nitrogen oxides
PM_{10} particulate matter
CO_2 carbon dioxide
C carbon
tpy tons per year

In addition to the increased emissions associated with the burning of coal or fuel oil, each of these fuels would also have to be imported into the project area and stored similarly to the proposed LNG. Further, the distribution of these fuels to market would also require more truck, barge, and train trips than the distribution of an equivalent amount of energy derived from natural gas, which would increase air emissions and traffic congestion as well as have other environmental risks.

No Action or Postponed Action Conclusions

As described in section 1.2, the FERC's NE Report suggests that by 2009 there will be demand during peak periods of use in New England for an additional 500 MMcfd of natural gas above what the current infrastructure is able to provide (FERC, 2003). This increasing demand is largely expected to come from demand for additional capacity to generate electricity. Although not expected, it is conceivable that this demand could be reduced by increasing use of other energy sources and/or conservation. Because natural gas is the cleanest of the fossil fuels, the increased use of other fossil fuels would result in higher air emissions that can contribute to climate change, acid rain, and smog. The economic, ecological, and human health benefits of reduced air emissions have been well documented (EPA, 1999). It is also conceivable that increasing energy efficiency and use of renewable sources of energy could reduce the projected future demand for natural gas. However, it is noteworthy that a report by the ACEEE (2003) concluded that additional energy efficiency and renewable energy projects could reduce the consumption of natural gas in the Northeast by only about 0.9 percent by 2008. EIA (2005) estimates, which include increased use of renewable energies, support this conclusion. Neither conservation measures nor renewable energy sources are expected to replace or substantially offset the demand for additional natural gas supplies in the New England region.

As noted above and as described in section 3.2, if the no action or postponed action alternative is adopted there are two likely outcomes: 1) negative environmental and economic impacts associated with more limited supplies of natural gas; and/or 2) the development of other natural gas infrastructure projects that meet some or all of the project objectives identified by KeySpan (see section 3.2).

3.2 SYSTEM ALTERNATIVES

System alternatives are options to the proposed action that would make use of other existing or proposed LNG or natural gas facilities to meet the stated objectives of the proposed project. A system

alternative may make it unnecessary to construct all or part of the proposed project even if some modifications or additions to the existing or proposed facilities are necessary. These modifications or additions would result in environmental impacts that could be less than, similar to, or greater than those associated with construction of the proposed project. Ultimately, the purpose of identifying and evaluating system alternatives is to determine whether potential environmental impacts associated with the construction and operation of the KeySpan LNG Project could be avoided or reduced by using another system.

The New England natural gas and LNG market is concentrated in Massachusetts, Connecticut, Rhode Island, and also includes the southernmost portions of New Hampshire and Maine. Currently, this market area is supplied with natural gas and vaporized LNG through interstate pipeline systems and an existing LNG import terminal in Everett, Massachusetts (the Distrigas facility). As described in section 1.2, the objectives of the KeySpan LNG Project are to augment the supply of LNG to fill regional storage capacity via truck deliveries, and to provide 375 MMcfd of new, firm, reliable baseload supply of natural gas to meet the increasing energy demand in Rhode Island and the New England region in the near future. The analysis below examines other potential existing, modified, or proposed LNG and pipeline systems and considers whether these systems could meet the project objectives.

3.2.1 Existing and Proposed Onshore LNG Facilities in New England[2]

Companies that supply natural gas to the New England region use LNG from storage facilities to help meet peak demand during periods of high natural gas use. Currently, there are 46 LNG storage facilities throughout New England (FERC, 2003). Although several of these storage facilities are capable of liquefying natural gas during periods of low demand, it is frequently not economical to do so. As such, the New England LNG market is supplied largely with LNG trucked from the Distrigas LNG import facility. In addition, there are proposals for several new LNG terminals in the region. The general locations of the existing and proposed LNG facilities in the New England region are illustrated in figure 3.2.1-1.

3.2.1.1 Distrigas LNG Terminal – Everett, Massachusetts

The only existing LNG import facility in the New England market area is the Distrigas LNG import facility. The Distrigas facility is owned by Tractebel LNG North America, L.L.C. (Tractebel). This facility occupies a 24-acre site on the Mystic River in Boston Harbor that is surrounded by industrial development on all sides. In service since 1971, the Distrigas facility is the oldest LNG import terminal in the United States. In 2000 and 2001, the FERC authorized installation of a vapor recovery system to recover flash gas during ship unloading, replacement of all vaporizers to be compatible with a new thermal transfer system with a new adjacent power plant, and the installation of additional vaporizers and pumps to provide natural gas service to an electric power generation plant (Mystic 8 and 9). The Distrigas facility has two tanks that can store a total of 974,000 barrels (155,000 m^3) of LNG, and has an installed vaporization capacity of 1.035 billion cubic feet per day (Bcfd), although maximum sendout is limited to 715 MMcfd due to pipeline capacity. A significant quantity of LNG is loaded onto LNG trucks and delivered to peak shaving facilities throughout New England (including the current KeySpan LNG facility in Providence). The four-bay truck station on the site can fill and send out up to 100 trucks per day. In 2003 about 53 LNG ships made deliveries to the facility. In 2004, deliveries went up to about 68 ships (Katulak, 2005).

[2] Although we included an analysis of the planned Somerset LNG Project in the draft EIS, we have eliminated it from our discussion in the final EIS because no change in status of the project has occurred since the draft EIS and no formal application has been filed for this project. As such, we do not believe the Somerset LNG proposal is a viable alternative to the KeySpan LNG Project.

Figure 3.2.1-1

You don't have permission to access this document over the Internet. This document is Non-Internet Public (NIP). Public access to this document is available through the **public.referenceroom@ferc.gov**

The Distrigas facility is dedicated to LNG imported by Tractebel and is not operated as an open-access import terminal that provides terminalling services to other parties. To provide the same service as proposed by KeySpan LNG, it would be necessary to add another 95,000 m^3 of storage and 375 MMcfd of additional vaporization. There is no space on the existing 24-acre site to construct the new storage or additional vaporization facilities associated with the proposed KeySpan LNG Project, nor is there available adjoining property to accommodate these facilities and the associated exclusion zones. As a result, expansion of the existing Distrigas LNG import terminal is not a reasonable system alternative.

We also considered an additional alternative involving the Distrigas facility. As noted above, the current vaporization capacity at Distrigas is 1.035 Bcfd; however, actual sendout capacity of the facility is less (about 715 MMcfd) due to limited pipeline capacity to transport the gas to market. Expanding the existing pipeline system to accommodate Distrigas' current vaporization capacity would provide an additional 320 MMcfd of gas to the New England region. This volume of gas, while significant, is 55 MMcfd less than the maximum volume proposed by KeySpan LNG; thus, additional vaporization capacity would need to be constructed. In addition, to transport the additional volumes, it would be necessary to expand the existing sendout pipeline system.

Distrigas has not proposed to expand its facilities and we are unaware of any current proposals to expand the associated pipeline systems. However, to estimate the potential impacts of such expansions, we reviewed a previously proposed project that could serve as a potential alternative. The project was filed by Algonquin as the HubLine Phase II Project (also known as the Everett Extension Project, FERC Docket No. CP01-5-003). Algonquin proposed this project in 2003, but later withdrew it. The HubLine Phase II Project was proposed in part to augment the take-away capacity on the Algonquin facilities providing service to Distrigas and would have provided an additional 110 MMcfd of firm transportation service. Implementation of the project would have depended on construction of the Deer Island Lateral, which was approved by the FERC in 2002 but never constructed. If it were to be implemented, the HubLine Phase II Project would involve construction of a new lateral pipeline that would extend the Deer Island Lateral to a connection with Algonquin's existing J-System, which interconnects with the Distrigas facility in Everett. The project would also require that Distrigas construct (as a separate activity) new processing facilities within the existing boundaries of the Distrigas property. The new pipeline facilities, including the Deer Island Lateral and the HubLine Phase II Project, would result in a total 12.4 miles of pipeline. Approximately 4.2 miles of this new pipeline would be onshore. The remaining 8.2 miles would be offshore pipeline in Boston Harbor, of which about 2.4 miles would be installed by HDD, and the rest would be installed by dredging, jetting, or plowing.

Based on the previous environmental assessments of these projects, construction of the onshore facilities associated with the combined HubLine Phase II and Deer Island Lateral Projects would disturb about 75 acres of land. Construction of the offshore pipeline would disturb around 860 acres of seabed. Impacts would include temporary disruption of local roadways and recreational trails, noise during construction, increased turbidity and sedimentation as a result of offshore construction, and direct and indirect impacts on aquatic resources. The environmental impact associated with this pipeline expansion would be much greater than that associated with the 1.44 miles of pipeline proposed for the upgrade of KeySpan LNG's existing facility.

In addition to the potential environmental impacts of pipeline construction, increasing the sendout volumes from Distrigas would require either an increase in the number of LNG ships unloading at the facility or a reduction in the volume of LNG available for trucking. Assuming the trucking of LNG does not diminish, the number of LNG ships unloading at the facility, based on 2004 deliveries (Katulak, 2005), would need to increase by 67 percent to about 113 ships per year. If the number of LNG ships unloading at the facility does not change, less LNG would be available for trucking, which would likely create additional demand for LNG to be trucked from other locations. As discussed above, currently there

are no other LNG import terminals in the region that could supply trucked LNG economically with minimal environmental impact. For these reasons we do not believe that adding additional pipeline capacity at Distrigas to meet KeySpan LNG's proposed maximum sendout capacity is a reasonable system alternative.

3.2.1.2 Weaver's Cove LNG Project – Fall River, Massachusetts

In December 2003, Weaver's Cove Energy filed an application with the FERC to construct and operate a new LNG terminal in Fall River, Massachusetts. The LNG terminal facilities would include a ship unloading facility with a single berth capable of receiving LNG ships with cargo capacities up to 145,000 m^3; a 200,000 m^3 full containment storage tank; vaporization equipment sized for a normal sendout of 400 MMcfd and a maximum sendout of 800 MMcfd; four truck loading stations; 6.1 miles of 24-inch-diameter pipeline; and two meter stations. The proposed terminal would be located on a 73-acre former oil terminal site bordering the Taunton River.

We are currently evaluating the Weaver's Cove LNG Project proposal. We conducted public scoping on the Weaver's Cove LNG Project proposal and issued a draft EIS in August 2004. The results of our analysis are available in that document.[3] Based on our analysis, it appears the Weaver's Cove LNG Project would be capable of providing the volumes and LNG trucking services proposed by KeySpan LNG. However, the Weaver's Cove LNG Project would result in comparatively greater environmental impact than upgrading the existing KeySpan LNG facility. For example, the development of the Weaver's Cove LNG Project would require the maintenance and improvement 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. The KeySpan LNG Project has environmental advantages when compared to Weaver's Cove Energy's proposal because it only requires upgrading an existing LNG facility rather than the construction and development of a new LNG facility. Even so, we believe that the proposed Weaver's Cove LNG Project could be a reasonable alternative for meeting the stated purposes and needs of the KeySpan LNG Project.

3.2.1.3 Proposed LNG Projects in Maine

Over the last 1 to 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 all 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, LLC appears to be the only developer moving forward with plans to construct and operate an LNG import terminal in Maine. Quoddy Bay's proposal includes developing an LNG import terminal in cooperation with the Passamaquoddy Indian Reservation in Pleasant Point, Maine (see figure 3.2.1-1). The proposed Pleasant Point Energy Facility would be located on a 40 to 50 acre site and have an LNG storage capacity of 150,000 to 200,000 m^3. The proposed facility could accommodate 52 LNG vessels per year that would dock and unload at a 3,400-foot-long pier. Because the ships would dock in waters about 85 feet in depth, no significant dredging would appear to be required for the project. We are not aware of any plans to use this facility as a source of trucked LNG. In addition, because the site is located at least 350 miles from the Boston area, it does not appear ideally suited to serve the LNG peakshaving market which is concentrated in southern New England.

[3] Weaver's Cove LNG Project, Draft Environmental Impact Statement, FERC/EIS-0169D, Docket Nos. CP04-36-000 and CP04-41-000.

The Pleasant Point Energy Facility would interconnect with the Maritimes and Northeast Pipeline, L.L.C. (M&N) 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). The M&N pipeline system provides gas to markets in both the United States and Canada. Currently, the M&N system appears capable of transporting about 350 MMcfd of natural gas to markets in northern Massachusetts. It appears that the M&N pipeline system could be expanded to deliver at least another 400 to 500 MMcfd to northern Massachusetts, primarily through the addition of compression to its system. Presumably, additional looping of its pipeline system would allow even greater volumes to be transported. The specific details of a possible pipeline expansion project are not available at this time, although M&N has recently completed an open season to determine the potential for a future expansion of its system (Northeast Gas Association, 2005).

The future of the project also remains uncertain despite the approval of the majority Passamaquoddy Indians. Some tribal members are concerned with the potential environmental impacts the proposed project may cause. Additionally, many residents adjacent to the reservation and activist groups (e.g., Save Passamaquoddy Bay and We Take Care of the Homeland) are opposed to the proposed LNG terminal due to potential impacts on commercial and recreational fisheries, local businesses, and the safety of residences and schools in the proximity of the proposed project site. In a recent referendum held in the neighboring town of Perry, Maine voters rejected the development of the proposed LNG facility by a margin of 279 to 214, with about 70 percent voter turn-out. The Passamaquoddy tribe stipulated that Perry voters would have approval of any use of the site when they acquired the land from the town in 1986 (Bangor Daily News, 2005).

Given the early stage of the Pleasant Point Energy Facility and because no formal application has been submitted to the FERC, we believe it would be highly speculative at this time to consider this as a viable alternative to the KeySpan LNG Project.

3.2.2 Proposed Offshore LNG Facilities in New England

To avoid many of the environmental issues and safety concerns associated with siting an LNG facility onshore, many companies have considered siting LNG import terminals in offshore areas. Offshore LNG import terminals located in federal waters fall under the jurisdiction of the DOT and the Coast Guard (pursuant to the Deepwater Port Act of 1974, as amended by the Maritime Transportation Security Act of 2002). Offshore LNG import terminals located in state waters fall under the jurisdiction of the FERC (pursuant to the NGA).

Companies have introduced various strategies for operating an LNG import terminal in offshore waters (LNG Express, 2003). These strategies include:

- offshore docking/onshore storage
- fixed offshore terminals (gravity based structures or platforms)
- transport/regasification vessels; or
- floating, storage, and regasification units (FSRU).

Offshore Docking/Onshore Storage

Where deepwater access to a coastal port or harbor is unavailable, LNG can be transported to onshore storage tanks from ships using specially designed cryogenic pipelines. Such facilities enable LNG ships to berth and transfer their LNG cargo to the cryogenic pipeline at docking facilities in offshore areas where natural water depths exceed 40 feet. Although feasible, a number of technical factors related to transporting LNG in a pipeline place limits on the practical maximum length of such a pipeline to about

3 miles. This approach has been used at the existing Cove Point LNG Terminal, where the ship docking/unloading platform is located in the Chesapeake Bay about 1 mile from the shoreline. Similar facilities have been proposed for the Irving Oil LNG site in New Brunswick, Canada, and the Keltic Petrochemicals LNG and Bear Head LNG facilities in Nova Scotia, Canada. While it would be possible to transfer LNG to shore through a cryogenic pipeline from an offshore docking structure, such a design would still require locating LNG storage tanks and process facilities at an onshore location, which would involve most of the same disadvantages of an onshore terminal (in addition to the disadvantages associated with an offshore docking structure and pipeline). Furthermore, industrial ports in the New England region are largely situated along narrow waterfronts that are accessible only from narrow navigational channels. Therefore, an offshore docking structure and a cryogenic pipeline would have to be located relatively close to a navigational channel, which could interfere with other port operators or marine traffic. Although considered, we did not identify a site where the use of this approach appeared practical.

Fixed Offshore Terminals

There are basically two different types of fixed structures that can be used as an offshore LNG import terminal, either a gravity based structures (GBS) located directly on the seafloor or pile-based platforms.

A GBS facility would include placing LNG storage tanks and associated facility platforms on foundations directly on the seafloor. 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. GBS terminals would only be feasible in areas of relatively shallow water, where the depths range between 45 and 100 feet. Given the costs 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., 250,000 to 330,000 m^3) and large natural gas sendout volumes (e.g., 800 to 2,000 MMcfd). ChevronTexaco has received approval from the Coast Guard to build a facility of this design in the Gulf of Mexico (the Port Pelican Project), but is still seeking approval from the Coast Guard and Texas regulators for its GBS construction yard in Corpus Christi, Texas. The construction of Port Pelican is currently on hold until ChevronTexaco identifies an LNG source. Another potential obstacle for the project is cost, which current reports indicate have increased to nearly three times the cost projected by ChevronTexaco last year (LNG Express, 2004a).

Another strategy using a fixed offshore terminal involves constructing or converting existing offshore platforms to LNG use. Because these platforms are or would be anchored using fixed-tower structures, they could be located in a much broader range of water depths than a GBS unit. These platforms could be fitted with docking, unloading, storage, and vaporization equipment. 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. recently proposed to use an existing platform as a terminal to import natural gas to markets in California. Given the lack of existing offshore platforms in the New England region, this approach would require construction of a new platform.

Transport/Regasification Vessels and Floating, Storage, and Regasification Units

Another strategy for importing LNG to an offshore terminal includes the use of conventional LNG ships fitted with regasification equipment (e.g., transport/regasification vessels) or a floating, storage, and regasification unit. Both of these strategies are currently being proposed in the New England region and are discussed below.

3.2.2.1 Neptune LNG and Northeast Gateway Projects – Gloucester, Massachusetts

A formal deepwater port application to build an LNG facility offshore of Gloucester, Massachusetts was filed with the Coast Guard by Neptune LNG (a subsidiary of Tractebel LNG) on February 15, 2005.[4] In addition, Excelerate Energy, L.L.C. (Excelerate) and Algonquin Gas Transmission filed environmental notification forms for the Northeast Gateway Deepwater Port and associated pipeline projects with the Secretary of the Massachusetts Executive Office of Environmental Affairs on March 15, 2005. Because these two projects would utilize very similar technology and would be located in essentially the same area of Massachusetts Bay, we have combined the discussion of both projects.

The Neptune LNG and Northeast Gateway Projects would both be located in federal waters about 12 miles east of Marblehead and 10 miles southeast of Gloucester, Massachusetts (figure 3.2.2-1). Both proposed projects would utilize two turret buoys (docking stations) and varying lengths of subsea pipeline that would interconnect with the existing HubLine pipeline system (operated by Algonquin). Neptune LNG has indicated that the project would have an average sendout capacity of 400 MMcfd and a peak capacity of 750 MMcfd. Excelerate has indicated that the Northeast Gateway Project would have a baseload capacity of 400 MMcfd and a peak capacity of 800 MMcfd. However, it appears the 800 MMcfd capacity could rarely if ever be achieved and that the actual maximum delivery capacity of the project would likely be between 500 and 690 MMcfd.[5]

Additional physical structures that would be needed for either project include pipeline end manifolds (PLEMs) to connect each turret buoy with the sendout pipelines, and anchor arrays to support the docking stations and ships during unloading. In addition to the PLEMs and anchor arrays, the Neptune LNG Project would also require a central pipeline manifold to regulate flows from each of the docking stations and a transition manifold upstream of the connection with the HubLine pipeline. Algonquin has indicated that minor modifications to its existing metering facilities in Methuen, Salem, and Weymout, Massachusetts would be needed to regulate gas entering its system from the Northeast Gateway terminal. We assume that similar metering additions would also be needed for the Neptune LNG Project.

Excelerate has indicated that for the Northeast Gateway Project the Coast Guard would probably require a minimum 1640-foot safety and security zone around each docking station. Excelerate and the Coast Guard would also request from the IMO an additional *No Anchor Area* of about 1 nautical mile in diameter around each buoy. In addition, Excelerate has indicated it would request the Coast Guard to establish an *Area to be Avoided* of 2.2 nautical miles around each docking station. Although not a restricted area, the *Area to be Avoided* would be posted on nautical charts to provide a warning to vessels operating in the vicinity of the port. Neptune LNG has indicated that operational activities would limit offshore recreational activities within 2,600 feet of each terminal (or 0.49 nautical mile). The Neptune LNG application did not discuss the additional safety and security areas described by Excelerate, but it is reasonable to expect similar safety and precautionary zones would also be established for the Neptune LNG Project.

---

[4] The discussion of the Neptune LNG Project in this EIS is based on a preliminary review of the Deepwater Port Act application that was submitted to the Coast Guard and the other agencies participating in the NEPA process. Specific project details and the analysis of environmental impacts may be refined and/or change as a result of the Coast Guard's review of the Neptune LNG Project.

[5] In its November 16, 2004 letter to the FERC regarding the Weaver's Cove LNG project, Excelerate indicated that as currently planned, the Northeast Gateway project is intended to deliver baseload natural gas supplies of 400 MMcfd.

Figure 3.2.2-1

You don't have permission to access this document over the Internet. This document is Non-Internet Public (NIP). Public access to this document is available through the **public.referenceroom@ferc.gov**

Existing Pipeline Capacity

We are uncertain about the ability of the existing HubLine pipeline to carry the sendout volumes planned by either Neptune or Excelerate. The HubLine EIS states that the combined Maritimes Phase III/HubLine Project was designed to transport up to 230.5 MMcfd per day of natural gas (FERC, 2001). Excelerate indicates that the HubLine pipeline facilities would be capable of transporting the proposed 400 MMcfd of additional incremental volume without displacing existing deliveries of natural gas being transported on the HubLine pipeline. These volume differences appear significant, and raise the question whether improvements may be necessary to the existing pipeline infrastructure to deliver the baseload sendout volumes proposed by either the Neptune LNG or Northeast Gateway Projects.

Operational Sea Conditions

After anchoring and connecting to the docking buoy, LNG would be vaporized on the LNG ships for either project and sent out through the pipeline as natural gas. The vaporization and unloading process would take about 7 days for each shipment of LNG. Due to the length of time required to offload and the location of the docking facilities further offshore, there would be an increased potential for delays associated with inclement weather and seas. For the Northeast Gateway Project, the following docking and transfer design criteria have been established: a 16-foot sea condition maximum for connecting at the docking station, and a 39-foot sea condition maximum discharge (unloading). The Neptune LNG Project has established slightly lower operational sea conditions of 11.5 feet for connections and 36 feet for unloading. Similar docking systems are currently in use for crude oil transfers in the North Sea where docking maneuvers have occurred in seas up to 18 feet and loading/unloading operations have occurred in seas of 43 feet (Coast Guard, 2003).

To evaluate the sea conditions in the area that both Neptune and Excelerate are considering for their projects, we examined wave height data from the National Data Buoy Center for Station Number 44013. This buoy is located about 16 nautical miles east of Boston at 42º 21' 14'' North and 70º 41' 29'' East, and has a relatively continuous record of meteorological data extending back to 1986 (NOAA, 2004b). Wave height data were missing for the first 5 months of 1986, but we evaluated wave height data for the remainder of 1986 and even-numbered years[6] from 1986 through 2002, as well as 2003. Seasonal average wave heights ranged from 3.4 feet (winter) to 1.6 feet (summer); suggesting that the 11.5- and 16-foot sea conditions for connecting to the buoys are achievable throughout much of the year. Because peak demand for natural gas is likely to coincide with periods of the worst weather conditions, we also looked at maximum wave heights for the months of November through March. Maximum wave heights ranged from 26.4 feet in December 2003 to 5.2 feet in March 1988. Maximum wave heights during the winter and early spring months suggest that the 39-or 36-foot sea conditions chosen for unloading conditions may also be achievable in most years.

Potential Environmental Impacts

Potential environmental impacts associated with the Neptune LNG or Northeast Gateway Projects would result from both construction and operation of the facilities. Construction-related impacts would result from installing the physical structures necessary for the system to function. Operational impacts would result from docking procedures and vaporization of LNG prior to injecting the natural gas into the sendout pipeline(s). These potential impacts are discussed in the following sections.

[6] We limited our evaluation of wave height data to even-numbered years because of the large size of the data set available.

Impacts Associated With the Port Anchor Array

Operation of the docking stations for either project would require the construction and use of a large, permanently-fixed anchor array. Each array would likely consist of eight anchors located in a circular fashion between 1,148 to 4,000 feet from the docking buoy depending on the orientation of the anchor positions. Depending on the design of the anchors, the entire anchor array for each project would disturb between 0.01 and 0.18 acre.

At either project location, additional seafloor disturbance from anchor chain movements would occur each time the turret buoys are raised and lowered to dock and release the LNG vessels. The additional disturbance area would likely range between 4 and 42 acres according to information filed by Excelerate. This disturbance would be a periodic and long-term impact on the seafloor for the life of either project.

Impacts Associated With the Pipeline Facilities

The Neptune LNG and Northeast Gateway Projects would involve construction of 11.1 and 16.4 miles of pipeline, respectively, in the offshore waters off the coast of Massachusetts. Impacts associated with offshore pipeline construction would depend on the specific construction techniques used and whether or not the pipelines would be buried. Pipelines installed in waters less than 200 feet deep need to be buried in the seafloor as required by DOT regulations (49 CFR 192.319(c)). Pipelines installed in waters greater than 200 feet deep (at least in federal waters) would likely be placed directly on the sea floor. Assuming a similar level of impact per mile as was projected for other offshore pipeline projects in the region, we estimate that construction of the Northeast Gateway pipeline could disturb between 1,190 and 1,876 acres of seafloor. Much of this impact would be associated with anchor strikes and cable sweep as a result of positioning and stabilization of construction equipment. Neptune LNG has indicated that it would use dynamically positioned construction vessels. Because these vessels do not require the use of anchors, pipeline installation would likely affect less than 100 acres of seafloor (assuming that dynamically positioned vessels would be feasible for the entire route). In addition to the direct impacts associated with the pipeline, trenching equipment, and anchors/cables, indirect impacts from both projects could result from the suspension, transport, and redeposition of sediments during construction. Impacts associated with offshore pipeline construction in this region are discussed in detail in the EIS for the Phase III/HubLine Project (see FERC Docket Nos. CP01-4-000, CP01-5-000, or CP01-8-000).

The sendout pipelines for the Neptune LNG and Northeast Gateway Projects would both cross about 9 miles of the South Essex Ocean Sanctuary. In addition, the pipeline for the Northeast Gateway Project would cross about 2.8 miles of the Northshore Ocean Sanctuary. The Ocean Sanctuaries Program is administered by the Massachusetts Department of Conservation and Recreation. Crossing these sanctuary requires a Chapter 91 license and review and comment by the Ocean Sanctuaries staff under MEPA regulations.

Aquatic Resources

The impacts of pipeline construction on aquatic resources would depend on the habitats that are crossed and the organisms that occur there. Potential impacts could include covering epibenthos and the smothering of sessile invertebrates through the clogging of their respiratory structures, and potential impacts on eggs and juveniles of bottom-dwelling finfish. Habitat conversion would occur in areas where fine sediments suspended by construction cover cobble, gravel, or other hard bottom substrates. Our review of the substrates along the proposed pipeline route for the Neptune LNG Project (Butman et al., 2004a and 2004b) indicates that much of the currently proposed route across areas requiring pipe burial would impact a mixture of hard and medium bottom substrates. The areas of hard bottom are likely

composed of erosional lag deposits of gravel and cobble covering drumlin-like features. Substrates along the HubLine pipeline route near the proposed interconnect with the Neptune LNG pipeline were reported to include coarse-grained sediments, medium- and fine-grained sediments, fine- to coarse-grained sediments, and fine- to medium-grained sediments (FERC, 2001). Based on this information, it seems probable that some hard substrate (e.g., coarse-grained substrate) would be encountered along the pipeline route for the Neptune LNG Project. Algonquin has routed the pipeline associated with the Northeast Gateway Project to avoid areas of hard-bottom substrate as much as practicable, however, similar impacts on aquatic resources (with less hard bottom habitat impacts) would be likely from installation of the Northeast Gateway pipeline.

Essential Fish Habitat

According to NOAA Fisheries information (NOAA, 2004c and 2004d), the pipeline for the Neptune LNG Project would cross two 10- by 10-minute latitudinal/longitudinal EFH squares. The pipeline for the Northeast Gateway Project would cross the same two squares and a small portion of a third EFH square. There are a total of 28 federally managed fish species that occur in these three squares. Species that occur in the three squares include Atlantic cod, haddock, whiting, red hake, white hake, redfish, witch flounder, winter flounder, yellow tail flounder, summer flounder, windowpane, American plaice, ocean pout, Atlantic halibut, Atlantic sea scallop, Atlantic sea herring, monkfish, black sea bass, long finned squid, short finned squid, Atlantic butterfish, Atlantic mackerel, and bluefin tuna. All three areas include designated EFH for all four life stages (e.g., eggs, larvae, juveniles, and adults) of 14 of these species. One of the squares also includes pollock (all four life stages), and juveniles and adults of bluefish, scup, surf clam, and spiny dogfish. The potential impacts of both projects on EFH would include degradation of water quality through temporary increases in turbidity and potential introduction of chemical contaminants such as fuel and lubricants from equipment operating in and over the water. Additionally, the resuspension of organic materials and sediments could cause an increase in biological and chemical use of oxygen, resulting in a decrease of dissolved oxygen concentrations in the affected area. Lower dissolved oxygen concentrations could cause a temporary displacement of motile organisms and may stress or kill sessile benthic organisms within the affected area.

Lobstering Areas

The sendout pipelines associated with both projects would be located primarily within Massachusetts DMF Statistical Reporting Areas 3 and 19, which are productive lobstering areas. The Northeast Gateway pipeline would also cross a small portion of Area 2. According to 2002 Massachusetts lobster fishery statistics, these areas yielded more than 12 percent of the state's territorial catch, or between 1 and 2 million pounds of the lobster landings in 2002 (Dean et al., 2004). Potential impacts on lobster would include temporary loss of habitat and burial, injury, or death of lobsters in and adjacent to the pipeline trench. Early benthic phase lobster larvae may be particularly susceptible to the latter impact. In deep waters (i.e., greater than 200 feet) where the pipeline may not be buried, the pipeline could create a several mile long barrier to lobster migration, which lobsters may have difficulty crossing.

Based on the information provided by Northeast Gateway, the Coast Guard safety and security zones and *No Anchor Area* would encompass about 1 nautical mile around each docking buoy. We expect similar zones would be established for the Neptune LNG docking buoys. These zones would preclude other vessel traffic and thus would permanently exclude fisherman, including lobster fisherman, and other boaters from fishing or using about 2.0 square miles or 1,331 acres of the ocean during the operational life of either facility.

Threatened and Endangered Species

In addition to finfish and lobsters, several federally listed threatened and endangered species could also potentially occur in the area that would be occupied by the deepwater ports and crossed by the pipelines for both projects. These species include the northern right whale, humpback whale, fin whale, sei whale, sperm whale, and blue whale. In addition, leatherback, loggerhead, Kemp's ridley, green, and hawksbill sea turtles may also occur in the area.

Northern right whales generally occur in the area from January through April but have been known to occur in the area throughout the year. Fin and humpback whales generally are in the area from April to October. These whales are known to frequent Stellwagen Bank, which is near the area both projects are considering for buoy locations, but could also occur closer to shore. Potential impacts on whales could include vessel noise, blasting (if any is necessary), ship strikes or collisions with construction vessels and LNG ships, loss of feeding habitat and prey items, and fuel spills. Additionally, although the final EIS for the HubLine Pipeline Project concluded that it was unlikely that an endangered whale would be affected by that project, this finding was in large part due to the nearshore location of the HubLine Pipeline Project and its distance from Stellwagen Bank and Cape Cod Bay. It has not yet been determined if this same conclusion could be reached for the Neptune LNG or Northeast Gateway Projects, which would be much further from shore and closer to Stellwagen Bank. The potential impacts of both projects on northern right, fin, and humpback whales and other federally listed species would need to be determined based on consultations with the NOAA Fisheries under section 7 of the ESA.

The sea turtles generally occur in the project area from May through October and could be affected by trench excavation, construction vessel traffic, blasting (if any is necessary), and fuel spills. However, the majority of potential impacts on sea turtles would be avoided because both projects have indicated that pipeline construction would be restricted to the winter months, when the turtles are not in the area. Similar to the KeySpan LNG Project, impacts on endangered sea turtles from LNG ship traffic would still be possible during port operations since LNG vessels would arrive and depart throughout the year (see section 4.7.1).

Impacts Associated With Facility Operations

Operation of the LNG import terminals proposed by Excelerate and Neptune LNG would result in air emissions and impacts on aquatic resources.

Air Emissions

The unloading process used by an LNG transport and regasification ship involves the vaporization of LNG and injection of natural gas directly into the sendout pipeline(s). The vessels used for the Northeast Gateway Project would employ a shell-and-tube vaporizer system that would operate in both open- and closed-loop modes. In the open-loop mode, seawater is pumped through the shell and tube system to provide the heat necessary to convert the LNG to the vapor phase. In the closed-loop system, a natural gas-fired boiler is used to heat water circulated in a closed-loop through the shell-and-tube vaporizer and a steam heater. Excelerate has indicated that only closed-loop vaporization would be used to regasify LNG at the Northeast Gateway terminal. The vaporization equipment that would be utilized by the Neptune LNG Project is a combination of closed-loop recirculating propane and closed-loop shell and tube water-based heat exchangers. Based on the environmental notification forms filed by Excelerate, each LNG ship would have a capacity of 138,000 m^3 of LNG (this is equivalent to about 2.95 billion cubic feet of natural gas). The vessels proposed for use by the Neptune LNG Project are similar in size and capacity. Using the closed-loop vaporization process indicated for both projects, it would take

about 7 to 8 days to unload a single cargo of LNG. The closed-loop vaporization process would result in longer durations of unloading than those at the proposed KeySpan LNG facility.

The longer unloading times required to discharge a cargo at the offshore ports would result in increased air quality impacts. Regasification would require each LNG ship to remain at the offshore terminal for about 7 days. Regardless of the mode of vaporization, the ship would need to operate its engines throughout the unloading process, resulting in air quality impacts. Excelerate and Neptune LNG have both indicated that vessels unloading LNG at the terminal would operate using natural gas in place of diesel during cargo discharge operations. The use of either the Northeast Gateway or Neptune LNG facility to provide baseload gas supplies would require one ship to be docked at an unloading platform every day of the year. Closed-loop vaporization would require the use of a gas-fired boiler to operate the vaporizers. Based on the EA for the Gulf Gateway Project (Coast Guard, 2003), the onboard boilers used for the Northeast Gateway Project would use 7,117 million Btu per day, or 4.98 x 10^{10} Btu per cargo of LNG. We expect similar emissions would result from cargo discharges associated with the Neptune LNG Project. The estimated air emissions presented below do not account for those times when two LNG ships would be unloading simultaneously to maintain baseload sendout, and therefore underestimate potential air quality impacts slightly (see table 3.2.2-1). As noted in Neptune LNG's application, additional air emissions would result from the standby vessel that would be present at all times during port operation. We assume a similar support vessel would be required for the Northeast Gateway Project.

TABLE 3.2.2-1

Estimated Air Emissions from LNG Vessel Operations During Offshore Cargo Unloading

NO_x		CO		CO_2		SO_2		VOC	
lb/delivery [a/]	tpy	lb/delivery	tpy	lb/delivery	tpy	lb/delivery	tpy	lb/delivery	tpy
9,464	247	4,186	109	5,978,280	155,862	30	0.78	39	7.1

[a/] delivery is based on 400 MMcfd vaporization rate using closed-loop vaporization (about 7 days per shipload)
NO_x oxides of nitrogen
CO carbon monoxide
CO_2 carbon dioxide
SO_2 sulfur dioxide
VOC volatile organic compounds
lb/delivery pounds per LNG ship delivery
tpy tons per year; (lb/day x 365 days/ year)/ 2000 lb per ton

Although we recognize that air quality impacts occur within a broader global context, prevailing winds in the area are to the east, which might mitigate some of the direct air quality impacts within the United States.

Aquatic Resources

Similar to the KeySpan LNG Project, eggs and larvae of various marine species would be subject to entrainment and impingement impacts from ballasting operations (see section 4.6.2). According to Northeast Gateway, the LNG ships would arrive at the port carrying no ballast water. We assume this would also be the case for vessels operated by Neptune LNG. As the LNG ships offload their cargo, ballast water must be taken onboard to maintain ship stability. Each LNG ship used for the Northeast Gateway Project would utilize about 13.8 million gallons of ballast water per cargo delivery. The regasification ships that would be utilized by the Northeast Gateway Project are currently configured with sea chest intakes equipped with 21 millimeter slotted grates for appropriating ballast water (Coast Guard, 2003). We have assumed a similar grate-slot size for estimating potential impacts from the Neptune LNG

Project. Grates of this size would minimize the entrainment of foreign objects and larger flora and fauna, but would not prevent impingement or entrainment of the eggs and larvae of many marine fish species.

To quantify the potential for entrainment and impingement of ichthyoplankton from ballast water withdrawals, we used data provided in the Neptune LNG deepwater port application. Neptune LNG summarized ichthyoplankton data collected by NOAA Fisheries as part of the MARMAP project from the portion of Massachusetts Bay where both projects would be located. Based on these data and assuming one ship per week and 13.8 million gallons of ballast water for each ship (as reported by Northeast Gateway), we estimate that entrainment or impingement could be as high as about 168,000 eggs and 29,000 larvae (from a variety of fish species) for each shipload of LNG. Although these numbers appear quite large, we note that impacts on ichthyoplankton can be difficult to interpret due to the low natural survival rates of fish eggs and larvae.

Safety and Security Issues

Various commentors have expressed the opinion that an offshore LNG terminal would generally be a preferable alternative to the proposed KeySpan LNG Project. The commentors state that an offshore LNG terminal would avoid public safety concerns of populations adjacent to the LNG shipping route and the terminals, specifically with regard to terrorism. Based on the potential area affected by an LNG spill on water (discussed in section 4.12), our review finds that more people could be potentially affected by a major spill at KeySpan LNG's site than at either the Neptune or Northeast Gateway deepwater port sites. As a result, section 4.12 describes numerous protective plans and mitigation measures as part of the detailed discussion of public safety and security issues associated with the KeySpan LNG Project.

Conclusions for the Neptune LNG and Northeast Gateway LNG Projects

If the Neptune LNG or the Northeast Gateway Projects were constructed, either could potentially meet the KeySpan LNG Project objective of providing a new source of imported LNG in the New England market area. However, the reliability of the supply remains uncertain. To meet peak winter demand in New England, it is essential that an offshore system have the proven reliability to meet the both the average baseload and maximum sendout during the most severe offshore weather. Although the Coast Guard has approved the Gulf Gateway Project for offshore Louisiana, and the port has received its first cargo, the reliability of this type of system to provide continuous service during the most severe offshore conditions has not yet been demonstrated in practice. In addition, service reliability of this alternative is dependent on the availability of uniquely designed ships. At present only one LNG regasification ship is available for the Northeast Gateway Project. As noted earlier, Excelerate expects delivery of its second vessel in late April 2005, and the third ship is not expected to be delivered until October 2006. To provide continuous baseload service, Excelerate would need to have all three ships operating. Until all of Excelerate's ships are constructed and commissioned, reliable baseload operations at the Northeast Gateway terminal are not possible.

The specialized regasification vessels required for the Neptune LNG Project are not yet under construction. As noted earlier, construction of vessels such as these typically requires about 27 months per vessel (Engineering News Record, 2004). In addition, Neptune LNG has indicated that it would not award contracts for the final design and construction of the vessels until the deepwater port license is approved by the Coast Guard and DOT (Neptune LNG, L.L.C., 2005, 1-11). Since review of the license application could take up to 18 months, construction of the LNG regasification vessels would not likely begin before perhaps July 2007. As with the Northeast Gateway Project, Neptune LNG would require all three of its regasification vessels to provide continuous baseload gas service.

In addition to the service reliability question, neither the Neptune LNG nor the Northeast Gateway Project could provide an additional source of LNG to meet existing peak-shaving facilities' needs, which are currently critical in meeting peak winter demand in the New England region (Power Planning Committee, 2005) as discussed in section 1.2. This is because LNG cannot be practically transported by pipeline more than about 3 miles. Both the Neptune LNG and Northeast Gateway Projects would have to convert the LNG back to the gas phase for transport to shore by conventional pipeline. Although we recognize the potential for offshore docking and LNG regasification ships to have a future role in the gas supply mix in New England as well as other areas, these facilities by themselves would not be a viable alternative that meets all of the objectives of the proposed KeySpan LNG Project.

3.2.2.2 Broadwater LNG Facility – Long Island Sound

In November 2004, TransCanada Corporation and Shell US Gas & Power LLC announced plans to develop an offshore LNG import terminal in Long Island Sound. Referred to as the Broadwater LNG Project, the proposed terminal would be capable of receiving, storing, and regasifying imported LNG for delivery as natural gas to the onshore markets via an existing offshore pipeline (Broadwater, 2004). The Broadwater LNG terminal would be located in New York State waters near the center of Long Island Sound about 9 miles off the coast of New York and 11 miles off the coast of Connecticut (see figure 3.2.1-1). The terminal would consist of a Floating Storage Regasification Unit (FSRU). Basically, an FSRU is an oversized, moored LNG vessel fitted with LNG vaporization and docking/unloading equipment that would be about 1,200 feet long by 180 feet wide. The FSRU would be permanently moored in 90 feet of water where it would receive conventional LNG ships every 2 to 3 days. These LNG ships would unload their cargo into the FSRU, which would be designed to store about 350,000 m^3 of LNG. The LNG would then be available for vaporization and sendout through a new 25-mile-long offshore pipeline that would be connected to the existing Iroquois pipeline at an offshore location where the Iroquois pipeline crosses Long Island Sound. According to information provided by the project sponsors, the Broadwater LNG terminal would be able to send out about 1 Bcfd of natural gas to the Iroquois pipeline system.

According to the project sponsors, the Broadwater LNG terminal would be located in an area that avoids the need for onshore development and would not require a shoreline crossing. Thus, the project would avoid sensitive areas found in coastal habitats and beaches as well as avoid the need to construct and operate the facility in populated areas. We anticipate initiating an environmental review of the Broadwater LNG Project sometime in 2005. Pending the review of this proposed project, we feel that our recent analysis of the Islander East pipeline project is illustrative of the various environmental issues associated with construction of natural gas facilities in Long Island Sound (FERC, 2002). Based on this information and our initial review of information available for the Broadwater LNG Project, we anticipate environmental issues associated with the project would include those related to aesthetics, water quality, biological communities, socioeconomics, fishing and lobstering, and air quality. These potential impacts are discussed in the following paragraphs.

The FSRU would be constructed at a shipyard and be towed to the project location for permanent mooring. As such, environmental impacts in the Sound would largely be limited to the construction of the mooring system and the subsea pipeline. As discussed previously for the Neptune LNG and Northeast Gateway Projects, equipment necessary to lay, excavate a trench for, and backfill the subsea pipeline, as well as site the anchors and cables associated with the construction vessels would all result in disturbances to the seafloor (e.g., resuspension and redeposition of bottom sediments). Moreover, it is anticipated, due to its greater length, that the subsea pipeline for the Broadwater LNG project would likely have more impact on the seafloor than the subsea pipelines for either the Neptune LNG or Northeast Gateway Projects. Additionally, the FSRU mooring tower would permanently impact about 0.2 acre of seafloor. The particular impacts that these disturbances would have on aquatic resources

depend on the habitats affected and the organisms that occur in the area. Potential impacts could include covering epibenthos and the smothering of sessile invertebrates through the clogging of their respiratory structures and potential impacts on eggs and juveniles of bottom-dwelling finfish. Marine sediment resuspension and redeposition during construction should be temporary and localized and should not result in sediment disturbance outside the siting area.

Water for hydrostatic testing of the pipeline or as ballast for the LNG ships would be withdrawn from the Sound. These periodic withdrawals could result in the entrainment of phytoplankton and zooplankton, including some fish eggs and larvae.

The Coast Guard would most likely establish security zones around the FSRU and LNG ships. Although the size of these zones has not yet been determined, the project sponsors predict that commercial/recreational boating and fishing activities within about 0.5 mile of the FSRU would be permanently limited. The security zones around incoming or outgoing LNG ships may also temporarily create minor delays in other marine traffic in the Sound. However, the location of the FSRU away from major shipping lanes would minimize these delays.

A new LNG import terminal in New England has the potential to help reduce overall air emissions in the region by reducing dependency on less clean fossil fuels. However, construction vessels, LNG ships, and equipment on the FSRU (e.g., submerged combustion vaporizers) would result in localized emissions.

The FSRU would rise 75 to 100 feet above the water line and would include operational lighting. As such, this facility could potentially impact the offshore viewshed. Because the facility would be located 9 to 11 miles from shore, the FSRU and LNG ships would be barely visible (even on clear days) and would resemble a conventional ship or freighter from a distance. Additionally, the project sponsors suggested that they would limit lighting of the facility to levels necessary for safe operation of both the FSRU and any other area vessel traffic. Cut-off or directional lighting could be used to focus and direct light generally towards work areas.

From a technical perspective, there is uncertainty regarding the existing Iroquois pipeline system's capability of delivering 1,000 MMcfd. Currently, it is our understanding that the Iroquois system has a delivery capacity of about 500 MMcfd into New York City and Long Island. Even if 500 MMcfd were sent to New York and 500 MMcfd were sent to Connecticut, the Iroquois system could require upgrades that would be indirectly related to construction and operation of the Broadwater LNG Project. Further, to provide any of this gas to southeastern New England, additional upgrades to the existing Algonquin pipeline system could be required. These issues will be evaluated in more detail as part of the FERC's review of the Broadwater LNG Project. As noted above in the discussion of the Neptune and Northeast Gateway Projects, an offshore facility would not be able to provide a source of truckable LNG for the New England peakshaving market. Consequently, the Broadwater LNG Project would also not be able to satisfy one of the objectives of the KeySpan LNG Project. Although we recognize the potential for offshore FSRU facilities as another source of natural gas to the New England region, the Broadwater LNG Project cannot satisfy all of the objectives of the proposed KeySpan LNG Project.

3.2.3 Proposed or Existing Sources of Natural Gas Outside of New England

As an alternative to developing a new LNG import terminal in New England, we considered the feasibility of accessing existing or proposed sources of natural gas outside of the region. Natural gas currently used in the eastern United States comes from existing production areas in Canada, the central and western United States, and the Gulf Coast. Generally, the production of natural gas from these

sources is not expanding or is expanding too slowly to meet the growing demand for natural gas (National Petroleum Council, 2003). One promising source of new supplies of natural gas includes LNG imports. As previously discussed, the Distrigas LNG facility currently provides natural gas to New England from vaporization of imported LNG. Outside of the New England region there are existing LNG import terminals at Cove Point, Maryland; Elba Island, Georgia; Lake Charles, Louisiana, and the Gulf of Mexico (the newly constructed Gulf Gateway terminal). Additionally, there have recently been numerous proposals to develop new LNG import terminals throughout North America. Those that have recently been approved are listed in table 3.2.3-1.

TABLE 3.2.3 -1

Recently Approved LNG Import Terminals [a/]

Project /Owner	Location	Sendout Capacity	Storage Tanks, Capacity	Status
Gulf Coast LNG Import Terminals				
Cameron LNG Project *Sempra Energy*	Hackberry, LA	1.5 Bcfd	Three 160,000 m^3 tanks	FERC approval issued September 2003; construction pending
Freeport LNG Project *Cheniere Energy, Inc.*	Freeport, Texas	1.5 Bcfd	Two 160,000 m^3 tanks	FERC approval issued June 2004, construction pending
Gulf Gateway Project *Excelerate*	Lease Block West Cameron 603, Cameron, LA	0.5 Bcfd	Transport and regasification vessel; no storage	Coast Guard and DOT approvals issued in January 2004; Construction completed in February, 2005, first cargo received late March, 2005
Port Pelican Offshore Deepwater Port Project *Chevron-Texaco*	Vermillion Block 140, Offshore LA.	1.0 Bcfd	Two 165,000 m^3 gravity-based structures	Coast Guard and DOT approvals issued in November 2003; facility currently under construction
Canadian LNG Import Terminals				
Irving Oil LNG and Multi-purpose Pier Project *Irving Oil*	Saint John, New Brunswick	1.0 Bcfd	Three 160,000 m^3 tanks	Canadian government approvals issued August 2004
Bear Head LNG Project *Anadarko Petroleum Corp.*	Point Tupper, Nova Scotia	1.0 Bcfd (Phase I) 1.5 Bcfd (Phase II)	Two 180,000 m^3 tanks (Phase I) One 180,000 m^3 tank (Phase II)	Canadian government approvals issued Mid-2004; construction began in late 2004

[a/] Table based on information obtained from LNG Express, Vol. XIV, No.6, June 2004; Vol. XIV, No. 8, August 2004; Vol. XIV, No. 9, September, 2004; and Vol. XV, No. 6, March 2005; EPA informal dockets;, and project applications/Environmental Impact Statements.

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 KeySpan LNG. Existing pipeline systems in the New England region include those owned and operated by Algonquin, Tennessee Gas Pipeline Company (Tennessee Gas), Iroquois Gas Transmission Company (Iroquois), M&N, and Portland Natural Gas Transmission Company (PNGT) (see figure 3.2.1-1). For the most part, these pipeline systems provide natural gas from production areas in Canada, the central United States, and the Gulf Coast. While new supplies of natural gas might be developed outside of the market area, including the construction or expansion of other LNG

import facilities along the Gulf and Atlantic Coasts, the interstate pipelines serving the New England market are already operating at or near capacity during the winter months (Tobin, 2001; FERC, 2003). Continued reliance on existing pipeline systems in the face of increasing demands for natural gas in the region will likely result in future supply problems associated with regional and/or localized capacity constraints (Tobin, 2001; FERC, 2003).

Expanding or modifying the existing pipeline systems to be able to deliver natural gas to the New England market would result in a variety of environmental impacts depending on the project size, length, and design. It is typical for significant pipeline construction projects in the region to result in short- or long-term impacts on water resources, upland vegetation, wetlands, wildlife habitats, traffic patterns, and land use. Substantial expansion or modifications to the existing pipeline systems would be required to deliver the gas volumes (up to 375 MMcfd) to the New England market proposed by KeySpan LNG. In addition to construction-related impacts, the operation of pipeline compressor stations also results in permanent noise and air quality impacts. The construction of new pipeline facilities would likely result in higher rates being charged for natural gas transmission - additional costs that are ultimately passed on to the consumer.

Specific issues associated with accessing sources of natural gas outside of the New England region are discussed below.

3.2.3.1 United States/Gulf Coast Sources of Natural Gas

Of the recently approved LNG projects listed in table 3.2.2-1, the four projects located along the Gulf Coast are too far from the New England region to efficiently provide the natural gas delivery volumes proposed by KeySpan LNG, particularly during peak demand periods. Additionally, the use of the Gulf Coast projects as alternatives would likely require substantial expansion of the existing pipeline systems, which could have significant environmental impacts.

In addition to general construction-related effects noted above, the expansion and operation of new compressor stations along the existing pipeline systems needed to deliver additional gas volumes to New England would also result in noise and air quality impacts. Depending on the design parameters, interstate pipeline systems have compressor stations located at 40 to 120 mile intervals. About 5.0 to 8.5 percent of the gas delivered long distances on interstate pipeline systems is used to power the pipeline compressor stations. By comparison, the vaporization process for the KeySpan LNG Project would consume only about 1.0 to 2.0 percent of the natural gas delivered to the New England market. As shown in table 3.2.3-2, the estimated emissions from transporting 375 MMcfd of natural gas from the Gulf of Mexico to New England are much higher than the emissions that would be generated by vaporizing the same volume of natural gas from LNG as proposed by KeySpan LNG. If all other considerations are equal, the direct delivery of LNG to the market where the natural gas is consumed is environmentally and economically more efficient than delivering LNG to locations where the natural gas would need to be delivered long distances. Because KeySpan LNG could efficiently deliver high pressure natural gas to the Algonquin pipeline system, the need for compression facilities (and hence noise and air emissions) along Algonquin's pipeline system would be reduced.

TABLE 3.2.3-2

Comparison of Air Emissions Associated With Transporting Natural Gas Via Pipeline From the Gulf of Mexico Versus Vaporizing LNG in New England [a/]

Delivery Mechanism	SO_2 (tpy)	NO_x (tpy)	PM_{10} (tpy)	CO_2 (tpy)
Pipeline Transport From Gulf of Mexico	18	522	35	580,499
LNG Vaporization	<1	124	10	149005

[a/] Assumes the transmission or vaporization of 400 MMcfd of natural gas.
SO_2 = Sulfur Dioxide
NO_X = Nitrogen Oxides
PM_{10} = Particulate Matter
CO_2 = Carbon Dioxide

The interstate pipelines serving the New England market are already operating at or near capacity during the winter months (Tobin, 2001; FERC, 2003). Consequently, existing pipeline systems would have to be expanded to allow significant volumes of additional natural gas to reach markets in the region. As an example of the technical issues and costs associated with such an expansion, Algonquin recently provided information in response to our data request regarding modifications to its system that would allow delivery of an additional 375 MMcfd of natural gas to New England. Specifically, the theoretical expansion would allow additional volumes of natural gas to be delivered from its interconnection with the Texas Eastern pipeline system in New Jersey to a potential delivery point south of Boston (general market area served by the KeySpan LNG Project). This expansion would include:

- replacing (relaying) about 94 miles of 24- and 26-inch-diameter mainline and mainline loop with a 42-inch-diameter pipeline;
- looping about 6.5 miles of its 24-inch-diameter mainline and mainline loop with another 36-inch-diameter pipeline;
- installing additional 15,000 to 30,000 hp compression units at seven of Algonquin's existing compressor stations;
- uprating existing compressor units at two of Algonquin's existing compressor stations;
- installing appropriate cooling equipment at five of Algonquin's existing compressor stations; and
- updating meter stations as necessary to accommodate changes in operating pressures.

Algonquin's preliminary estimate of the cost of these facilities is approximately $700 million. Depending upon the location of the shippers' delivery points, additional pipeline modifications would also be required on Algonquin's existing laterals where the new incremental gas supply is needed. It is typical for significant pipeline construction projects in the region to result in short- or long-term impacts on water resources, upland vegetation, wetlands, wildlife habitats, traffic patterns, and land use. In addition to construction-related effects, as noted above, the operation of pipeline compressor stations also results in permanent noise and air quality impacts. The KeySpan LNG Project would avoid most of the environmental impacts listed above.

Although this would be a significant expansion of the region's pipeline infrastructure that would allow additional volumes of natural gas to reach New England from the south (potentially originating

from new sources of natural gas in the Gulf Coast region), this expansion would not satisfy the project objective of providing LNG for delivery to peakshaving facilities.

3.2.3.2 Canadian Sources of Natural Gas

New sources of natural gas located to the north of the New England region include two recently approved LNG import terminals in Canada, the Bear Head LNG Project in Nova Scotia and the Irving Oil LNG Project in New Brunswick.

The Bear Head LNG Project is sponsored by Anadarko Petroleum and includes a new LNG import terminal located off the Straight of Canso near Point Tupper, Nova Scotia (see figure 3.2.1-1). The authorized LNG facility will include two 180,000 m^3 storage tanks, with space available for a third tank in the future. A jetty is being constructed to allow unloading of 70 to 135 LNG ships per year. Because the jetty would be constructed out to a depth of 59 feet, significant dredging to allow access for LNG ships is not necessary. The Bear Head facility will be able to initially vaporize and send out about 1 Bcfd of natural gas to the M&N pipeline system (this system runs from Goldboro, Nova Scotia to Dracut and Beverly, Massachusetts). Future expansion of the facility could allow natural gas deliveries of up to 1.5 Bcfd. The Bear Head LNG terminal is being constructed on a 160-acre parcel that is 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. (2004), and environmental approvals for the project have been obtained. This analysis, however, did not consider the facilities that would be needed for the M&N pipeline system to carry the gas to the New England market. Construction of the Bear Head LNG Project began in late 2004 and it is expected to be in-service by November 2007.

The Irving Oil LNG Project is sponsored by Irving Oil, Ltd and will include a new LNG import terminal and multi-purpose pier at the Irving Canaport facility in Saint John, New Brunswick (see figure 3.2.1-1). Current land use in the general area of the project site is residential, commercial, and industrial. Although the site is zoned for industrial use and is adjacent to the Irving Canaport facility, the site is currently forest land. The LNG terminal will include three 160,000 m^3 single containment storage tanks. A 1,000-foot-long pier will be built from the shore to the docking/unloading facilities which will be located in water depths greater than 82 feet. Due to the depth of water at the site for the docking/unloading facilities, dredging and disposal of sediments will not be necessary. The facility will be able to accommodate 80 to 120 LNG vessels a year with capacities up to 200,000 m^3. The LNG terminal will be able to vaporize and sendout about 1.0 Bcfd of natural gas. Natural gas sendout will be via a 5.6-mile-long pipeline that will connect to the Irving Refinery. In addition to the Irving Refinery, the project will supply natural gas to other markets in Canada and the northeastern United States (presumably through the M&N pipeline system). Recent information from Irving Oil indicates that a large portion of the project's projected sendout volume will go to a newly proposed electric power plant (Canadian Broadcasting Corporation, 2004), so it is uncertain how much of the gas provided by the Irving Oil LNG facility will actually be available for other markets. An analysis of the environmental impacts associated with construction and operation of this facility was prepared by Irving Oil Ltd. (2004) and environmental approvals for the project have been obtained. This analysis, however, did not consider the facilities that would be needed for the M&N pipeline system to carry the gas to the New England market. Similar to the Bear Head LNG Project, the Irving Oil LNG Project is expected to be in-service by late 2007.

For New England to receive new supplies of natural gas from either of these Canadian LNG facilities, the M&N pipeline would have to be expanded. Currently, the M&N system is able to deliver 350 to 400 MMcfd of natural gas to markets in New England. It appears that this system could be expanded to deliver at least another 400 to 750 MMcfd of natural gas to New England through the addition of pipeline loops and compression to its system. As an example, M&N proposed its Phase IV

Project in 2002 as a way to increase the capacity of its system by about 385 MMcfd (see FERC Docket No. CP02-78-000). Although this project was withdrawn because the source of the new natural gas supplies was never developed, the Phase IV Project was proposed to include about 31 miles of pipeline looping, four new compressor stations, and modifications at three existing compressor stations. The cost of the expansion was estimated to be $250 million. As noted above, both of the Canadian LNG projects discussed above have been approved and are expected to supply gas volumes to M&N. Currently there are no proposals to expand the M&N pipeline system to allow additional deliveries to New England. We note however, that M&N has recently concluded an open season to assess the potential for new suppliers and consumers of natural gas to utilize the M&N system to transport new volumes of natural gas (Northeast Gas Association, 2005; M&N, 2005). The final outcome of this open season is expected sometime in June 2005 (M&N, 2005). Potential expansion of the M&N system could be as large or larger than the Phase IV Project described above. In addition, Tennessee Gas Pipeline has recently announced a non-binding open season for its Atlantic Supply Expansion Project Northeast Gas Association, 2005). This project is also designed to respond to the development of LNG terminals in eastern Canada and Maine. The project could supply up to an additional 250 MMcfd to the Tennessee system at its Dracut, Massachusetts interconnect with the joint facilities of M&N and PNGT. This project could not be constructed, however, unless an expansion of the M&N system capable of delivering the additional gas volumes were also constructed.

As with the potential offshore LNG facilities in the New England region and the potential LNG facilities in Maine, these Canadian LNG facilities could not provide a source of LNG for the New England peak shaving market.

3.2.4 Existing or Proposed System Alternative Conclusions

As discussed in section 3.1, if the no action or postponed action alternative is adopted there are several potential effects. Two likely outcomes would be: 1) negative environmental and economic impacts associated with more limited supplies of natural gas, and/or 2) the development of other natural gas infrastructure projects that meet some or all of the project objectives identified by KeySpan LNG. At this time, it is not possible to foresee which (if any) of the LNG import projects proposed in the New England region will move forward and be constructed. Regardless, when considered independently, none of the LNG import projects in the region would be capable of serving as a complete alternative to the KeySpan LNG Project.

In any event, we expect that new pipelines or proposals to modify existing pipelines will continue to increase the capacity of existing systems delivering natural gas to the New England region (EIA, 2003b). A case in point is Tennessee Gas Pipeline's 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. Projects such as this will allow access to sources of natural gas outside of the region, including new LNG import terminals that are constructed. However, because of the seasonal nature of energy demand in New England, pipeline infrastructure designed to provide natural gas from outside the region during peak periods of use would be underutilized during much of the year. As a result, the cost of natural gas from outside of the New England region would also generally be higher. Although they would provide an additional source of gas, new or expanded pipeline projects would not be able to meet all of the objectives stated for the KeySpan LNG Project (e.g., a new LNG import terminal and competitive source of imported LNG in the New England market area, an LNG storage facility that would be able to provide a new source of LNG for delivery via truck to peakshaving facilities throughout the region). When considered together, however, several of the projects in or outside of the region could meet many of the project objectives. Table 3.2.4-1 summarizes the capabilities of the various existing or

proposed projects in comparison to the KeySpan LNG Project. However, due to the associated costs and environmental impacts, we do not believe that any of these single or combined system alternatives would provide a clear advantage over the KeySpan LNG Project.

3.3 LNG TERMINAL SITE ALTERNATIVES

3.3.1 Regional Review

As discussed in section 1.2, there is a current and growing demand for natural gas in the New England region. Due to the limitations in the existing pipeline systems serving the region as well as the other disadvantages discussed previously, we believe an LNG import facility located north of the southern terminus of the M&N system or west of the Iroquois Pipeline system would not efficiently serve the New England market (see figure 3.2.1-1). As such, we did not consider alternative LNG terminal sites north of the Massachusetts/New Hampshire border or west of New Haven, Connecticut. In support of this determination, a separate FERC analysis of natural gas infrastructure in the region concluded that siting an LNG import terminal between Boston and New York City would be ideally suited to free up capacity on the Algonquin and Tennessee Gas pipeline systems, thereby providing access to natural gas in the storage fields in New York and Pennsylvania. This would have the effect of reducing New England's reliance on limited aboveground storage, pipeline imports, and LNG during periods of peak natural gas demand during the winter months (FERC, 2003).

3.3.2 Onshore Port Review

Our consideration of alternative onshore LNG terminal sites included a review of environmental, engineering, economic, safety, and regulatory factors. The next step in this analysis was identification of a specific port capable of accommodating LNG ships. Ships that are presently used to transport LNG typically have capacities of up to 145,000 m^3. The larger ships are about 950 feet long with typical drafts up to 38 feet. To ensure that the LNG ships do not easily or frequently run aground, an additional 2 feet of water is desirable under the keel. This means that LNG ships will typically only enter areas with depths of 40 feet or more. Although dredging in shallow water areas could provide access for LNG ships, the dredging required in undeveloped ports would generally be cost prohibitive and would most likely result in substantial environmental impacts. Consequently, our analysis of alternative onshore LNG terminal sites was limited to existing coastal ports that could readily accommodate LNG ships without dredging or with only a relatively small amount of dredging. Figure 3.3.2-1 shows the locations of coastal ports in New England and their proximity to existing pipeline systems.

TABLE 3.2.4-1

Existing and Proposed System Alternatives Compared to KeySpan LNG Project

KeySpan LNG	Distrigas LNG	Weaver's Cove LNG Project Objectives	Neptune LNG and Northeast Gateway LNG	Broadwater LNG	Quoddy Bay LNG	Natural Gas Sources Outside of New England
New LNG import terminal in New England	No (existing LNG import terminal)	Yes (construction of new facility would allow LNG import)	Yes (construction of new facility would allow LNG import)	Yes (construction of new facility would allow LNG import)	Yes (construction of new facility would allow LNG import)	No (new LNG facilities would be outside of the region)
Upgraded/new facilities allowing new access to world-wide natural gas reserves	No (existing LNG import terminal)	Yes (construction of new facility would allow LNG import)	Yes (construction of new facility would allow LNG import)	Yes (construction of new facility would allow LNG import)	Yes (construction of new facility would allow LNG import)	Yes (construction of LNG import terminals outside of the region and regional pipeline expansions)
Expansion to provide up to 375 MMcfd of new sendout capacity	No (existing sendout of up to 715 MMcfd; pipeline expansion could allow an additional 320 MMcfd of sendout)	Yes (new facility would allow sendout of 400 (average) MMcfd [maximum 800 MMcfd])	Yes (new facility would allow sendout of 400 (average) to 750 (maximum) MMcfd)	Yes (new facility would allow sendout of 1.0 Bcfd)	Yes (new facility would allow sendout of 500 MMcfd (average) to 1.0 Bcfd (maximum))	Yes (although there are currently no formal proposals, expansion of Algonquin and M&N/PNGT is conceivable)
Strengthened gas supply to Rhode Island and southeastern Massachusetts	No (expansion would indirectly strengthen Rhode Island and southeastern Massachusetts gas supply via deliveries to Boston area)	Yes (new facility would add natural gas to the Algonquin system south of Boston)	Yes (new facility would add natural gas to the Algonquin system south of Boston)	No (new facility indirectly strengthens southeastern Massachusetts and Rhode Island gas supply via deliveries to New York (Long Island) and Connecticut)	No (new facility indirectly strengthens southeastern Massachusetts and Rhode Island gas supply via deliveries to northern New England markets)	Yes (although there are no formal proposals, expansion of Algonquin could conceivably provide additional deliveries to southeastern Massachusetts and Rhode Island)
A competitive source of trucked LNG	No (currently Distrigas is the only major source of trucked LNG with delivery of 100 trucks/day)	Yes (normal trucked LNG sendout of 100 trucks per day)	No (new facility would not allow LNG trucking)	No (new facility would not allow LNG trucking)	No (new facility would not appear to include LNG trucking; economics of trucking over 350 miles also appear questionable)	No (existing or proposed LNG facilities outside of New England are too distant for economically trucking LNG)

Figure 3.3.2-1

You don't have permission to access this document over the Internet. This document is Non-Internet Public (NIP). Public access to this document is available through the **public.referenceroom@ferc.gov**

We applied siting criteria to screen the suitability of ports to support the necessary docking, storage, and vaporization facilities. Our review focused on both required and environmentally favorable siting criteria for LNG terminals.

Required criteria included regulatory specifications regarding LNG facility layout and safety siting factors that must be met for the project to be feasible. Required criteria included:

- **Thermal Exclusion/Vapor Dispersion Zone** (49 CFR 193.2057 and 193.2059) – Thermal exclusion and vapor dispersion zones must be established in accordance with NFPA 59A. Based on a typical project design, we have applied a thermal exclusion zone with a radius of 1,000 feet from the center of the LNG storage tank.

- **Airports** (49 CFR 193.2155(b)) – LNG storage tanks must not be located within a horizontal distance of 1 mile from the ends of the runway, or 0.25 mile from the nearest point of a runway, whichever is longer. The height of LNG structures in the vicinity of an airport must also comply with Federal Aviation Administration requirements.

- **LNG Waterfront Handling Requirements** (33 CFR 127.105) – Waterfront facilities where LNG is handled must comply with Coast Guard regulations pertaining to layout and spacing of the marine transfer area. These regulations require that each LNG loading flange be located at least 985 feet from general public or railway bridges crossing navigable waterways or entrances to any tunnel under navigable waterways.

Our responsibility under NEPA as the lead federal agency is to determine if environmentally preferable alternatives to the proposed action exist. Favorable review criteria, although not absolute alternative requirements, were applied to assess whether other sites would be reasonable and most likely to provide some environmental advantage over the proposed site. Favorable criteria included:

- **Population Centers/Residences** – We consider it preferable to locate LNG terminals in areas that are not close to population centers and/or residences. We also feel it is preferable for LNG ships to transit far from residentially and commercially developed shorelines. In addition to avoiding potential conflicts with existing land uses, application of this favorable criterion would ideally avoid conflicts regarding perceived safety issues related to transport and storage of LNG.

- **LNG Terminal Footprint** – An ideal waterfront site available for development would include an area in excess of the exclusion zone, which would provide an additional buffer from development.

- **Dredging Requirements** – We consider it preferable to site LNG terminals in areas that require either no or minimal dredging to obtain access to the site and develop and maintain a ship berth. In addition to avoiding impacts on water quality and aquatic resources, minimal dredging requirements provide the added benefit of reducing environmental impacts and costs associated with disposal of dredged material.

- **Parcel Availability** – We consider parcel availability critical for the siting of LNG terminals because Section 3 of the NGA does not provide the project proponent the authority of eminent domain in acquiring property for an LNG terminal project. One of the greatest challenges of siting an LNG facility in the New England region is finding suitable property that is available for industrial development. Although a site may possess the size required for an LNG terminal, the owner may be unwilling to sell or may place unacceptable conditions on the acquisition of the site.

- **Existing Land Use** – We consider it preferable if the development of an LNG terminal is consistent with existing land uses. We also find areas that have been previously disturbed or cleared for industrial or commercial activities preferable to undisturbed areas (greenfield sites), particularly if there are existing LNG facilities already at the site. Additionally, we prefer sites where existing zoning, coastal zone management guidelines, or development plans are consistent with an LNG import terminal.

- **Sendout Pipeline Length** – We consider it preferable for sites to be close to existing interstate pipeline systems that could accommodate the proposed volume throughput. In addition to the lower costs and environmental impacts, shorter pipelines would be expected to directly and indirectly affect fewer landowners/residences.

- **Road Access** – Because there would be traffic into and out of the site during construction and because access to the site would be required during facility operations, we consider site access from highways and other primary roadways preferable to access from undeveloped or secondary roads.

- **Navigational Suitability** – We consider it preferable if development of a site would have minimal disturbance on existing shipping and could be easily reached by LNG ships. Because LNG ships require a vertical clearance of at least 135 feet and horizontal clearance of not less than 165 feet, we also generally prefer shipping routes (navigation channels) that do not cross under bridges as such routes avoid potential concerns about bridge clearance and closures.

- **Environmental Justice** – As part of its NEPA analysis, the FERC addresses the potential for a federal action to result in disproportionately high and adverse health or environmental effects on minority or low-income populations. We consider per capita income, the percentage of minorities within the population, and the percentage of the population below the poverty level as general measures of the potential for a site to meet or conflict with environmental justice objectives. We consider sites in communities with the lowest per capita income, the highest percentage of minorities, or the highest percentage of the population below the poverty level to have the highest potential to raise environmental justice issues.

- **Various Environmental Factors** – We prefer sites in uplands that avoid or minimize wetland impacts or potential impacts on rare or protected species. We also prefer sites that avoid or minimize impacts on recreational activities, and sites that have suitable soils for the necessary LNG facilities.

- **Special Interest Areas** – We consider sites favorable if they avoid conflicts with special interest areas such as state or national parks and marine sanctuaries. When applying this criterion, we consider potential conflicts with special interest areas from either an LNG terminal or its associated sendout pipeline.

For an alternative site to be determined preferable to the proposed site, it either must be superior to the proposed site with respect to most of the siting criteria discussed above, or it must have an overwhelming benefit that the proposed site lacks that would outweigh any potential disadvantages it may have. Under either scenario, it is important to understand the advantages and disadvantages of the proposed site.

KeySpan LNG's proposed project is favorable with respect to most of the additional siting criteria described above. It is located on available land in an industrial port area that is not in a special interest

area. It already supports an operating LNG storage facility and is accessible from a major interstate highway. The presence of an existing LNG storage facility near a highway on an industrial property already owned by the project proponent mitigates many of the issues typically associated with LNG terminal facilities including land ownership issues; visual impacts; traffic and truck route concerns; potential safety concerns about the introduction of LNG storage and vaporization facilities; and socioeconomic concerns related to the impact of the facility on surrounding land uses, property values, and homeowner insurance rates. Section 4.12.3 identifies for the Commission's consideration certain areas in which the existing KeySpan LNG facility does not comply with the new construction safety standards in 49 CFR 193 and the measures required to comply.

We received comments that expressed concern about potential environmental justice issues associated with the KeySpan LNG's project site. Although the existing site is near environmental justice areas, we have not identified any significant environmental justice concerns related to the operational impacts or environmental effects of the proposal, and our analysis indicates that construction and operation of the proposed new facilities would not disproportionately burden these communities with adverse environmental or health impacts (see section 4.9.8).

The KeySpan LNG site is in a port area that is accessible from the ocean and would not require dredging specifically for the project. The site's location in the Port of Providence is adjacent to the Providence River navigation channel, a federal shipping channel that is already traveled by a number of ships and is currently being dredged as part of the COE's maintenance program. LNG ships would be able to enter the site without additional dredging and without the water quality and aquatic resource impacts that would result from development of a site in a shallower water area.

The site is near an existing natural gas pipeline system to which it could be connected by construction of a 1.44-mile-long pipeline that would avoid wetlands, streams, and trees. The proposed pipeline route generally crosses commercial/industrial land along two roadways, one of which is heavily traveled, thus construction impacts associated with the pipeline would likely be limited primarily to temporary noise, traffic, and air emission impacts, but could also include uncovering contaminated soils.

When taken together, the attributes of the proposed site significantly narrow the types of onshore sites that might reasonably be considered alternatives to the proposed site. Reasonable alternatives would be limited to existing and more remotely located deep-water areas that can be reached by LNG ships and that include existing LNG storage facilities near existing pipeline systems.

Figure 3.3.2-1 identifies other ports and the locations of existing pipeline systems, and figure 3.3.2-2 illustrates the locations of LNG storage facilities relative to existing ports in the New England area. A review of these figures indicates that in addition to the proposed location, there are six other potential ports with existing LNG storage facilities that are reasonably close to existing pipeline systems. These include the:

- Distrigas LNG import facility in Boston Harbor (discussed as a system alternative above);
- NEGC LNG storage tank in Fall River;
- Energy East LNG storage tank in Milford, Connecticut; and
- KeySpan LNG storage tanks in Dorchester, Lynn, and Salem, Massachusetts.

Figure 3.3.2-2

You don't have permission to access this document over the Internet. This document is Non-Internet Public (NIP). Public access to this document is available through the **public.referenceroom@ferc.gov**

All of these locations have serious drawbacks that make them less suitable than the proposed site for an LNG terminal. Most of the sites are too small to allow for adequate expansion to provide the LNG terminalling and natural gas delivery services proposed by KeySpan LNG. Additionally, the NEGC site has a number of other limitations:

- the site is located farther from an existing natural gas pipeline system than the proposed site and would likely require construction of a new pipeline through downtown Fall River;
- use of the existing NEGC tank would likely require construction of a cryogenic pipeline about 1,000 feet long to connect docked vessels with the tank; and
- a significant amount of dredging would be required to create a berth and turning basin for LNG carriers to dock and offload.

The KeySpan LNG site in Dorchester is the only site that appears to have adequate space to potentially handle the required expansion. However, this site as well as the existing KeySpan LNG facilities in Lynn and Salem, and the Eastern Energy facility in Milford, are not adjacent to deep water areas. Development of any of these sites would require substantial dredging. For these reasons we do not believe there are any onshore alternatives that would be preferable to the proposed site for a new LNG terminal.

3.3.3 Offshore Ports

Currently, there are no operating offshore LNG storage facilities in the New England region. As discussed in section 3.2.2, there are several proposals to build offshore LNG import terminals in New England.

3.4 MARINE BERTHING ALTERNATIVES

During meetings between KeySpan LNG and the COE, the COE expressed concern that the location of the proposed ship berth adjacent to the federal shipping channel on the eastern waterfront of the existing facility would place most of the LNG vessel (i.e., all but 5 feet of the total beam width, or up to about 135 feet) within the navigation channel during offloading (see figure 3.4-1). We evaluated two potential berth alternatives that would increase the distance of the berth from the federal channel. One alternative, referred to in this analysis as the Eastern Bulkhead Alternative, would place the pier closer to the existing bulkhead (also on the eastern waterfront) (see figure 3.4-2). The other alternative, referred to in this analysis as the Northern Waterfront Alternative, would place the pier on the north side of the site (see figure 3.4-3). The direct river frontage at the existing site is referred to as the eastern waterfront. The northern waterfront abuts a shallow cove located northwest of the site. The proposed ship berth configuration and associated facilities are described in section 2.2.1.1. The same facilities would be required regardless of the final berthing location.

Figure 3.4-1

You don't have permission to access this document over the Internet. This document is Non-Internet Public (NIP). Public access to this document is available through the **public.referenceroom@ferc.gov**

Figure 3.4-2

You don't have permission to access this document over the Internet. This document is Non-Internet Public (NIP). Public access to this document is available through the **public.referenceroom@ferc.gov**

Figure 3.4-3

You don't have permission to access this document over the Internet. This document is Non-Internet Public (NIP). Public access to this document is available through the **public.referenceroom@ferc.gov**

For the proposed facilities, marine structures would be located both landward and offshore of the existing bulkhead. The proposed eastern waterfront location would place the berth parallel to and just outside the existing federal navigation channel (about 70 feet east of the existing bulkhead). The federal channel is about 1,500 feet wide near the KeySpan LNG facility and begins about 75 feet east of the existing bulkhead. The proposed waterfront berthing configuration would place the majority of the LNG carrier in the federal navigation channel during unloading operations, which is of concern to the COE. Although other ships currently dock within the navigation channel at various existing Providence River berths, none of the ships using these berths are as large as the largest LNG carriers that would call at the proposed LNG terminal site.

In response to the COE's comments on the draft EIS, we have included a discussion of potential economic impacts on users of the federal navigation project resulting from the proposed eastern berth alternative. The Coast Guard has indicated that the federal channel would not necessarily be completely closed while LNG ships are at berth at the terminal. Therefore, while other vessels would need to coordinate with the Coast Guard, access to areas upstream or downstream of the facility would not be prevented and very few associated economic impacts are anticipated. The Coast Guard has indicated that its goal is to minimize impacts on other users of the federal navigation channel. Section 4.12.5 provides an extensive discussion of navigational impacts on other ships and boats during transit of the LNG ships in Narragansett Bay and the federal navigation channel. Additional discussion of the potential economic impacts of ship delays in the federal channel is included in section 4.9.4.

The existing bulkhead at the KeySpan LNG site is a two-part system. The first part is the original granite block wall which is gravity-based, with a footing at an elevation of approximately 30 feet below mean sea level. The second component is a steel sheet pile bulkhead that was constructed directly in front of the gravity wall. The depth of penetration of the sheet piles is not known with any degree of certainty; however, condition analyses in the mid-1990s indicated a significant reduction in structural cross section of the sheets in various locations due to corrosion. Given the questionable condition of the existing bulkhead, minimizing impacts on the existing bulkhead would help ensure the geotechnical stability of the existing facility.

KeySpan LNG submitted an application to the COE on August 20, 2004 for authorization of the proposed project. As part of its review, the COE issued a public notice to several parties including but not limited to the Northeast Pilots Association, the Coast Guard, and harbormasters. In its comments to FERC staff, the COE stated that it could not identify or recommend a specific berth design until the public interest review was completed. The COE is still processing KeySpan LNG's permit application and will not likely decide whether to issue a permit until the EIS process is complete. Similarly, the Coast Guard has indicated that it cannot comment on the navigational aspects of the proposed berth design or recommend a berth design until after the EIS process has been completed.

Eastern Bulkhead Alternative

The Eastern Bulkhead Alternative would place the ship berth immediately adjacent to the existing bulkhead that borders the east side of the site. This alternative would reduce the proportion of the LNG vessel that extends into the federal navigation channel, and thus would reduce potential interference with channel traffic.

Moving the berth facilities closer to the existing bulkhead would locate the berth outside of the area scheduled to be dredged by the COE in conjunction with the Providence River Dredging Project and would, therefore, require an undetermined volume of dredging to achieve the 40-feet of water depth required by most LNG carriers. The excavation of the riverbed at this location would place the channel bottom about 10 feet below the footing of the existing granite block bulkhead. KeySpan LNG engineers

are concerned this could undermine the granite wall, and due to the existing corrosion in the steel sheet piles, could lead to partial or complete failure of the existing bulkhead. Failure of the existing bulkhead could, in turn, destabilize the soils underpinning portions of the existing LNG facility. In addition, as noted in NEGC's August 10, 2004 letter, dredging to allow adequate keel clearance would likely impinge on the three existing NEGC pipelines that cross the Providence River immediately in front of the terminal site.

Relocating the berth closer to the existing bulkhead would also require repositioning of the mooring and breasting dolphins, placing some of them inside the footprint of the existing LNG facility. This configuration would require the ship's lines to cross through the plant during the docking and departure of ships. During docking, the ship's handlers would need to carry leader lines into the plant to reach the dolphins. Upon departure, the lines would be pulled back through the plant as the ship's winches take up the slack during line retrieval. Both processes would pose a hazard for plant personnel and ship's handlers.

Given the potential personnel safety risks and the increased potential for environmental impacts associated with the dredging necessary to implement this alternative, we do not believe the Eastern Bulkhead Alternative provides a significant environmental or safety advantage over the proposed berth location.

Northern Waterfront Alternative

The Northern Waterfront Alternative would place the ship berth on the north side of the existing LNG facility, along the northern waterfront. Berthing on the northern waterfront would allow mooring of the vessel outside of the federal navigation channel and would eliminate most of the potential navigation issues associated with the proposed berth location.

In response to the COE's comments on the draft EIS, we have included a discussion of the potential economic impacts on users of the federal navigation project resulting from the Northern Waterfront Alternative. The Coast Guard has not designated a security zone for LNG ships berthed at the Northern Waterfront Alternative. However, the Coast Guard has indicated to FERC staff that it does not anticipate there would be any difference in navigational impacts between the proposed ship berth and the Northern Waterfront Alternative. The Coast Guard's intent is to minimize disruption of vessel traffic in the port area, and regardless of which berth design is constructed, the Coast Guard expects that it would, at its discretion and with proper coordination, allow passage of other vessels that need to access areas of the Port of Providence northward or southward of the berthed LNG ship. Therefore, no significant economic impacts on users of the federal navigation project are expected as a result of berthed LNG ships.

The northern side of the existing LNG facility is situated on a shallow cove of the Providence River. Water depths within the cove range from 5 to 19 feet. The shoreline at the existing facility is protected with rock rip-rap to reduce impacts from wave and wake action. A fuel unloading pier operated by Motiva Enterprises, L.L.C. (Motiva) is located along the northern edge of the cove. The distance between the shoreline at the existing LNG facility and the Motiva berth is between 500 and 600 feet.

Based on safe navigation and maneuvering guidelines (Permanent International Association of Navigation Congresses, 1996) the required channel width between the KeySpan LNG site and the existing Motiva berth would need to be a minimum of 500 feet. The position of the proposed northern waterfront alternative is based on that requirement and the assumption of a vessel at the Motiva pier during LNG vessel maneuvering and docking operations.

The development of an LNG ship mooring along the northern waterfront would disturb about 800,000 square feet (18 acres) of subtidal shallows and require the dredging of approximately 700,000 yd^3 of sediment. Providence River sediments in the vicinity of the project site are considered contaminated (COE, 2001). The depth of impacted sediments in the cove is not known, but general conditions in the Providence River indicate that the upper 6 feet or more of sediment is contaminated and could require controlled disposal (i.e., controlled aquatic disposal or confined upland disposal). In addition, because this area is located outside of the main flow of the Providence River, the rate of accumulation of sediments in this berth may be rapid, and frequent maintenance dredging of the berth may be necessary.

The channel position and dredging required to achieve sufficient channel depth could also affect the equilibrium of soils and sediments and destabilize the soils underlying the existing facility. This change in equilibrium soil conditions could result in the lateral movement of soils from below the site northward into the cove. KeySpan LNG's engineers have indicated that a bulkhead wall running along the length of the northern berth would be required to minimize the movement of soils. The wall would be located about 15 feet behind the proposed fender line of the marine facilities and about 330 feet north of the centerline of the existing LNG storage tank. The bulkhead wall would need to be about 1000 feet long and would be about 76 feet tall, with 52 feet extending below the mudline on the dredged side of the bulkhead. In addition, a tie-back system would be required to stabilize the wall. Construction of the bulkhead wall on the northern waterfront would also require filling of existing water areas. About 30,000 yd^3 of fill would be needed to construct the northern waterfront berth, which would result in the filling of about 2.5 acres of tidal waters. Potential environmental impacts associated with dredging, filling, and bulkhead construction necessary to implement a berth at this location are much more substantial than those associated with constructing the proposed berth. In addition, construction of the northern waterfront alternative could result in geotechnical soil conditions that could jeopardize the stability of portions of the existing facility. For these reasons, we do not believe that the northern waterfront alternative offers advantages that offset the likely environmental impacts associated with constructing a berth in this location.

3.5 PIPELINE ALTERNATIVES

3.5.1 Pipeline System Alternatives

KeySpan LNG proposes to deliver up to 375 MMcfd of additional natural gas to the New England market. There are two potential pipeline systems in the Providence area capable of receiving this volume of natural gas; the Algonquin pipeline system through its G-12 pipeline, and the Tennessee system through its Cranston Lateral. Tennessee's Cranston Lateral is a single pipeline that crosses a number of the suburbs north and west of Providence. Portions of the Cranston Lateral are 16 inches in diameter; other portions are 20 inches in diameter. The shortest distance between the KeySpan LNG facility and Tennessee's pipeline is about 6.4 miles. A desktop analysis of potential alternative pipeline routes shows that they would have to be considerably longer than 6.4 miles because of the densely developed conditions in the Cities of Providence and Cranston. One potential pipeline route with an approximate length of 8.5 miles is illustrated in figure 3.5.1-1. Regardless of the specific route, a pipeline connection from the KeySpan LNG facility to the Cranston Lateral would be longer than the proposed connection to Algonquin's system and would have more impact on landowners, residences, and businesses. Therefore, we do not believe modification of or additions to the Tennessee system would be preferable to the proposed pipeline.

Figure 3.5.1-1

You don't have permission to access this document over the Internet. This document is Non-Internet Public (NIP). Public access to this document is available through the **public.referenceroom@ferc.gov**

3.5.2 Major Route Alternatives

In evaluating pipeline alternatives, we also assessed whether it might be possible to reduce the environmental impacts associated with the proposed pipeline by developing alternative pipeline routes. We assessed environmental factors (i.e., wetlands, waterbodies, land use, public lands, cultural resources, and proximity to residences) and engineering factors (i.e., terrain, potential construction techniques, and the number of roads and railroads crossed). Through this process, we identified seven pipeline route alternatives or variations. The relative locations of these route alternatives and variations are shown on figure 3.5.2-1. A comparison of these seven routes to the proposed route is provided in table 3.5.2-1.

3.5.2.1 Alternative 1

Alternative 1 would connect Algonquin's existing G-12 Lateral to the KeySpan LNG terminal by crossing the western side of the Providence River using horizontal directional drill (HDD) technology. HDD is a trenchless installation process by which the pipeline is installed beneath obstacles or sensitive areas, such as a river crossing. The installation is a multi-stage process consisting of establishing a small diameter pilot hole along the crossing profile of a feature, followed by enlargement of the pilot hole to accommodate pullback of the proposed pipeline. Drilling fluids, composed of a bentonite and water slurry, are circulated through the borehole to lubricate the bit and drill pipe, stabilize the hole, carry the cuttings away from the drill bit, and reduce friction on the pipe as it is pulled into the hole.

Alternative 1 would include about 1 mile of 24-inch-diameter pipe, beginning at the KeySpan LNG terminal and extending to the G-12 Lateral located in Collier Point Park in Providence (see figure 3.5.2-1). The project area is heavily industrialized with major waterfront businesses including the KeySpan LNG facility and St. Lawrence Cement Facility on Terminal Road, as well as a number of waterfront fuel storage facilities along Allens Avenue including Sprague Energy, Northeast Petroleum, and Motiva.

To accommodate construction along the Providence River, additional staging areas would be needed at both ends of the pipeline to assemble and fabricate the length of pipe necessary to complete the crossing, as well as complete the approximately 1-mile pullback.

At least one staging area would be located at Collier Point Park. This recreational area consists of an L-shaped, 6-acre public park containing grassy areas, a public boat ramp and floating dock, a two-story observation deck, picnic areas, some non-functional coal-moving equipment, as well as the Russian Submarine Museum. The park was created during the Manchester Street Station Repowering Project in 1995 and 1996, and is subject to an environmental land usage restriction. In 2002, the USS Saratoga Museum Foundation, Inc. (Museum Foundation) acquired a 300-foot-long Russian submarine, which was decommissioned in 1994. The submarine is currently docked at Collier Point Park. The Museum Foundation is leasing all or a portion of the park to accommodate the trailers and other facilities associated with the submarine museum.

The berm on the western and northern boundaries, as well as the other park features described above, make any potential workspace layout difficult. Given these characteristics, available areas for HDD workspace and pipe pullback operations at Collier Point Park would be extremely limited. In addition, RIDOT is reconfiguring Interstate Routes 95 and 195 in Providence. This highway project will eventually relocate Route 195 through part of the Manchester Street Site taking a portion of Collier Point Park and affecting a portion of Allens Avenue (see section 4.8.3.2 for more details).

Figure 3.5.2-1

You don't have permission to access this document over the Internet. This document is Non-Internet Public (NIP). Public access to this document is available through the **public.referenceroom@ferc.gov**

The nearly 1-mile length of the HDD necessary to cross the Providence River using Alternative 1, combined with the limited work space on either end of the drill could result in an increased potential for problems during drilling. In addition, workspace for pull section fabrication is limited, potentially resulting in the need for marine-based construction from barges in the Providence River. These factors could lead to schedule delays and an increased potential for drill failure.

Drilling fluid can be unintentionally released through fractures in the bedrock or through permeable soils (commonly referred to as a "frac-out"). Such frac-outs result in an inability to maintain pressure in the drilled hole. Frac-outs may be detected through visual observations or by the loss of pressure and circulation of the drilling fluid. Alternative Route 1 would require the pipeline to pass beneath a number of old piers and docks that are pile-supported along the western shore of the Providence River. These piles could potentially act as conduits for drilling fluid and would increase the risk of a frac-out during the HDD operation resulting in increased potential for the release of drilling fluid into the Providence River. Based on data collected by the COE for the Providence River Dredging Project (COE, 2001), the sediments in this area are likely to be contaminated. If so, the presence of contaminated sediments would complicate efforts to clean up a drilling fluid release into the river. The limited workspace on both ends of the proposed drill would also slow the HDD operation due to constraints on equipment placement and sequencing of operations.

Because of the potential environmental impacts associated with Alternative 1, we do not feel it provides any advantages over or is preferable to the proposed route.

3.5.2.2 Alternatives 2, 3, 4, and 5

Alternative routes 2, 3, 4, and 5 would all cross the Providence River using HDD technology. However, each alternative follows a different alignment across the river, makes landfall at a different location on the east side of the river, and for at least a portion of its length follows a different onshore alignment to an interconnect with Algonquin's G-12 line.

Alternative 2 proceeds in a north-northeast direction from the KeySpan LNG facility across the river to a landfall site in East Providence. The landfall site is located on a rectangular-shaped area of previously filled land owned by the Providence & Worcester Railroad (PWR), which is locally known as the "South Quay." From this point the route heads northeast across the South Quay for approximately 1,600 feet until it reaches the PWR right-of-way. Alternative 2 then heads north parallel to the PWR for approximately 1,500 feet to Algonquin's G-12 Lateral at "Bold Point" in East Providence. The land in this area is generally vacant and unimproved and is known as the "Colfax" property (City of East Providence, 2003).

Alternative 3 leaves the KeySpan LNG facility, crosses the Providence River at a more easterly angle than Alternative 2, and makes landfall at the southern edge of the South Quay. Alternative 3 extends on-land to the northeast across the South Quay to the PWR right-of-way and then heads north up to the G-12 Lateral following the same path as Alternative 2.

Alternative 4 leaves the KeySpan LNG facility and heads east-northeast across the Providence River, making landfall on the 26-acre Chevron Property in East Providence. The Chevron property is linear in shape and slopes down steeply from Veterans Memorial Parkway (VMP or Parkway) to the Providence River. From this location Alternative 4 heads north along the PWR right-of-way until it joins the same alignment as Alternative 3.

TABLE 3.5.2-1

Environmental Comparison of Alternative Routes to the Preferred Route

Environmental Factor	Proposed Route	Alternative 1	Alternative 2	Alternative 3	Alternative 4	Alternative 5	Alternative 6	Alternative 7
Length (miles)	1.44	1.0	1.2	1.23	1.31	1.4	1.56	1.56
Collocated with Existing ROW (percent)	79	0	23	43	54	37	32	32
Wetlands Crossed (feet)	0	0	1,500	1,500	1,500	240	0	0
Forest Land Traversed (miles)	0	0					0	0
Cultural Resource Sites (number)	0	0	0	0	0	1 [a/]	0	Not available
Industrial/Commercial Land Crossed (miles)	1.44		1.20	1.23	1.31	0.6	1.56	1.56
Waterbodies Crossed (numbers)	0	1	1	1	1	1	0	0
Underwater HDD [b/] Distance (feet)	0	5,200	3,200	3,300	3,200	2,900	0	0
Residences within 50 feet of Construction Right-of-Way (numbers)	0	0	0	0	0	0	0	0
Major Paved Roads Crossed (numbers)	2	0	1	1	1	3	9	8
Railroads Crossed (numbers)	11	0	1	1	1	2	3	3

[a/] National Register of Historic Places Eligible

[b/] HDD – Horizontal Directional Drill

Alternative 5 follows the same alignment across the river and makes landfall on the east side of the river at the same location as three existing 10-inch-diameter NEGC pipelines. In a previous proposal, when the KeySpan LNG facility was owned by Algonquin LNG, Algonquin had proposed to acquire and use two of these pipelines instead of constructing a new pipeline across the river. According to Algonquin, this option is no longer feasible.[7] As a result, if Alternative 5 were selected, Algonquin would have to construct an additional pipeline across the Providence River using HDD technology.

From the landfall on a dismantled tank farm property owned by Chevron, Alternative 5 turns and proceeds northward parallel with the river for about 400 feet. The alternative then joins and follows a former driveway across the PWR right-of-way. It then proceeds up a slope and crosses the VMP. On the east side of the VMP, Alternative 5 proceeds northward adjacent to the eastern edge of the VMP for about 1,900 feet. The alternative then turns and proceeds southwest across the VMP and the East Bay Bike Path. It then continues down a steep slope. At the bottom of the slope, Alternative 5 turns and proceeds north across vacant industrial land for 1,800 feet adjacent to the PWR and a sewer right-of-way. It then crosses the PWR right-of-way and ends at Algonquin's existing G-12 Lateral, approximately 250 feet northeast of the entrance to Bold Point in the City of East Providence.

The primary advantage of Alternatives 2, 3, 4 and 5 is that they would avoid the traffic and noise impacts and slower construction progress associated with the in-street construction down Allens Avenue and Henderson Street. This benefit, however, would be offset by potential impacts on the Providence River, particularly if there is a frac-out in the water. Additionally, all four alternatives, particularly Alternatives 2, 3, and 4 would affect wetlands that are avoided by the proposed route.

Another issue specific to Alternative 5 is its location on the VMP. The VMP was constructed in the early 1900s, was designated as a Scenic Roadway in 1991, and is also eligible for listing on the NRHP. Construction within the Parkway would present several challenges and result in additional impacts, including the need to work in closer proximity to residential areas on the east side of the Parkway, impacts on the East Bay Bike Path, the potential need for tree clearing along the road shoulder, and utility development constraints along the Parkway as outlined in the Waterfront District Plan (City of East Providence, 2003). In addition, the Waterfront District Plan states that future utility installations must use the existing paved portion of the right-of-way:

> *"Utility installations, both above and below ground, that require destruction of existing aesthetic elements of the Parkway, such as trees, rock outcrops, and existing topography, shall be prohibited. There shall be no new utility installations in the unpaved portion of the Parkway right-of-way and in adjoining properties that create negative visual qualities…"*

Because of the need for a significant HDD crossing of the Providence River and potential impacts on wetlands and the river, and in the case of Alternative 5, the VMP and the East Providence waterfront, we do not believe that Alternatives 2, 3, 4, or 5 provide any environmental advantage over or would be preferable to the proposed route.

3.5.2.3 Alternatives 6 and 7

Alternatives 6 and 7 (see figure 3.5.2-1) were identified to minimize the amount of pipeline within Allens Avenue. Algonquin has still not provided complete detailed engineering information for the proposed route but has identified a number of utilities within Allens Avenue. Alternatives 6 and 7

[7] NEGC and KeySpan were able to determine the elevation of the pipelines allowing completion of the maintenance dredging of the federal navigation channel in the area of the pipelines. Therefore, NEGC will not have to lower or reconstruct any of its existing pipelines.

would reduce the amount of pipeline within Allens Avenue, which would put the pipeline in a less well traveled area and might reduce traffic impacts.

Alternative 6 follows the same alignment as the proposed route from the KeySpan LNG facility west to Allens Avenue. Where the proposed route turns and proceeds north along Allens Avenue, Alternative 6 crosses Allens Avenue and heads west across the property owned by Motiva until it reaches Interstate 95. Alternative 6 then turns and proceeds north parallel to the east side of the Interstate 95 corridor. After crossing the Thurbers Avenue interchange, the alternative joins Poe Street, and proceeds north within Poe Street until it rejoins the proposed route in Allens Avenue at MP 1.27. It then follows the same alignment as the proposed route to the tap valve site adjacent to Henderson Street.

Alternative 7 is a minor route variation that follows the same alignment as Alternative 6 from the KeySpan LNG facility to the point where it leaves the Interstate 95 corridor and turns to join Allens Avenue at MP 1.27. At this point, Alternative 7 continues northward, crossing under Blackstone Street in the median between the north- and south-bound lanes of U.S. Route 1 to a point opposite Henderson Street. Alternative 7 then turns nearly 90 degrees, crosses Allens Avenue, and joins the proposed route at Henderson Street.

Alternatives 6 and 7 are slightly longer and therefore may disturb more land than the proposed route. Algonquin also expressed concern about the potential to encounter contaminated soils along these routes and the difficulty of constructing across the Thurbers Avenue interchange. While we agreed in the draft EIS that these issues might pose challenges, we recommended that Algonquin provide in its comments on the draft EIS additional environmental and engineering information regarding Alternatives 6 and 7. We recommended that Algonquin further assess Alternatives 6 and 7 because of the presence of several utilities along Allens Avenue, which we thought could potentially complicate construction along the proposed route. In its response to our February 24, 2005 data request, Algonquin stated that the available utility information it has gathered to date indicates that there are available corridors within Allens Avenue without known existing utilities in which the proposed pipeline could be placed (Algonquin noted, however, the possibility that additional, previously unidentified utilities could be found during construction that would require avoidance). As discussed in section 2.3.2, two idle NEGC pipelines are among the facilities currently within Allens Avenue. Algonquin and NEGC are evaluating the possibility of Algonquin replacing one of the idle NEGC pipelines with Algonquin's proposed pipeline and Algonquin believes this may be a viable option.

Specifically, we recommended that Algonquin provide an assessment of the engineering feasibility of each of these alignments, including detailed drawings showing the width of the proposed construction right-of-way and the location of buried utilities. Algonquin provided the information on Alternatives 6 and 7 as requested. Construction of Alternative 6 would require substantial deep excavation associated with crossing the exit and on-ramps at exit 18 of Interstate 95 (I-95). Excavations required for the conventional bore crossing could compromise the I-95 ramps. Construction in the area of the Poe and Lehigh Street intersection could present additional hazards to the stability of I-95. Additionally, construction within Poe Street would likely require the use of the entire street as additional work space, resulting in street closures and potentially significant impacts on local businesses. Use of Alternative 6 would potentially result in greater disturbance of contaminated soils and groundwater. Algonquin identified eight potential contamination sources along the route of Alternative 6. In contrast, pre-characterization of soil and groundwater along the proposed route in Allens Avenue has not identified any hazardous wastes requiring special handling procedures. For all of these reasons we do not believe that Alternative 6 provides any environmental advantage over or would be preferable to the proposed route.

The route for Alternative 7 would place the pipeline in direct conflict with the RIDOT's realignment project for I-95 and I-195. As such, construction of this alternative would not be feasible, and we do not believe that Alternative 7 provides any environmental advantage over or would be preferable to the proposed route.