3.0 ALTERNATIVES

In considering Weaver's Cove Energy's proposal, the FERC will review both the environmental and non-environmental record in deciding whether it is in the public convenience and necessity to issue any authorization for the project. In accordance with NEPA and Commission policy, we have evaluated a number of alternatives to the Weaver's Cove LNG Project to determine if any are reasonable and environmentally preferable to the proposed action. Alternatives described in the following sections include no action or postponed action, system alternatives, LNG terminal site alternatives, LNG terminal layout alternatives, pipeline alternatives, and dredging/dredge disposal alternatives.

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

- are technically and economically feasible, reasonable, and practical;
- offer significant environmental advantage over the proposed project; and
- meet the project objectives of providing a new LNG import terminal, including a new LNG storage facility, in New England and source of imported LNG for New England markets; access to natural gas reserves in production areas throughout the world; a new supply of natural gas for New England, and the ability to deliver LNG by truck to LNG storage facilities throughout the region (see section 1.3).

With respect to the first criteria, 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 that 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 to construct an LNG import terminal and natural gas pipeline. It may: 1) deny the approvals; 2) postpone action pending further filings or study; or 3) grant the approvals with or without conditions.

If the Commission denies the Certificate or postpones action on the application, 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 Weaver's Cove Energy would not be able to provide a new and competitively priced supply of natural gas and the ability to deliver LNG by truck to the New England region in the near future. It is purely speculative to predict the resulting effects and actions that could be taken by other suppliers or users of natural gas in the region as well as any associated direct and indirect environmental impacts. However, since the existing natural gas pipeline system in New England is nearly at capacity during peak

use months (FERC, 2003) and demand for energy in New England is predicted to increase, customers would have fewer and potentially more expensive options for obtaining natural gas 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 alternative proposals to develop natural gas delivery or storage infrastructure, increased efficiency and conservation or reduced use of natural gas, and/or the use of other sources of energy. The effect of high natural gas prices on the increased demand for other fuels is supported by the energy consumption projections provided in EIA's Annual Energy Outlook 2004 report. The projections for the national growth of total coal consumption increased 0.3 percent from 2003 to 2004 primarily due to higher natural gas prices. Higher natural gas prices were also cited as a reason for the projected increased demand for total renewable fuels (EIA, 2004).

Alternative Natural Gas Infrastructure Proposals

The adoption of the no action alternative would 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 Weaver's Cove 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 (see section 3.2). 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 and Other Sources of Energy

Denying or postponing a decision on Weaver's Cove Energy'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. 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 with 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 (DOER) reported several benefits of energy efficiency programs (DOER, 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;
- 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 analyzed projected energy demands in the Northeast. The ACEEE reviewed the national and regional relationship between natural gas price effects of energy efficiency and renewable energy practices and policies (ACEEE, 2003). The 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 result in a 0.9 percent reduction by 2008 in natural gas consumption in the northeastern states, which include the New England states as well as New York, New Jersey, Pennsylvania, Delaware, and Maryland. 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. An 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, 2005). Furthermore, each of these sources of energy would have project- and site-specific environmental issues such as the disposal of toxic materials, alterations to hydrological/biological systems, and visual impacts.

Denying or postponing a decision on Weaver's Cove Energy'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 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 EIA estimates that in 2005, energy consumption in New England from renewable sources such as hydroelectric, geothermal, wood and wood waste, municipal solid waste, other biomass, wind, ethanol, photovoltaic, and solar thermal sources will account for about 9 percent of the region's total energy consumption as compared to estimates of 23 percent from natural gas, 51 percent from petroleum, 6 percent from coal, 10 percent from nuclear power, and about 1 percent from electricity imports. The EIA also predicts that consumption of renewable energy will increase by 1.1 percent a year until 2025. The majority of the increase in renewable energy generation is expected to come from wind power. The EIA predicts that natural gas consumption will increase over the same period by 1.4 percent per year, consumption of petroleum and coal will increase by 1.0 and 1.1 percent per year, respectively, and there will be virtually no increase in consumption of energy from nuclear power (EIA 2005).

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 substantially reduce demand or increase its development of infrastructure before 2010 to ensure reliable delivery of natural gas in the winters beyond 2010 (see more discussion of this topic in section 1.3). 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 include 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 include construction of onshore, in-region LNG expansion projects like the proposed KeySpan LNG Facility Upgrade Project (see section 3.2.1.2); construction of one or more new onshore, in-region LNG terminals like the proposed Weaver's Cove LNG Project; construction of one or more new offshore, in-region LNG terminal similar to the Northeast Gateway or Neptune LNG, L.L.C. (Neptune LNG) Projects (see section 3.2.2.1); and construction of one or more new 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 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 opinion, 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. Nuclear energy in particular, which currently accounts for about 10 percent of the energy consumed in the New England region, is not expected to provide an additional source of energy over the next few years. New nuclear facilities are unlikely to be built in the region given public opposition, environmental issues, and regulatory hurdles. Additionally, cost overruns that occurred during nuclear facility construction in the 1970s and 1980s make financing new nuclear facilities problematic (EIA, 2004). It is also important to note that the Governors Conference Report did not consider the environmental impact of any of the nine scenarios.

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 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 Weaver's Cove LNG Project assuming it provides about 400 MMcfd of natural gas to the New England market and the corresponding emissions that would result if an equivalent amount of energy were generated using coal or fuel oil in lieu 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.

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, similar to the proposed LNG. The distribution of these fuels to market would require more truck, barge, and train trips than the distribution of an equivalent amount of energy derived from natural gas, which would increase emissions and traffic congestion.

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	44	6,622	530	7,333,333	2,000,000
Fuel Oil	34,657	13,245	751	10,633,333	2,900,000
Coal	92,714	46,357	2,053	13,933,333	3,800,000

a/ The emissions generated by coal, fuel oil, and natural gas were estimated using the most 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 British thermal units per hour. The emissions from each fuel source are estimated based on a total annual fuel use of 146,000,000 million British thermal units (Btu) per year (400 million cubic feet per day, 365 days per year, 1000 Btu/cubic foot).

SO_2 = Sulfur Dioxide
NO_X = Nitrogen Oxides
PM_{10} = Particulate Matter
CO_2 = Carbon Dioxide
C = Carbon
tpy = tons per year

No Action or Postponed Action Conclusions

As described in section 1.3, a recent FERC study 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 (2004) estimates, which include increased use of renewable energies, support this conclusion. Neither conservation measures nor renewable energy sources are expected to replace or significantly offset the demand for additional natural gas supplies in the New England region.

As noted above, 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 Weaver's Cove Energy.

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 would 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, 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 Weaver's Cove 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 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 LNG facility). As described in section 1.3, the objectives of the Weaver's Cove LNG Project are to construct and operate a new LNG import terminal that could provide a new source of natural gas and trucked LNG deliveries to the New England market. Specifically, the Weaver's Cove LNG Project would provide:

- a new LNG import terminal and competitive source of imported LNG in the New England market area;
- a new facility in New England for the storage of up to 200,000 m^3 of LNG;
- access to natural gas reserves in production areas throughout the world that are inaccessible by conventional pipelines;
- a new supply of natural gas to New England (normal pipeline sendout of 400 MMcfd and a maximum sendout of 800 MMcfd);
- strengthened gas supply to southeastern Massachusetts and Rhode Island; and
- a competitive source of LNG delivered by truck to LNG storage facilities throughout the region (normal trucked LNG sendout of 100 trucks per day).

The analysis below examines other potential existing, modified, or proposed LNG and pipeline systems and considers whether these systems could meet some or all of the project objectives.

3.2.1 Existing and Proposed Onshore LNG Facilities in New England

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 scattered throughout New England. 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 from the Distrigas LNG import facility. Providing a new source of LNG from outside of the New England region would require trucking LNG from one of the other existing LNG import terminals in the United States. The closest of these terminals is the LNG import facility in Cove Point, Maryland, which is located about 475 miles from the project area. The other LNG import terminals are located considerably further away. One LNG ship is able to transport the equivalent of about 3,300 LNG trucks. Due to the transportation costs associated with trucking LNG over long distances, we believe the option of transporting LNG from an import terminal outside of the New England region is not a reasonable alternative.

The two existing LNG facilities in the New England market area that are reasonable to consider as potential system alternatives are the Distrigas LNG facility and the KeySpan LNG facility. Additionally, there have been public announcements to construct LNG import terminals in Long Island Sound, off the coast of Massachusetts, and in Maine. These offshore proposals are discussed in section 3.2.2. Although there have been reports in the press that Somerset LNG, L.L.C. (Somerset LNG) may propose an LNG import facility at Brayton Point in Somerset, Massachusetts, the FERC has not yet

received a formal application nor has there been any recent news regarding the development of the project. As such, we considered an LNG terminal at Brayton Point as a site alternative rather than a system alternative (see section 3.3.3). Our system alternative analysis of existing and proposed onshore LNG facilities in New England, therefore, includes the Distrigas LNG facility, the KeySpan LNG facility, and potential LNG projects in Maine. The general locations of all of the existing and proposed LNG facilities in the New England region are illustrated on figure 3.2.1-1.

3.2.1.1 Distrigas LNG Facility - Everett, Massachusetts

The only existing LNG import terminal in New England is the Distrigas LNG facility owned by Tractabel. The 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 adjacent power plant, and the installation of additional vaporizers and pumps to provide natural gas service to the power plant. The Distrigas LNG facility has two tanks that can store 974,000 barrels (155,000 m^3) of LNG and an installed vaporization capacity of 1.035 billion cubic feet per day, 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 peakshaving facilities throughout New England. The four-bay truck station on the site can fill up to 100 trucks per day. In 2003 and 2004, 53 and 68 LNG ships, respectively, made deliveries to this facility (Katulak, 2005).

The Distrigas LNG facility is dedicated to LNG imported by Tractabel 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 Weaver's Cove Energy, it would be necessary to add 1,250,000 barrels of storage and 800 MMcfd of vaporization. There is no space on the existing 24-acre site to construct the additional facilities associated with the proposal, nor is there available adjoining property to accommodate these facilities and the associated exclusion zones. There are no pending proposals to expand the Distrigas LNG facility. While it does not appear this existing facility could be reasonably expanded to satisfy all of the objectives of the Weaver's Cove LNG Project, it is conceivable that the facility could be expanded to provide some additional natural gas sendout capacity. For example, in 2003 the FERC received an application for the Everett Extension Project. Although this proposal was later withdrawn by the proponents because it was not thought to be economically viable, the Everett Extension Project would allow the Distrigas LNG facility to mitigate some take-away constraints and allow sendout of an additional 110 MMcfd of natural gas via a pipeline operated by Algonquin. The proposed project would include construction of the Deer Island Lateral, which was approved by the FERC in 2002 but never constructed, and 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 LNG facility. The facilities required for the project would include reconfiguration of existing vaporization equipment within the existing boundaries of the Distrigas property and new pipeline facilities to be constructed by Algonquin.

Insert Figure

3.2.1-1 New England Pipeline Systems and Existing/Proposed/Planned LNG Facilities

The pipeline facilities for the Everett Extension Project would include 12.4 miles of pipeline (which includes the Deer Island Lateral Pipeline). About 4.2 miles of this 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 horizontal directional drill (HDD); the rest of the offshore pipeline would be installed by dredging, jetting, or plowing. About 36 percent of the pipeline would be adjacent to or within roads or other utility rights-of-ways. Construction of the onshore facilities would disturb about 75 acres of land. Construction of the offshore pipeline would disturb about 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. Because of environmental and permitting constraints, the working conditions in Boston Harbor, and other factors, the Everett Extension Project was not considered economically viable. We are not aware of other ways in which the Distrigas LNG facility could be reasonably expanded to allow additional natural gas sendout or provide more LNG storage.

3.2.1.2 KeySpan LNG Facility - Providence, Rhode Island

KeySpan owns and operates an existing LNG facility on a 17.5-acre site in an industrial section of Providence, Rhode Island. The 600,000 barrel (95,000 m^3) tank is filled by LNG trucks primarily from the Distrigas LNG facility. During periods of peak demand throughout the winter months, natural gas is either vaporized into New England Gas Company's medium pressure pipeline system, or loaded onto LNG trucks and delivered to local natural gas distribution companies. The plant has an LNG barge unloading and cargo transfer system on the dock that it shares with the St. Lawrence Cement Company, its neighbor to the south. The unloading facility was used only once for the LNG barge *Massachusetts* in July 1974, and has not been used since. Although there were plans to expand this facility to accommodate LNG ships during the 1970s, the necessary upgrades were never completed.

On April 30, 2004, KeySpan filed an application with the FERC to modify its existing facility to allow import of LNG by ships, potentially as soon as late 2005 (see FERC docket number CP04-223-000). The FERC issued a draft EIS for this project on November 30, 2004 and a final EIS for the project is scheduled to be issued in May 2005. The project would include modifications to the sendout system that would increase maximum vaporization capacity from 150 to 525 MMcfd and construction of facilities to allow docking and unloading of LNG ships. BG LNG Services, L.L.C. (BG LNG) would be responsible for shipping LNG to the KeySpan facility after the expansion is completed. On average, about one LNG ship per week would unload its cargo at the KeySpan facility. Associated with this project is a proposal by Algonquin to construct a 7,400-foot-long, 24-inch-diameter pipeline that would interconnect with Algonquin's existing G-12 lateral to the north of the terminal. The KeySpan and Algonquin proposals are subject to approval of the FERC under sections 3 and 7(c) of the NGA.

The KeySpan facility is located adjacent to the Fox Point Reach of the Providence River federal navigation channel. The COE recently approved and began dredging this portion of the channel to a depth of 40 feet below MLLW. As part of ongoing industrial operations in the area, the COE also authorized St. Lawrence Cement Company to dredge 11,800 to 32,000 cubic yards of material from the common dock area immediately in front of the KeySpan facility to a depth that would accommodate LNG ships. After the authorized dredging has been completed and the existing barge unloading dock replaced with a new unloading facility, LNG ships would be able to access the site. Given the depths of the Providence River federal navigation channel, LNG ships could move up the Providence River to the KeySpan facility even during periods of low tide. Furthermore, ships accessing the KeySpan facility would only pass under the Newport Bridge; whereas ships accessing the proposed terminal site would pass under the Newport Bridge and under or through three other bridges (see section 4.12).

One issue that the KeySpan site has in common with the proposed site is its location within an industrial area near residential neighborhoods. However, the density of industrial development surrounding the KeySpan site is greater than at the proposed site while the number of residences within 0.5 mile of the site is lower (60 residential structures within 0.5 mile of the KeySpan site compared to 290 residential structures within 0.5 mile of the proposed site). Another similarity between the two sites is the relatively long distance that LNG ships must transit navigation channels to reach the sites. After entering Narragansett Bay, the ship route to the KeySpan site would be about 25.5 nautical miles long, about 2.75 nautical miles longer than the route to the proposed site in Fall River.

The primary disadvantages of the KeySpan facility is the limited capacities of the LNG tank and vaporization system. The current vaporization capacity of 150 MMcfd and planned expansion up to 525 MMcfd is below the peak sendout of 800 MMcfd in Weaver's Cove Energy's proposal. On a sustained basis, it appears that the KeySpan facility would only be able to deliver about 200 MMcfd of natural gas (about half of the average sendout capacity of the Weaver's Cove LNG Project). Also, the existing tank at the KeySpan facility is only capable of storing 600,000 barrels (95,000 m^3) which is about half (48 percent) the volume of the proposed tank (see section 2.2.1.2). Therefore, it does not appear that the KeySpan facility could fully unload LNG ships up to the 145,000 m^3 capacity of the proposed project. To be capable of storing similar volumes of LNG as the Weaver's Cove LNG Project, the KeySpan facility would have to be expanded to accommodate additional storage of LNG. As such, an additional storage tank with capacity of about 650,000 barrels would need to be added at the site or the existing tank would need to be replaced by a new tank with a capacity of about 1,250,000 barrels (200,000 m^3). KeySpan has not proposed any tank expansion plans, nor is there adequate space on the 17.5-acre site to accommodate the thermal exclusion zones of an additional or larger LNG storage tank. We are not aware that the adjacent properties are available and could be used to expand the existing KeySpan facility.

Another disadvantage of the KeySpan facility is the limited capacity of its truck loading station, which is capable of loading up to 24 LNG trucks per day. KeySpan is not proposing to expand its truck loading station. Consequently, the KeySpan facility would not be able to provide the level of truck loading of the proposed facility, which would have a truck loading capacity of up to 100 trucks per day.

The KeySpan expansion would meet several project objectives by providing a new LNG import terminal in New England and source of imported LNG for New England markets, access to natural gas reserves in production areas throughout the world, a new supply of natural gas for New England, and the ability to deliver LNG by truck to LNG storage facilities throughout the region. Based on the limited capacity of the existing LNG tank and the planned increase of the vaporization system, the KeySpan expansion would only provide a partial system alternative in meeting the objectives of the Weaver's Cove LNG Project.

Based on recent projections of natural gas demand in the New England region, by 2009 there will be demand for an additional 500 MMcfd of natural gas above what the current infrastructure is able to provide during peak periods of use (FERC, 2003). Even if it is expanded, the KeySpan facility would not likely be able to deliver this volume of natural gas on a sustained basis (i.e., the average sendout capacity of the KeySpan facility would be about 200 MMcfd). Although it is conceivable that the expansion of the KeySpan facility could be combined with another LNG import terminal that is slightly smaller than the one proposed by Weaver's Cove Energy (e.g., with an average natural gas sendout capacity of around 300 MMcfd), the economics of a new and smaller terminal do not appear practical. See section 4.13 for additional discussion of natural gas infrastructure in the New England region.

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, L.L.C. 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.

The Pleasant Point Energy Facility would interconnect with the 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 Pleasant Point Energy Facility also remains uncertain despite the approval of the majority of the 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. Additionally, when the neighboring town of Perry, Maine sold the property where the LNG facility is proposed to the Passamaquoddy Indians in 1986, the town stipulated that its voters would have the opportunity to review and approve future industrial uses of the property (Bangor Daily News, 2005). In a recent referendum held in Perry, voters rejected the development of the proposed LNG facility.

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 Weaver's Cove 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 (see section 3.2.2.1 for a discussion of impacts associated with offshore pipelines). 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 Corporation (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.

Currently, no company is proposing to build a fixed offshore LNG import terminal in the waters off of New England.

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 in sections 3.2.2.1 and 3.2.2.2.

3.2.2.1 Neptune LNG and Northeast Gateway Projects – Gloucester, Massachusetts

A deepwater port application to build an LNG facility offshore of Gloucester, Massachusetts was filed with the Coast Guard by Neptune LNG, (a subsidiary of Tractabel) on February 15, 2005.[1] In addition, Excelerate Energy, L.L.C. (Excelerate) and Algonquin filed environmental notification forms for the Northeast Gateway Deepwater Port and associated pipeline projects with the Secretary of the EOEA on March 15, 2005. Because these two projects would utilize 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 (see 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 its 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.[2]

---

[1] 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.

[2] 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.

INSERT FIGURE

3.2.2-1 Northeast Gateway and Neptune LNG locations

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 Weymouth, Massachusetts would be needed to regulate gas entering its system from the Northeast Gateway terminal. We assume similar metering additions would also be needed for the Neptune LNG Project.

Excelerate indicated that for the Northeast Gateway Project the Coast Guard would probably require a minimum 1,640-foot safety and security zone around each docking station. Excelerate and the Coast Guard would also request from the International Maritime Organization (IMO) an additional *No Anchor Area* of about 1 nautical mile in diameter around each buoy. In addition, Excelerate indicated they 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.

Existing Pipeline Capacity

There is a question about the ability of the existing HubLine pipeline to carry the sendout volumes planned by either Neptune LNG or Excelerate. The HubLine EIS states that the combined Maritimes Phase III / HubLine Project was designed to transport up to 230.5 MMcfd 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 LNG 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, 2004a). 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[3] 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.

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 no require the use of anchors, pipeline installation would likely impact 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

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

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 sanctuaries 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 information from NOAA Fisheries (NOAA, 2004b), the pipeline for the Neptune LNG Project would cross two EFH areas. The pipeline for the Northeast Gateway Project would cross the same two areas and a small portion of a third EFH area. There are a total of 28 federally managed fish species that occur in these three areas, including 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 areas 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's 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 square miles or 1,330 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 include six whale species (North Atlantic right, humpback, fin, sei, sperm, and blue) and five sea turtle species (leatherback, loggerhead, Kemp's ridley, green, and hawksbill).

North Atlantic 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 both project areas, 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 North Atlantic 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 Weaver's Cove 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 to be used for the Northeast Gateway Project would employ a shell and tube vaporizer system that operates 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 has 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 Weaver's Cove 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 environmental assessment (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 4.98×10^{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.

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 onshore areas of the United States.

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

Aquatic Resources

Similar to the Weaver's Cove 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 marine organisms, but would not prevent impingement or entrainment of the eggs and larvae of many 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. However, these numbers are generally similar to those we have estimated for the Weaver's Cove LNG Project (see section 4.6.2).

Safety and Security Issues

Various commentors have expressed the opinion that an offshore LNG terminal would generally be a preferable alternative to the proposed Weaver's Cove LNG Project. The commentors state that an offshore LNG terminal would avoid public safety concerns of populations adjacent to LNG ship routes and onshore terminals. 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 the proposed Weaver's Cove LNG terminal than at either the Neptune LNG 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 Weaver's Cove LNG Project.

Conclusions for the Neptune LNG and Northeast Gateway LNG Projects

If the Neptune LNG or the Northeast Gateway Projects were constructed, either project could potentially meet some of Weaver's Cove Energy's 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 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 this 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. 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. In addition, service reliability of this alternative is dependent on these specially designed regasification ships because docking and cargo transfers that would be necessary for the facility to function cannot presently be performed by conventional LNG ships. Furthermore, 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 may not be 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, 2005). 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 need all three of its regasification vessels to provide continuous baseload gas service.

It has yet to be determined whether the Neptune LNG or Northeast Gateway Projects would be able to provide the service reliability of a traditional onshore LNG storage facility. Additionally, neither the Neptune LNG Project nor the Northeast Gateway Project could provide an additional source of LNG to meet the needs of existing peakshaving facilities, which are currently critical in meeting peak winter demand in the New England region (Power Planning Committee, 2005). Because LNG cannot be practically transported by pipeline more than about 3 miles, the Neptune LNG and Northeast Gateway Projects would not be able to transport LNG to onshore facilities. 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 Weaver's Cove LNG Project.

3.2.2.2 Broadwater LNG Facility – Long Island Sound

In November 2004, TransCanada Corporation and Shell US Gas & Power, L.L.C. 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 an 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. In early 2005, we initiated an environmental review of the Broadwater LNG Project using our Pre-Filing Process. Pending further 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.

The FSRU would be constructed at a shipyard and be towed to the project location for permanent mooring. As such, environmental impacts in the Long Island 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 would not be expected to 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 Long Island Sound. These periodic withdrawals could result in the impingement and entrainment of ichtyophytoplankton.

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 Long Island 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, we have some concerns as to whether the existing Iroquois pipeline system is capable 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 may 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 LNG 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 Weaver's Cove 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 Weaver's Cove 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 slowly to meet the growing demand for natural gas (NPC, 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 along the East Coast at Cove Point, Maryland and Elba Island, Georgia as well as two facilities in the Gulf Coast region. 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.

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 Weaver's Cove Energy. Existing pipeline systems in the New England region include those owned and operated by Algonquin, Tennessee Gas, Iroquois, M&N, and PNGTS (see figure 3.2.1-1). For the most part, these pipeline systems provide natural gas from production areas in Canada, 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).

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, Louisiana	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; facility currently under construction.
Gulf Gateway Project *Excelerate*	Lease Block West Cameron 603, Cameron, Louisiana	0.5 Bcfd	Transport and regasification vessel; no storage	Coast Guard and DOT approvals issued in January 2004; facility began operation in March 2005.
Port Pelican Offshore Deepwater Port Project *ChevronTexaco*	Vermillion Block 140, Offshore Louisiana	1.6 Bcfd	Gravity-based structure; 330,000 m^3 of storage capacity	Coast Guard and DOT approvals issued in November 2003; construction pending.
Sabine Pass LNG Project *Sabine Pass LNG LP*	Sabine Pass Channel, Louisiana	2.6 Bcfd	Three 160,000 m^3 tanks	FERC approval issued December 2004; facility currently under construction.
Gulf Landing Project *Shell US Oil and Gas*	38 miles off the coast of Louisiana in West Cameron lease block 213	1.0 Bcfd	Gravity-based structure; 200,000 m^3 of storage capacity	Initial Coast Guard and DOT approvals issued February 2005.
Cheniere Corpus Christi LNG Terminal Project *Corpus Christi LNG LP*	Corpus Christi, Texas	2.6 Bcfd	Three 160,000 m^3 tanks	FERC approval issued April 2005; construction pending.
Canadian LNG Import Terminals				
Irving Oil LNG and Multi-purpose Pier Project *Irving Oil*	Saint John, New Brunswick	1.0 Bcfd	Three 160,000 m3 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 m3 tanks (Phase I) One 180,000 m3 tanks (Phase II)	Canadian government approvals issued Mid-2004. Construction began in late 2004.

a/ Project information as of April 19, 2005. Obtained from LNG Express (Vol. XV, No.6, March 2005), U.S. Environmental Protection Agency informal dockets, and project applications and Environmental Impact Statements. More specific information for many of these projects, included in-depth environmental analyses, can be obtained through the Coast Guard or FERC document management systems (see http://dms.dot.gov/ and http://www.ferc.gov/docs-filing/elibrary.asp).

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 800 MMcfd) to the New England market as proposed by Weaver's Cove Energy. In addition to construction-related effects, 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 3.2.3-1, the seven projects located along the Gulf Coast are too far from the New England region to efficiently provide the natural gas delivery volumes proposed by Weaver's Cove Energy. 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 Weaver's Cove LNG Project would consume only about 1.5 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 400 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 Weaver's Cove Energy. 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 Weaver's Cove Energy 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	19	557	37	619,199
LNG Vaporization	1	132	11	158,939

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 regarding modifications to its system that would allow delivery of an additional 375 MMcfd of natural gas to New England (see FERC Docket No. CP04-358-000). 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 Weaver's Cove 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. 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 would satisfy only a portion of the natural gas deliveries proposed by Weaver's Cove Energy.

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 proposed by Anadarko Petroleum and will include a new LNG import terminal located off the Straight of Canso near Point Tupper, Nova Scotia. The proposed LNG facility will include two 180,000 m^3 storage tanks, with space available for a third tank in the future. A jetty will be constructed to allow unloading of 70 to 135 LNG ships per year. Because the jetty will be constructed out to a depth of 59 feet, significant dredging to allow access for LNG ships will not be necessary. The Bear Head facility will be able to initially vaporize and sendout about 1.0 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 will be constructed on a 160-acre parcel that is currently 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. Construction of the facility began in late 2004 and it is expected to be in-service by November 2007.

The Irving Oil LNG Project is proposed 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. Current land use in the general area of the proposed site is residential, commercial, and industrial. Although the proposed site is zoned for industrial use and is adjacent to the Irving Canaport facility, the site is currently forest land. The proposed 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 proposed site for the docking/unloading facilities, dredging and disposal of sediments will not be necessary. The proposed facility could accommodate 80 to 120 LNG vessels a year with cargo 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). 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. 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. Costs for the expansion were estimated to be $250 million. As noted earlier, both of the Canadian LNG projects discussed above have been approved. 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 additional 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 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 Gas system at its Dracut, Massachusetts interconnect with the joint facilities of M&N and PNGT. However, this project could not be constructed unless an expansion of the M&N system capable of delivering the additional gas volumes was 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 peakshaving 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 (see section 3.1); and/or 2) the development of other natural gas infrastructure projects that meet some or all of the project objectives identified by Weaver's Cove Energy. 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 an alternative to the Weaver's Cove 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' 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 most of the year. As a result, the cost of natural gas from outside of the New England region would also generally be higher. Nevertheless, these projects would not be able to meet all of the objectives stated for the Weaver's Cove 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 Weaver's Cove LNG Project.

3.3 LNG TERMINAL SITE ALTERNATIVES

The examination of alternative sites for an LNG import terminal involved a comprehensive process that considered environmental, engineering, economic, safety, and regulatory factors. The first step included determining the most suitable area for an LNG terminal based on the stated purpose of the project of providing a new LNG import terminal as well as a new supply of natural gas and LNG deliveries to the New England market. The second step included identification of a specific port capable of accommodating ships that can transport up to 145,000 m^3 of LNG. The third step included comparatively evaluating specific sites within suitable ports that are capable of supporting the necessary docking, storage, and regasification facilities.

3.3.1 Regional Review

As discussed in section 1.3, 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 in section 3.2.3, we believe an LNG import facility located north of the southern terminus of the M&N pipeline system or west of the Iroquois Pipeline system would not efficiently serve the New England market (see figure 3.3.1-1). 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).

TABLE 3.2.4-1

Existing and Proposed System Alternatives Compared to the Weaver's Cove LNG Project

Weaver's Cove LNG Project Objectives	Distrigas LNG	KeySpan LNG	Neptune LNG or 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 (expansion of storage 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)
New facility in New England region capable of storing up to 200,000 m3 of LNG	No (existing LNG storage of 155,000 m3)	No (existing LNG storage of 95,000 m3)	No (new facility would not allow LNG storage)	Yes (new facility would allow LNG storage of 350,000 m3)	Yes (new facility would allow LNG storage of 150,000 to 200,000 m3)	No (new LNG facilities would be outside of the region)
New facilities allowing access to "stranded" natural gas reserves	No (existing LNG import terminal)	Yes (expansion of storage 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)
New natural gas deliveries in New England averaging 400 MMcfd (max. 800 MMcfd)	No (existing sendout of up to 715 MMcfd; expansion could allow an additional 100 MMcfd of sendout)	No (existing sendout of up to 150 MMcfd; expansion could allow an additional 50 (average) to 375 (maximum) MMcfd of sendout)	No (new facility would allow sendout of 400 (average) to 500 (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 is no formal proposals, expansion of Algonquin and M&N/PNGTS is conceivable)
Strengthened gas supply to southeastern Massachusetts and Rhode Island	No (expansion would indirectly strengthen southeastern Massachusetts and Rhode Island gas supply via deliveries to Boston area)	Yes (expansion would directly serve Providence area)	Yes (new facility would add natural gas to the Algonquin system south of Boston)	No (new facility indirectly strengthen southeastern Massachusetts and Rhode Island gas supply via deliveries to New York (Long Island) and Connecticut)	No (new facility indirectly strengthen southeastern Massachusetts and Rhode Island gas supply via deliveries to northern New England markets)	Yes (although there is no formal proposals, expansion of Algonquin could conceivably provide additional deliveries to southeastern Massachusetts and Rhode Island)
A competitive source of trucked LNG (normal trucked LNG sendout of 100 trucks per day)	No (currently Distrigas is the only major source of trucked LNG with delivery of 100 trucks/day)	No (expansion would allow delivery of 24 LNG trucks/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)	No (existing or proposed LNG facilities outside of New England are too distant for LNG trucking)

Insert Figure

3.3.1-1 New England Pipeline Systems and Coastal Ports

3.3.2 Port Review

Ships that are presently used to transport LNG typically have capacities of up to 138,000 m^3. The larger ships are from 950 to 1,000 feet long with typical drafts up to 38 feet. To ensure that the LNG ships do not easily or frequently run aground, up to an additional 2 feet of water is desirable under the keel. This means that LNG ships will typically only access areas with depths of 40 feet.[4] Although dredging in shallow water areas could provide access for LNG ships, the dredging required in undeveloped ports would be cost prohibitive and would most likely result in significant environmental impacts. Consequently, our analysis of alternative LNG terminal sites was limited to offshore or existing deepwater coastal ports that could readily accommodate LNG ships without dredging or without significantly more dredging than would be required for use of the proposed site.

3.3.2.1 Coastal Ports

As discussed previously, LNG ships can typically only access areas with depths of at least 40 feet. Throughout ports in the New England region, it is common for large ships to take advantage of rising or high tides when accessing shallow ports. This effectively increases the depth of the channel depending on the tide by several feet (typically 3 to 5 feet). In combination with some dredging, LNG ships could reasonably access ports deeper than 35 feet below MLLW. Figure 3.3.1-1 illustrates the ports in the project area that were originally considered in our analysis. The following ports were removed from further consideration since the amount of dredging required to use these ports was considered excessive and substantially more than the proposed project:

- Massachusetts: Gloucester, Beverly, Salem, Lynn, Quincy, Weymouth, Fairhaven, New Bedford;
- Rhode Island: Tiverton, Galilee/Jerusalem, Westerly; and
- Connecticut: Bridgeport.

Seven coastal ports or port areas were identified that have depths that would allow LNG ship access and that are located in areas that could provide reasonable access to the New England market. These port and port areas include: Boston Harbor, Brayton Point, Providence Harbor, Quonset Point, Coddington Cove/Melville, New London Harbor, and New Haven Harbor.

3.3.2.2 Offshore Ports

An offshore LNG import terminal would not be capable of delivering LNG by truck to LNG storage facilities throughout the region. Because an offshore LNG import terminal would not meet one of the primary objectives of the project (see section 1.3), offshore site alternatives were not considered in this analysis. However, there are several proposals to build offshore LNG import terminals in New England. The potential for one of these proposed offshore terminals to satisfy some of the other objectives of the Weaver's Cove LNG Project and the environmental issues associated with offshore LNG terminals are discussed in section 3.2.2.

[4] In New England, it is typical for deep-draft vessels to navigate channels with depths shallower than 40 feet below MLLW by transiting the channel on a rising or high tide, as is proposed for the Weaver's Cove LNG Project (see discussion in section 3.3.2.2).

3.3.3 Specific Port and Site Review

In addition to providing reasonable access to the New England market from sites with depths that would allow LNG ship access, coastal ports or port areas were evaluated for the availability of sites suitable for developing an LNG terminal. After initially considering both offshore and coastal ports, we identified seven coastal ports or port areas for further examination. To narrow the range and fully evaluate project alternatives, we developed criteria to assist in identifying and comparing specific sites for consideration as LNG terminal alternatives. The review process included the examination of required and favorable review criteria.

Required criteria included regulatory specifications regarding LNG facility layout and safety siting factors that are required to be met for the project to be feasible. If not met, the required criteria served to exclude a site from further consideration. 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 the proposed 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 ¼ 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.

We received numerous comments from Fall River residents that the proposed LNG terminal should not be developed in an urban setting near a densely populated residential area. While we evaluated alternative LNG terminal sites, we emphasize that our responsibility under NEPA as the lead federal agency is to determine if environmentally preferable alternatives to the proposed action exist. All alternative sites were, therefore, compared to the proposed LNG terminal site. Favorable review criteria, although not absolute alternative requirements, were applied to identify those sites that would be reasonable and most likely to provide some environmental advantage over the proposed project. For example, criteria were identified that would specifically improve upon some aspects of the Weaver's Cove LNG Project such as those associated with its location to nearby population centers/residences and project dredging requirements. Favorable criteria were not intended to strictly eliminate the evaluation of certain sites. Some sites were selected for further analysis because they satisfied a majority, but not all of the favorable criteria. Given the limited availability of suitable sized parcels in areas with deepwater access, it was not possible to locate an alternative that met all of the favorable review criteria. Favorable criteria included:

- **Population Centers/Residences** - We made an effort to identify alternative LNG terminal sites in areas that are not in close proximity to population centers and/or residences. Similarly, alternative LNG terminal sites were considered preferable if the location did not require LNG ships to transit near 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** - Based on the proposed design and the need to contain the thermal exclusion zone, a waterfront site of about 60 acres (about the size of the southern parcel at the proposed site) would be preferable to accommodate the proposed configuration of the LNG unloading, storage and sendout facilities. Assuming the LNG storage tank is located at the waterfront, this site would have to be about 2,200 feet by 1,200 feet to contain the thermal exclusion zone that is centered on the LNG storage tank. 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. In addition, because the federal and state resource agencies in the region prefer to avoid offshore disposal of dredged materials, any alternative LNG terminal site may also need to accommodate the reuse of dredged material onshore. However, to expand the range of potential candidate sites, we have relaxed the preferred acreage limit, recognizing that the facilities would need to be compressed and that exclusion zones may extend offshore or onto adjacent properties.

- **Dredging Required** - Few ports in the New England market area have navigation channels depths that would readily allow access to LNG ships. However, there are several ports that would accommodate LNG ships with some dredging. Given the environmental impacts associated with significant dredging projects, we considered the amount of dredging necessary to provide access to LNG ship access one of the alternative site review criteria. Areas requiring minimal dredging to develop and maintain a ship berth and a shipping channel of sufficient depth for the LNG ships were considered more favorable than those areas requiring more substantial dredging. In addition to avoiding impacts on water quality and aquatic resources, minimal dredging requirements provide the added benefit of reducing costs associated with disposal of dredged material.

- **Parcel Availability** - 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. Availability is critical since section 3 of the NGA does not provide the project proponent the authority of eminent domain in acquiring property for the LNG terminal project facilities. In some cases, a site may possess the size required for an LNG terminal but the owner is unwilling to sell or has placed unacceptable conditions on the acquisition of the site.

- **Existing Land Use** - Areas previously disturbed or cleared for industrial or commercial activities were preferable over undisturbed areas (greenfield sites) when identifying alternative LNG terminal sites. Additionally, we preferred sites where existing land use zoning, coastal zone management guidelines, or development plans were consistent with an LNG import terminal. For example, although we considered all areas with deepwater access, areas outside of designated ports were generally determined to be less preferable than areas within designated ports. Those sites in areas consistent with existing land uses were considered the most practical alternatives to the proposed site.

- **Sendout Pipeline Length** - We considered sites proximate to existing interstate pipeline systems which could accommodate the proposed volume throughput more favorable than sites further from existing pipelines. For purposes of this analysis, we assumed a pipeline should be at least 20 inches in diameter to accommodate the normal project volumes. On

top of the additional costs and environmental impacts, longer pipelines would likely directly and indirectly affect more landowners/residences.

- **Highway Access** - As discussed previously, one of the objectives of the project is to provide a new LNG import terminal with the ability to deliver LNG by truck to LNG storage facilities throughout the region.[5] To minimize traffic impacts from LNG trucks that would deliver LNG to storage facilities throughout New England, we considered sites proximate to major highways, which would avoid or minimize the transit of LNG trucks through residential neighborhoods, more favorable than sites further from major highways.

- **Navigational Suitability** - Sites that offer minimal disturbances to existing shipping and allow for good access by LNG ships were considered a favorable selection criterion. We also considered bridge transit along the navigation channel in our site analysis, since LNG ships require a vertical clearance of at least 135 feet and horizontal clearance of not less than 165 feet.

- **Environmental Justice** - As part of its NEPA analysis, the FERC is responsible for addressing the potential for a federal action to result in disproportionately high and adverse health or environmental effects on minority or low-income populations. We have not identified any significant environmental justice concerns related to the operational impacts or environmental affects of the proposal (see section 4.9.7). Nevertheless, we considered 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 have an environmental justice issue. Those 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 were considered to have the highest potential to raise environmental justice issues.

- **Various Environmental Factors** - Environmental factors that were considered in our site selection included: minimizing wetland disturbance and preferring sites in uplands; identifying soil conditions with suitable foundation materials for the LNG storage tank development; avoiding areas that would conflict with recreational activities; and selecting sites where the LNG storage tank would minimally impact the viewshed from roadways and surrounding communities.

- **Special Interest Areas** - We considered favorably those sites that avoided conflicts with special interest areas such as state or national parks and marine sanctuaries (e.g., some of the islands in Boston Harbor and Narragansett Bay, the Cape Code Marine Sanctuary). When applying this criterion, we considered potential conflicts with special interest areas from either an LNG terminal or its associated sendout pipeline.

The ports, port areas, and specific sites discussed below are the most reasonable alternatives to the terminal location proposed by Weaver's Cove Energy that we identified.

---

[5] We received a comment from the OCZM questioning the importance of LNG trucking as a project objective and our use of it in determining the highway access siting criteria for evaluating alternatives. We recognize that it may be possible to develop an LNG terminal in New England without the capacity to truck LNG. However, we also note that trucking of LNG is an important business component of both the existing Distrigas LNG terminal in Everett and the proposed KeySpan LNG terminal in Providence. We believe an LNG terminal facility without this capacity would not be as competitive and would be at a disadvantage.

Boston Harbor

Boston Harbor is one of the oldest and busiest ports on the East Coast that includes facilities supporting bulk and carrier cargo industries, cruise ship docking, fishing operations, shipyards, ferry services, marine research institutions, recreational marinas, and a major Coast Guard station. As discussed in section 3.2.1.1, the existing Distrigas LNG import terminal is located inland of the Boston Inner Harbor on the Mystic River. We are aware of only one site that is potentially available for development as a large industrial facility in Boston Harbor - the Mass Marine Terminal located on the south side of the main harbor channel (see figure 3.3.3-1). This site would be preferable to the proposed site in that Boston Harbor is accessible to LNG ships without the need for significant dredging. However, this site is currently being used for construction staging associated with the Central Artery Project and would not be available until at least 2007. Regardless, this site is located less than 1 mile from the end of a runway at the Logan International Airport. Because federal safety regulations prohibit locating an LNG storage tank this close to an airport runway (see *Required Siting Criteria* described above), an LNG facility at the Mass Marine Terminal is not a viable alternative to the proposed project. Table 3.3.3-1 provides a comparison of the review criteria evaluated for this site and the proposed site.

Narragansett Bay

Within Narragansett Bay, four alternative terminal sites were identified in addition to the proposed site. These were Brayton Point, Providence Harbor, Quonset Point, and the Coddington/Melville area. Other potential sites with deepwater access in Narragansett Bay were excluded because they were inconsistent with or did not satisfy multiple review criteria. For example, Prudence Island was considered as the potential site of an LNG terminal in the 1970s. However, we did not consider this a viable alternative location because a large portion of the island was designated a National Estuarine Research Reserve in 1980. In addition to requiring the development of a greenfield site in a location outside of a designated port area, an LNG terminal located on Prudence Island would not be able to meet the project objective of delivering LNG by truck to other LNG storage facilities in the New England region.

Brayton Point

During the public and agency scoping process, we received several suggestions to analyze an alternative LNG terminal site at Brayton Point in Somerset, Massachusetts. Somerset LNG also announced in 2003 that it is exploring development of an LNG import terminal at this location. Because Somerset LNG has not initiated a filing process at the FERC and there is some question as to whether an application will be forthcoming, we have considered development of a terminal at this location an alternative terminal site and not a system alternative.

The Brayton Point site is located along Mount Hope Bay less than 3 miles downstream from the site proposed by Weaver's Cove Energy (see figure 3.3.3-2). Currently, Dominion operates a coal, oil, and gas-fired 1,550 megawatt power plant at this property (Dominion recently purchased this facility from USGen). There are five fuel storage tanks and a large coal stockpile on the southern portion of this site. Natural gas is provided via a 20-inch-diameter pipeline that is connected to Algonquin's pipeline system. If gas flow were reversed, this pipeline could potentially be used to deliver about 400 MMcfd of natural gas to the Algonquin system. Table 3.3.3-1 provides a comparison of the review criteria evaluated for this site and the proposed site.

Insert Figure

3.3.3-1 Boston Harbor – LNG Terminal Site Alternative

Insert Figure

3.3.3-2 Brayton Point – LNG Terminal Site Alternative

TABLE 3.3.3-1

Environmental Comparison of the Terminal Site Alternatives to the LNG Terminal Site Proposed by Weaver's Cove Energy

	Proposed Site	Boston Harbor	Brayton Point	Providence Harbor	Quonset Point	Coddington/ Melville	New London Harbor
	Taunton River - Fall River, MA	Boston Harbor Main Channel - Boston, MA	Mount Hope Bay - Somerset, MA	Providence Harbor - East Providence, RI	Western Narragansett Bay	Rhode Island - Melville, RI	New London Harbor - Groton Heights, CT
Required Criteria							
Site Satisfies Thermal Exclusion/Vapor Dispersion Zone Requirements	Yes	Yes	Unknown	Yes	Yes	No	No
Site Satisfies Airport Setback Requirements	Yes	No	Yes	Yes	No	Yes	Yes
Site Satisfies Waterfront Handling Requirements	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Favorable Criteria							
Population Centers/ Residences	290 residential structures within ½ mile of site	0 residential structures within ½ mile of site	0 residential structures within ½ mile of site	140 residential structures within ½ mile of site	5 residential structures within ½ mile of site	3 or 4 residential structures within ½ mile of site	270 residential structures within ½ mile of site
Population Count	2,140 people within ½ mile of site	97 people within ½ mile of site	0 people within ½ mile of site	160 people within ½ mile of site	6 people within ½ mile of site	9 people within ½ mile of site	1,907 people within ½ mile of site
Site Size	73 acres	26 acres	15 acres	>100 acres	44 acres	34 acres	22 acres
Dredging Required	2.6 million cubic yards (predominately silts and clayey silts)	<100,000 cubic yards (predominately silts and clayey silts)	2.4 to 3.0 million cubic yards (predominately silts and clayey silts)	<100,000 cubic yards	3.0 million cubic yards (predominately gray clayey silt)	<100,000 cubic yards	<100,000 cubic yards
Parcel Availability a/	High	Medium (not available until 2007)	Low	Low	Medium	Medium	Medium
Existing Land Use	Former petroleum products terminal	Construction staging area for Central Artery Project	Operating power plant, fuel oil and coal storage	Petroleum products terminal	Port and Industrial Park	Former petroleum products terminal	Petroleum products terminal
Approximate Sendout Pipeline Length	<7 mile	<7 mile	0 b/	<7 mile	>40 mile	20 mile	35 mile
Highway Access	Adjacent to Route 79	1.9 miles to U.S. Interstate 93	1.6 miles to U.S. Interstate 195	2.4 to 3.3 miles to Interstate 195	2.5 miles to U.S. Hwy 1	2.6 miles to State Hwy 114	1.3 miles to Defense Hwy
Navigation Channel Transit Distance	20.9 nautical miles	2.2 nautical miles	20.0 nautical miles	24.3 nautical miles	12.8 nautical miles	11.0 nautical miles	3.3 nautical miles
Bridges (no.)	4	0	2	1	1	1	0
Per Capita Income	$16,118	$23,353	$22,420	$19,527	$25,441-29,188	$14,789	$22,239

TABLE 3.3.3-1 (cont'd)

Environmental Comparison of the Terminal Site Alternatives to the LNG Terminal Site Proposed by Weaver's Cove Energy

	Proposed Site	Boston Harbor	Brayton Point	Providence Harbor	Quonset Point	Coddington/ Melville	New London Harbor
	Taunton River - Fall River, MA	Boston Harbor Main Channel - Boston, MA	Mount Hope Bay - Somerset, MA	Providence Harbor - East Providence, RI	Western Narragansett Bay	Rhode Island - Melville, RI	New London Harbor - Groton Heights, CT
Percent Minority	8.8	45.5	1.8	13.5	12.4-20.2	21.0	22.3
Percent of Population below poverty level (all ages)	17.1	19.5	4.0	8.6	5.6-9.2	7.3	9.9
Shellfish Production Areas	Yes (closed to harvest)	Yes (closed to harvest)	Yes (closed to harvest)	Yes(closed to harvest)	Yes(closed to harvest)	Yes(closed to harvest)	Yes(closed to harvest)
Essential Fish Habitat (number of managed species)							
• Eggs	7	15	7	7	7	7	3
• Larvae	12	16	12	12	13	13	4
• Juveniles	13	21	13	13	13	14	6
• Adults	13	22	13	13	13	14	8
Special Interest Areas	None	None	None	None	None	None	None
Other Miscellaneous Environmental Factors	Site development would require the filling of a small amount of salt marsh.	--	--	Site development would require rerouting of a recreational bicycle path (recreation).	--	Site development would impact marina use (recreational/ commercial) and could potentially impact historical properties.	--

a/ High availability - the site is available for industrial use and a negotiated settlement to use the property has been reached with the current landowner.

Medium availability - the site is available for industrial use but no negotiations have taken place with the current landowner.

Low availability - the site is not available based on discussions between us or Weaver's Cove Energy with the current landowner.

b/ Existing 20-inch-diameter pipeline currently delivers natural gas to the Dominion facility. Additional sendout pipeline would likely be necessary.

Available space at the property appears to be limited. According to information in the local press provided by Somerset LNG, it would be possible to remove two or three of the existing fuel storage tanks to make room for a 15-acre site on the southern portion of Brayton Point. Depending on the specific size and containment design of the LNG storage tank, this property does not appear to be large enough for the thermal exclusion and vapor dispersion zones to be contained within the boundaries of the 15-acre site. As such, an LNG developer would be required to demonstrate control of the adjacent properties to ensure use consistent with an LNG facility.

Based on comments on the draft EIS, we more closely examined the population within 0.5 mile of the site. We originally estimated that population surrounding each of the alternative terminal sites by reviewing aerial photographs to determine the number of structures within 0.5 mile of the potential center of an LNG tank at that site. In the case of Brayton Point, we originally identified 90 structures that were near the edge of the 0.5-mile radius. By shifting the center of the tank slightly to the south and west, all of these structures are outside of the 0.5-mile radius. To further assess population in the vicinity of the alternative terminal sites, we also examined information from a U.S. Census Bureau database (see table 3.3.3-1). Based on the results of this new analysis, there would be no residences within 0.5 mile of the Brayton Point site. There would also be no need to clear forested vegetation and/or to disturb wetlands at the Brayton Point site. An additional advantage of this site would be the avoidance of the LNG ship navigation through two bridges along the Taunton River required for the proposed site (Braga and Brightman Street Bridges). A disadvantage of the Brayton Point site would be construction and LNG truck access to the terminal would be through the power plant property, potentially disrupting operation of the power station. Additionally, the closest access to a major road is Interstate 195. Specifically, traffic traveling to and from the site would need to travel on Brayton Point Road and Route 103 to access Interchange Number 4 on Interstate 195. This would require construction and operation traffic, including LNG trucks, to travel about 1.6 miles from the site to the highway and go past residential areas, a playground, and a school. Although one commentor suggested that these impacts could be avoided by constructing a new ramp onto Interstate 195, there are other disadvantages to the site that make this level of analysis unnecessary (see discussion on site ownership below).

In the draft EIS we estimated that development of an LNG terminal at the Brayton Point site would require dredging of between 2.4 and 3.0 million cubic yards. The actual dredging required would depend on the facility and pier design as well as the location of the channel and turning basin. In response to comments on the draft EIS, we have reassessed the amount of dredging needed for the Brayton Point site. It seems reasonable to assume that LNG ships en route to Brayton Point would travel the federal navigation channel through Mount Hope Bay to a point about 1 mile south of the Braga Bridge. Based on estimates for the proposed project, this segment of the ship route would require about 0.7 million cubic yards of dredging. At the top of Mount Hope Bay, the LNG ships would need to turn and proceed west to Brayton Point. For the purposes of this analysis, we have assumed the LNG ships would travel along an existing navigation channel, which leads to the power plant. Since this channel does not lead directly to the site and is too shallow and narrow for LNG ships, additional dredging would be required. We estimate that improvement of this channel would require dredging of about 0.3 million cubic yards of sediment. A turning basin would need to be developed somewhere along this channel in an area known as Borden Flats, an area that is generally 14 to 16 feet deep. To create a turning basin 41 feet deep would require dredging 25 to 27 feet of sediments. Assuming 1 foot of overdredge, we estimate this would require about 2.1 to 2.3 million cubic yards of dredging. Combined, we estimate that development of the Brayton Point site would require about 3.1 to 3.3 million cubic yards of dredging, or between 19 and 27 percent more dredging than the proposed site.

USGen indicated that there is space on the Brayton Point property to store about 500,000 cubic yards of dredged material. As such, a proponent building an LNG facility at this site would need to dispose of 2.6 to 2.8 million cubic yards of material at an offsite location. The cost of disposing of this

material would vary greatly depending on the disposal location (see section 3.6). Locating and using property away from Brayton Point for onshore dredged material disposal could be so costly as to make the project economically prohibitive.

Given our estimate of the dredging required for development of an LNG terminal at Brayton Point, we believe offshore disposal of dredged materials is the only reasonable disposal alternative (see section 3.6). Offshore disposal of the dredged material may be possible but is generally less preferred by most agencies and could have additional environmental impacts including potential short-term and/or long-term impacts on water quality, fish, benthic habitats, and local fishing industries. The costs and environmental impacts associated with dredging (and disposal) would increase significantly if the material is contaminated. To our knowledge, there has been no sampling of the sediments that would need to be dredged for a turning basin and to widen the narrow ship channel leading to Brayton Point. However, based on the sampling conducted by Weaver's Cove Energy and previous sampling done by the Massachusetts OCZM and others in the general area, there is reasonable probability that the sediments that would need to be dredged to develop an LNG terminal at the Brayton Point site would be similar in quality and texture to the sediments that would be dredged for the proposed project (see section 4.2.2). It is also reasonable to assume that the aquatic resources inhabiting the area that would be disturbed for the Brayton Point site are similar to those that would be affected by the proposed project (see section 4.6.2).

Commentors on the draft EIS suggested that siting an LNG terminal adjacent to the power plant at Brayton Point could provide beneficial operating advantages. An LNG import terminal located at Brayton Point could theoretically obtain "waste heat" from the adjacent power plant that could be used in a closed-loop system to vaporize the LNG, thus eliminating or reducing the need to burn natural gas in the vaporization process. This could provide both environmental and economic benefits to the operation of the LNG terminal (e.g., avoid/minimize need to burn 1.5 to 2.0 percent of import product thus reducing air emissions and natural gas costs). A system similar to this is currently being proposed by Ingleside Energy Center, LLC in Corpus Christi Bay, Texas (see FERC Docket No. CP05-13-000).

Additionally, the Brayton Point power plant could also benefit from having a consistent and reliable source of natural gas and a source of "waste cold" that could be used to condense the steam used to produce electricity at the facility. Although the facility is set up to burn natural gas or fuel oil, the power plant's primary source of energy is coal (see section 3.1 for a description of the environmental disadvantages of coal versus natural gas). Historically, the power plant also used water from Mount Hope Bay for the cooling process. The withdrawal of large volumes of water along with the discharge of warm water has caused or contributed to the collapse of certain fish stocks in Mount Hope Bay (EPA, 2002a). A recent NPDES permit for this facility requires that the power plant operator reduce water withdrawals and warm-water discharge. It is conceivable that an LNG terminal at this site could provide a source of cold water (or other liquid mixture) as part of a closed-loop system between the power plant and the LNG vaporizers that could help meet these permit conditions or further reduce the need to withdraw or discharge water into Mount Hope Bay.

In September 2003, Weaver's Cove Energy approached USGen regarding the availability of the property at Brayton Point. According to Weaver's Cove Energy, the President of USGen New England, indicated that the property was not for sale at that time. According to public news reports, Somerset LNG also appeared to pursue obtaining property at this site. In September 2004, Dominion (one of the largest energy producing companies in the United States) reached an agreement with USGen to purchase the existing power plant and the property at Brayton Point. Because USGen filed for bankruptcy protection early in 2003, discussions regarding the sale of the property were subject to the review and agreement of the creditor's committee in the USGen bankruptcy proceedings. On November 23, 2004 Dominion was granted approval by the U.S. Bankruptcy Court for the District of Maryland to purchase the Brayton Point facility and two other power plants. The sale of the three properties was concluded on January 1, 2005.

We recognize the potential environmental and economic advantages an LNG terminal at Brayton Point could provide. Even the disadvantages of LNG trucking or dredging at this site could conceivably be managed depending on the design of an LNG facility. For example, an LNG facility at the site could be planned so that it would not involve trucking or so that it would take shallow-draft LNG barges from other LNG terminals along the Atlantic coast (thus eliminating or reducing the need for the dredging necessary to allow deliveries from deep-draft LNG vessels). However, these design features would not allow the LNG facility to satisfy the objectives of the Weaver's Cove LNG Project. Because Dominion now owns the site and has not indicated that it intends to pursue development of an LNG facility at the site, an LNG terminal at Brayton Point can only be considered conceptually and may never be a practicable and feasible alternative to the Weaver's Cove LNG Project. For these reasons, we do not believe that an LNG terminal at the Brayton Point site is a reasonable alternative to the proposed project.

Providence Harbor

The Providence River federal navigation channel has been approved to be dredged to a depth of 40 feet below MLLW. Dredging was officially completed in December 2004; however, final bathymetric surveys and Coast Guard approval of the channel are still pending. Because the future depth of the navigational channel at this location would accommodate LNG ships without the need for significant additional dredging, we considered LNG terminal locations in Providence Harbor as alternatives to the proposed site in Fall River. The existing KeySpan LNG facility, located adjacent to the Fox Point Reach of Providence Harbor, was previously evaluated as a partial system alternative (see section 3.2.1.2). Another potentially suitable site that could be developed as an LNG terminal is one owned by ExxonMobil in East Providence (see figure 3.3.3-3). Table 3.3.3-1 provides a comparison of the review criteria evaluated for this site and the proposed site.

ExxonMobil currently operates a liquid petroleum products terminal located near the Fuller Rock Reach of the Providence River federal navigation channel. Based on a review of aerial photographs and field visits to this site, the aboveground storage tanks that were formerly present on the site have been removed. It appears that products are currently unloaded at the docking structure and sent via two pipelines to a tank farm about 0.9 mile to the east. The ExxonMobil property adjacent to the navigational channel is about 100 acres in size, and would be adequate for an LNG storage tank and the associated thermal exclusion and vapor dispersion zones. The property is bisected by the East Bay Bike Path. The 14.5-mile-long asphalt path along the upper Narragansett Bay was the first abandoned railroad corridor to be converted to recreational uses and has been described as one of Rhode Island's "recreational jewels" for cyclists, walkers, wheelchair users, and in-line skaters (URITC and RIDOT, 2003). Abutting the property to the north and east is the Silver Springs Golf Course, a small L-shaped six hole semi-private course that is open from April 1 to December 1. The area beyond the golf course to the east is used for light industrial and commercial purposes. There are about 140 residential structures within 0.5 mile of the site and Bradley Hospital, a psychiatric hospital devoted to children and adolescents, is within about 0.75 mile.

The site is about 2.3 miles from Algonquin's nearest existing natural gas pipeline system. Although we have not completed a detailed routing analysis, it appears that a natural gas sendout pipeline from an LNG terminal could be co-located with existing pipeline rights-of-way to an interconnect point with the Algonquin pipeline system east of the alternative terminal site. To accommodate the project volumes, Weaver's Cove Energy would need to construct the 2.3 miles of interconnecting pipeline and an additional 2.2 miles of pipeline (adjacent to or within an existing pipeline right-of-way) to allow a connection to the Algonquin system at a point where it has greater capacity. In either case, the sendout pipeline route would not cross any residential areas. The only obvious environmental impacts of the sendout pipeline route are that it would require the removal of vegetation and would cross the Runnins River. It also seems likely, based on the amount of exposed bedrock on the ExxonMobil property, that a

considerable amount of blasting may be necessary to bury the pipeline near the shoreline. There are also wetlands in the vicinity of the interconnect point with the Algonquin pipelines which could be affected depending on the pipeline alignment.

The primary advantage of the ExxonMobil site is that it offers deepwater access that would require less dredging than the proposed site to allow LNG ships to berth and unload (less than 100,000 cubic yards of dredging would be needed). The existing berth on the ExxonMobil property can accommodate fairly large ships (we have observed ships at the berth between 500 and 600 feet in length), but it is unclear whether it is long enough or deep enough to receive LNG ships. It is likely that some additional dredging would be needed for a berth and turning basin that would accommodate LNG ships. As an alternative to a turning basin LNG ships accessing a terminal at this site could continue north to the Fox Point Reach where the federal navigation channel is wide enough for an LNG ship to turn. During dredging for the Providence River and Harbor Maintenance Dredging Project, the portion of the Providence River Channel adjacent to the ExxonMobil site (the lower portion of the Fuller Rock Reach) did not require sequencing or timing restrictions to avoid impacts on fishery resources (COE, 2001). Although timing restrictions to minimize impacts on winter flounder or quahog spawning areas were necessary for portions of the Providence River channel both north and south of the lower portion of the Fuller Rock Reach, the fishery resources in this area did not warrant these mitigation measures. This suggests that the fishery resources in the vicinity of the ExxonMobil site may be relatively poor. So in addition to reduced volumes of dredged material compared to the proposed site, it appears the fisheries resources in the vicinity of the ExxonMobil site are not worthy of the same protection as those found in the Taunton River federal navigation channel. A potential disadvantage of this site is that a marine terminal would place the LNG vessel at the edge of the Fuller Rock Reach channel and exposed to potential allisions for vessels as they turn into this channel from the Sabin Point Reach channel en route to Providence.

One relative disadvantage of the site compared to the proposed site is its proximity to the East Bay Bike Path. Assuming the LNG tank is located close to the waterfront to maximize its distance from residences, the East Bay Bike Path would be within 200 to 300 feet of the tank. This would put recreational users of the path within the 1,600 Btu ft^2 hr thermal exclusion zone of the tank. To increase the separation of the path from the tank to 1,000 feet, it would be necessary to relocate about 1,500 feet of the path to the east further from the waterfront.

Another disadvantage of the site is its distance from the nearest divided highway. In order to access markets, LNG trucks would travel 0.4 mile east on Industrial Way and then turn north on Pawtucket Avenue. LNG trucks traveling east would proceed north on Pawtucket Avenue for 1.6 miles and then turn and proceed west for 0.4 mile on Warren Avenue, at which point they would turn right onto the east bound entrance ramp of Interstate 195. LNG trucks traveling west would proceed north on Pawtucket Avenue for 0.3 mile and then turn and proceed northwest onto Veterans Memorial Parkway for 2.6 miles, at which point they would enter the west bound ramp of Interstate 195. The result is that depending on their final destination, LNG trucks would need to travel between 2.4 and 3.3 miles on residential and commercially developed city streets to reach a divided highway.

Another issue is that the site is not available according to Weaver's Cove Energy. Weaver's Cove Energy indicated in its application that it discussed the site with ExxonMobil in late 2002 and were informed that the property in East Providence is not available for development as an LNG terminal.

Insert Figure

3.3.3-3 Providence Harbor – LNG Terminal Site Alternative

In summary, the ExxonMobil property appears to be large enough to accommodate an LNG import terminal. Additionally, compared to the proposed terminal site, an LNG terminal at the ExxonMobil property has the environmental advantage of minimal dredging requirements. This site also avoids LNG ship navigation through three bridges which are required for access to the proposed site. In other respects, the ExxonMobil site is similar or worse than the proposed site. Although the ExxonMobil property is located within 0.5 mile of about half the number of residential structures than the site at Fall River, the property is still located in an area that is relatively highly developed. Additionally, highway access is poorer than at the proposed site and LNG trucks would need to travel for several miles through residential and commercially developed city streets in order to reach the highway. The East Bay Bike Path is another issue that makes the ExxonMobil property less preferable than the proposed site. Additionally, the site seems to be unavailable. Given the current property ownership, the use of the ExxonMobil property is not an alternative that Weaver's Cove Energy appears able to reasonably pursue. While this site has several environmental advantages over the proposed site, the primary disadvantage of this alternative site is its lack of availability for potential LNG development. Therefore, we do not believe that an LNG terminal at the East Providence Harbor is a reasonable alternative that provides a clear environmental advantage over the proposed location.

Quonset Point

There is an existing marine facility with deepwater access located near Quonset Point east of Quidnessett, Rhode Island (see figure 3.3.3-4). Located in a relatively isolated portion of Narragansett Bay, this site has been previously developed to provide ship docking/unloading and was formerly used as a layup berth for large ships repossessed by the DOT Maritime Administration. At present, the Rhode Island Economic Development Corporation is developing this site as a port and commerce park. Based on discussions with the Rhode Island Economic Development Corporation, there is a 45-acre parcel available for development at the waterfront. Other lands at Quonset Point are currently under lease and are being used by other tenants of the port and commerce park. Although this alternative site is located in an area more isolated from residential development than the proposed LNG terminal site, there are several disadvantages and/or limitations associated with building an LNG terminal at this site. The available parcel is less than 0.5 mile from the end of a runway of the Quonset Point Air Station and, consequently, is inconsistent with the required LNG terminal siting criteria.

In addition to the location and small size of the parcel, the site is near the end of a ship channel that would require significant dredging to accommodate LNG ships. Based on navigation charts, it appears that this site is located on a channel that is currently dredged to about 30 feet. Dredging of the channel, turning basin, and berthing area would require dredging an estimated 3 million cubic yards of material. Because the property does not have an existing pier, additional dredging would likely be necessary for a ship docking/unloading facility. Additionally, the site is located about 35 miles from the nearest large-diameter pipeline system that could allow natural gas from the site to be distributed to the broader New England market (compared to the 6.1 miles of pipeline that would be constructed as part of the proposed project). For these reasons and because the site does not meet the safety siting requirement regarding its proximity to Quonset Point Air Station, we have not further considered a potential LNG terminal in the Quonset Point area.

Insert Figure

3.3.3-4 Quonset Point – LNG Terminal Site Alternative

Coddington Cove/Melville

There are areas north of Newport where there is deepwater access adjacent to the East Passage (see figure 3.3.3-5). Coddington Cove and the waterfront to the north are part of a U.S. Naval Reservation and are not available for LNG development. While there is deepwater access at Melville, the area is largely developed for recreational or commercial purposes. A portion of the Melville area was formerly used by the U.S. Navy as a fuel distribution terminal. Fuel terminal operations ceased in 1998 and the 34-acre property may be available for use as a marina or for use by light industry/commercial developers. The State of Rhode Island Economic Development Corporation is pursuing acquisition of this property. Table 3.3.3-1 provides a comparison of the review criteria evaluated for this site and the proposed site. Given the proximity of the deep waters of the East Passage, an LNG terminal at Melville would require much less dredging than would be necessary to develop the proposed site in Fall River. Additionally, the area within 0.5 mile of the property has few residential structures. However, because of the relatively small parcel size and the presence of marinas adjacent to the north and south side of the property, there is not adequate space available for an LNG terminal of the size proposed by Weaver's Cove Energy. Other disadvantages of the property are that development may require mitigation given the historic nature of the site (i.e., it is a district eligible for listing on the NRHP) and it is located over 20 miles away from the nearest suitable interconnect with the Algonquin pipeline system (the closest natural gas pipeline system). For these reasons and because this site does not meet the safety siting requirement regarding the thermal exclusion/vapor dispersion zone, we have not further considered a potential LNG terminal in the Coddington Cove/Melville area.

New London Harbor

The New London Harbor in Connecticut is located at the mouth of the Thames River on the north shore of Long Island Sound. The harbor offers deepwater access to a variety of commercial, industrial, recreational, and military vessels (i.e., the main navigation channel is about 40 feet below MLLW). The western side of the harbor is relatively shallow and is dominated by non-industrial developments (e.g., parks, public walkways, ferry terminals). The eastern side of the harbor is closer to the ship channel and has been developed for industrial users. Weaver's Cove Energy indicated that they considered the Hess Oil Terminal, located on the eastern side of the harbor, as a potential alternative location for an LNG facility (see figure 3.3.3-6). Table 3.3.3-1 provides a comparison of the review criteria evaluated for this site and the proposed site. Because the existing berth at the Hess Terminal is 35 to 40 feet deep, development of this property as an LNG terminal would require much less dredging than would be necessary for the proposed site. However, the property is only about 22 acres and there is an adjacent office building that would significantly constrain siting an LNG storage tank. Further disadvantages of the site include the distance to the nearest large-diameter natural gas pipeline system (about 35 miles) and the lack of ready access to a major highway for construction vehicles and LNG trucks. We are not aware of other sites in the New London Harbor area that would be suitable and/or available for development as an LNG import terminal. For these reasons and because this site does not meet the safety siting requirement regarding the thermal exclusion/vapor dispersion zone, we have not considered further a potential LNG terminal in the New London Harbor area.

Insert Figure

3.3.3-5 Coddington Cove/Melville – LNG Terminal Site Alternative

Insert Figure

3.3.3-6 New London – LNG Terminal Site Alternative

New Haven Harbor

The New Haven Harbor along the northern shore of Long Island Sound is accessible to large ships via a channel that the COE is authorized to maintain to a depth of 35 feet below MLLW. To make New Haven Harbor suitable for LNG ships, improvement dredging would be required along about 5 miles of navigation channel. Additionally, the presence of the Tweed-New Haven Airport, the public bridges across the north end of the harbor, and various conflicting land uses (e.g., East Shore Park) would limit potentially suitable sites to a relatively narrow area of waterfront that has been developed for industrial uses. We are not aware of any property in this area that would be suitable for an LNG terminal. The lack of site availability, the dredging requirements, the long distances (about 20 miles) to the nearest large-diameter pipeline system, and the developed nature of the land surrounding the harbor are all factors weighing against New Haven Harbor providing any clear environmental advantage over the proposed site. For these reasons, we have not considered further a potential LNG terminal in the New Haven Harbor area.

3.4 LNG TERMINAL LAYOUT ALTERNATIVES

To minimize potential visual impacts (see section 4.8.7.1), we examined the possibility of constructing an LNG terminal that would include two smaller LNG storage tanks with the same capacity of the single storage tank proposed by Weaver's Cove Energy. A tank with a capacity of about 100,000 m^3 would be about 145 feet high and 240 to 245 feet in diameter compared to the proposed tank which is 195 feet high and 280 feet in diameter. Because of the tank spacing requirements, the thermal exclusions zone for a second LNG tank would fall outside the site boundaries. Additionally, the construction costs for LNG storage would increase by an estimated $25 million. For these reasons, we do not believe an alternative site design of two LNG storage tanks is a reasonable alternative to the design proposed by Weaver's Cove Energy.

As described in section 4.4, construction of the LNG terminal would result in permanent impacts on a small amount of salt marsh (0.04 acre) bordering the Taunton River. These wetlands, which are dominated by smooth cordgrass, are of limited ecological value due to their small size and the disturbed nature of the surrounding industrial area. Nevertheless, to avoid or minimize these impacts, we considered whether an alternative LNG terminal layout could be used. Much of the LNG terminal layout is dictated by the location of the LNG storage tank. Due to the size of the thermal exclusion and vapor dispersion zones (see section 4.12.4) and the limited space available at this property, it is not possible to move the LNG storage tank significantly further from the current location. As such, a specialized retaining wall would need to be constructed to maintain adequate construction work zones and operational security zones between the shoreline and the LNG storage tank as well as to ensure the stability of the shoreline and the perimeter berm. The outside perimeter of the alternative layout would be highly irregular along the shoreline to avoid the salt marshes along the Taunton River. While possible, Weaver's Cove Energy indicates that the alternative layout would be significantly more expensive to design and construct compared to the proposed layout. Because security of the site is improved through the use of straight sightlines compared to sightlines interrupted by an irregular outside perimeter, the proposed site layout provides superior site security. For these reasons and because Weaver's Cove Energy would take appropriate steps to compensate for wetlands permanently impacted by construction, we do not believe an alternative site layout is a reasonable alternative to the design proposed by Weaver's Cove Energy.

As discussed in section 3.6, we evaluated alternatives to disposing the sediments dredged from the federal navigation channel and turning basin. As currently proposed, this material would be placed at the LNG terminal site and be used to elevate the grade at the LNG tank site, truck loading area, and LNG piping area. Additionally, the dredged material would be used to create a landform on the north and east side of the LNG tank. The landform, which would be vegetated and/or covered with a stabilizing material

such as crushed rock, would have a maximum height ranging between about 148 feet and 188 feet MSL and provide some visual screening of the facility from locations to the east and northeast of the site. However, the top of the LNG storage tank would still be at about 220 feet MSL and would rise over the top of this landform. If the dredged material were to be disposed of at an offsite location (e.g., offshore), Weaver's Cove Energy would still require fill material to elevate the grade at the LNG tank site, truck loading area, and LNG piping area. However, the FERC may not necessarily require the landform be a component of the project. As such, a potential alternative site layout may not include a landform or any of the associated benefits (e.g., visual screening, reduction in facility noise noticeable from adjacent areas). Visual and noise issues are further discussed in sections 4.8.7.1 and 4.11.2.

3.5 PIPELINE ALTERNATIVES

Weaver's Cove Energy proposes to deliver an average of 400 MMcfd of natural gas to the New England market, and 800 MMcfd during periods of peak demand. The Algonquin pipeline system is the only system near the proposed LNG terminal with the capacity to deliver these volumes of natural gas. The portion of the Algonquin system (referred to as Algonquin's "G" system) near the proposed LNG terminal site is made up of a series of pipeline laterals that include:

- the G-1 lateral - two parallel pipelines (10-inch-diameter and 20-inch-diameter) located east of the LNG terminal in Fall River;
- the G-4 lateral - a single pipeline (8-inch-diameter) located to the south of the LNG terminal in Fall River;
- the G-20 lateral - a single pipeline (16-inch-diameter) located north of the LNG terminal in Freetown, Massachusetts; and
- the G-22 lateral - a single pipeline (20-inch-diameter) located to the west of the LNG terminal, primarily in Somerset and Swansea, Massachusetts.

An engineering analysis conducted by FERC staff concluded that no single lateral would be able to provide sufficient capacity to deliver all of the volumes of natural gas from the LNG terminal. Each of the laterals has some capacity to transport a portion of the project volumes to the New England market. However, Algonquin would have to upgrade and/or uprate (increase the MAOP) its pipeline to accommodate additional volumes of natural gas on any of these laterals. Because of the limited capacity of any one lateral, Weaver's Cove Energy proposes interconnects with two of these laterals to provide the delivery capacity and the flexibility necessary for the project. The Northern Pipeline would interconnect with the G-20 lateral; the Western Pipeline would interconnect with the G-22 lateral. Both of these routes would minimize the length of pipeline needed to interconnect with the Algonquin system. While the primary advantage of the proposed pipeline routes is their use of existing utility corridors, both routes are in close proximity to residential areas and both routes would or could have direct or indirect impacts on the Taunton River and its associated wetlands.

In evaluating pipeline alternatives, we assessed whether it might be possible to reduce the environmental impacts associated with construction and operation of the proposed pipelines by developing an alternative pipeline route that would either interconnect with one of the other Algonquin laterals or interconnect with the Algonquin lateral as proposed while following an alternative pipeline route. Additionally, we evaluated minor variations to the proposed pipeline routes to avoid or minimize impacts on specific, localized resources such as residences, waterbodies, and wetlands. Figure 3.5-1 shows the Algonquin laterals and the alternative pipeline routes that we considered in this analysis.

Insert Figure

3.5-1 Pipeline Route Alternatives

3.5.1 G-1 Lateral Interconnect (Eastern Pipeline Alternative)

To minimize the residential impacts and impacts on the Taunton River associated with the proposed pipeline routes, we evaluated the Eastern Pipeline Alternative as an option for connecting the LNG terminal to Algonquin's G-1 lateral in Fall River. This alternative begins at the LNG terminal site and follows the same alignment as the proposed Northern Pipeline route for about 0.8 mile until it reaches Wilson Road. The alternative then deviates from the proposed route and proceeds east adjacent to Wilson Road through a residential neighborhood, across Route 79, and through another residential neighborhood. When it reaches Route 24, the alternative turns and proceeds to the northeast across the highway to an existing electric transmission line. The alternative follows the existing electric transmission line through an industrial zone for about 0.4 mile and then crosses the Freetown-Fall River State Forest, Pond Swamp, and Queen Gutter Brook, before interconnecting with Algonquin's G-1 lateral on the northeast side of Copicut Reservoir. The Eastern Pipeline Alternative is about 6.5 miles long. An environmental comparison of the Eastern Pipeline Alternative and both of the proposed routes is summarized in table 3.5.1-1.

TABLE 3.5.1-1

Environmental Comparison of the Eastern Pipeline Alternative to the Proposed Routes

Environmental Factor	Proposed Northern Pipeline Route	Proposed Western Pipeline Route	Eastern Pipeline Alternative
Total length (miles)	3.6	2.5	6.5
Length adjacent to or within existing rights-of-way (miles)	3.5	1.8	5.9
Wetland impacts (acres)	1.0	0	4.6
Forest clearing (acres)	1.2	2.6	0 a/
Number of Perennial Waterbodies Crossed	2	1	4
Number of Major Waterbodies (>100 feet wide) Crossed	0	1	0
Number of Residences within 50 feet	19	21	28
Crossing of State Forest (miles)	0	0	4.0

a/ This estimate assumes that the Eastern Pipeline Alternative could be constructed entirely within the existing transmission line corridor.

Unlike either of the proposed routes, the Eastern Pipeline Alternative route traverses about 4.0 miles of the Freetown-Fall River State Forest. Largely undeveloped, the Freetown-Fall River State Forest is part of the 14,000-acre Southeastern Massachusetts Bioreserve (SMB). The SMB was established as part of a collaborative effort to protect, restore, and enhance the biological diversity and ecological integrity of a large-scale ecosystem in the region; to permanently protect public water supplies and cultural resources; to offer interpretive and educational programs communicating the value and significance of the bioreserve; and to provide opportunities for appropriate public use and enjoyment of the natural environment. This area provides various recreational opportunities to hikers, horseback riders, dog sledders, mountain bikers, motorcyclists, snowmobilers, hunters, and anglers.

Weaver's Cove Energy did not conduct field surveys of the Eastern Pipeline Alternative. However, the portion of the route through the Freetown-Fall River State Forest traverses areas known to support both sensitive natural and cultural resources. Information provided by the Massachusetts Natural Heritage and Endangered Species Program indicates that several rare and/or protected species are known to occur in the vicinity of the alternative pipeline route including the spotted turtle (*Clemmys guttata*), marbled salamander (*Ambystoma opacum*), Plymouth gentian (*Sabatia kennedyana*), and the New

England bluet (*Enallagma laterale*). Additionally, there are several documented prehistoric sites near the Eastern Pipeline Alternative.

The Eastern Pipeline Alternative also crosses several wetland areas that amount to nearly five times the length of mapped wetlands crossed by either of the proposed routes. Additionally, five of the wetlands and streams crossed by the Eastern Pipeline Alternative are considered Outstanding Resource Waters because they feed into public water supplies including Watuppa Pond and Copicut Reservoir. Use of the Eastern Pipeline Alternative could reduce the impact on forested areas if construction activities could be confined within the existing transmission line corridors. If this would not be possible, the Eastern Pipeline Alternative could result in anywhere between about 12.1 and 48.5 acres (depending on the amount of overlap with the previously cleared corridor) of forest clearing, which would be substantially more forest clearing than would be required for either of the proposed routes.

The potential advantage of the Eastern Pipeline Alternative is that it does not cross the Taunton River. While this would reduce impacts on the river compared to the Western Pipeline route, it does not offset the relative environmental disadvantages of the Eastern Pipeline Alternative (e.g., wetland impacts, disturbances within the SMB). In addition, this alternative route is significantly longer than either of the proposed routes and thus would result in more land disturbance. We do not believe that an interconnection with the G-1 lateral provides any clear environmental advantage over either of the proposed pipeline routes, and we do not recommend further consideration of the Eastern Pipeline Alternative.

3.5.2 G-4 Lateral Interconnect (Southern Pipeline Alternative)

The Southern Pipeline Alternative was considered as a possible route for interconnecting the LNG terminal with the Algonquin G-4 lateral in Fall River (see figure 3.5-1). Although this alternative would cross fewer waterbodies than either of the proposed routes and no mapped wetlands, the alternative route would be longer and would require construction through densely populated areas in Fall River. We estimate that the alternative would require construction within 50 feet of more than five times as many homes as either of the proposed routes. Furthermore, the G-4 lateral would not have the capacity to accommodate the projected volumes delivered from the LNG terminal without substantial upgrades. Therefore, we do not recommend further consideration of the Southern Pipeline Alternative.

3.5.3 G-20 Lateral Interconnect (Northern Pipeline)

As currently proposed, Weaver's Cove Energy would interconnect with Algonquin's G-20 lateral via the Northern Pipeline. This route generally follows an existing naphtha pipeline and the CSX railroad right-of-way from the LNG terminal to an interconnect with Algonquin's system in Freetown. To avoid or minimize impacts resulting from construction and operation of the Northern Pipeline, we considered an alternative route (Northern Highway Alternative) and several minor realignments (minor route variations) to the proposed route.

Northern Highway Alternative

The Northern Highway Alternative was considered as an alternative to the proposed Northern Pipeline route in an attempt to minimize impacts on residences along the CSX railroad and to avoid the constricted work areas along the proposed route. This alternative route begins at the LNG terminal site and follows the same alignment as the proposed Northern Pipeline route for about 0.8 mile. The alternative then deviates from the proposed route and proceeds east along Wilson Road through a residential neighborhood until it reaches Route 79. At the highway, the alternative turns and proceeds northeast adjacent to the Route 79 right-of-way (which is joined by Route 24) for about 2.6 miles. The

Northern Highway Alternative terminates at a potential interconnection with the Algonquin G-20 lateral at a point where the lateral crosses Routes 24/79. In total, the Northern Highway Alternative is about 3.6 miles long, and would interconnect with the Algonquin G-20 lateral in Freetown about 2,000 feet east of the proposed interconnection.

Table 3.5.3-1 provides an environmental comparison of the proposed route and the Northern Highway Alternative. Both routes are 3.6 miles long and follow existing rights-of-way. An advantage of the alternative route is that it avoids crossing any mapped wetlands. The primary disadvantage of the alternative route would be that it would be constructed within 50 feet of six more residences.

TABLE 3.5.3-1

Environmental Comparison of the Northern Highway Alternative to the Proposed Northern Pipeline Route

Environmental Factor	Proposed Northern Pipeline Route	Northern Highway Alternative
Total length (miles)	3.6	3.6
Length adjacent to existing rights-of-way (miles)	3.5	3.4
Wetland crossings (feet)	1.0	0
Forest clearing (acres)	1.2	15.4
Number of Residences within 50 feet	19	25

One of the biggest challenges in constructing the alternative would be traversing the area between the CSX railroad and Route 24/79. Workspace in this area is limited and it is likely that Wilson Road would need to be closed to through traffic during construction of the pipeline. Construction along or in the road would also be slow and maintaining access to homes along the road would be difficult.

Another issue is that the alternative may not be able to take full advantage of the Route 24/79 right-of-way. The width of the cleared road right-of-way is narrow in spots and additional area adjacent to the cleared right-of-way may be necessary to safely and feasibly accommodate construction activities. This would require clearing forest vegetation adjacent to the highway, a portion of which would be within the Freetown-Fall River State Forest. To use the highway right-of-way, Weaver's Cove Energy would also need to obtain approval from MassHighway. Historically, this agency has discouraged lengthy utility corridors within its rights-of-way where feasible alternatives exist. If permission to use the highway right-of-way could not be obtained, the construction right-of-way would need to be located beyond the road right-of-way, which could result in up to 30.8 acres of tree clearing.

For all of these reasons we do not believe the Northern Highway Alternative provides a clear advantage over the proposed Northern Pipeline route. And most importantly, the Northern Highway Alternative would not provide any advantages over the proposed route regarding potential residential impacts. Consequently, we do not recommend further consideration of the Northern Highway Alternative.

Northern Pipeline Minor Route Variations

We examined several minor route variations to the proposed Northern Pipeline route that would avoid or minimize potential impacts on wetlands and residences.

Northern Parcel Variation

We examined a minor route variation to the segment of the proposed Northern Pipeline route between MPs 0.26 and 0.55 to minimize potential wetland impacts and increase the riparian buffer zone between the construction right-of-way and the Taunton River. Between these MPs, the proposed pipeline

route follows the existing naphtha pipeline on the west side of the CSX railroad right-of-way. This portion of the pipeline route is adjacent to the Taunton River and a narrow salt marsh (Wetland N4) that borders the river (see figure 3.5.3-1). This salt marsh provides both wildlife and fish habitats. Although most of the construction right-of-way for the proposed route appears to avoid direct impacts on the river and salt marsh, there is minimal workspace on the west side of the railroad and a steep embankment between the railroad tracks and the river. These constraints would complicate construction and potentially lead to indirect impacts on the river and salt marsh by removing adjacent vegetation and increasing the potential for stormwater runoff and associated sediments to discharge directly to the river and salt marsh during rainfall events. Additionally, the location of the extra workspace required for the proposed pipeline crossing of the railroad track near MP 0.55 would be immediately adjacent to the river.

As shown on figure 3.5.3-1, the route variation, referred to as the Northern Parcel Variation, would cross from the west to the east side of the CSX railroad tracks on the northern end of the LNG terminal property and would remain adjacent to the east side of the CSX railroad right-of-way for its entire length. The location for the crossing of the railroad tracks by the Northern Parcel Variation and the extra work space for this crossing would be in a previously disturbed upland area of the property further from the river than the crossing location and extra workspace required for the proposed route. The Northern Parcel Variation would traverse primarily upland forest and a small portion of wetland on the northern parcel of the LNG terminal site, which would be largely disturbed to construct of the administration building for the LNG terminal facilities.

The Northern Parcel Variation would be the same length and thus require the same amount of land disturbance as the corresponding segment of the proposed route but would require more clearing of upland forest (<0.1 acre along the proposed segment compared to 1.8 acres along the Northern Parcel Variation). As stated above, the upland forest clearing required for the proposed administration building diminishes the additional tree clearing along this variation. The variation would, however, increase the distance of the right-of-way from the river and avoid the potential direct or indirect impacts on the Taunton River and associated wetland habitats. For these reasons and because the Massachusetts Wetlands Protection Act protects riverfront areas and salt marshes that provide wildlife or fisheries habitats (see 310 CMR 10.32 and 10.58), we recommended in the draft EIS that Weaver's Cove Energy incorporate the Northern Parcel Variation into the proposed route. In its comments on the draft EIS, Weaver's Cove Energy agreed to incorporate the Northern Parcel Variation into the proposed route. As such, the Northern Parcel Variation is now considered an adopted segment of the proposed route.

River Street Variation

We received comments from the Massachusetts EFSB recommending that we consider an alternative alignment to avoid or minimize the loss of trees and vegetation that provide aesthetic value, shade, and/or visual screening at the residential locations between MPs 0.54 and MP 0.91 of the Northern Pipeline route.

The portion of the proposed route between MPs 0.54 and 0.68 would primarily be constructed on property owned by the New England Power Company. Because there are large transmission line towers located within this property, the area is periodically cleared of tall vegetation. Currently, there is little vegetation that provides significant shade and/or visual screening to the adjacent residences. Because there is limited space to work on the west side of the railroad right-of-way without removing vegetation that buffers the Taunton River, we do not believe an alternative alignment for this segment is environmentally preferable.

Insert Figure

3.5.3-1 Northern Parcel Variation

The portion of the route between MPs 0.68 and 0.91 would be constructed within the property of 11 landowners. There are three residences along this portion of the route that are within 50 feet of the pipeline construction right-of-way. Mature vegetation that provides aesthetic value, shade, and/or visual screening to the residences along this segment of the route would be removed during construction. A narrow intermittent stream and associated 5-foot-wide wetland would also be crossed. To avoid or minimize affecting landowners, removing vegetation, and affecting the intermittent stream and wetland, we considered the River Street Variation that would cross the railroad right-of-way at MP 0.68 and follow the west side of the railroad right-of-way until it rejoins the proposed route at MP 0.91 (see figure 3.5.3-2). Because of the steep slope adjacent to the west side of the railroad right-of-way, a route variation at this location would likely be most feasible if constructed from or within River Street, a narrow road located on top of the slope. Although this variation would increase the distance between the pipeline and the residences, use of the road for construction would interfere with traffic accessing the nearby boat marina (Captain John O'Connell Marina).

We received several comments on the draft EIS regarding the River Street Variation, including:

- the variation would include 90 degree pipe bends;
- the variation would run within 15 feet of four homes and other buildings and a 6,000 gallon gasoline tank on River Street;
- a portion of the variation along Collins Street would cross an area that consistently floods; and
- the bridge at the foot of Collins Street is scheduled to be rebuilt.

Weaver's Cove Energy examined the feasibility of this variation and agreed that by maximizing the use of Collins and River Streets, it would minimize impacts on nearby residences and mature vegetation as well as avoid a wetland on the east side of the railroad. While the construction of a pipeline would temporarily inconvenience residents along River Street, there would be no apparent long-term impacts. While the commentors suggested that four homes would be within 15 feet of the River Street Variation, we only identified two residences that would be within 50 feet of the construction workspace associated with the variation in our review (compared to three residences along the corresponding segment of the proposed route). Regardless of the bends in the pipe or the nature of area flooding, the pipeline would be installed in a manner that the pipeline's integrity would be protected. Additionally, the pipeline would be constructed and operated in compliance with DOT safety standards.

In its comments on the draft EIS, Weaver's Cove Energy agreed to incorporate the River Street Variation into the proposed route. As such, the River Street Variation is now considered as an adopted segment of the proposed route.

While we find that incorporating this variation into the proposed route would minimize landowner impacts while making use of an existing road corridor, we believe that mitigation is required to ensure that this segment of the proposed route limits construction and access disturbances on local residences and commercial facilities along the River Street corridor. Therefore, **we recommend that**:

- **Weaver's Cove Energy develop a site-specific plan for construction of the adopted River Street Variation that includes a description of any special construction techniques that would be used (e.g., stove-pipe or drag-section techniques) and other steps taken to minimize impacts on local residences and commercial facilities. This plan should be filed with the Secretary for review and approval by the Director of OEP <u>prior to construction.</u>**

Insert Figure

3.5.3-2 River Street Variation

Golf Course Variation

The Massachusetts EFSB also recommended that we consider an alternative alignment to avoid or minimize the loss of trees and vegetation that provide aesthetic value, shade and/or visual screening at the residences near MP 2.0 along the Northern Pipeline route. The portion of the Northern Pipeline route between MPs 2.00 and 2.40 is located between the railroad right-of-way and seven condominiums (multi-residential buildings). Because there are steep slopes on both sides of the railroad, it does not appear feasible to move the pipeline route closer to the railroad and within the railroad right-of-way. As currently aligned, the pipeline segment through this area would necessitate clearing most of the mature trees between the buildings and the railroad. The pipeline would also cross 155 feet of one wetland (Wetland N9) and likely require extra workspace in another wetland (Wetland N12) to accommodate the pipeline crossing of the railroad near MP 2.4. Because four of these condominiums are within 50 feet of the proposed construction right-of-way, many people could also potentially be inconvenienced by the noise and traffic associated with pipeline construction.

To avoid or minimize these impacts, we evaluated an alternative pipeline alignment between MPs 1.89 and 2.43 (referred to as the Golf Course Variation) in the draft EIS. Both Weaver's Cove Energy and the Fall River Country Club commented that this variation could affect the golf course's Number 7 tee box, fairway, and green (a hole that runs parallel to the east side of the railroad). By crossing to the west side of the railroad before reaching the Number 7 tee box, the pipeline route could avoid the need to clear vegetation adjacent to the condominiums and minimize impacts on the golf course. Based on comments from Weaver's Cove Energy and the Fall River Country Club, we have expanded the Golf Course Variation to include a new pipeline alignment between MPs 1.58 and MP 2.43. This variation is shown on figure 3.5.3-3.

The Golf Course Variation would deviate from the proposed route at MP 1.58 by crossing to the west side of the railroad right-of-way. Although this cross-over would necessitate additional workspace on the Fall River Country Club property, it would not have a direct impact on the golf course fairways east or west of the railroad (see section 4.8.6.1 for additional discussion of impacts on the Fall River Country Club). After crossing the tracks, the variation would proceed north along the railroad right-of-way until it rejoins the proposed route at MP 2.43. The primary disadvantage of the Golf Course Variation is that it would require about 3.2 acres more tree/shrub clearing than the proposed route. The removal of this vegetation may result in a minor alteration of the visual aesthetic of one of the golf course holes. However, the Golf Course Variation would avoid construction disturbance and vegetation clearing adjacent to the condominiums located near MP 2.0 of the proposed route, and eliminate one wetland crossing and the potential need for extra workspace in another wetland. For these reasons, we recommended in the draft EIS that Weaver's Cove Energy incorporate this variation into the proposed route.

In its comments on the draft EIS, Weaver's Cove Energy agreed to incorporate the Golf Course Variation (as modified to include the portion of the route between MPs 1.58 and 2.43) into the proposed route. As such, the modified Golf Course Variation is now considered as an adopted segment of the proposed route. In addition, we find that the modified variation between MPs 1.58 and 1.89 is environmentally preferable to the corresponding segment of the original route, since it reduces disturbances to the Fall River Country Club.

Insert Figure

3.5.3-3 Golf Course Variation

3.5.4 G-22 Lateral Interconnect (Western Pipeline)

As currently proposed, Weaver's Cove Energy would interconnect with Algonquin's G-22 lateral via the Western Pipeline. After crossing the Taunton River, the Western Pipeline route generally follows existing electric transmission line rights-of-way to an interconnect with Algonquin's pipeline system in Swansea. To avoid or minimize impacts on the Taunton River and upland forests and to reduce visual impacts on adjacent residences resulting from construction and operation of the Western Pipeline, we considered several minor realignments of the proposed pipeline route. Also, an alternative construction method (horizontal directional drill) was evaluated for the Taunton River crossing as a mitigative measure and is discussed in section 4.3.2

Western Pipeline Minor Route Variations

To minimize potential impacts on the Taunton River, we examined alternative crossing methods as well as minor route variations to the Western Pipeline route (Taunton River Variations) that would provide an alternative pipeline alignment around the Montaup Power Plant on the western bank of the Taunton River. We also considered route variations that would minimize impact on residences in close proximity to the proposed route's alignment with the existing electric transmission corridor (Jaffrey Street Variations), and a variation that would avoid creating a new right-of-way through a forested area near the terminus of the proposed route (Ferncroft/Dwelly Road Variation).

Taunton River Crossing Methods

To avoid impacts on the Taunton River and address agency concerns regarding an open-cut pipeline crossing of the river, we investigated the potential to install the Western Pipeline across the river using the HDD method. We also received public comments on the draft EIS that we should consider the potential for Weaver's Cove Energy to use plowing or jetting instead of dredging to install the pipeline. Plowing and jetting installation techniques are commonly used in the construction of offshore pipelines. Both techniques typically require large barges for pipeline installation, which are typically moored in place and secured by an array of large anchors. These vessels are typically 400 feet long by 120 feet wide and have a draft of approximately 20 feet. Upstream of the existing turning basin water depths are significantly less than 20 feet along most of the proposed pipeline crossing. Due to the size of the vessels and the draft requirements, which precludes their use in shallow waters, we do not believe that plowing or jetting would be feasible for pipeline installation across the Taunton River.

The HDD method involves drilling a hole under the waterbody and pulling a prefabricated segment of pipe through the hole. The first step in an HDD crossing is to drill a small-diameter pilot hole from one side of the crossing (entry side) to the other (exit side). Drilling is achieved using a hydraulic powered drill bit. The drilling fluid, commonly referred to as mud, is a mixture of water and bentonite (a naturally occurring clay mineral), which is circulated through the drill hole during the drilling process.

As the drilling of the pilot hole progresses, segments of drill pipe are inserted into the pilot hole to extend the length of the drill. When the pilot hole is completed, the hole is enlarged to accommodate the pipeline. The enlargement of the pilot hole is accomplished by attaching a reaming tool to the end of the drill on the exit side of the hole and drawing the reaming tool back through the pilot hole to the drill rig. Typically, several passes of consecutively larger reaming tools are required before the hole is sufficiently sized to accommodate the pipeline. The final hole is typically about 12 inches larger than the diameter of the pipeline segment to be installed.

The pipeline segment to be installed beneath the waterbody is fabricated and radiographically inspected and/or hydrostatically tested on the right-of-way on the exit side of the crossing during the

drilling and reaming process. When the final hole is completed, the pipeline segment is attached to the drill string on the exit side of the hole and pulled back through the drill hole toward the drill rig.

HDD techniques have become increasingly common to avoid disturbing the bed and banks of major waterbodies during pipeline installation. However, there are several factors that must be evaluated in determining the feasibility of the HDD method. For one, the substrate must be suitable for drilling. Drilled crossings are typically designed to maintain a drill path of at least 20 feet or more below the waterbody to minimize the potential for an inadvertent release of drilling mud. Certain subsurface conditions make maintenance of an open drill hole difficult. In particular, the presence of glacial till or outwash interspersed with boulders and cobbles, fractured bedrock, or non-cohesive coarse sands and gravels increase the likelihood of HDD failure due to refusal of the drill bit or collapse of the bore hole in non-cohesive, unstable substrate. Drilling through bedrock can also be problematic if the rock is fractured, which may provide conduits within the rock through which drilling mud can travel to the surface. If these fractures lead to the surface under or near the waterbody, drilling mud could “frac-out” into the water, covering benthic habitat with drilling mud and increasing suspended sediment levels and turbidity. As discussed in section 4.1.2, the proposed facilities are located in an area generally underlain by glacial till over bedrock. The glacial till consists of very dense poorly sorted sand and gravel with fine silt interbeds and some black shale and pink granite cobbles. Furthermore, the area is affected by the Beaverhead Fault Zone, which is a zone of highly broken rock, coincident with the run of the Taunton River (see section 4.1.4).

Although Weaver’s Cove Energy has not conducted specific geotechnical borings to determine the suitability of the substrate for HDD, it did collect bore samples to characterize the subsurface geology underlying the proposed LNG tank. These data suggest that at least a portion of the drill path would cross through poorly graded gravels or gravel sand mixtures with little or no fines, which may not be suitable for drilling. The data also indicate that the underlying bedrock is fractured shale and silty sandstone. Deep borings conducted approximately 1,200 feet south of the proposed river crossing document shattered bedrock. Recovered cores measured from these borings have low rock quality designations that range from 20 to 30 percent, which is indicative of poor rock quality and highly fractured rock. This information regarding the underlying geology is also supported by reports prepared by di Cervia and Taylor of the Trevicos Corporation, who was awarded the contract for installation of the drilled shafts for the Brightman Street Bridge piers. They reported that the geology of the bridge "site consists of sands and gravels over a layer of cobbles and boulders 30 feet thick above sandstone and shale bedrock." They also reported that as soon as work started on the east pier of the bridge, they "encountered large numbers of cobbles and boulders in the sand-and-gravel stratum in a percentage much greater than shown in the contract boring logs" (di Cervia and Taylor, 2003). This geotechnical information suggests that the underlying substrate in the project area is not conducive to drilling and that drilling would not be without environmental risks.

Another requirement for the HDD method is that there must be workspace on one side of the waterbody for the drill rig and workspace on the opposite side of the waterbody to fabricate the pipeline segment for the crossing. There are several general requirements for the pipe fabrication workspace. Ideally, the area should be generally level to gently sloping, equal in length to the fabrication segment, and aligned with the drill path. Steep topography or bends in the fabrication area can put additional stresses on the pipeline that can complicate the pullback operation and potentially damage the pipe. Under some circumstances, it may be possible to use less workspace for pipe fabrication by welding shorter segments of pipe together during the pull-back operation. However, this would require the pullback operation to be halted to complete the necessary welds, which is not recommended by drilling experts and greatly decreases the probability for a successful HDD crossing. For these reasons and because the substrate does not appear to be highly suitable for HDD, we do not consider halting the pullback operation to weld on additional sections of pipe practical for this project. We received a

comment from NOAA Fisheries that we should evaluate the possibility of welding the pipeline during the pullback (e.g., welding on the move) to avoid interrupting the pullback operation. We believe this would be impractical due to the length of time required for each weld, the need to radiographically inspect the weld before installing the pipeline, and the challenges of completing a suitable weld while the pipeline is in motion.

We reviewed both sides of the river upstream and downstream of the proposed crossing location to identify potential workspace locations to fabricate the pipe segment for a HDD crossing. We divided our review into two areas: areas located within one mile of the proposed crossing; and areas located more than one mile from the proposed crossing.

Since the narrowest point of the river within one mile of the proposed crossing location is about 1,400 feet across, we assumed the pipe fabrication area for any HDD crossing within one mile of the proposed crossing location would need to be at least 1,500 feet in length. Our review revealed that the riverfront on both sides of the river is well developed and that there are no unobstructed areas of this size within one mile of the proposed crossing location. Route 79, North Main Street, and the CSX railroad are all within 1,500 feet of the eastern shore of the river and Riverside Avenue and County Road are both within 1,500 feet of the western shore on the river. The fabrication of the pipeline segment on either side of the river would require the closure of roads and/or the railroad for at least several hours.

Our review of potential fabrication areas more than a mile from the proposed crossing location was limited primarily to areas north of the site. We could not find any suitable fabrication areas south of the proposed crossing location (e.g., south of the existing Brightman Street Bridge) that would not require road closures. Furthermore, any crossing of the river more than a mile south of the site would require construction of additional pipeline through highly developed areas of Fall River.

We found one area located about 4.5 miles north of the proposed crossing where there may be sufficient area on the eastern shore of the river to fabricate the pipeline segment without interrupting road or railroad traffic. However, the river is wider at this location, which would increase the length of the HDD crossing to about 4,500 feet. Crossing the river at this location would also increase the amount of pipeline that would need to be constructed on both sides of the river. The pipeline route on the west side of the river, in particular, would create a new right-of-way and pass through several residential areas. This pipeline route would also cross several perennial waterbodies (including the Cole River) and cross several thousand feet of wetland.

We also considered the possibility of a land-to-water or water-to-water HDD (techniques typically used in offshore pipeline construction). Due to the relatively narrow width of the river, we do not believe a water-to-water drill is possible or would have any advantages. Moreover, a water-to-water drill would likely release substantial drilling fluid within the river at the exit or entry point and increase the chances of a release where the drill path is within 20 feet of the river bottom. We did, however, evaluate completing an HDD crossing of the river by stationing a drill rig in the center of the river and drilling both east and west to points on the eastern and western shores of the river. This method would require installation of a drill platform in the river and driving piles or spuds into the river bed to stabilize the platform. Two drill entry pits would likely need to be excavated in the river bottom. We estimate each of these pits would be about 10 feet deep, 10 feet wide, and 30 feet long, assuming sheetpiling is used (if sheetpiling is not used, the pits would be larger). Drilling mud would be injected from the head of the drill into the underwater pilot hole. The completed pilot hole would exit onshore and would then be enlarged as described above by reaming. When the hole is sufficiently sized, a section of pipe that has been prefabricated onshore would be pulled into the exit hole and back to the drill entry pit in the center of the river. After both HDDs and pipe installations have been completed, the two sections of pipe would need to be connected underwater, most likely with a special flange.

By splitting the HDD operation into two sections, the land-to-water method would reduce the length of pipe required for each HDD and thus the amount of onshore area required for pipe prefabrication and laydown. This could potentially avoid some of the road and railroad conflicts described above and increase the number of potential prefabrication areas. However, drilling from the center of the river would also result in considerable disturbance of the riverbed and the release of drilling mud into the river. HDDs that begin or end in the Taunton River would require dredging of the river bottom to receive and/or tie in the pipeline sections and bury the pipeline beneath the river bottom. In our view, these impacts would significantly diminish the environmental advantages of the HDD. Additionally, it is questionable whether such short drill segments for 24-inch-diameter pipe are feasible. The minimum length of an HDD depends on several factors including the depth and path of the drill as well as the diameter of the pipe. Generally, larger diameter pipe requires a greater minimum drill distance. Typically, HDDs with 24-inch-diameter pipe are considerably longer than half the width of the Taunton River. As a result, we believe that a land-to-water HDD would offer no clear environmental advantage over the proposed open-cut crossing.

Even though a successful HDD crossing would avoid potential impacts on aquatic organisms in the Taunton River, the factors discussed above suggest that the subsurface conditions underlying the river may not be suitable for HDD. Additionally, the use of the HDD method would be more costly (Weaver's Cove Energy indicated that the HDD crossing would be about $2.5 million more expensive than an open-cut crossing) and would result in additional environmental impacts that would be avoided by an open-cut crossing. As discussed in section 4.6.2, we have also recommended that Weaver's Cove Energy schedule the open-cut crossing of the Taunton River to minimize adverse impacts on important aquatic resources such as winter flounder habitat. For these reasons, we do not believe a HDD crossing of the Taunton River is a practicable alternative that provides a clear environmental advantage over the open-cut crossing method that would be implemented for the Weaver's Cove LNG Project.

Taunton River Variations

We examined Taunton River Variations A and B as alternatives to the segment of the Western Pipeline between MPs 0 and 0.8 in an attempt to minimize impacts on the Taunton River and to minimize impacts on residences along Annette Avenue north of the Montaup Power Plant. As shown on figure 3.5.4-1, Taunton River Variation A begins at the same location on the LNG terminal site as the proposed route and proceeds west across the Taunton River. Taunton River Variation A reaches the west bank of the river at a point south of the Montaup Power Plant. Taunton River Variation B begins on the southern edge of the LNG terminal site approximately 2,000 feet south of the starting point for the proposed route and makes landfall on the west bank of the river at the same location as Taunton River Variation A. After coming onshore on the west bank of the river, both variations go around the southern perimeter of the power plant before turning north at Riverside Avenue. The variations continue north for about 500 feet along Riverside Avenue before turning west and following Stevens Street for about 700 feet. The variations then turn north and proceed along Route 138 (County Street) for about 1,000 feet before joining the proposed route at the intersection of Clifford M. Holland Road near MP 0.8. Both variations align the pipeline within the proposed turning basin of the river and avoid the dredging of a new area north of the turning basin, as required by the proposed route.

Insert Figure

3.5.4-1 Taunton River Variations

The Taunton River Variations A and B are about 0.2 to 0.4 mile longer, respectively, than the corresponding segment of the Western Pipeline route. In other respects, the onshore portions of the variations are similar to the proposed route, although the Taunton River Variation B crosses 260 feet of salt marsh on the east bank of the river that is avoided by the other routes. The primary difference between the variations and the proposed route is that the crossing of the Taunton River would be several hundred feet longer for the variations than for the proposed route. Additionally, since the variations cross the river in an area that would be dredged for the LNG ship turning basin (between 1,000 and 1,500 feet, or 44 to 55 percent of the crossings, would be in areas proposed to be dredged), they would require more dredging than the proposed pipeline. This is because a pipeline under the turning basin would need to be buried with 10 feet of cover for safety reasons, whereas a pipeline outside of the turning basin would require only 5 feet of cover. Thus while the variations would somewhat reduce the area disturbed by dredging, the additional depth of cover necessary for the variations would more than double the volume of dredging required for the pipeline installation when compared to the proposed route. For this reason, we do not believe either the Taunton River Variation A or Taunton River Variation B provides a clear advantage over the corresponding segment of the proposed pipeline route and do not recommend that either variation be adopted as part of the preferred route.

Clifford M. Holland Road Variation

In its comments on the draft EIS, Weaver's Cove Energy indicated that it is considering a minor route variation along Clifford M. Holland Road between approximate MPs 0.80 and 1.06 of the Western Pipeline route.[6] This minor route variation would involve shifting the pipeline centerline to the south from the edge of Clifford M. Holland Road into the center of the road and reconfiguring areas needed for temporary extra work space. The result of this minor route variation would be the preservation of existing vegetation that provides aesthetic value and/or visual screening for motorists using the road or persons using the athletic fields on the south side of the road (many of the oak trees that would be avoided by this minor route variation have diameters between 10 and 24 inches). As described, we believe this is an acceptable route variation and encourage Weaver's Cove Energy to take steps necessary to avoid or minimize the need to clear vegetation along Clifford M. Holland Road.

Jaffrey Street Variations

As shown on figure 3.5.4-2, we identified two Jaffrey Street Variations as alternatives to the segment of the Western Pipeline between MPs 1.5 and 1.9 to:

- increase the distance of the pipeline from residences along Brayton Avenue and the south side of Jaffrey Street; and
- minimize potential visual impacts associated with the clearing of vegetation for the construction right-of-way.

Weaver's Cove Energy proposed alignment in this area would be constructed entirely within the existing electric transmission line corridor using a 100-foot-wide construction right-of-way. The proposed pipeline would be about 22 feet north of the base of the northernmost transmission line towers and 35 feet south of the northern edge of the electric transmission line right-of-way. In this position, the pipeline would be about 30 feet from a residence on Brayton Avenue and between 60 feet and 80 feet of 12 residences along Jaffrey Street. Based on a field review of the area, it seems likely that the construction right-of-way for the proposed route would remove at least some of the vegetation that currently screens the transmission lines from these residences.

[6] In its comments on the draft EIS, Weaver's Cove Energy inadvertently indicated that this route variation is between MPs 0.49 and 0.54 of the Western Pipeline route.

Insert Figure

3.5.4-2 Jaffrey Street Variations

One alignment that would increase the distance of the pipeline from these homes and minimize the clearing of screening vegetation would be to put the pipeline on the opposite (south) side of the transmission line right-of-way between Brayton Avenue and Swansom Road (see figure 3.5.4-2). The variation, referred to as Jaffrey Street Variation South, would increase the distance of the pipeline from the residences on Jaffrey Street by at least 200 feet. However, construction of the pipeline on the south side of the transmission line corridor would put the pipeline on the edge of a Junior High School parking lot approximately 130 feet to 170 feet from the nearest school building. It would also increase the amount of tree clearing required. Weaver's Cove Energy has indicated that it is infeasible to construct the pipeline entirely within the electric transmission line corridor at this location due to the presence of an existing water supply line. As a result, it may be necessary to put the pipeline outside of the transmission line corridor, which could result in up to 2.6 acres of new forest clearing and the acquisition of up to 50 feet of new permanent right-of-way outside of the existing corridor.

Another alignment, referred to as Jaffrey Street Variation Center, that would increase the distance of the pipeline from residences would be to put the pipeline down the center of the transmission line corridor between the two most northern lines (see figure 3.5.4-2). There is about 50 feet of space between the towers for these two transmission lines. Locating the variation here would generally avoid the clearing of screening vegetation but maintain most of the buffer between the pipeline and the Junior High School (the distance between the variation and the nearest school building would be about 375 feet, or about 45 feet less than of the distance between the proposed pipeline alignment and the building). This alignment would provide less available workspace than the other alignments. The limited amount of space between the electric towers would require Weaver's Cove Energy to use a narrower right-of-way, which would complicate and likely slow the rate of construction. The need to work under and around multiple power lines may also increase safety concerns for workers and may require additional cathodic protection to protect the pipeline.

In response to the draft EIS, Weaver's Cove Energy indicated that it has further reviewed the Jaffrey Street Variations. The potential for AC interference or effects on the pipeline's cathodic protection system still cannot be fully addressed until Weaver's Cove Energy obtains data from National Grid concerning the existence of counterpoise wires. In the meantime, Weaver's Cove Energy made adjustments to permanent easements and temporary workspaces to mitigate potential effects on stone walls and trees that are on those properties impacted by the proposed route. Additionally, National Grid filed comments with the Commission indicating it believes the Jaffrey Street Variation Center would constrain National Grid from future (although currently not planned) modifications or reconstruction of its transmission facilities. Furthermore, National Grid believes that this variation would pose safety concerns during construction and operation of the pipeline. Because of these concerns and because of the uncertainties associated with the Jaffrey Street Variation Center, we do not believe either variation provides a reasonable alternative that offers a clear environmental advantage over the proposed route. We find that Weaver's Cove Energy would adequately minimize residential impacts along Jaffrey Street by overlapping its proposed right-of-way with the existing utility corridor and by avoiding vegetation clearing which currently screens the transmission lines. Weaver's Cove Energy's development of site-specific residential plans would include measures to minimize residential impacts along this segment.

Ferncroft/Dwelly Road Variation

We examined the Ferncroft/Dwelly Road Variation as an alternative to the segment of the Western Pipeline between MPs 1.9 and 2.5 to minimize forest land impacts near the terminus of the proposed route. As shown on figure 3.5.4-3, this variation deviates from the Western Pipeline route near MP 1.9, where the proposed route turns north and follows the northern extension of the electrical transmission line right-of-way. Rather than turning to the north, the Ferncroft/Dwelly Road Variation

proceeds west generally adjacent to Ferncroft and Dwelly Roads. The variation continues west beyond the ends of the roads and crosses a narrow forested area before interconnecting with Algonquin's G-22 lateral about 1,450 feet south of where the Western Pipeline route interconnects with the G-22 lateral.

With a length of about 2,600 feet, the Ferncroft/Dwelly Road Variation is about 425 feet shorter than the corresponding segment of the proposed route. The variation would also disturb less land, and cross about 1,675 feet less forest land than the corresponding segment of the proposed route.

A significant disadvantage of the variation is that it would involve substantially more disturbance to residential areas during construction. The construction right-of-way for the Ferncroft/Dwelly Road Variation would be within 50 feet of 23 additional homes when compared to the corresponding segment of the proposed route. Construction near these homes would increase impacts on nearby residents, which would include increased noise, dust, traffic, visual impacts associated with tree clearing, and other inconveniences. Additionally, construction and restoration costs of this route variation would be greater than for the corresponding segment of the Western Pipeline due to the need to repair and repave streets and driveways as well as to replace residential landscaping. We do not believe that the reduction in the length of forest land crossing outweighs the increased residential impacts of the Ferncroft/Dwelly Road Variation and do not recommend it be adopted as part of the proposed route.

3.6 DREDGING AND DREDGE DISPOSAL ALTERNATIVES

As discussed in section 2.4.1.3, Weaver's Cove Energy would dredge up to about 2.6 million cubic yards of sediment from the Mount Hope Bay/Taunton River federal navigation channel and a turning basin to enable LNG ships to transit, dock, and turn in the Taunton River. This volume was determined based on the minimum volumes needed to safely accommodate LNG ships. Alternatives requiring more dredging could be identified. However, alternatives requiring less dredging would not be able to safely accommodate LNG ships. As such, we did not consider it feasible to reduce the volume or extent of dredging and still satisfy the objectives of the project at the proposed site.

Dredging and related activities would be conducted in accordance with applicable federal, state, and local permit stipulations. To avoid or minimize impacts on water quality or biological resources associated with these activities, alternative dredging methods and dredge disposal alternatives were considered.

3.6.1 Alternative Dredging Methods

Large-scale dredging operations in the region typically utilize mechanical dredging equipment for maintenance and improvement dredging of the harbors and channels. Mechanical dredging involves equipment such as clamshell dredges, dipper dredges, draglines, grab buckets, and barge-mounted excavators for the removal of bottom sediments and other materials. The dredged material removed by mechanical methods is typically high in solids content and lower in mixed waters that are more common with hydraulic dredge methods. Mechanical dredging equipment involves the use of a bucket to place dredged materials in scows or on barges for transport to a disposal area. Various bucket designs are available that are able to reduce the amount of solids suspended in the water column. Two types of buckets considered for this project include the open bucket and the closed bucket (or occasionally referred to as the environmental bucket). The open bucket involves dredging material at almost in-situ concentrations. Excess material and water are allowed to spill off the top so that little excess water is dumped into the scow. The closed bucket reduces turbidity at the dredge site but entrains more water.

Insert Figure

3.5.4-3 Ferncroft / Dwelly Road Variation

Mechanical dredges are rugged, highly reliable, and capable of removing a broad range of materials. Such equipment is also able to operate in an open channel as well as confined berth spaces. Barge and scow transport of dredged material is efficient over long-haul distances, although mechanical dredging productivity is generally slow compared to hydraulic dredging operations due to the scow loading process. Additionally, such operations are subject to spillage and splashing, which allows sediments to resuspend in the water. In the draft EIS, we recommended that, in consultation with NOAA Fisheries and applicable state resource agencies, Weaver's Cove Energy identify measures (e.g., changes in dredging equipment, dredging procedures, and/or dredging schedules) to avoid or minimize potential dredging impacts on fishery resources in the project area. Subsequent to the draft EIS, Weaver's Cove Energy adopted several measures, including closed buckets in certain sediments types and restricted dredging windows and no scow overflow in certain areas, to minimize aquatic impacts (see sections 2.4.1.3 and 4.6.2).

Hydraulic dredging equipment is an alternative that could be used for this project. Hydraulic dredges operate using a centrifugal pump capable of handling solids to transport a slurry of dredged sediments and water through a pipeline. The slurry containing the dredged materials is hydraulically transported through the pipeline from the dredged area to a disposal site. For long distance transport, the slurry can also be placed in barges for removal to the disposal site. Hydraulic dredges are able to excavate a broad range of materials. An advantage of the hydraulic dredge is that it typically generates somewhat lower levels of turbidity throughout the water column at the dredge site compared to mechanical dredging methods. Turbidity is managed by controlling the cutterhead rotation speed and the swing speed of the dredge and by implementing operational controls.

There are also several disadvantages associated with the use of hydraulic dredge equipment. The hydraulic dredge typically requires a long, temporary pipeline system, which could potentially become an obstruction to navigation and or vessel movement within the harbor. Moreover, hydraulic pipeline transport of dredged materials typically requires in-line booster pumps to extend pumping distances and thus are restricted by practical and economic constraints. Hydraulic dredging also draws in significant amounts of water during the dredging process. This intake of water has the potential to entrain significant numbers of fish eggs and larvae as well as other benthic organisms. Hydraulic dredging also requires a much larger disposal area and longer drying times. If barges are used to transport the dredged material, it requires more barge movements between the dredge site and the disposal area than would be necessary if mechanical dredging were used. There are sometimes water quality issues associated with overflow off of the barge. Given these disadvantages we do not believe hydraulic dredging methods are a practical alternative to mechanical dredging equipment for this project.

Hopper dredges are another type of dredging equipment. Hopper dredges are self-propelled ships that include an integral suction pipe or several suction pipes, which are dragged along the channel bottom. The bottom materials are drawn through a suction head, pass through the suction pipe and pump, and are deposited as a slurry in a large onboard hopper. Once full, the hopper dredge can travel to an offshore or other designated dumpsite, open its bottom doors, and discharge the dredged material. Some hopper dredges also can offload the dredged material by pumping. An advantage of hopper dredges is that they have minimal interference on other vessel operations and can efficiently transport materials over short haul distances. However, the use of the hopper dredge to dispose of dredged materials requires that the dredging process be suspended while the dredged material is transported to the disposal site. Hopper dredges are also not effective in restricted areas, such as berths and docking facilities. In addition, when used to dredge very fine silts that do not readily settle, the dredge generally can carry only partial loads, with relatively high water content, to the disposal site, which generally makes it inefficient for dredging in areas with these sediment types.

All three of these dredge types were assessed in detail for the Providence River and Harbor Maintenance Dredging Project, which involved sediment conditions similar to the proposed project. The COE concluded that hydraulic and hopper dredge equipment, while physically capable of conducting the work, were not preferable because they entrain significant amounts of water and result in fairly unconsolidated material. The COE (2001) identified the following disadvantages of these dredging methods:

- both hydraulic and hopper dredges require a larger dewatering site and longer drying times;
- the hydraulic dredge requires a long pipeline system that could interfere with other vessel's navigation; and
- the hopper dredge is not suited for operating in restricted areas or long haul disposal due to long cycle times for the dredging operations.

3.6.2 Dredge Disposal Alternatives

Weaver's Cove Energy proposes to dispose of the sediments that are removed from the federal navigation channel and turning basin by reusing the dredged material as general site fill material at the LNG terminal site (see section 2.4.1.3). Other potential options that were considered for the project include offshore disposal, confined aquatic disposal, confined disposal facility, island/habitat creation, landfill disposal, and other upland disposal sites. Table 3.6.2-1 lists all of the various dredging and disposal options that have been considered and summarizes the material processing requirements and potential advantages and disadvantages of each option. For a more detailed discussion of these options see Weaver's Cove Energy's *Dredging Program Report* (C2D, 2003). An electronic copy of this report is available under the "Proposal" link on Weaver's Cove Energy's website at www.weaverscove.com.

Effects of Time-of-Year Restrictions on Dredging Plan

After additional review and consultations with state and federal agencies, we concluded that the dredging program currently proposed by Weaver's Cove Energy could negatively affect biological resources in the Taunton River (see section 4.6.2). As a result, we have recommended that Weaver's Cove Energy modify its proposed dredging program within the Taunton River to prohibit dredging activities during the winter flounder spawning period (January 15 through May 31). Based on our analysis, additional time-of-year restrictions beyond the winter flounder spawning period do not appear warranted. However, the COE is currently considering additional information regarding potential dredging impacts on anadromous fish movements and may require an even longer time-of-year restriction on dredging activities (January 15 through July 31 or January 15 through October 31). These timing restrictions would leave Weaver's Cove Energy with the following time to conduct its dredging operations:

- 228 days per year (January 15 through May 31 restriction);
- 167 days per year (January 15 through July 31 restriction); or
- 75 days per year (January 15 through October 31 restriction).

TABLE 3.6.2-1

Summary of Dredging and Disposal Alternatives

Alternative (Material Placement)	Dredging Methods	Material Processing	Considerations
On-site Upland Reuse (Proposed Action)	Mechanical	Mixing mill, spread and till, or in-barge mixing of cement for stabilization	The proposed site is available and large enough to accommodate dredged materials. Use of the site would require modification of the existing groundwater remediation system as well as resolution of MCP concerns related to the placement of sediments on the site (see section 4.2.2). General costs: $35-55 per cubic yard.
Offsite Upland Reuse	Mechanical	Mixing mill, spread and till, or in-barge mixing of cement for stabilization	Weaver's Cove Energy has not been able to obtain access to another property for upland reuse of the dredged materials. Additionally, any site in Massachusetts would have the same MCP concerns related to the placement of sediments as the proposed site. General costs: $35-55 per cubic yard (assuming site is available).
Offsite Upland Disposal (Landfill)	Mechanical	Untreated	The dredged material quantity exceeds the capacities of regional landfills. Trucking dredged materials long distances is prohibitively expensive and would result in air quality and traffic impacts. General costs: $75-100 per cubic yard.
Offsite Upland Disposal (Dewatering)	Hydraulic	Naturally dewater through settling and consolidation	An upland site that would be capable of storing the dredged material during the dewatering process is not available. Additionally, any site in Massachusetts would have the same MCP concerns related to the placement of sediments as the proposed site. General costs: $20-25 per cubic yard (assuming site is available).
Offshore Disposal	Mechanical	Untreated	Offshore disposal would result in short-term (up to 3 years) impacts on water quality, benthic habitats, and fishing industry. Some sites may be permanently impacted. Additional sediment sampling and analysis has been conducted to determine the suitability of the sediments for offshore disposal. General costs: $12-27 per cubic yard.
Confined Aquatic Disposal cell (CAD)	Mechanical	Untreated	This alternative involves underwater storage of material after additional dredging is completed. A confined aquatic disposal cell is sometimes considered for isolating contaminated sediments. This alternative requires dredging and disposal of additional materials. General costs: $40-60 per cubic yard.
Confined Disposal Facility (CDF)	Mechanical or Hydraulic	Untreated	A confined disposal facility would require the construction of a wall or berms in a nearshore area. Can result in short-term and long-term negative impacts on some resources (e.g., permanent habitat replacement, short term impacts on water quality and benthic habitats). General costs: $20-25 per cubic yard.
Island/Habitat Creation	Mechanical	Untreated	Dredged material can be used to create or enhance aquatic habitats. Can result in short-term and long-term negative impacts on some resources (e.g., permanent habitat replacement, short term impacts on water quality and benthic habitats). General costs: $45-100 per cubic yard.

As described in section 2.4.1.3, the currently proposed dredging program is closely linked to the placement operations whereby the dredged materials would be stabilized and placed on the LNG terminal site. As described, the process of the onshore placement of the stabilized volumes (i.e., stabilization using cement, rate of placement, and compaction) has more impact on the project schedule than the dredging process itself. Timing restrictions, particularly those that overlap the warmer spring and summer months when dredged material stabilization and placement rates would be the highest, would particularly impact the project schedule. Weaver's Cove Energy has estimated that dredging could take approximately 650 operational days. Accounting for expected weather and equipment (moving and maintenance) delays, Weaver's Cove Energy conservatively estimated that the entire dredging and placement program would require about 975 days. Based on our own independent analysis of equipment and cycle times as well as

down time for inclement weather and equipment movement and maintenance, these assumptions seem reasonable.[7]

In response to comments on the draft EIS that we expand the analysis of impacts of various time-of-year restrictions on the proposed project schedule, we have evaluated the effects of three different time-of-year restrictions. The first restriction would prohibit dredging between January 15 and May 31 during the winter flounder spawning period. This time-of-year restriction would permit dredging 228 days a year or 684 days over a 3-year period including the summer months, which would likely be the months when the highest production and placement rates can be achieved. The second restriction would prohibit dredging between January 15 to July 31, which encompasses both the winter flounder spawning period and the anadromous fish upstream migration period. This time-of-year restriction would permit dredging 167 days a year or 501 days over a 3-year period, but would prevent dredging during the late spring and early summer months, which are expected to be when some of the highest production and placement rates can be achieved. The third restriction would prohibit dredging between January 15 and October 31, which would encompass the winter flounder spawning period and both the anadromous fish upstream and downstream migration periods. This time-of-year restriction would permit dredging 75 days a year or 225 days over a 3-year period, but would limit dredging to the coldest months of the year, when production and placement rates would be lowest.

It seems unlikely that the dredging program could be completed in 3 years under the January 15 to May 31 time-of-year restriction unless numerous barges could be filled and moored for an indefinite period. It is more likely that this restriction would add between 1 and 2 years to the proposed schedule. The January 15 to July 31 time-of-year restriction would add between 2 and 4 years to the proposed project schedule. The January 15 to October 31 time-of-year restriction would likely add up to 6 years to the proposed project schedule. Based on these timing restrictions and the onshore placement of dredged material, we believe it is reasonable to assume that time-of-year restrictions would likely lengthen the project schedule for onshore disposal a minimum of 1 to 2 years to as long as 6 years beyond the currently proposed 3-year project schedule. The significance of the time-of-year restrictions on the project schedule is reduced based on the MassHighway's anticipated completion of the new Brightman Street Bridge and demolition of the existing bridge until some time in 2010, which may add up to 2 years to Weaver's Cove Energy's currently proposed project completion date of 2008.

Offshore Disposal Alternatives

Based on consultations with state and federal agencies, there is a general consensus among most agencies that disposal of the dredged material in an upland location is preferred and could reduce water quality impacts. The DEP, however, has expressed concerns about the regulatory feasibility of placing the dredged sediment on the proposed site without some additional testing of the existing site soils and the effects of the dredged material on the existing remediation system (see section 4.2.2). If these concerns can not be reconciled, it may not be possible to place the dredged material on the proposed site. In addition, the time-of-year restrictions described above may also unduly delay the schedule for the proposed onshore placement of the entire dredged volumes. Because other onshore disposal sites are not currently available or would be prohibitively expensive, offshore disposal of the dredged material may be an alternative method for disposing of some or all of the dredged material.

Offshore disposal of the dredged material may be possible but also may involve additional water quality impacts and new regulatory issues. Although offshore disposal is not part of its proposed

[7] We estimated that based on 1 foot of overdredge, average projected production rates, and 100 percent efficiency, dredging would take approximately 560 days. With expected delays, which we assumed could result in only 50 percent efficiency, the entire dredging and placement program would take approximately 1,120 days.

dredging plan, Weaver's Cove Energy initiated a Tier III analysis program[8] in accordance with the COE- and EPA-approved protocols to determine the suitability of the materials for offshore disposal at the Rhode Island Sound Disposal Site (RISDS) formerly referred to as Site W or Site 69b and the Massachusetts Bay Disposal Site (MBDS). The results of the Tier III testing were filed with the EPA and COE on April 12, 2005. Preliminary indications provided by Weaver's Cove Energy are that the majority of the dredged material would be suitable for offshore disposal. The EPA and COE will subsequently review the Tier III testing results and make a suitability determination for offshore disposal. As of the publication of this final EIS, the EPA and COE have not made a final determination regarding the suitability of the proposed dredged sediment for offshore disposal. If the COE and EPA concur with Weaver's Cove Energy's determination that most of the dredged material is suitable for offshore disposal, Weaver's Cove Energy would likely be able to avoid dredging during the winter flounder spawning period without adversely affecting the 3-year project schedule by using multiple dredges and disposing of the dredged material at an offshore site. Thus the offshore disposal of sediments could potentially avoid impacts on winter flounder eggs and some other sensitive aquatic organism in Mount Hope Bay and the Taunton River. Another potential advantage of offshore disposal is that it would avoid the issues raised by the DEP about the regulatory feasibility of placing the dredged sediment on the proposed site and the effects of the sediments on the existing remediation system. If the dredged material is not considered suitable for offshore disposal, however, Weaver's Cove Energy has indicated that imposing the more restrictive time-of-year windows with its proposed sediment placement plan at the LNG terminal site could impact the financial viability of the project. Although we currently do not know whether the COE and EPA will determine whether the dredged material would be suitable for offshore disposal, we have conducted the following analysis of the impacts associated with offshore disposal.

Effects of Offshore Disposal and Multiple Dredges on the Project Schedule

Offshore disposal, unlike onshore disposal, would enable Weaver's Cove Energy to potentially use multiple dredges, primarily because this disposal option does not have the constraints associated with the proposed onshore dredged material stabilization and placement process. The effect offshore disposal of sediments has on the construction schedule depends on how much of the sediment qualifies for offshore disposal and how many dredges are employed. As discussed above, a final determination regarding offshore disposal based on the Tier III tests results has not yet been made. However, it appears likely based on the results of the Tier II testing, if any sediment qualifies for offshore disposal, one of two offshore disposal scenarios are probable. One scenario would be that only the native sediments (about 0.6 million cubic yards) are determined to be suitable for offshore disposal. The other scenario would be that all (2.6 million cubic yards) of the sediments are determined to be suitable for offshore disposal. Our review indicates that the first scenario (offshore disposal of only the native sediments) would have little effect on the project schedule and costs regardless of the number of dredges used. This is because the volume of native sediments relative to non-native sediments is relatively small and the stabilization and placement of the native sediments would be easier, faster, and less expensive than the stabilization of non-native sediments. Weaver's Cove Energy has estimated that under the current onshore management plan, it would take between 90 and 120 days to excavate, stabilize, and place the native sediments on the site. Weaver's Cove Energy has suggested that it might be possible to double the dredging rate if the native sediments are disposed of offshore, which would reduce the time required to dredge and dispose of the native sediments by about 50 percent. However, the overall effect of this change would only shorten the dredging schedule by about 45 to 60 days.

We then assessed the potential impacts on the schedule assuming all of the sediments are disposed of offshore. Based on the areas to be dredged, we assumed it might be possible to use two and

[8] Tier III testing involves the assessment of contaminants in the dredged material on appropriately sensitive and benchmark organisms to determine if there is the potential for an unacceptable toxicity or bioaccumulation impact at the disposal site.

perhaps three dredges effectively if some or all of the dredged material could be placed at an offshore disposal site. We then looked at the potential of using multiple dredges to accelerate the dredging schedule if certain time-of-year restrictions are imposed. Table 3.6.2-2 shows the results of our analysis of potential effects of using multiple dredges on the proposed schedule assuming various time-of-year restrictions. Based on the results of our analysis, it appears that two dredges would minimize the impact on the proposed 3-year schedule if a January 15 to May 31 time-of-year restriction is imposed. Three dredges could effectively shorten the proposed 3-year schedule if a January 15 to May 31 time-of-year restriction is imposed or minimize the impact on the proposed schedule if a January 15 to July 31 time-of-year restriction is imposed.

TABLE 3.6.2-2

Effects of Multiple Dredges and Time-of-Year Restrictions on the Proposed Dredging Schedule a/

Number of Dredges	No Restriction	Jan 15-May 31 Restriction	Jan 15-July 31 Restriction	Jan 15- Oct 31 Restriction
1	~3 yrs	~4-5 yrs	~5-7 yrs	~11-14+ yrs
2	NA	~3-4 yrs	~4-5.5 yrs	~9-12+ yrs
3	NA	~2-2.5yrs	~2.5-3.5 yrs	~5-7+ yrs

a/ The figures above assume disposal of 2.6 million cubic yards of sediment and are based on production rates similar to those that would be achieved for the proposed project. Weaver's Cove Energy believes these production rates could be increased, and thus the effect of the timing restrictions on the overall schedule could be reduced if dredge material is disposed of offshore.

To determine the potential costs of dredging and offshore disposal, we reviewed the unit costs provided by Weaver's Cove Energy and estimates of unit costs from the Providence River and Harbor Maintenance Dredging Project and the Rhode Island Regional Long-Term Dredged Material Disposal Site Evaluation Project (adjusted for inflation). Based on these dredging cost estimates, it appears that the costs of dredging and offshore disposal of 2.6 million cubic yards could be in the range of $31 to $70 million (compared to the estimated $91 to $143 million for the upland disposal on the terminal site as proposed). We estimate that a January 15 to May 31 time-of-year restriction on dredging activities would increase these costs by at least $1 to $2 million (not including the costs of additional dredges), a January 15 to July 31 time-of-year restriction would increase costs by at least $2 to $5 million (not including the costs of additional dredges), and a January 15 to October 31 time-of-year restriction would increase the costs of dredging and offshore disposal even more.

Under any of these scenarios, Weaver's Cove Energy's proposed LNG terminal design would not change significantly. As such, the offshore disposal options would require Weaver's Cove Energy to import replacement material (soils or fill material) to support the proposed site grading plan, which includes increasing the elevation of the present site. Weaver's Cove Energy would continue to regrade the site to support the proposed LNG tank, truck loading area, and LNG piping area. In addition, Weaver's Cove Energy has indicated that replacement fill material would also be required to create the proposed landform designed to visually screen the LNG terminal from the adjacent landowners. Although the landform may provide some visual screening of the facilities at the LNG terminal from the east and northeast, the FERC would not necessarily require that this landform be a component of the project. As such, an alternative site layout would not need to include this landform (see section 3.4). The cost associated with bringing any replacement material onsite and the associated offsite trucking to transport these materials would offset some of the cost benefits of offshore disposal.

Impacts of Offshore Disposal

The MBDS Site is located 12 nautical miles southeast of Gales Point, Massachusetts in water depths of about 270 to 300 feet. Because scows/barges would have to transport dredged material from the project site in the Taunton River about 180 nautical miles to this disposal site, we believe this site is economically and logistically impractical and have not considered it further in our analysis. This determination is supported by the findings of a site screening study conducted as part of the Rhode Island Regional Long-Term Dredged Material Site Evaluation Project (Battelle and Maguire Group, Inc., 2002). Consequently, we have only considered potential environmental issues associated with disposal at the RISDS. On December 16, 2004, the EPA designated RISDS as an ocean dredged material disposal site that would provide a long-term disposal option for the COE to maintain deep-draft, international commerce and navigation through authorized federal navigation projects and to ensure safe navigation for public and private entities. Use of RISDS as a disposal site was analyzed in detail in the Providence River and Harbor Maintenance Dredging Project Final EIS (COE, 2001) and the Rhode Island Region Long-Term Dredged Material Disposal Site Evaluation Project Final EIS (EPA, 2004a). Much of the discussion below is based on these documents.

As part of our analysis of offshore disposal to RISDS, we reviewed equipment requirements and potential costs associated with offshore disposal based on using one, two, or three dredges. Our analysis indicates that offshore disposal to RISDS could be accomplished using between four and eight scows (4,000 cubic yard capacity) if one dredge is utilized, between twelve and thirteen scows if two dredges are utilized, and about seventeen scows if three dredges are utilized. These scow estimates are generally consistent with or slightly below the fifteen to twenty scows that Weaver's Cove Energy proposes to use for onshore dredge disposal. We also estimated the number of scow trips that would be required if all of the 2.6 million cubic yards of dredged material is placed at one of the offshore disposed sites. Our analysis indicates that about 1,300 round trips would be required between the dredge areas and RISDS if 4,000 cubic yard scows are used and about 868 round trips would be required if 6,000 cubic yard scows are used.

Existing Conditions

The RISDS is located approximately 13 miles (21 kilometers) south of the entrance to Narragansett Bay and approximately 37 miles from the proposed terminal site (see figure 3.6.2-1). The site is located in a topographic depression where water depths range from 120 to 130 feet. Approximately 50 percent of the RISDS is located within an existing historic disposal site (Site 69B). For the purposes of analyzing the RISDS, a majority of the data provided was compiled from existing data on Site 69B.

The surface sediment in the central and western portions of the RISDS has an unconsolidated soft bottom, consisting of very fine sand mixed with silt-clay, suggesting a depositional environment. The northern half of the disposal area is hard bottom (cobbles and gravel) and the eastern side of the site consists of fine, rippled sand.

Currents occur ten times per year or on average once every 35 to 40 days and have the potential to erode sediments. Erosion potential was based upon modeling of representative, loosely consolidated, non-cohesive sediments, which showed initiation of movement when bottom currents reached 20 to 25 cm/sec (7.9 to 9.9 in/sec). This current speed generally occurs during a significant storm surge or when wave heights exceed 10 to 12 feet (3.05 to 3.66 meters) in the 130-foot-deep disposal site. Measurements taken for a full month period showed that peak currents were generally less than 15 cm/sec in Rhode Island Sound. The one exception was when Hurricane Floyd passed over Rhode Island Sound in September 1999 causing peak currents of 34 cm/sec (1.1 ft/sec) at the RISDS.

Insert Figure

3.6.2-1 Rhode Island Sound Disposal Site (Site 69b)

The organism-sediment index for the site was +7 in June 1997 and +6 in November 1999 which indicates the site has a high overall benthic habitat quality. Species expected to occur within the site include the amphipod *Ampelisca* sp., the bivalve *Nucula* sp., and various polychaetes, such as *Nepthys incisa* and *Pholoe minuta*, among others.

The RISDS has the potential to contain several commercially important molluscan species, including ocean quahogs, Atlantic surf clams, sea scallops, whelks, northern quahogs, blue mussels, and razor clams. The most important and abundant of these is the ocean quahog. A study to determine the organisms found at four disposal areas in Rhode Island Sound (Site 16, Site 18, Site 69A, and the RISDS (69B)) was conducted in 1997 in support of the EIS for the Providence River and Harbor Maintenance Dredging Project (COE, 2001). Four tows were conducted just outside of the RISDS to the north and west. These four tows all yielded similar ocean quahog catches (0.66 to 2.28 quahogs/m2). The low ocean quahog densities in these four tows indicate that the potential value of the site as an ocean quahog resource is low.

The American lobster is an important ecological and economic resource throughout the northwest Atlantic Ocean from Labrador to North Carolina. Data from commercial fisheries and site specific surveys were used to determine the abundance of lobsters at the site. According to these data, lobster numbers are on the decline in the Rhode Island Sound. The number of lobsters reported per vessel trip has declined from greater than 800 lbs/trip in 1994 and 1995 to a low of 300 lbs/trip in 2002. Lobster pots were used to sample the lobster population at three disposal locations (Site 18, Site 69A, and the RISDS) in the Rhode Island Sound (COE, 2001). The mean catch-per-unit-effort values from this study suggested that Site 69A had significantly more lobsters (13 lobsters/trap) than either Site 18 (10.3 lobsters/trap) or the RISDS (8.6 lobsters/trap) (COE, 2001). Across all sites, the largest catches of lobsters occurred during August (14.6 lobsters/trap), and the smallest catches during November (7.3 lobsters/trap).

Information from NOAA Fisheries annual spring/fall bottom-trawl surveys was used to determine finfish composition and abundance at the disposal site. According to these data, five species of finfish (skate, sea raven, silver hake, windowpane, and winter flounder) have a high likelihood of occurrence at the RISDS (COE, 2001).

Effects of Disposal on Biological Resources

In general, the primary effects of disposal of dredged material in offshore areas are an increase in the concentrations of suspended solids and contaminants in the water column, and burial of aquatic organisms with sediment. Except for changes in bathymetry, resources impacted by offshore disposal generally recover over time.

Disposal of dredged material at RISDS would expose the material to currents, which may have the potential to erode sediments and redeposit them in the surrounding aquatic environment. Eroded material would disperse quickly with deposits no more than 0.5 inches (1.3 cm) deep at a distance of one mile from the mound formed during disposal of the dredged material. With time, the mound would become consolidated and as material erodes, the mound would eventually become self-armored. Once the mound is armored, further erosion would be minimal.

During disposal, a plume would be created containing elevated levels of suspended sediments and associated contaminants. Sediments suspended during disposal can affect aesthetics, light penetration, feeding by benthic organisms and fish, and, at very high levels, can destroy or injure fish and benthic organisms. Toxic chemicals that dissolve when the dredged material is exposed to the water column can kill or impair marine animals if they are exposed to high concentrations over a sufficiently long period of

time. However, since dredged material must meet testing guidelines (see the discussion of Tier III testing above), toxicity levels should not cause undesirable environmental effects.

Sediment losses during disposal would be minimal because the sediment falls to the bottom and dilutes rapidly. Research has shown that disposal losses typically range from 1 to 5 percent of the amount disposed (Truitt, 1986). Recent laboratory studies with material in the size range of fine silt (0.01 mm) to medium sand (0.5 mm) (Ruggaber and Adams, 2000) estimated a loss of less than 1 percent of material.

A frequently expressed concern about offshore disposal is the effect of this material on nearby benthic habitats. A 5 percent loss of sediments during disposal would result in accumulation of less than 0.4 inch (1 cm) of sediment on the bottom, assuming that these sediments all deposited within a 0.5 mile radius of the disposal location. Such a thin layer would be diluted with the ambient sediments and mixed into the bottom by the benthos, thereby minimizing its impact by reducing exposure concentrations. However, dispersion beyond these limits, as expected, would result in even greater dilution further reducing the concern.

Direct impacts to the benthic community would be realized through burial, and potentially at adjacent areas, through increased siltation and burial during the disposal process. It is expected that any newly deposited dredged material at the RISDS would be rapidly recolonized by a pioneering assemblage of benthic organisms, consisting primarily of surface-dwelling tubicolous polychaetes and amphipods. Over time, it is expected that the dredged material would experience a natural advancement of successional stages. The initial recolonization by pioneering species would gradually advance to a more stable, head down deposit-feeding community in the soft, organic rich sediments.

As filter feeders, bivalves (e.g., shellfish) are particularly susceptible to mechanical or abrasive action of suspended sediments (i.e., clogging of gills, irritation of tissues, etc.) (Carnes, 1968). However, the response of organisms to suspended sediments is difficult to determine and may not be due to the actual concentrations of suspended solids, but to the number of particles in suspension, their densities, size distribution, shape, mineralogy, sorptive properties, or presence of organic matter and its form (Sherk et al., 1972).

The potential short-term effects of offshore disposal on lobster resources include burial, exposure to increased concentrations of suspended sediments, temporary loss of refuge habitat, and temporary loss of feeding habitat (i.e., loss of bottom invertebrates, including mussels, polychaetes, and snails). It should be assumed that lobsters would be killed in the area that would be covered by greater than 12 inches (30 cm) of dredged material. Lobsters buried under less than 12 inches (30 cm) of dredged material may be able to burrow up to the surface.

Lobsters generally burrow into soft substrates, including both sand and mud. They are capable of remaining in mud burrows for extended periods of time and have been observed to remain in burrows covered in silt (Cooper and Uzmann, 1980). They exhibit high tolerance to low concentrations of oxygen (as low as 0.2 milligrams per liter (mg/L), even without acclimation (Cooper and Uzmann, 1980), suggesting that, even if increased concentrations of suspended sediments resulted in temporary coating of their gills, lobsters would not become incapacitated. Lobsters exposed to increased total suspended solids during an extended period of repeated disposal activity might move away from the immediate vicinity of the disposal site. It is predicted, however, that periods of highly elevated total suspended solid concentrations would be episodic and the location would vary with the tidal conditions.

It is reasonable to assume that the benthic community at the offshore disposal area, which would eventually provide feeding opportunities for lobsters, would recover to present conditions within about 1 year following final disposal operations. Some benthic resources would be present in the interim, but

would not represent good food resources for lobsters. Lobster feeding and use of the disposal area would be impacted for approximately 18 months of disposal operations and an additional 1 year for recovery of the benthic community on which lobsters feed.

Fisheries resources may be impacted by offshore disposal activities both directly and indirectly. Potential direct impacts from disposal operations may be incurred through exposure to high concentrations of suspended sediment (i.e., suspended solids), burial, and/or loss of habitat. Potential indirect impacts may result from the temporary loss of benthic food organisms. The impact is greatest to demersal (bottom) fish, although pelagic (open water) fish may also be affected by temporary increases in total suspended solids.

Three species of endangered whales, three species of endangered sea turtles, and one threatened sea turtle may occur at the RISDS. NOAA Fisheries' concerns regarding the threatened and endangered whales and turtles include: 1) exposure to contaminants and bioaccumulation in tissues; 2) reduced forage opportunities; 3) habitat loss or degradation; and 4) physical injury from the activities proposed during the operations. However, significant adverse effects to these species are unlikely for several reasons. The dredged material that would be disposed of in Rhode Island Sound would be "uncontaminated" (i.e., dredged material that meets all Tier III testing guidelines for toxicity and bioaccumulation to be classified as suitable for open water disposal) and would not cause environmentally significant undesirable effects through bioaccumulation. The species listed are unlikely to obtain a significant portion of their food from the potential disposal site. None of the sea turtles and whales would experience major disruptions in foraging in the vicinity of the disposal site. The whales are only occasional visitors to Rhode Island Sound and are unlikely to feed for significant periods of time in the vicinity of the disposal site. The depth of the disposal site precludes several of the sea turtles from foraging there as well. The habitat would recover after disposal operations are complete. Indirect impacts, such as alterations of zooplankton populations due to elevated levels of total suspended solids, are expected to be short-lived. Although vessel traffic would increase during the period of the project, collisions between listed species and tugs and scows/barges carrying dredged material are unlikely. Direct impacts resulting from the physical dumping of dredged material from the barge is also expected to be minimal. Whales and sea turtles in the vicinity of the RISDS would actively avoid the area while disposal is occurring.

Conclusions on Offshore Disposal Alternatives

Based on the above environmental analysis of disposing the project dredged material at the RISDS, we believe that the offshore disposal alternative would be environmentally acceptable if the Tier III testing demonstrates that a significant volume of sediments are suitable for offshore disposal. However, we have also determined that offshore disposal of suitable dredged material is not without impacts and is not clearly environmentally preferable to Weaver's Cove Energy's proposed reuse of the dredged material as general site fill at the LNG terminal site. This conclusion assumes that Weaver's Cove Energy is able to resolve the regulatory and legal disputes of its proposed sediment management plan at the LNG terminal site (see section 4.2.2 for further discussion of these potential impediments). Based on the new/existing Brightman Street Bridge construction delays, we also believe that our recommended time-of-year restriction to avoid dredging from January 15 to May 31 would not impact the in-service date of the project or necessitate offshore disposal.