BROADWATER

RESOURCE REPORT NO. 10

ALTERNATIVES

FOR A

PROJECT TO CONSTRUCT AND OPERATE A

LIQUEFIED NATURAL GAS RECEIVING TERMINAL

IN

LONG ISLAND SOUND

LONG ISLAND, NEW YORK

UNITED STATES OF AMERICA

JANUARY 2006

PUBLIC

BW002433

RESOURCE REPORT 10 – ALTERNATIVES

Minimum Filing Requirements	Location in Environmental Report
• • Address the "no action" alternative. (§ 380.12 (*l*) (1))	Section 10.3
• • For large projects, address the effect of energy conservation or energy alternatives to the project. (§ 380.12 (*l*) (1))	Section 10.3.1
• • Identify system alternatives considered during the identification of the project and provide the rationale for rejecting each alternative. (§ 380.12 (*l*) (1))	Section 10.4
• • Identify major and minor route alternatives considered to avoid impact on sensitive environmental areas (e.g., wetlands, parks, or residences) and provide sufficient comparative data to justify the selection of the proposed route. (§ 380.12 (*l*) (3))	Section 10.6 (LNG Terminal) Section 10.7 (Pipeline)
• • Identify alternative sites considered for the location of major new aboveground facilities and provide sufficient comparative data to justify the selection of the proposed site. (§ 380.12 (*l*) (3))	Section 10.5

ENVIRONMENTAL INFORMATION REQUEST DATED JULY 12, 2005

Request	Location in Environmental Report
1. Regarding the stated minimum concept and site criteria for a viable Project alternative, define the water depths required to berth a 250,000 m^3 capacity LNG carrier.	Section 10.2
2. Regarding the No Action Alternative, the discussion concerning the ability of existing energy sources (particularly renewable energy sources) and conservation alternatives to meet the energy demands of the region relies primarily on national statistics and assessments. Regional entities including the States of New York and Connecticut, as well as some local municipalities, have adopted goals and incentives for increased energy conservation and the use of	Section 10.3.1

Request	Location in Environmental Report
renewable energy sources (e.g., New York State Executive Order 111) which must be addressed. Likewise, several renewable energy projects have recently been proposed in the region (e.g., Verdant Power, Roosevelt Island Tidal Energy Hydropower Project, and the Long Island Power Authority/FPL Energy offshore wind energy park). Provide a revised discussion of the potential for existing and planned energy sources and conservation alternatives to meet or offset the energy demands of the region, including consideration of such initiatives and projects both individually and cumulatively.	
3. For each of the system alternatives identified, provide a more detailed and quantitative comparison between the characteristics of the system alternatives and the Project that includes the following • Economic, environmental, technical, and scheduling advantages. • The size (diameter) and extent (miles) of any additional pipeline facilities as well as the number and size (horsepower) of any additional compression facilities, that would be required for each of the system alternatives.	Section 10.4.1
4. Update Section 10.4 to include a map that depicts each of the pipeline and LNG terminal system alternatives considered in the analysis. Also depict the existing target market of each system alternative in that figure.	Section 10.4, Figures 10-3, 10-4, and 10-5
5. Regarding offshore LNG terminal concept alternatives:	Section 10.5.2.1
• For construction and operation of a gravity-based structure LNG terminal of sufficient size to meet the stated Project objectives, provide the	Section 10.5.2.1, Table 10-8

Request	Location in Environmental Report
following: – An estimate of the permanent and temporary seafloor and onshore land requirements (i.e., graving dock facilities); and – The freeboard and dimensions of the above-water structures that would be associated with such a facility.	
• For construction and operation of an offshore LNG terminal that would use the shuttle regasification vessel (SRV) approach to meet the stated Project objectives, provide the following: – An estimate of the permanent and temporary seafloor land requirements. – The number of separate SRV mooring/LNG transfer buoys that would be required to provide reasonable assurances that this concept alternative could continuously provide 1.0 billion cubic feet per day to the region.	Section 10.5.2.2, Table 10-8
• Define the siting criteria and the permanent and temporary seafloor land requirements that would be associated with construction and operation of a turret-moored FSRU of sufficient size to meet the stated Project objectives.	Section 10.8.2.1, Table 10-8
• For each offshore LNG terminal concept alternative considered, provide the following: – An estimate of the maximum sea states at which LNG carrier berthing and LNG transfer/send-out operations could be accomplished. – The frequency of occurrence of those sea states within the geographic area for which offshore LNG terminal concept alternatives were considered (e.g., Long Island	Table 10-8

Request	Location in Environmental Report
Sound, Block Island Sound, and the Atlantic Ocean offshore of Long Island).	
6. Update Figure 10-3 to include both of the alternative sites that were considered for the SRV terminal concept.	Figure 10-6
7. Regarding the offshore LNG terminal concept alternatives considered in the Atlantic Ocean, provide an analysis of the environmental, engineering, and economic constraints that would be associated with the nearshore and/or onshore Long Island pipeline route that would be required to reach the Project target market.	Section 10.6.1.1
8. Depict the location of the MCI and Flag Atlantic-1 North cable corridors as well as the proposed Islander East pipeline, in relation to the identified FSRU siting sub-blocks provided in Figure 10-8.	Figure 10-12
9. Section 10.6.5 indicates that the specific location of the FSRU mooring tower and the IGTS interconnect (i.e., beginning and end control points) were based on coarse engineering criteria that were satisfied from observations made during a March 2005 reconnaissance survey. Define the coarse engineering criteria that were used in that assessment.	Section 10.6.5
10. Provide an environmental, engineering, and economic analysis of alternative interconnect locations with IGTS. The analysis should include representative locations in both New York and Connecticut waters that are feasible, given engineering and design constraints.	Section 10.7.3.5
11. For the planned pipeline route, provide the following:	Section 10.9
• A detailed comparison of the characteristics of alternative pipeline installation techniques. At a minimum, this analysis should evaluate and	Pipeline installation details are provided in Resource Report 1 (General Project Description).

Request	Location in Environmental Report
contrast the use of mechanical dredging, plowing, jetting, and rock cover (e.g., using a rock dumping vessel) operations for stabilization and protection of the installed pipeline.	
• A summary comparison of the environmental, engineering, and economic aspects of the alternative installation techniques.	Section 10.9.1
• Quantify the seafloor areas for each of the alternative construction techniques including: – The seafloor requirements that would be encompassed by both the construction and permanent rights-of-way (in acres); – The seafloor area that would be directly affected by construction (in acres); and – The seafloor area that would be indirectly affected (e.g., from sedimentation or turbidity) by construction (in acres).	Table 10-19
12. For pipeline installation, provide the following:	Section 10.9
(a) Identify the depth range at which each segment (i.e., milepost to milepost) of the pipeline would be installed along the planned Project route. (b) Identify the seafloor area that would be directly affected by pipe-lay vessel anchor placement and repositioning.	Pipeline installation details are provided in Resource Report 1 (General Project Description).
(c) Based on the data provided for items (a) and (b) above, provide an environmental, engineering (e.g., operational depth requirements), and economic comparison of the use of a conventional anchored, pipe-lay vessel with a dynamically positioned pipe-lay vessel (DPLV).	Table 10-17

ENVIRONMENTAL INFORMATION REQUEST DATED JULY 12, 2005

Request	Location in Environmental Report
13. For the planned vaporization technology alternatives, provide the following: • A description of the submerged combustion vaporization (SCV) alternative, including an estimate of the air emissions and liquid discharges, if any, that would be associated with use of this vaporization alternative. • Given that SCV technology is more efficient (i.e., requires combustion of less natural gas) than STV technology, clarify whether or not emission controls could be incorporated in SCVs to reduce air emissions to a level that would be equal to or less than those associated with the use of STVs.	Section 10.8.1

ENVIRONMENTAL INFORMATION REQUEST DATED DECEMBER 9, 2005

Minimum Filing Requirements	Location in Environmental Report
1. Section 10.3.1 presents energy source and energy conservation alternatives. Expand this section to provide information on how much of the projected natural gas need would be offset by each of the alternatives addressed (July 12 Request No. 32)	Table 10-1
2. Table 10-7 states that the seabed impact for a GBS would be 40,000 square meters plus an additional area for scour protection. Provide an estimate of how much additional area would be required (July 12 Request No. 35).	Additional information provided in Table 10-8
3. Table 10-7 states that the surface use area for an SRV terminal is 22,000,000 square meters and “assumes three buoys arranged symmetrically around a center platform.” However, the text in Section 10.5.2.2 indicated that the SRV buoys would be “tandem,” suggesting that the buoys would be aligned in a straight line. Please clarify.	Symmetrical arrangement assumed. Tandem reference deleted.
4. In Section 10.6.3, the final FSRU study area is defined as an area entirely within New York state waters. However, in Section 10.7, pipeline route alternatives traversing both New York and Connecticut state waters are evaluated. Provide an expanded FSRU study that includes sub-blocks located in Connecticut state waters or explain why this is not reasonable. Also, label all sub-blocks illustrated in Figure 10-12.	Section 10.6.2 Section 10.7.3.5 Figure 10-12

5. Provide a quantitative comparison of various pipeline installation techniques (e.g., jetting, plowing, or dredging) and backfill procedures (July 12 Request No. 41). At a minimum, the comparison should include the following: (a) The area of the seafloor (in acres) that would be directly affected by construction; and (b) The area of the seafloor (in acres) that would be indirectly affected by construction (e.g., due to sedimentation or turbidity).	Section 10.9.2

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List of Acronyms and Abbreviations

AHT	anchor handling tugs
BA	biological assessment
bcf	billion cubic feet
bcfd	billion cubic feet per day
Btu	British thermal units
CCEF	Connecticut Clean Energy Fund
CEAB	Connecticut Energy Advisory Board
CO	carbon monoxide
CSC	Connecticut Siting Council
CTDEP	Connecticut Department of Environmental Protection
DP	dynamically positioned
EIA	Energy Information Administration
EPA	(United States) Environmental Protection Agency
ER-L	Effects Range Low
ER-M	Effects Range Median
FERC	Federal Energy Regulatory Commission
FPSO	Floating Production Storage and Offloading unit
FSRU	Floating Storage and Regasification Unit
GBS	gravity-based structure
GPS	global positioning system
GWh	gigawatt-hours
HVDC	high-voltage direct current
IGTS	Iroquois Gas Transmission System
km	kilometer

LIPA	Long Island Power Authority
LNG	liquefied natural gas
MAOP	maximum allowable operating pressure
m	meter
m^2	square meter
m^3	cubic meter
mmBtu	million British thermal units
mmcfd	million cubic feet per day
MP	milepost
MW	megawatt
NOAA	National Oceanic and Atmospheric Administration
NO_x	nitrogen oxides
NYSDEC	New York State Department of Environmental Conservation
NYSERDA	New York State Energy Research and Development Authority
ORV	open-rack vaporization
PAHs	polycyclic aromatic hydrocarbons
PCBs	polychlorinated biphenyls
Ppmv	parts per million (by volume)
psi	pounds per square inch
M&NE	Maritimes & Northeast
SCV	submerged combustion vaporizer
SO_2	sulfur dioxide
SRV	shuttle regasification vessel
STV	shell and tube vaporizer
USACE	United States Army Corps of Engineers

USCG	United States Coast Guard
USDOE	United States Department of Energy
USDOT	United States Department of Transportation
USGS	United States Geological Survey
YMS	yoke mooring system

10. ALTERNATIVES

10.1 INTRODUCTION

Broadwater Energy, a joint venture between TCPL USA LNG, Inc., and Shell Broadwater Holdings LLC, is filing an application with the Federal Energy Regulatory Commission (FERC) seeking all of the necessary authorizations pursuant to the Natural Gas Act to construct and operate a marine liquefied natural gas (LNG) terminal and subsea pipeline for the importation, storage, regasification, and transportation of natural gas. The Broadwater LNG Project (the Project) will increase the availability of natural gas to the New York and Connecticut markets through an interconnection with the Iroquois Gas Transmission System (IGTS). The FERC application for the Project requires the submittal of 13 Resource Reports, with each report evaluating Project effects on a particular aspect of the environment.

Resource Report 10 describes alternatives considered in the development of the Project. Section 10.2 discusses the purpose and need for the Project in order to provide a context for determining the types of alternatives that reasonably could be expected to satisfy the identified need. Sections 10.3 through 10.7 discuss the various alternatives evaluated for the LNG terminal and pipeline proposed as the Project. These alternatives include the no action alternative, energy alternatives, system alternatives, LNG terminal site and concept alternatives, pipeline route alternatives, and technology alternatives. Section 10.7 summarizes the rationale for selecting the preferred LNG terminal site and pipeline route for the Project. Section 10.8 outlines some of the key technical selections considered for the Broadwater terminal. Section 10.9 discusses various pipeline construction alternatives that were considered.

The proposed Broadwater LNG terminal will be located in Long Island Sound (the Sound), approximately 9 miles (14.5 kilometers [km]) from the shore of Long Island in New York State waters, as shown on Figure 10-1. The LNG terminal facilitates the sea-to-land transfer of natural gas. It will be designed to receive, store, and regasify LNG at an average throughput of 1.0 billion cubic feet per day (bcfd) and will be capable of delivering a peak throughput of 1.25 bcfd. The Project will deliver the regasified LNG to the existing natural gas pipeline system via an interconnection to the IGTS pipeline. Onshore facilities are discussed in the Onshore Facilities Resource Reports.

The proposed LNG terminal will consist of a floating storage and regasification unit (FSRU) that is approximately 1,215 feet (370 meters [m]) in length, 200 feet (60 m) in width, and rising approximately 80 feet (25 m) above the water line to the trunk deck. The FSRU's draft is approximately 40 feet (12 m). The freeboard and mean draft of the FSRU will generally not vary throughout operating conditions. This is achieved by ballast control to maintain the FSRU's trim, stability, and draft. The FSRU will be designed with a net temporary storage capacity of approximately 350,000 cubic meters [m^3] of LNG (equivalent to 8 billion cubic feet [bcf] of natural gas), with base

Source: ESRI StreetMap, 2002.

Figure 10-1
Proposed Broadwater Project
Location in Long Island Sound

BW002450


L N G
BROADWATER - FSRU
BROADWATER

vaporization capabilities of 1.0 bcfd using a closed-loop shell and tube vaporization (STV) system. The LNG will be delivered to the FSRU in LNG carriers with cargo capacities ranging from approximately 125,000 m^3 up to a potential future size of 250,000 m^3 at the frequency of two to three carriers per week.

The FSRU will be connected to the send-out pipeline, which rises from the seabed and is supported by a stationary tower structure. In addition to supporting the pipeline, the stationary tower also serves the purpose of securing the FSRU in such a manner to allow it to orient in response to prevailing wind, wave, and current conditions (i.e., weathervane) around the tower. The tower, which is secured to the seabed by four legs, will house the yoke mooring system (YMS), allowing the FSRU to weathervane around the tower. The total area under the tower structure, which is of open design, will be approximately 13,180 square feet (1,225 square meters [m^2]).

A 30-inch-diameter natural gas pipeline will deliver the vaporized natural gas to the existing IGTS pipeline. It will be installed beneath the seafloor from the stationary tower structure to an interconnection location at the existing 24-inch-diameter subsea section of the IGTS pipeline, approximately 22 miles (35 km) west of the proposed FSRU site. To stabilize and protect the operating components, sections of the pipeline will be covered with engineered back-fill material or spoil removed during the lowering operation. Figure 10-1 presents the proposed pipeline route.

10.2 PURPOSE AND NEED

Based on historical trends and future projections, the Long Island, New York City, New York City metropolitan area, and Connecticut markets (the Region) will face a projected critical period over the next 10 to 15 years in meeting the anticipated energy needs of consumers. The Project will provide a source of reliable, long-term, and competitively priced natural gas to this Region to meet this growing demand. To fulfill this purpose and need, a viable LNG import terminal concept and site must meet, at a minimum, the following specific criteria:

- Be technically and economically feasible, practicable, and implementable;
- Maximize the buffer between the Project and populated areas;
- Have significant environmental benefits over other alternatives;
- Be able to provide reliable natural gas deliveries to the Region via pipeline connections;
- Provide deepwater berthing to accommodate up to 250,000-m^3 capacity LNG carriers, with a maximum draft requirement of 49 feet (15 m);
- Provide for short-term storage and vaporization facilities for at least 1.0 bcfd of natural gas for an in-service date of 2010;

- Comprise a site that allows the terminal to maintain sufficient control and proprietary rights of operation;

- Comprise a site situated close to an existing pipeline system serving the Region with downstream takeaway capability greater than 1.0 bcfd; and

- Be able to ensure facility and connecting pipeline operability for a minimum 30-year project life.

Broadwater evaluated potential alternatives to the proposed Project against the purpose and need criteria listed above. The purpose of the evaluation was to determine whether there are alternatives that are reasonably implementable and environmentally preferable. Broadwater has determined that the Project is the preferred alternative to meet these specific criteria.

10.3 NO ACTION OR POSTPONED ACTION ALTERNATIVES

If Broadwater is unsuccessful in gaining the necessary approvals to build and operate an LNG facility (the no action alternative), the short-term and long-term potential environmental impacts discussed in the Resource Reports prepared for the Project would not occur. However, the result of the no action alternative is that the objectives of the Project would not be met, and a source of reliable, long-term, and competitively priced natural gas would not be available to the Region. If FERC postpones action, the potential environmental impacts identified in the Project's Resource Reports either would be delayed or would not occur if Broadwater decided not to pursue the Project.

The United States Department of Energy, Energy Information Agency's (EIA's) *2005 Annual Energy Outlook* (EIA 2005) projects that the demand for natural gas within the U.S. will increase at an average annual rate of 1.5% through 2025. Nearly 75% of this increase is attributed to gas-fired power generating facilities and other industrial applications (EIA 2005, page 4).

Demand for natural gas is also expected to continue to increase within the Region. As presented in the New York State Energy Plan, natural gas demand within New York, in particular, is expected to grow nearly 37% by 2021 from its current levels, with nearly 61% of this increase due to natural gas demand for electrical power generation (NYSERDA 2002, page 3-9). Of this amount, nearly 70% is projected for use in the area from Rockland and Orange Counties through Long Island (NYSERDA 2002 page 3-159).

Absent regulatory approval of the Project, consumers will have fewer and potentially more expensive options for obtaining natural gas supplies in the near future and possibly face supply shortages.

In addition, should the no action alternative be adopted, potential customers would be forced to choose from among energy alternatives, such as nuclear, oil, or coal. Use of such alternative fuel sources to meet the Region's projected energy demand would have negative environmental and economic consequences. For example, increased use of fossil fuels such as oil and coal will result in significantly higher emission rates of oxides of nitrogen (NO_x), sulfur dioxide (SO_2), mercury, and greenhouse gases than the use of natural gas. Renewable energy sources have not been developed sufficiently to meet the anticipated energy needs of the Region. Traditional natural gas supplies from domestic production are expected to decline over the life of the Project, leading to significant threats of shortages and large price increases as the Region competes for supply with other parts of the country. Moreover, if FERC selects the no action alternative, the consumers in the Region would not benefit from greater energy price stability, direct and indirect jobs would not be created by the Project, and local communities would not benefit from the half billion dollars that the Project is expected to generate in tax revenues alone over its lifetime.

10.3.1 Energy Source and Energy Conservation Alternatives

As noted above, the no action alternative could lead to fuel substitution and, consequently, the increased use of other fossil fuels within the Region. As a result, air quality within the Region could be expected to decline.

Other traditional long-term fuel source alternatives to natural gas for electric generation are nuclear power, hydropower production, and the development of renewable energy sources. Because of regulatory implementability issues, cost considerations, nuclear waste disposal, and potential public concerns, new sources of nuclear power are unlikely to be sited within the Region in the foreseeable future. It also is unlikely that new and significant hydropower sources could be permitted and brought online as reliable alternatives to the natural gas that would be provided by the Project.

Although technology is improving and costs are declining for renewable sources of energy (e.g., wind, solar, and biomass), the percentage of the nation's electricity generated from non-hydropower renewable energy sources is projected to increase to only 3.2% by 2025 (EIA 2005, page 91).

Another alternative energy source to the Project would be traditional, non-LNG derived natural gas. While natural gas production is important to the overall supply of energy nationally, production levels are not expected to rise in the short term, except from the Arctic and unconventional sources (e.g., shale, tight sands, and coal bed methane). Traditional natural gas supplies from domestic production are expected to decline over the life of the Project (EIA 2005, page 95). Given the projected demand in markets nearer to production sources than the Region and currently unavailable infrastructure to deliver additional natural gas to the Region, these energy sources are not reasonable alternatives to the Project.

Conservation within the Region could help alleviate some of the growing demand for energy and, therefore, offset some of the need for new LNG supplies. However, while energy conservation can play a critical role in the future of the U.S. energy policy, growth projections continue to indicate that the demand for energy, and specifically natural gas, will outstrip cost-effective programs designed to stimulate energy conservation.

In summary, existing conservation programs cannot fully offset the projected growth in demand for energy, and a corresponding demand for natural gas, within the Region or nationally. Continued economic growth, particularly growth of electricity demand throughout the U.S. and the Region will lead to increased natural gas use, despite programs to encourage energy conservation. Thus, energy conservation is not a reasonable alternative to the Project and would not preclude the need for the Project.

The following sections examine renewable energy initiatives, as well as conservation measures, in the context of the specific Region to be served by the Project.

10.3.1.1 New York Renewable Energy and Conservation Measures

In 2003, NYSERDA published a report entitled *Energy Efficiency and Renewable Energy Resource Development Potential in New York State* (NYSERDA 2003). The study examined the long-range potential for energy efficiency and renewable energy technologies to displace fossil-fueled electricity generation in New York. The study had two main areas of focus and made projections over the 2007, 2012 and 2022 time horizons (5, 10, and 20 years, respectively). The areas of focus were:

- Conservation – an assessment of the potential available from both existing and emerging technologies to lower the end-use demand in residential, commercial, and industrial buildings; and

- Renewables – an assessment of renewable electricity generation potential from biomass, fuel cells, hydropower, landfill gas, municipal solid waste, solar power, and wind power.

The study concluded that for New York State as a whole, economically viable efficiency and renewable energy initiatives could be expected to reduce the state's annual electricity generation requirements by more than 19,939 gigawatt-hours (GWh) by 2012 and by more than 27,244 GWh by 2022. This represents 12.7% and 16.1%, respectively, of the expected statewide requirements for those years. Reductions of this magnitude or greater would allow the state to meet its own greenhouse gas emissions targets for the electricity sector.

The study authors, however, provided some significant qualifications of these results. The authors noted that the assessed economic potential analysis ignored the potential market acceptability of both efficiency and renewable energy technologies, as well as the cost of programs or policies to increase market acceptance. Consequently, the identified *economic* potential does not represent *achievable* potential in the absence of these other factors. The achievable potential could be significantly less than the economic potential.

When the study authors examined initiatives currently planned by state authorities (rather than economic potential), the estimated reduction in annual generation requirements by

2022 fell to 13,675 GWh. Compared to projected state requirements of 188,923 GWh, this accounts for only 7.5% of projected annual requirements. For initiatives relating to increased energy efficiency (conservation), a range of only 14% to 16% of the assessed economic potential is projected to be realized. For renewable energy, only 8% of the economic potential is projected to be realized under currently planned initiatives. These results suggest that conservation or renewable energy will not preclude the need for the Project.

Regional Analysis – New York City and Long Island

In addition to looking at statewide potential, the study further analyzed the technical and economic potential for electricity from both energy efficiency and renewable resources within each of five control-area load zones in the state. Two of the load zones examined were Zone J (New York City) and Zone K (Long Island).

For each load zone, forecasts of economic potential were estimated and compared to individual forecasts of that load zone's electrical energy requirements.

With respect to New York City, the study found that there was significant economic potential associated with energy efficiency initiatives, while there was very limited potential for renewable energy projects. For the year 2022, the study identified an economic potential of 23,690 GWh associated with energy efficiency, representing 37.6% of the projected electricity demand. In the same year, the economic potential for renewable energy in New York City was assessed at 2,155 GWh, or 3.4% of the projected demand. This latter potential was associated with biomass and municipal solid waste initiatives.

For Long Island, the study found that while energy efficiency potential was significant, a greater potential for renewable energy was identified. For the year 2022, the study identified an economic potential of 7,932 GWh associated with energy efficiency, representing 33.9% of the projected electricity demand. For the year 2012, the proportion of total demand that could potentially be supplied from renewables is assessed at 1,529 GWh, representing 7.0% of the demand for that year. Over the intervening 10-year period from 2012 to 2022, the study projects a dramatic growth in renewable energy potential, almost entirely associated with wind power. The economic energy supply increases from 1,529 GWh to 19,219 GWh from 2012 to 2022, which is a compound annual growth rate of 28.8%. Similarly, the generating capacity attributable to renewables on Long Island increases from 278 MW in 2012 to 2,468 MW by 2022.

While these estimates of economic potential show promise, the qualifications listed by the study authors must be restated. The identified economic potential does not represent achievable potential in the absence of other factors, such as the cost of programs or policies to stimulate market acceptance. At the state level, under currently planned initiatives, a range of only 14% to 16% of the assessed economic potential is projected to be realized for energy efficiency initiatives. For renewable energy, only 8% of the economic potential is projected to be realized under currently planned initiatives. Similar results could be extrapolated for the New York City and Long Island load zones.

This being the case, it can be concluded that while these initiatives will offer significant benefits over time, a significant and growing requirement for fossil-fueled power generation will remain. Further, there will be issues associated with the siting and development of renewable energy projects, as there are with traditional energy projects that will need to be addressed for a successful transition to these alternative energy sources. This point can be demonstrated in the context of specific renewable energy projects under development within New York.

Specific New York Renewable Energy Initiatives

Long Island Offshore Wind Park. In April 2005, the Long Island Power Authority (LIPA) and FPL Energy filed a joint application with the United States Army Corps of Engineers (USACE) seeking authorization to install a 140 MW offshore wind energy park on the south shore of Long Island. The project consists of 40 turbines and is proposed to be located southwest of Robert Moses State Park and southeast of the Jones Beach State Park. The project will be approximately 3.6 miles offshore from the nearest shoreline. Current plans call for the wind park to be operational in 2008 following an extensive regulatory and environmental review. When complete, the wind park will cover an area of 8 square miles (LIPA 2005a).

Each wind turbine will generate 3.6 MW of electricity under peak production. Each of the turbine rotors will be placed on a turbine tower that is approximately 260 feet high. The turbine rotors themselves consist of three blades, each approximately 182 feet long (LIPA 2005a). A transmission cable will be installed from the offshore location to the shoreline to connect to the electric grid.

If this project is permitted and proceeds, it can be a significant source of renewable energy for Long Island. However, continued expansion of wind power on Long Island will require the development of additional sites, whether offshore or onshore. Siting has proven to be a challenge to developments of this type in other jurisdictions and will be difficult in view of Long Island's population density. Second, as wind power penetration rates have increased in electricity supply systems in other jurisdictions, so have concerns about how to incorporate a significant amount of intermittent and non-dispatchable generation, without disrupting the finely-tuned balance that network systems demand. Grid integration issues are a challenge to the expansion of wind power in some jurisdictions.

To realize the economic potential cited above in the NYSERDA study for Long Island, two projects of this nature would be required by 2012 (278 megawatts [MW]) and 17 such projects would be required by 2022 (2,468 MW). It is unlikely that such a proliferation of wind power projects would gain public acceptance in the Region.

Roosevelt Island Tidal Energy Project (Verdant Power). Verdant Power's Roosevelt Island Tidal Energy project, in its ultimate configuration, proposes to site approximately 390 turbines to be located in the East Channel of the East River adjacent to the east shore of Roosevelt Island. The project will utilize axial flow turbines which will be placed underwater and will be driven by a three-bladed rotor that turns at a maximum operating speed of approximately 30 to 32 revolutions per minute. The project is currently testing a configuration of six units to be operated for at least 18 months, in order to confirm the project study parameters. When completed, the project will generate up to 10 MW of distributed electricity for use by customers in New York City. The tidal power project would be deployed along an approximately 1-mile section on the east shore of Roosevelt Island (Verdant Power 2005).

As above for wind power, this project holds significant promise in bringing a source of renewable energy to the Region. However, within the densely populated New York City region, it will be difficult to put additional facilities in new locations that will not conflict with alternative uses of the water resources. In addition, the generation capacity of the facility is small relative to the growth in electricity demand in the Region.

The NYSERDA study discussed above identified a very small amount of hydropower potential for New York City and Long Island.

Summary

While the quantity of energy that could be saved from energy efficiency initiatives and that could be generated from renewable energy sources has potential for development, these initiatives are not likely to provide a reasonable alternative to the increased supply of natural gas that the Project will provide to the New York City and Long Island regions. Table 10-1 provides a further illustration of this point by converting the projected savings of electrical energy into an equivalent average daily volume of natural gas. As the table shows, based on currently planned initiatives, the total volume of natural gas displaced would be approximately 57 mmcfd for New York City and Long Island by 2012, and only 131 mmcfd by 2022. For specific renewable energy initiatives, the amount of displacement of natural gas demand is modest.

Table 10-1 Summary of Renewable Energy and Conservation Measures

	2012		2022		
	Electric Energy (GWh)	Gas Equivalent (mmcfd)	Electric Energy (GWh)	Gas Equivalent (mmcfd)	Comments
Potential Based on Currently Planned Initiatives					
Total New York State	5,875	126	13,675	292	Electric savings from Table 2.38, Volume 2
Zone J (New York City)	1,897	41	2,972	64	
Zone K (Long Island)	746	16	3,122	67	
Specific Initiatives					
Long Island Offshore Wind Park	368	8	368	8	Assumed load factor = 30% for 140 MW wind facility

Table 10-1 Summary of Renewable Energy and Conservation Measures

	2012		2022		
	Electric Energy (GWh)	Gas Equivalent (mmcfd)	Electric Energy (GWh)	Gas Equivalent (mmcfd)	Comments
Roosevelt Island Tidal Energy Project	88	2	88	2	Assumed load factor = 100% for 10 MW facility

Assumptions:

1. All electrical energy is assumed to be converted into its gas equivalent.
2. Btu content of gas is assumed to be 1,025 Btu/ft^3.
3. Heat rate is assumed to be 8,000 Btu/kWh.
4. 2012 savings for Zone J and Zone K is assumed to be 8.5% of economic potential based on Table 2.41, Volume 2 (NYSERDA 2003).
5. 2022 savings for Zone J and Zone K assumed to be 11.5% of economic potential based on Table 2.41, Volume 2 (NYSERDA 2003).
6. No allowance is made for seasonal peak demand variations for electricity or natural gas.

10.3.1.2 Connecticut Renewable Energy and Conservation Measures

Due to its relatively smaller size and geographic context, the opportunities for renewable energy development in Connecticut are significantly less than that for New York. The Connecticut Clean Energy Fund (CCEF) estimates that the current installed capacity of renewable energy within Connecticut is approximately 9.2 MW (CCEF 2004). Most of this energy comes from landfill gas and fuel cells. This must be compared to a projected 2004 summer peak demand for Connecticut of 6,765 MW (CSC 2004). Renewable energy sources currently represent 0.14% of this demand.

The CSC projects that summer peak demand for electricity between 2004 and 2013 will increase by approximately 1,106 MW to 7,871 MW (CSC 2004).

In terms of energy conservation, the Connecticut Conservation and Load Management Fund reports that conservation activities saved a total of 0.29 GWh of electrical energy (CCLM 2005). However, this must compared to the overall electricity consumption. In 2002, annual retail sales of electricity in Connecticut amounted to 30.9 GWh (EIA 2002). Conservation activities produced energy savings slightly less than 1% of 2002 demand.

While there is potential for modest growth in both renewable energy and conservation initiatives, these are not likely to provide a reasonable alternative to the increased supply of natural gas that the Project can provide to the Connecticut region.

10.3.2 Summary

As outlined above, it is clear that conservation and renewable energy initiatives in the Region will not eliminate the need for the Project. The no action and postponed action alternatives fail to provide a source of reliable, long-term, and competitively priced natural gas to the Region that would meet the criteria listed in Section 10.2.

10.4 SYSTEM ALTERNATIVES TO THE PROJECT

System alternatives would make use of other existing or proposed LNG or natural gas facilities to meet the stated objectives of the Project. A system alternative would make it unnecessary to construct all or part of the Project (although some modifications or additions to an existing or proposed system may be necessary). These modifications could result in environmental impacts that could be less than, similar to, or greater than those associated with the Project. The reason for identifying and evaluating system alternatives is to determine whether potential environmental impacts associated with the siting and operation of the Project could be avoided or reduced by using another system.

To be considered a viable alternative to the Project, the existing or proposed facilities, even when considering current and potential expansion capacities, would need to provide a source of reliable, long-term, and competitively priced natural gas to the Region comparable to the Project. Moreover, in order to be a viable alternative to the Project, the existing or proposed facilities would have to meet the stated purpose and need for the Project.

As a part of its review of potential alternatives to the Project, Broadwater evaluated existing and proposed transmission pipeline alternatives as well as LNG terminal system alternatives. However, the geographic, economic, regulatory, environmental, and public safety and security concerns associated with these potential alternatives would not meet the purpose and need criteria established for the Project.

10.4.1 Transmission Pipeline Alternatives

Broadwater considered the feasibility of utilizing or expanding existing transmission pipelines to provide an equivalent amount of natural gas to the Region as an alternative to the Project. Broadwater determined that these existing pipelines would not be able to provide the additional 1 bcfd of reliable, long-term, and competitively priced natural gas to the Region, consistent with the Project objectives. Recent experience has shown that natural gas flows into the Region under conditions of peak winter demand approach the available pipeline capacity. When these circumstances arise, the supply of natural gas to the Region is constrained and available gas volumes are allocated to those customers most willing to pay premium prices, resulting in increased price levels and price spikes. Owing to the population density in the Region, expansions of existing infrastructure to accommodate the Project requirements were determined not to be viable alternatives. Furthermore, expansions of the existing pipeline infrastructure would, in most cases, only add natural gas transmission capacity from existing supply sources and thus would not provide a new source of natural gas supply.

10.4.1.1 Existing Pipelines

Table 10-2 provides a summary of the existing pipelines that serve the Region, their capacities and average operating pressures. Figure 10-3 identifies the locations of the major pipelines serving the Region and the Northeast in general. Each of these pipelines, and their potential suitability as an alternative means of providing 1 bcfd of incremental natural gas supply, is discussed below.

Table 10-2 Pipelines Serving the Region

Pipeline	Pipeline Diameter (inches)	Average Operating Pressure (psi)	Pipeline Capacity in the Region (bcfd)	Data Sources
Algonquin Pipeline	26"/30"	750	1.15	EIA pipeline database
Columbia Gas Transmission	10"/12"	650	0.20	Columbia Web site
Tennessee Pipeline	24"/30"	800	0.50	Energy and Environmental Analysis (EEA)
Iroquois Gas Transmission System	24"/30"	1,440	1.15	EIA pipeline database
Texas Eastern Transmission	20"/20"/36"	1,100	2.34	Texas Eastern Web site
Transco Pipeline				Transco Web site
Leidy Facilities	30"/36"	800	2.71	
Gulf Coast Transmission	30"/42"	800	1.54	

Data Sources: Average operating pressures from EIA pipeline database.

From Table 10-2, it is clear that, relative to the pipeline capacities for these systems in the Region, the addition of 1 bcfd of incremental gas supply on any of these pipeline systems, with the exception of Iroquois, would constitute a significant system expansion.

Algonquin Pipeline System

Algonquin Natural Gas Transmission interconnects with many pipelines in the Region. At its southern extent, Algonquin connects with the Texas Eastern, Transco, Columbia, and Tennessee systems in New Jersey. From there, the pipeline runs in a northeasterly direction into the New England states. Near its northern terminus in the Boston area, Algonquin connects with the Maritimes & Northeast (M&NE) system at Beverly, Massachusetts, as a result of the recent completion of Algonquin's Hubline project. The Algonquin system, therefore, relies on connecting pipeline systems from either the north or south to meet Algonquin's demand requirements.

To meet Project objectives the Algonquin system must access incremental gas supply from interconnections either from the south or the north. Southern alternatives are discussed in the remainder of this section (Texas Eastern, Transco, and Tennessee, respectively). Upstream expansion of these facilities to accommodate 1 bcfd would have significant environmental impacts compared to the Project. The M&NE interconnection to the north is discussed in Section 10.4.2.4 (Other Proposed Terminals).

Compared to the Iroquois system, the average operating pressure of the Algonquin system is relatively low (750 psi). Expansion of Algonquin facilities to accommodate

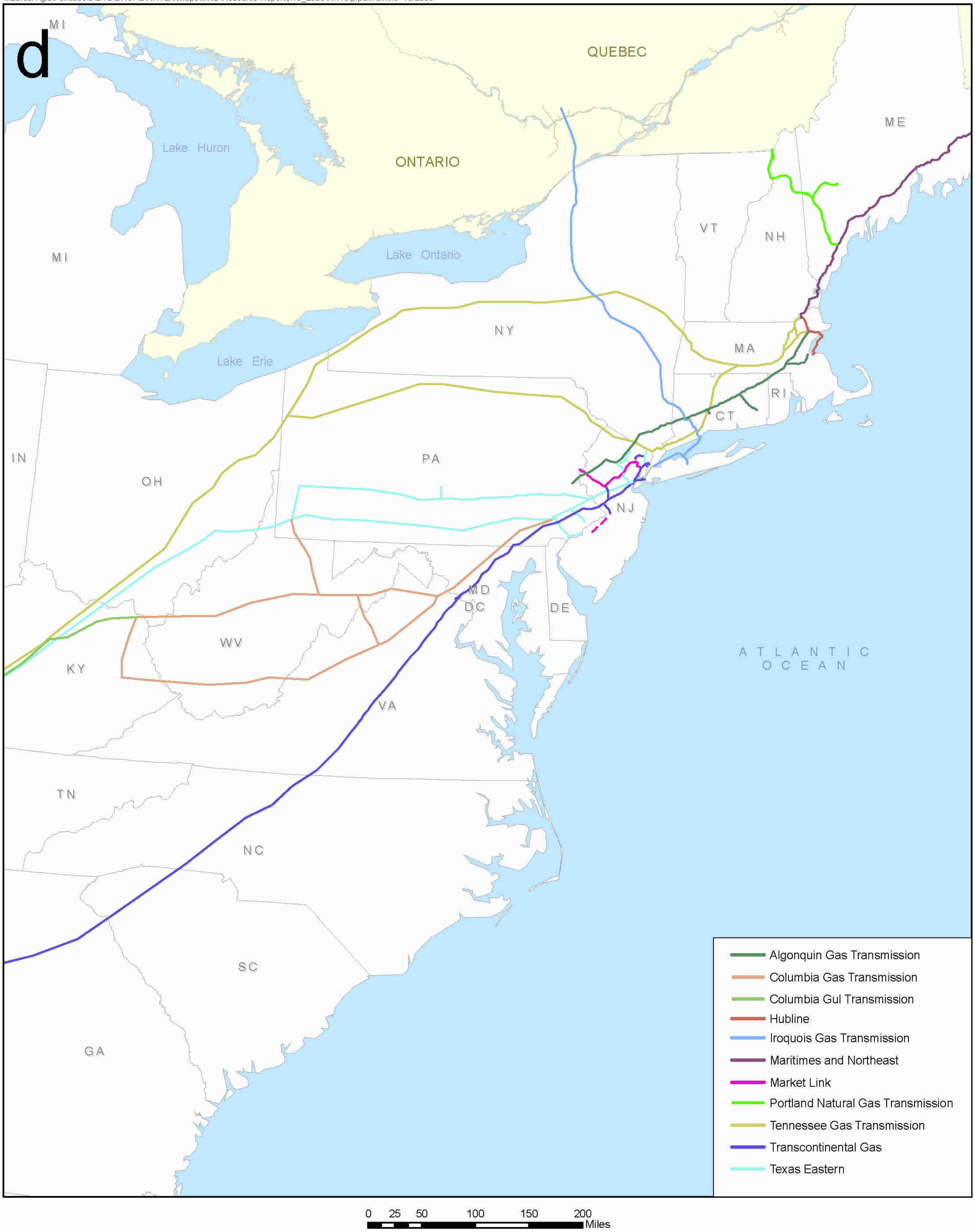

Figure 10-3 Existing Natural Gas Transmission Pipelines Serving the Project Area

incremental gas volumes, particularly if looping is required, would require comparatively larger pipeline diameters than a higher-pressure transmission system. Aside from this technical disadvantage, the Algonquin system does not offer direct access to the New York City and Long Island markets. For these reasons, expansion of the Algonquin system does not meet Project objectives.

Columbia Gas Transmission

The Columbia Gas Transmission system is, for the most part, a local transmission system within New York State. This pipeline is of a comparatively small diameter and capacity and is therefore unsuitable as an alternative. The proposed Millennium Pipeline project is intended to replace much of the functionality provided by this system.

Tennessee Pipeline System

The Tennessee pipeline system has relatively low average operating pressure, limited capacity in the Region, and lacks direct access to the downstate New York and Connecticut markets. In view of these considerations, expansion of the Tennessee Pipeline system is not a suitable alternative for the Project.

Iroquois Pipeline System

Although the Iroquois system consists of a single pipeline of 30- and 24-inch diameters, it offers a significantly higher operating pressure than the other existing pipeline systems in the Region (as shown in Table 10-2), with corresponding efficiencies in transporting gas volumes. In terms of pipeline hydraulics, the Iroquois pipeline system offers direct access to the New York City, Long Island and southern Connecticut markets.

Texas Eastern System

Texas Eastern is a long-haul transmission pipeline originating in the Gulf Coast region. In addition to being a large provider of capacity into the New York area, it also provides significant access to storage in the Region. An alternative to the Project could be the expansion of the Texas Eastern system and the delivery of 1 bcfd of LNG imports from the Gulf Coast. Natural gas price behavior in the New York and New England markets during periods of sustained cold weather suggest that pipeline capacities are reached during these periods. To address this situation, incremental pipeline facilities will be required. Expansion of this long-haul pipeline system to meet the objectives of the Project would be significant and would have substantial environmental impact. Further, the incremental volumes transported on an expanded pipeline system would be available to serve markets along the pipeline route as well as those markets in the Region.

Transco System

Similar to the Texas Eastern system, the Transco system is a long-haul pipeline delivering gas from the Gulf Coast. In Pennsylvania, Transco also provides the capability to move gas into and out of storage in western Pennsylvania through its Leidy lateral that runs from the storage fields in Leidy to an interconnect with its Gulf Coast mainline in New Jersey. The Transco system is the largest provider of gas deliveries to the New York City area.

As discussed above, an alternative could be to expand the portion of the Transco system extending from the Gulf Coast to the Region. Similar issues, however, would pertain to the Transco system as for Texas Eastern. Also, the Transco system has a relatively low operating pressure and an integrated expansion with the rest of the system would not be as efficient as for a system with a higher operating pressure. Expansion of the Leidy facilities would increase access to storage, but would not increase access to new supplies of natural gas. Increasing access to the New York City market from the Transco system could require facility expansions across the Hudson River, which has generated environmental concerns in the past. As the environmental impact of the required facility expansion is likely to be greater than that for the Project as proposed, expansion of the Transco system was not deemed to be a suitable alternative.

10.4.1.2 New Pipeline Proposals

There are currently three proposals that would add new pipeline infrastructure to the Region, as depicted on Figure 10-4. The pipeline capacity and limitations to serve Broadwater's target market are provided in Table 10-3.

Table 10-3 New Pipeline Proposals to the Region

Pipeline	Pipeline Diameter (inches)	Pipeline Length (miles)	Pipeline Capacity (bcfd)	Limitations
Millennium Pipeline	30	187	0.49	Downstream of supply sources, therefore no incremental gas supply for the Region. Insufficient to meet Project needs.
Islander East Pipeline	24	50	0.28	Additional onshore infrastructure, associated impacts. Insufficient capacity to meet Project needs.
Leidy to Long Island Pipeline	26	0 (existing pipeline)	0.60	Expansion project will add 0.1 bcfd of additional capacity through existing pipeline connection. Downstream of supply sources, therefore, no incremental gas supply for the Region. Gas supply is contracted. Insufficient to meet Project needs.

Broadwater evaluated the Millennium Pipeline, the Islander East Pipeline, and the Leidy to Long Island Project. The Millennium Pipeline, if constructed, would increase gas transmission capacity to the U.S. Northeast. However, the design capacity of the line is insufficient for Broadwater's requirements and the pipeline is located at the downstream end of the supply chain. The pipeline project connects to the Empire State Pipeline which in turn connects to the TransCanada PipeLine system. This suggests that gas supplies for the Millennium Pipeline would have to be sourced from traditional markets in a declining domestic supply environment. To meet the stated Project needs, Millennium would need to loop a substantial portion of its currently proposed system,

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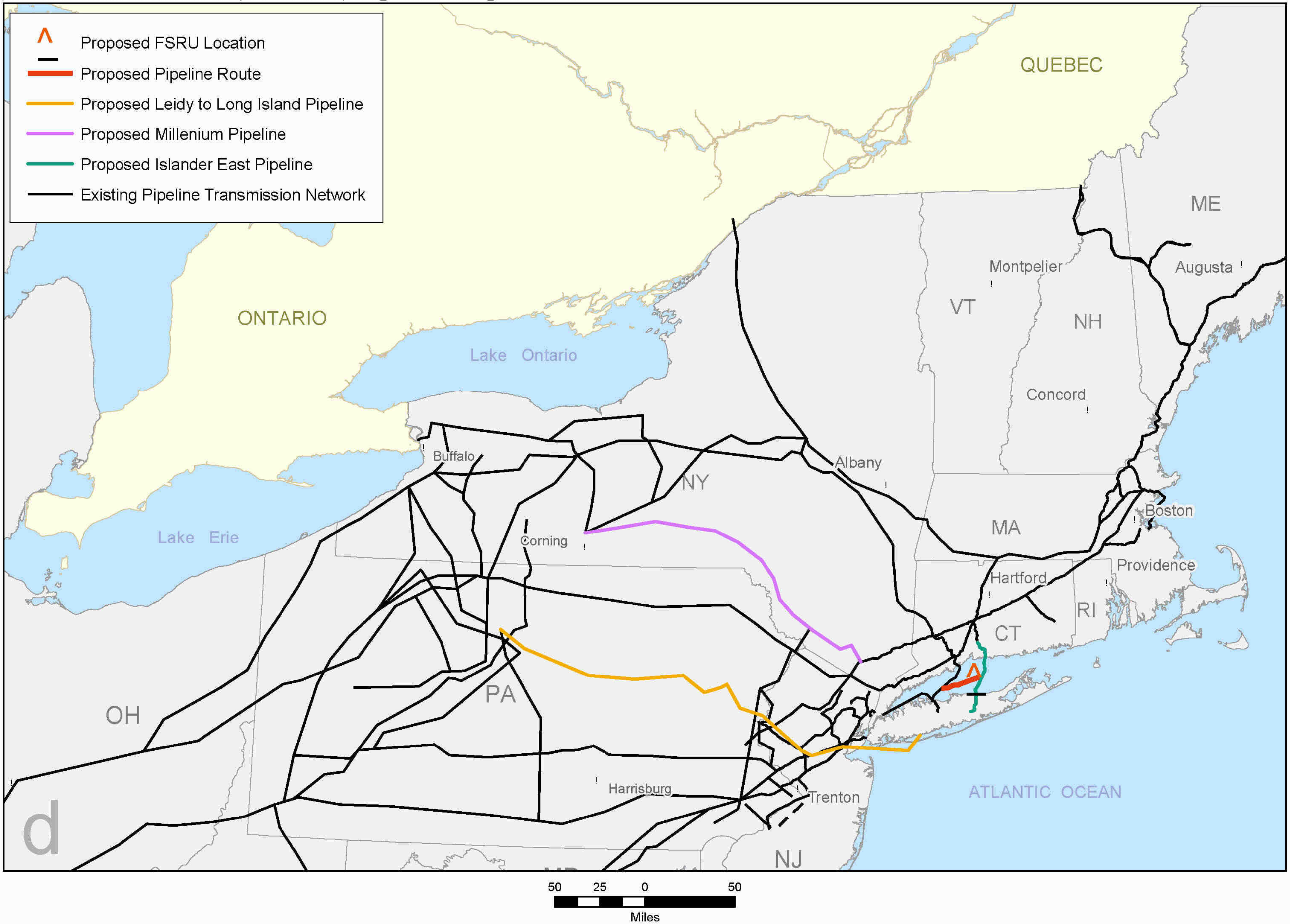

Figure 10-4 Proposed Natural Gas Transmission Pipelines in Relation to the Proposed Broadwater Energy Project Area

resulting in significantly greater environmental impacts than those associated with the Broadwater Project. Moreover, Millennium's Phase 1 proposal to deliver gas to Ramapo, New York, does not provide direct access to the New York City market. Due to the increased environmental impacts, and because this alternative cannot provide incremental gas supply, Broadwater did not consider it a suitable alternative.

Millennium's Phase 2 proposal will cross the Hudson River, linking to the New York City metropolitan market. In an effort to advance this phase of the project, Millennium filed an appeal in Federal District Court of a U.S. Department of Commerce ruling relating to the project's Hudson River crossing plan. Millennium has not yet set an in-service date for Phase 2, but is proceeding with Phase 1 as the appeal moves forward. While the Phase 2 proposal, if approved, would provide access to the New York City market, it could not accommodate the incremental volume requirements of the Project and would not access incremental supplies of natural gas.

The proposed Islander East Pipeline also would not be a reasonable alternative to the Project because it cannot deliver the volume of natural gas that the Project would deliver without significant alteration from its current project description. In addition, the capacity of the KeySpan Long Island pipeline system starting at Yaphank, New York, which would interconnect with the Islander East Pipeline, would not be adequate to transport the volume of natural gas to be supplied by the Project. Moreover, any contemplated upgrades to the Keyspan Long Island pipeline system would occur in areas with high population density. For Islander East to achieve the Project objectives, significant additional pipeline facilities would also need to be constructed along the Algonquin system to be able to provide increased gas supply to the New York City area. As such, Broadwater does not consider expansion of the Islander East pipeline to be a practicable alternative.

The third project considered, the Leidy to Long Island Project, is an expansion of an existing system running from New Jersey to Nassau County, traversing the mouth of the New York/New Jersey harbor and the Atlantic Ocean. Significant portions of the upstream system in New Jersey and Pennsylvania would need to be expanded to provide up to 1 bcfd of gas to the New York City area and Long Island. This would result in significantly greater onshore and offshore environmental impacts and could potentially require additional shore crossings on the Atlantic coastline of Long Island. The expansion project is intended to increase access to storage fields in Leidy, Pennsylvania and as such, would not provide access to incremental supplies of natural gas. Finally, since all of the gas for the current proposed Leidy to Long Island Project has already been fully contracted to end users, this pipeline is not a reasonable alternative to the Project.

As a result, Broadwater believes that while the proposed transmission pipeline alternatives, if constructed, may improve transmission infrastructure flexibility in the Region, they are not reasonable supply alternatives to the Project.

10.4.2 LNG Terminal Alternatives

As an alternative to the Project, Broadwater also considered the feasibility of relying on current and proposed LNG terminals to provide a source of reliable, long-term, and competitively priced natural gas to the Region. As with the transmission pipeline alternatives, proposed and existing LNG terminals were evaluated against the criteria listed in Section 10.2. Each of the existing and proposed terminals in relation to the Broadwater Project is presented on Figure 10-5.

Based upon this analysis, Broadwater concluded that these proposed or existing LNG terminals are not reasonable alternatives to the Project.

10.4.2.1 Existing Onshore Terminals

There are four existing onshore LNG facilities operating in the United States: Everett, Massachusetts; Lake Charles, Louisiana; Cove Point, Maryland; and Elba Island, Georgia. With the exception of the facility in Everett, Massachusetts, all of these locations are too distant to competitively serve the Region (*see* Table 10-4).

The expansion of the Everett facility as a means to serve the Region is not a viable alternative, primarily because transport of the regasified natural gas from the Everett facility to the Region would require a new pipeline system or significant expansion of existing pipeline systems which, because of population density, would be difficult to site and obtain regulatory approvals. Other expansion constraints include the size of the existing site, the high levels of shipping traffic within Boston Harbor, and the terminal's location in an urban area with a high population density.

10.4.2.2 Existing Offshore Terminals

A single offshore LNG terminal, Gulf Gateway, is currently in operation in the Gulf of Mexico. To deliver gas, this facility requires the presence of a shuttle regasification vessel (SRV), and offers no onboard storage (meaning that it is dependent on the continuous presence of an SRV to provide a supply of natural gas). This system, which has recently commenced operation, will offer a natural gas capacity of 0.5 bcfd. However, without the continuous presence of an SRV, this system cannot ensure a reliable supply of natural gas. Coupled with its distance from the Region, this facility is excluded from being a viable alternative to the Project.

10.4.2.3 Proposed/Approved LNG Terminals

Eight new onshore U.S. LNG terminals have been approved by FERC for construction and operation as import terminals. These terminals are located in Cameron, Louisiana; Sabine, Louisiana; Freeport, Texas; Sabine, Texas; Corpus Christi, Texas (three terminals); and Fall River, Massachusetts. As well as these facilities, two pipeline projects to import regasified LNG from the Bahamas have also been approved. Two additional offshore facilities have been approved by the United States Coast Guard

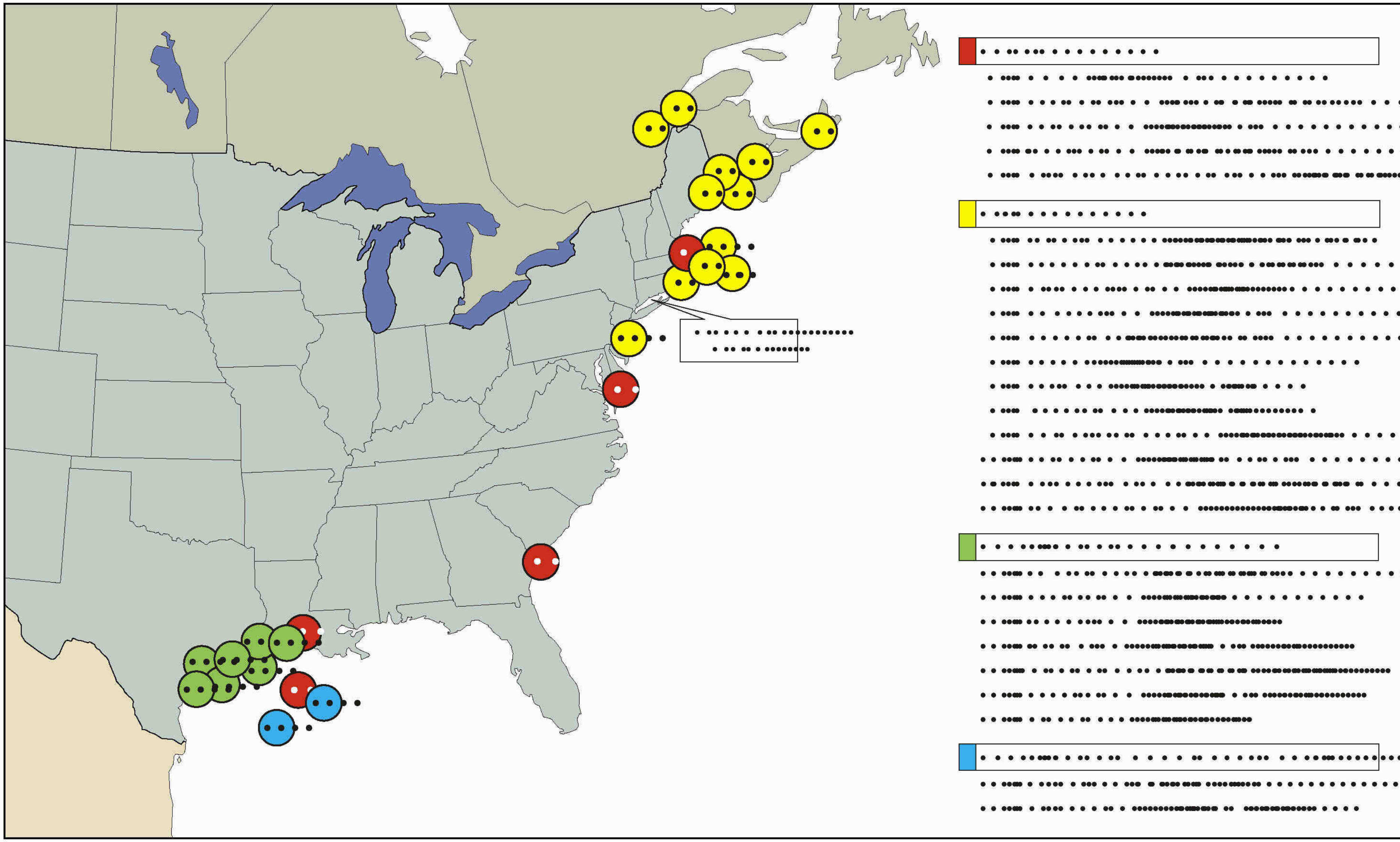

Table 10-4 Existing Capacity and Planned Expansions at Existing LNG Import Terminals

Facility	Storage Capacity (bcf)	Daily Send-out Capacity Baseload (bcfd)
Everett, Massachusetts		
Existing	3.5	0.715
Lake Charles, Louisiana		
Existing	6.3	0.630
Planned Expansion (2005)	3.0	0.570
Planned Expansion (2007)	0	0.600
Total w/Expansion	9.3	1.800
Cove Point, Maryland		
Existing	7.8	1.000
Planned Expansion (2008)	6.8	0.800
Total w/Expansion	14.5	1.800
Elba Island, Georgia		
Existing	4.0	0.446
Planned Expansion (2005)	3.3	0.360
Total w/Expansion	7.3	0.806
Total Existing Capacity	18.8	2.551
Total Planned Expansion	16.4	2.330
Total w/Expansion	35.2	4.881

Source: EIA 2004, page 6.

(USCG)[1]. All but three of these terminals are located along the Gulf Coast and are not considered viable options for serving the Region (*see* Table 10-5 and Figure 10-5). Although these Gulf Coast terminals, if constructed, represent significant new sources of natural gas supply, they are located far from the Region. Accessing supply from these terminals would entail significant expansion of the pipeline systems extending from the Gulf Coast to the Region. Expansion of these systems, in particular the more northern segments discussed in Section 10.4.1.1, would have both significant environmental impact and would be difficult to execute in view of increasing population density and encroachment along existing pipeline rights-of-way. Finally, these Gulf Coast pipelines serve alternative markets along their geographic extent, which could reduce the incremental supply available to the Region.

[1] The project sponsor of the Port Pelican facility recently announced that that project would be indefinitely postponed.

Table 10-5 LNG Import Terminals Approved for Construction

Facility	Storage Capacity (bcf)	Daily Send-out Capacity Baseload (bcfd)
Cameron, Louisiana	10.4	1.5
Sabine, Louisiana	10.4	2.6
Freeport, Texas	6.7	1.5
Corpus Christi, Texas (3 terminals)	28.3	4.6
Sabine, Texas	17.7	1.0
Port Pelican, Gulf of Mexico (USCG approved)	3.6	1.6
Gulf Landing, Gulf of Mexico (USCG approved)	3.9	1.0
AES Ocean Express, Florida/Bahamas (pipeline)	N/A	0.8
Calypso Tractebel, Florida/Bahamas (pipeline)	N/A	0.8
Fall River, Massachusetts	4.3	0.8
Total Planned Capacity	85.3	16.2

While the Fall River facility has been approved by FERC, it is unclear at this time whether the facility will be built due to the legislation passed as part of the Federal SAFETEA-LU bill signed into law in August, 2005. Even if built, significant additional pipeline infrastructure would be required to transport this new gas supply to the New York City area via the Algonquin pipeline system. In addition, the site for the Fall River facility, at 73 acres, has limited room for expansion of facilities.

Four other LNG import terminals are proposed in the Northeast (*see* Table 10-6). The Providence facility was denied certification by FERC, but is currently in the process of appealing the FERC decision. The Providence facility's capacity is not compatible with Broadwater's project objectives and may be difficult to expand to accommodate increased volumes at its onshore location. Further, increasing delivery volumes would increase the rate of LNG tanker transits within Narragansett Bay.

Table 10-6 Proposed Northeast LNG Import Terminals

Facility	Daily Send-out Capacity Baseload (bcfd)	Target Markets	Facility Type
Providence	0.5	New England, New York	Onshore
Northeast Gateway	0.8	New England	Offshore
Suez Neptune	0.4	New England	Offshore
Crown Landing	1.2	Maryland, Pennsylvania, and New Jersey	Onshore (Delaware River)

Two additional offshore terminals, the Northeast Gateway project and the Suez Neptune project, have been proposed near Boston, Massachusetts. These terminals would employ

SRV technology. This option was considered by Broadwater (*see* Section 10.5.2.2) and rejected due to the inability of the technology to provide a sufficiently reliable supply of natural gas to meet the Project's objectives. These proposed facilities are generally designed to serve the New England market and cannot meet the current and projected gas demands of the Region.

The fourth proposed import terminal in the Northeast is the Crown Landing project on the Delaware River. Coastal zone consistency for this facility was denied, which prevents this facility from being considered a viable option for the Project. Furthermore, a lack of spare pipeline capacity, particularly under winter demand conditions, would prevent a significant quantity of natural gas from this project from reaching the Region without pipeline expansion facilities.

Even if one or more of these facilities are permitted, no pipeline infrastructure currently is available, other than the existing IGTS pipeline, to provide a reliable supply of an additional 1 bcfd of natural gas to the Region, as discussed in Section 10.4.1. The construction of the necessary incremental pipeline infrastructure would result in significant environmental impacts in comparison with that of the Project.

10.4.2.4 Other Proposed Terminals

In addition to those terminals proposed to FERC or to the U.S. Coast Guard, there are a number of terminal proposals that have been announced but that have not been formally proposed to U.S. regulatory authorities or are located in Canada (*see* Table 10-7).

Table 10-7 Announced U.S. and Canadian LNG Terminals

Facility	Daily Send-out Capacity Baseload (bcfd)
U.S. Terminals	
Downeast LNG (Robbinston, Maine)	0.5
Quoddy LNG (Pleasant Point, Maine)	0.5
BP Consulting LNG (Calais, Maine)	1.0
AES Battery Rock (Boston, Massachusetts)	0.8
Canadian Terminals	
Rabaska (Quebec City, Quebec)	0.5
Cacouna Energy (Gros Cacouna, Quebec)	0.5
Bear Head LNG (Point Tupper, Nova Scotia)	1.0
Canaport LNG (Saint John, New Brunswick)	1.0

Source: FERC 2005.

With respect to the Canadian terminals, the Rabaska and Cacouna Energy terminals are remotely located relative to the Region. Markets in Eastern Canada will be served by these projects before volumes could be available to meet the needs of the Region. This issue has been recognized by the New England Council in a recent report entitled *The Economic Imperatives of Additional LNG Supplies in New England* (NEC 2005). The report notes that the Province of Ontario has made a commitment to significantly reduce its heavy reliance on coal fired electricity generating plants. The first of five coal fired plants, Lakeview Generating Station (1,140 MW), was closed in April, 2005. Natural gas fired generation is one of the alternatives to replace this capacity. The NEC report notes that "New England faces tangible competition from these proposed sources of LNG from neighboring markets."

Two Canadian projects located in the Maritime provinces, Bear Head and Canaport, which have a combined daily send-out capacity of 2 bcfd, have been approved by Canadian regulatory authorities. These projects are intended to serve the New England and Eastern Canadian markets. Pipeline transport from the Maritimes to New England must utilize the Maritimes & Northeast (M&NE) pipeline system. In July 2005, M&NE announced that it had executed precedent agreements for the transport of 813,000 MMBtu/d from the Bear Head terminal and 750,000 MMBtu/d from the Canaport terminal.

M&NE is currently in the FERC Pre-file process for the Phase IV expansion of its system to transport this gas into the U.S. Northeast. To accommodate the requested natural gas volumes from the Canadian terminals, M&NE is proposing a significant system expansion. For the U.S. portion of the M&NE system, it proposes the construction of 146.2 miles of 36-inch pipeline loop and the construction of five new compressor stations in Eliot, Westbrook, Searsmont, Brewer, and Woodchopping Ridge, Maine, and one new compressor station in Methuen, Massachusetts. Additional compression is proposed for existing stations in Baileyville and Richmond, Maine. The total incremental compression is in excess of 196,000 horsepower.[2] M&NE plans to submit an application to FERC in the first quarter of 2006. While this expansion could provide new volumes of gas supply to the Boston region, further transport from this point would require accompanying expansion of the connecting Tennessee and Algonquin pipeline systems to deliver incremental supply volumes to the Region.

The scope and scale of the M&NE expansion, combined with potential expansion of the Algonquin and Tennessee systems, must be contrasted with the construction of 21.7 miles of 30-inch subsea pipeline to allow access to 1 bcfd of supply directly to the Region, as proposed by Broadwater. Expansion of volumes beyond those currently identified in the M&NE Phase IV expansion would likely entail further additions of pipeline loop, in what would amount to an eventual twinning of the original M&NE pipeline.

The proposed terminals in Maine generally lie to the northern end of the U.S. portion of the M&NE pipeline. These terminals, if approved and constructed, would be expected to require additional pipeline looping of a similar scale to that discussed above.

10.4.2.5 Summary

None of these alternatives can satisfy the Project objective of providing the Region with 1 bcfd of additional natural gas supply without significant expansion of pipeline facilities.

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[2] Data source: M&NE website - http://www.mnp-usa.com/

These impacts are anticipated to be greater than that for the Project as proposed. Further, in many instances these impacts would occur in areas of significant population density. Therefore, none of the proposed terminals represents a viable alternative to the Project.

10.4.3 Electric Transmission Alternatives

As discussed in Section 10.3, most of the projected growth in the demand for natural gas is for electricity generation. Alternative means are possible to meet this growth in electricity demand. If it can be shown that electricity requirements can be met by other means, then the need for incremental supplies of natural gas, and hence the Project, would be reduced.

Within the Region, LIPA has contracted with Neptune RTS for transmission rights on Neptune's proposed 660 MW, high-voltage direct current (HVDC) transmission cable (LIPA 2005b). The cable, which extends 67 miles from New Jersey to Long Island, will allow the transmission of electrical energy from the Pennsylvania, New Jersey, and Maryland power market to Long Island. LIPA has contracted for this capacity for a 20-year term.

The Neptune project will provide an additional source of electric power for Long Island and could supplant about 12% of the generation capacity on Long Island. On a peak basis, however, Neptune's capacity represents less than 11% of the Long Island peak electric usage and this will decrease over time as the demand for electricity grows.

The gas consumption for electric generation on Long Island that is potentially offset by Neptune represents less than 16% of Broadwater's nominal output and less than 11% of Broadwater's peak output (assuming that Broadwater's entire output was converted to electricity). Output from Broadwater, however, is intended to meet the growing demands of the Region. Further, increased availability of natural gas supplies may reduce the amount of electric generation from coal and fuel oil, resulting in substantial environmental benefit. To the extent that electricity supplies for the Neptune project are based upon the use of coal or fuel oil, the Neptune project can only change the location of the source of the emissions from electric generation activities, not the quantity of the emissions themselves, as would be the case for generation associated with incremental supplies of natural gas.

The gas supply from Broadwater will have other uses besides electric generation, such as residential and commercial space heating, that can be satisfied without the conversion losses associated with generating electricity for the same uses.

10.5 LNG TERMINAL ALTERNATIVES

As a part of its evaluation of alternatives, Broadwater examined the feasibility of constructing onshore and offshore LNG terminals to meet the criteria listed in Section 10.2. Broadwater found an offshore FSRU to be the preferred alternative.

10.5.1 Onshore LNG Terminal Concept Alternatives

Broadwater evaluated options for siting an LNG terminal at an onshore location in the Region bordering the Sound. Broadwater focused on identifying existing port facilities and/or industrial areas on the shoreline at which an LNG terminal could be co-located. As an initial matter, Broadwater recognized that construction of an onshore facility would have significant and permanent impacts on nearshore and shoreline environments. Based on the existing nearshore bathymetry at these potential sites, in order to facilitate access by LNG carriers, Broadwater would need to undertake significant shoreline earthwork and nearshore dredging to provide berthing and a turning basin or would need to construct a mooring jetty of more than 1 mile or more out into the Sound to accommodate LNG carriers. An onshore location also would result in the Project and LNG carriers supplying the Project being close to densely populated areas. Finally, overland construction to gain access to an interstate natural gas pipeline would present additional environmental concerns.

As noted in Section 10.6, several potential locations were evaluated along shorelines within the Region; however, because of the potentially significant environmental impacts and perceived safety concerns associated with an onshore location, Broadwater concluded that an onshore facility would not be a reasonable alternative to the Project.

10.5.2 Offshore LNG Terminal Concept Alternatives

Broadwater evaluated three viable offshore LNG import facility options for the Project. These included a gravity-based structure (GBS), an SRV, and an FSRU. Table 10-7 provides a comparative summary of the three different technologies and also considers two different means of mooring the FSRU (a YMS and a turret mooring system).

From Table 10-8, the advantages of the application of FSRU technology combined with a yoke mooring system are compared to the other systems considered. First, the tower system which secures the yoke-moored FSRU has the smallest amount of impact on the seafloor. Second, the yoke-moored FSRU occupies a relatively compact amount of surface area in comparison with the other alternatives. Further discussion of the various offshore terminal technologies is provided in the sections that follow.

10.5.2.1 Gravity-Based Structure

The GBS approach uses a large, concrete structure that contains integrated storage tanks. Because of the significant material needs, the GBS option is generally more economically viable when located in water 60 feet (18 m) or less in depth. The GBS would be constructed in one or two sections at a graving dock and then floated out to the site where ballast is added to sink the structure and ground it on the seafloor.

An additional environmental impact resulting from the construction of the GBS in the Long Island Sound would be associated with the establishment of a graving dock for the construction of the GBS. A graving dock in Long Island Sound, or anywhere within the

Table 10-8 Comparison of Offshore LNG Terminal Concepts

Feature	Broadwater (Yoke Moored FSRU)	Gravity-Based Structure (GBS)	Turret Moored FSRU	Shuttle Regasification Vessel (SRV)	Comments
Location	Long Island Sound	Long Island Sound	Atlantic Ocean	Atlantic Ocean	
Cryogenic Storage (permanent location)	350,000 m^3	350,000 m^3	350,000 m^3	None – no dedicated storage facility	
Preferred Water Depth	15 m to 30 m	15 m	50 m or more required	85 m to 350 m (model tests completed for 40 m to 900 m)	15 m is the minimum water depth for LNG carrier operations in sheltered waters.
Freeboard (Height of Deck Above Water Line)	15 m (to main deck) 25 m (to trunk deck)	20 m	15 m (to main deck) 25 m (to trunk deck)	15 m (assumes fully loaded draft)	
Construction Location	Conventional shipyard	Graving yard required - yard sizing depends on construction methods chosen, but at a minimum would involve an excavation of approximately 70,000 m^2 x available depth	Conventional shipyard	Conventional shipyard	
Sea Bed Impact	1,225 m^2	40,000 m^2 plus an additional area of 28,400 m^2 around the perimeter for scour protection	6 or 8 leg anchor system plus anchors extending 1,000 m horizontally from the turret (distance will increase with water depth)	6 or 8 leg anchor system plus anchors extending up to 1,000 m horizontally from the buoy (for 80 m water depth)	Requirements will vary according to sea bottom conditions and water depth.

Table 10-8 Comparison of Offshore LNG Terminal Concepts

Feature	Broadwater (Yoke Moored FSRU)	Gravity-Based Structure (GBS)	Turret Moored FSRU	Shuttle Regasification Vessel (SRV)	Comments
Number of units required to supply 1 bcfd	1	1	1	3	A single GBS unit is unlikely to be constructable due to stresses in the concrete structure. Two or three separate units adjacent to each other are more probable.
Terminal Surface Use Area	548,000 m^2 (full turn of FSRU)	40,000 m^2	548,000 m^2 (full turn of FSRU)	22,000,000 m^2 (assumes three buoys arranged symmetrically around a center platform)	No allowance made for safety zones or maneuvering areas in areal estimates.
Separate Metering/ Compression Platform Required	No	No	Possibly	Yes	
Distance from Nearest shore	9 miles (8 nautical miles)	As close as 1.2 miles (1 nautical mile) depending on bathymetry	17.3 miles (15 nautical miles)	17.3 miles (15 nautical miles)	GBS must be located closer to shore to access shallower water depths.
Pipeline Beach Crossing	No – Iroquois subsea connection	No – Iroquois subsea connection	Yes – to bring natural gas ashore, or a subsea pipeline of 100 or more miles	Yes – to bring natural gas ashore, or a subsea pipeline of 100 or more miles	
Onshore Pipeline Construction	No	No	Yes	Yes	

Table 10-8 Comparison of Offshore LNG Terminal Concepts

Feature	Broadwater (Yoke Moored FSRU)	Gravity-Based Structure (GBS)	Turret Moored FSRU	Shuttle Regasification Vessel (SRV)	Comments
Marine Operability (Berthing and Mooring Operations)	2.0 m waves 17.0 m/s wind (33 knots) 0.45 m/s current	1.75 m waves 15.0 m/s wind (27 knots) 0.4 m/s current	2.0 m waves 17.0 m/s wind (33 knots) 0.45 m/s current	Predominantly limited by sea states of 5-6 m or higher but offloading will be constrained by ability of LNG carrier to discharge in worsening weather conditions	Limiting case is a combination of wind, wave and current conditions. Effectiveness of tugs is typically a controlling factor in marine operability (weathervaning FSRU and GBS breakwater improve berth operability).
Potential Marine Uptime	98%	90%	<75% using conventional offloading technology due to weather constraints	98% - no allowance made for vessel voyage delays	
Modified LNG Carrier Design Requirement	No – accommodates industry standard LNG carriers	No – accommodates industry standard LNG carriers	Yes	Yes	Tandem offtake system most probably required for FSRU moored in the Atlantic Ocean.
Capital Cost	Moderate	Moderate/High	Moderate but individual LNG carrier costs will be higher for tandem offtake modifications	Low for mooring facilities but individual LNGC costs are about 15% greater than conventional vessels	
Operating Cost	Moderate	Moderate	Moderate	High - vessel utilization is low (+/- 6 days to discharge)	Assumes use of submerged combustion vaporizers or shell and tube vaporizers.

U.S. would require either greenfield development or expansion of existing facilities, which could result in potential significant environmental impacts within a coastal area. Construction in an overseas graving dock would require additional structural design for the GBS to enable trans-Atlantic shipment that would significantly increase the capital costs of the project. To prepare the seabed for the installation of the GBS structure, some dredging could potentially be required.

Although Broadwater initially considered GBS technology, preliminary assessments conducted for the concept recognized that the GBS alternative carried added environmental consequences such as long-term impacts on the seafloor. Further, because of its maximum depth limitations, a GBS would require the facility to be located closer to the shore, thereby increasing impacts on sensitive nearshore ecosystems and visual quality. It also would result in the facility being sited closer to populated areas.

Given these potential impacts, GBS technology was not considered a viable option for an offshore LNG facility within the Region.

10.5.2.2 Shuttle Regasification Vessel

The SRV approach uses specialized LNG vessels that contain onboard regasification equipment. The SRV would enter the unloading area and instead of docking with a GBS or other type of terminal, it would transfer its cargo directly into a subsea natural gas pipeline system. Unlike standard LNG carriers, which typically offload LNG in 18 hours or less, SRVs offload natural gas (i.e., regasified LNG) and inject it into a subsea natural gas pipeline at standard pipeline flow rates and pressures, as the offloading capacity is defined by the rate at which the LNG can be vaporized. As a result, this process can take six days or more to unload a full cargo of natural gas, and continuous off-loading operations are essential to minimize fluctuations in the amount of natural gas entering the pipeline system.

To achieve the stated Project objectives, three offloading buoys would need to be constructed. Each unloading buoy would require as many as eight mooring lines to anchor points on the seabed, interconnecting pipelines to a central manifold, and a large diameter pipeline to transport the gas to the regional distribution network. For safe operability, the buoys could be located up to two miles apart. The necessity of three buoys to meet Project needs would result in restricted access to a significantly greater area then necessitated by either a GBS or an FSRU. This is shown in Table 10-8, where the areal extent of operations for three SRV vessels is much greater than for either a FSRU or a GBS.

Additionally, since SRV technology does not provide on-site storage capabilities, any disruption of the shipping supply chain would result in an inability to deliver a reliable supply of natural gas to the Region.

A minimum of 130 feet (40 m) of water depth is required for SRV technology and this water depth is not available in the Sound in any practical location with a viable pipeline length as discussed in Section 10.7. Based on the regional alternatives assessment, SRV technology is not feasible within Long Island Sound and would need to be located in the Atlantic Ocean. The impacts associated with a pipeline connection from an Atlantic Ocean location are discussed in Section 10.6.1.1. After consideration of the operational and connecting pipeline impacts, an SRV was not considered to be a viable alternative compared to an FSRU.

10.5.2.3 Floating Storage and Regasification Unit

FSRU technology is based on LNG carrier technology and features of floating production storage and offloading (FPSO) units currently in use around the world to produce, treat, and store hydrocarbon products. The FSRU represents a modification of this type of facility in that it has LNG storage, regasification, and natural gas send-out capabilities. The Broadwater FSRU consists of a floating ship-like vessel, approximately 1,215 feet (370 m) in length, 200 feet (60 m) in width, and rising approximately 80 feet (25 m) above the water line to the trunk deck. The FSRU's draft is approximately 40 feet (12 m). The FSRU will be designed to accommodate temporary storage of approximately 8 bcf (350,000 m^3) of LNG, with base vaporization capabilities of 1.0 bcfd using a closed-loop STV vaporizer system. The LNG will be delivered to the FSRU in LNG carriers with cargo capacities ranging from 125,000 m^3 up to a potential future size of 250,000 m^3 at the frequency of two to three carriers per week.

The FSRU will be moored in place using a YMS that allows the FSRU to pivot around the stationary tower, as shown in Figure 10-2. The YMS is attached to the stationary tower structure which also secures the send-out pipeline and is connected to the seafloor by multiple legs. The total area under the tower structure that houses the connection between the FSRU and the proposed new subsea connecting pipeline is of open design and will be approximately 13,180 square feet (1,225 m^2). This entire area would be disturbed during the construction phase as the leg pilings are driven into the seafloor and the tower is installed in place. However, it is expected that a functional community will reestablish under the tower following installation as the sediments are naturally redistributed.

In other Environmental Impact Statements for various LNG projects (for example, Weavers Cove LNG Terminal Final Environmental Impact Statement, Docket No. CP04-36 at 3-10), issues were raised concerning the technical feasibility of an FSRU, in particular with respect to the LNG transfer system. Broadwater will utilize conventional hard loading arms for the FSRU. These are similar in design to those used in onshore applications. The loading arms, however, will include an enhanced connecting mechanism. This enhancement enables connections for relative motions between the mating flanges over a significantly greater range than conventional hard arms. The enhancement consists of the use of a constant-tension guide-cable between the FSRU loading arm and the manifold on the LNG carrier. Technical details are provided in Resource Report No. 13. In addition, the metocean conditions within Long Island Sound are relatively benign in comparison to what would be found in a more exposed location, such as the Atlantic Ocean. Based on this combination of factors, Broadwater has concluded that the operational availability of the FSRU if located in the Sound is 98% or greater. This result is shown in Table 10-8.

Broadwater considers the FSRU technology to be the most viable, environmentally sound, and economically feasible alternative for the waters of the Sound for the following reasons:

- The FSRU requires significantly less bottom area for mooring purposes than a GBS.

- The GBS structure would have a greater visual impact due to its building-like appearance and its proximity to the shoreline. The FSRU provides a ship-like appearance that is more consistent with the current visual canvas of the Sound.

- The GBS would need to be located closer to populated areas than the FSRU due to maximum water depth limitations and thus has the potential to impact sensitive nearshore ecosystems.

- An FSRU would ensure a continuous supply of natural gas to the Region by providing on-site storage versus a likely intermittent supply from SRVs, which would require the continued presence of an LNG carrier for storage.

- An FSRU in Long Island Sound will require significantly less associated infrastructure (on- and offshore pipeline facilities) than an SRV located off the Atlantic Coast of Long Island.

- At the end of its useful life, the FSRU can be removed by detaching it from its mooring and towing it away. This would have significantly less environmental impact than comparable decommissioning of a GBS.

10.6 ALTERNATIVE LNG TERMINAL SITES

10.6.1 Regional Screening Criteria

Initial efforts to identify the preferred site for the Broadwater LNG terminal began in the fall of 2002. From that time until the fall of 2004, Broadwater engaged in a comprehensive, phased analysis of various LNG sites and facility concepts (i.e., GBS, FSRU, onshore terminal, and SRV). Alternative concepts and sites evaluated covered Long Island Sound, Block Island Sound, and the Atlantic Ocean. The general methodology for this site selection process involved:

- Identifying a potential geographical area in which an LNG facility could be sited to best serve the Region;

- Identifying a feasible siting area, given the broad application of technical and environmental siting criteria; and

- A step-by-step narrowing of the potential geographical area down to a proposed site judged to be most appropriate with respect to potential environmental impacts.

As a result of this analysis, Broadwater identified 24 individual alternative facility concepts and site locations for further analysis. Figure 10-6 presents the potential locations for the proposed LNG terminal considered by Broadwater. The 24 sites and concepts provided a range of options in terms of both offshore and onshore areas of the Region, with the ultimate objective of meeting the purpose and need for the Project and providing a reliable natural gas supply to the Region. The facility concepts for the 24 sites include:

- **Nine GBS Sites.** Potentially technically feasible GBS sites could only be identified in Long Island Sound and Block Island Sound. GBS sites on the Atlantic Coast were not considered feasible because of the rapid bathymetric drop-off of the sea floor, which would result in the GBS being located close to the coastline.

- **Five FSRU Sites.** Potentially technically feasible FSRU sites could be identified only in Long Island Sound and Block Island Sound (tower-moored) as well as the Atlantic Ocean close to Long Island (turret-moored).

- **Eight Land-based Sites.** Eight potentially feasible onshore locations were identified on both the Connecticut and New York shorelines as well as on Block Island. Primary areas considered were locations either within or adjacent to existing commercial activities and were primarily associated with existing ports due to the need for access for the deep-draft LNG carriers.

- **Two SRV sites.** Two potentially feasible SRV sites were identified within the Atlantic Basin, close to Long Island.

Following the identification and an initial analysis of the 24 sites, a field survey was conducted in March 2003. This field survey, conducted by vehicle and helicopter and supplemented with available environmental map data for the sites, provided information on existing environmental conditions, the density and nature of local development, and the surrounding infrastructure in the vicinity of both onshore and offshore areas.

As a result of this field survey, Broadwater eliminated 16 of the 24 site concept options. The 16 excluded sites had significant constraints, including:

- Unsuitable metocean (weather and marine related) conditions;

- Proximity to densely populated areas;

- Pipeline routing, constructability, and operability issues due to length and seafloor environment;

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\\BUFSDL4\GIS\Pensacola\LNG\BROADWATER\Maps\MXD\Resource_Reports_Final\RR10\10-6 Potential LNG Sites.mxd 01/17/06

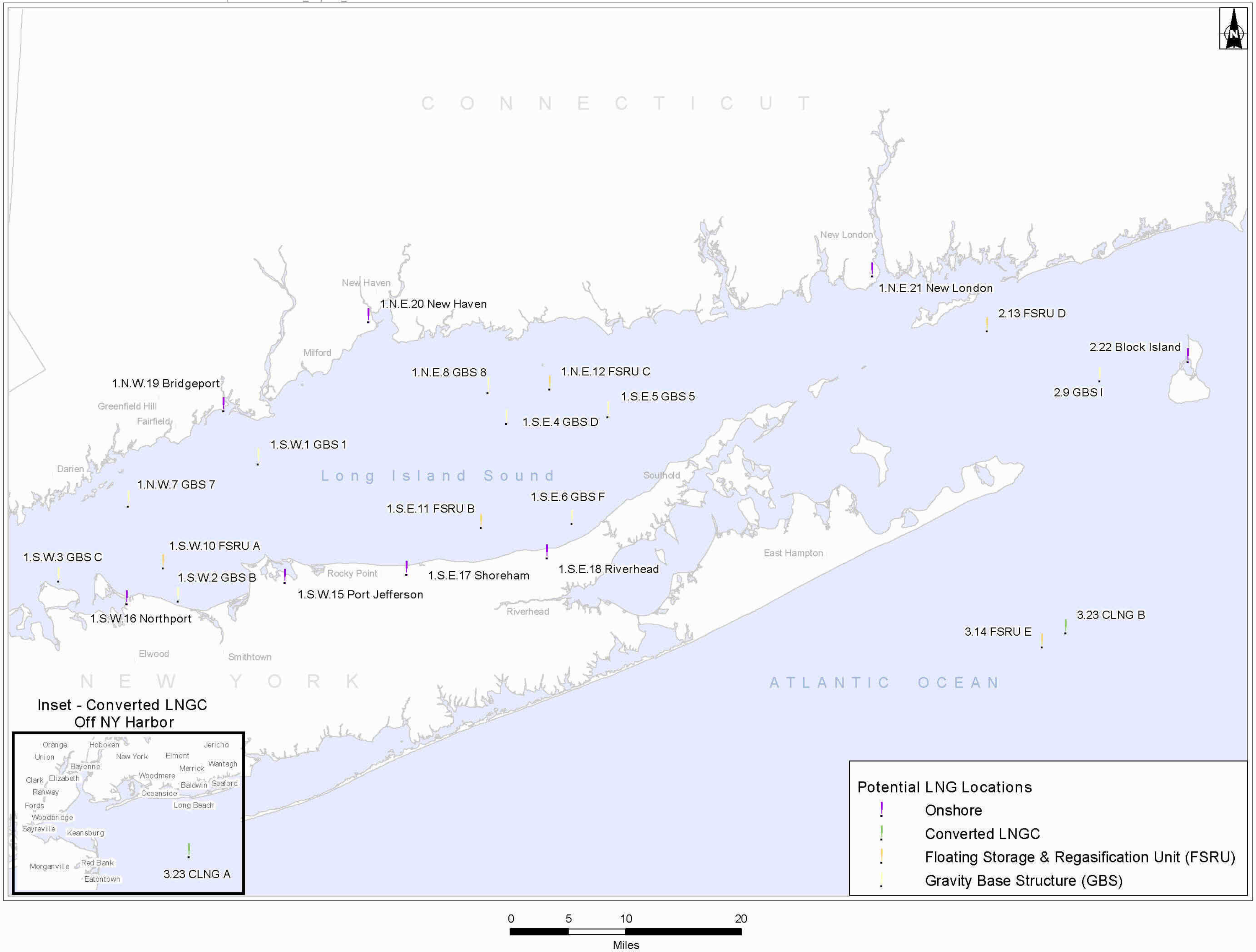

Figure 10-6 Potential LNG Sites Considered By Broadwater

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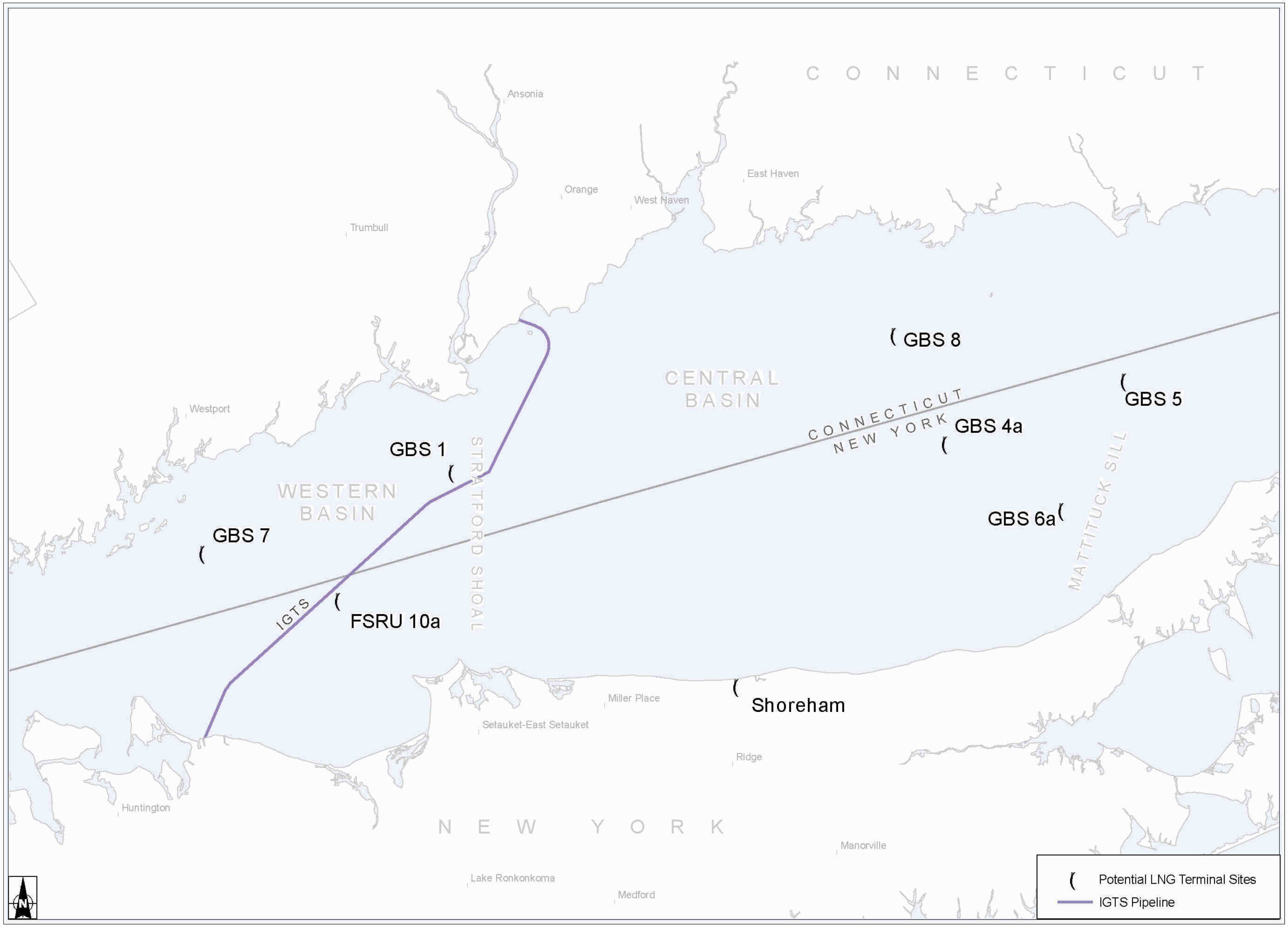
- Impact on other users of the Sound;
- Proximity to, and impact on, sensitive environmental resources; and
- Potentially significant dredging requirements.

Of the sites eliminated, the areas evaluated in Block Island Sound and the Atlantic Ocean presented two significant siting issues: the ability to unload LNG carriers in a routine and reliable manner and gas pipeline construction impacts. Current technology requires LNG carriers to berth alongside the LNG terminal in order to offload their cargos. Weather and marine related conditions in Block Island Sound and the Atlantic Ocean would result in significant periods when LNG carriers would be unable to unload cargo due to excessive relative motion between the vessel and the berth. This downtime would effectively compromise supply reliability and decrease viability. Furthermore, a significantly longer pipeline crossing Long Island Sound and/or an onshore pipeline and associated shore crossing sited across Long Island potentially would be required for any site in the Block Island Sound and Atlantic Ocean area. Based on anticipated natural gas heating and operating pressure requirements, Broadwater determined that an offshore pipeline longer than approximately 40 miles would require intermediate pressure boosting located between the FSRU and the interconnection with the IGTS pipeline. This additional pressure would be provided by a new compressor station development, which would raise significant challenges to this alternative from both an economic and environmental standpoint. Depending on the final siting location, the additional compressor station may need to be situated in an offshore environment on a platform, significantly increasing the socioeconomic and recreational offshore impacts. In addition, a longer onshore pipeline on Long Island would raise additional environmental and resource concerns, especially in sensitive nearshore locations, thereby significantly challenging the viability of these alternatives.

Within Long Island Sound, sites that were located in the western portions of the Sound or closer to the shoreline were considered non-viable and were eliminated from further consideration due to higher population densities surrounding those portions of the Sound, higher density recreation and commercial boating activity, proximity to sensitive marine resources, and potential dredging issues.

With the exception of the Shoreham, New York site, all other onshore options were considered non-viable and were eliminated from further consideration based on population densities, need for significant dredging, and potential impacts to significant nearshore marine resources.

Through the initial screening process, Broadwater carried eight sites/concepts forward for further evaluation. The eight sites included a single onshore alternative near Shoreham, and FSRU and GBS alternatives located throughout Long Island Sound, from Northport, east toward Orient Point on the north fork of Long Island (see Figure 10-7). Although only one FSRU site is included among the eight, it was understood and taken into account that an FSRU could be sited anywhere in the Sound with a minimum 45 foot water depth from a technical screening perspective.



Source: U. S. Geological Survey Open-File Report OFR 00-304, 2000.

0 2.5 5 10
Miles

Figure 10-7 LNG Locations Considered for Further Evaluation

Broadwater then initiated a comparative evaluation for each of the eight remaining potential locations/concepts utilizing a broad number of environmental, socioeconomic, technical and commercial criteria. Broadwater assembled a team representing each of the key disciplines and held a site selection workshop to study, evaluate, and compare the remaining alternatives in greater detail.

As a result of the site selection workshop, no sites were eliminated; however, it was determined that the GBS option carried with it significant environmental challenges with respect to impacts on the seafloor and proximity to populated areas. Overall, the FSRU option was determined to be the most viable and environmentally sound technology alternative for the Region because of the following factors:

- Less impact to the seafloor than GBS technology;
- Less visual impact than a GBS facility;
- Sufficient storage capacity; and
- Ability to be sited far enough offshore (in deeper waters than GBS) to avoid populated areas and limit nearshore impacts.

10.6.1.1 Analysis of Pipeline Routes from Atlantic Ocean Sites

Regarding the offshore LNG terminal concept alternatives considered in the Atlantic Ocean near the eastern end of Long Island, Broadwater prepared an analysis of the environmental, engineering, and economic constraints that would be associated with the pipeline routes that would be required to reach the Project target market.

For illustrative purposes, and in order to conduct the analysis, Broadwater developed preliminary desktop pipeline routes between prospective Atlantic Ocean LNG terminal sites and an interconnection with the Iroquois pipeline, as shown in Figure 10-8. These routes are described below and compared in Table 10-9.

Long Island Onshore Route Alternative

For this analysis, Broadwater assumed that:

- An Atlantic Ocean LNG terminal is located approximately 20 miles southeast of the Hamptons at Latitude 40° 38’ Longitude 72° 09’ in about 200 feet (61 m) of water.
- A viable landfall along the 41 miles of beaches on the south shore of Long Island bounded by the Fire Island National Sea Shore to the west and the Amagansett National Wildlife Refuge to the east near East Hampton can be sited. For illustrative purposes, a landfall just east of Southampton comprising a dune crossing, a crossing of Mecox Bay, then a second landfall at Water Mill to a junction with Highway 27 is assumed.

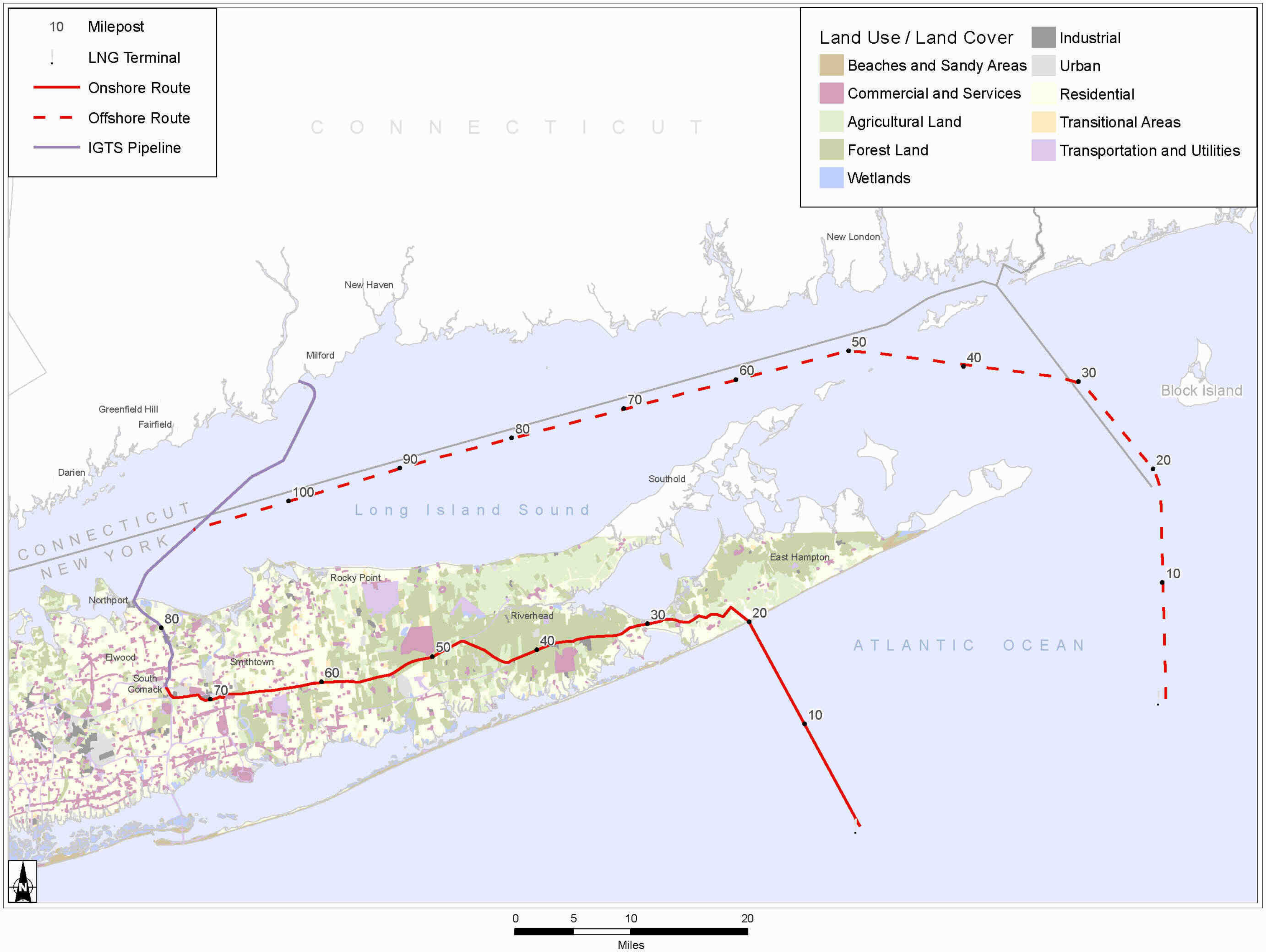


Figure 10-8 Pipeline Routes from Atlantic Ocean Sites

Table 10-9 Comparison of Pipeline Routes from Atlantic Ocean LNG Terminal Site Alternatives

Route Alternative	New-Build Pipeline Length	Environmental Constraints	Engineering Constraints	Cost Constraints
Long Island Onshore Route Alternative	20 miles offshore Atlantic 2 miles inshore bay crossing 58 miles onshore Total: approx. 80 miles	• Increased sedimentation in sensitive coastal areas due to pipeline construction • Noise and visual impacts in surrounding areas during pipeline construction and operation from on-shore compressor station • Disturbance of contaminated sediments in shoreline areas during construction • Disturbance to tidal and inter-tidal wetland communities containing sensitive habitats in National Seashore and Wildlife Refuge area • Disruption to traffic patterns and highway use for extended periods during pipeline construction due to restrictive rights-of-way • Impacts to surrounding land use	• 2 landfalls in sensitive nearshore and beach environments • Collocation along busy and congested urban roadways • Siting of a new-build onshore compressor station	• Excessive overall route length • Construction issues: - offshore Atlantic weather - shore crossings - congested onshore right-of-way

Table 10-9 Comparison of Pipeline Routes from Atlantic Ocean LNG Terminal Site Alternatives

Route Alternative	New-Build Pipeline Length	Environmental Constraints	Engineering Constraints	Cost Constraints
Long Island Offshore Route Alternative	20 miles offshore Atlantic 30 miles Block Island Sound 60 miles Long Island Sound Total: approx. 110 miles	• Impacts to Race area and surrounding islands which contain DOS significant and rare habitats • Impacts to the Race as a migratory corridor for marine life • Decreased access to high use fishing areas during construction • Obstruction to commerce in the Race area that is used by charter boats • Obstruction or potential construction delays due to exclusions zones from Navy vessels in the Race • Increased sedimentation due to excessive pipeline length • Increased disturbance to benthic habitats due to increase pipeline length • Increased risk for collisions in high traffic areas of the Race with risks for spills • Additional offshore platforms result in greater water quality and benthic impacts • Potential to encounter more cultural resources such as shipwrecks	• Potential to encounter unexploded ordinances in the offshore Atlantic • Reefs, shoals and ledges off Montauk Point and through the Block Island Sound • Sandwave zones and exposed bedrock areas through the Block Island Sound • Restricted anchoring zones (submarines) • High traffic through the Race during construction • Strong tidal currents through the Race and associated subsea scouring issues • Siting and design of offshore compressor station platforms	• Excessive overall route length • Design issues: - pipeline on-bottom stability assurance - all-weather remote offshore platform reliability assurance • Construction issues: - offshore Atlantic weather - seabed obstacles, potential span correction requirements and currents - offshore platform logistics

The onshore routing would be co-located with existing linear features on Long Island until it reaches the existing IGTS meter station at South Commack in the Town of Smithtown where it would interconnect via a tap with the existing IGTS pipeline on Long Island. For this illustrative case, the new-build pipeline route would run westerly while co-located with Highway 27 between Water Mill and a point near Eastport; with Highway 111 to a point near Manorville; with Interstate 495 to the Motor Parkway in Smithtown; and then from the Motor Parkway within existing roadways traveling in a mainly northerly direction to the IGTS South Commack meter station site.

The length of onshore co-located pipeline route would be approximately 58 miles, and of the inshore Mecox Bay crossing about 2 miles, with a total route length from the Atlantic Ocean LNG terminal to South Commack of approximately 80 miles of new build pipeline. The total flow length to Northport would be 88.5 miles by incorporating the 8.5 mile IGTS pipeline from South Commack to Northport.

To ensure delivery of gas at sufficient pressure and temperature to the IGTS system, a new-build onshore compressor station would be required along the route at about the midway point between the Atlantic Ocean LNG terminal and Northport in the vicinity of Eastport.

Long Island Offshore Route Alternative

For this analysis, Broadwater assumed that:

- An Atlantic Ocean LNG terminal is located approximately 20 miles southeast of Montauk Point at Latitude 40^{o} 47' Longitude 71^{o} 39' in about 200 feet (61 m) of water.

- A viable subsea pipeline route can be negotiated around Montauk Point, through Block Island Sound, through the Race passing south of Valiant Rock (north of Little Gull Island), and westward along the central axis of Long Island Sound to the proposed subsea interconnect with the existing Iroquois pipeline crossing of Long Island Sound.

To ensure delivery of gas at sufficient pressure and temperature to the IGTS system along the pipeline's approximately 110-mile length, two new-build offshore platform based compressor stations would be required along the route, one notionally in Block Island Sound and one in mid-Long Island Sound.

Summary

As both the Long Island Onshore and Long Island Offshore alternatives from the Atlantic Ocean require significant new pipeline construction in order to access the Iroquois Gas Transmission System, these alternatives are less desirable than alternatives located within the interior of Long Island Sound.

10.6.1.2 Block Island and Plum Island Onshore Locations

In the process of consultation with stakeholders, alternative onshore locations that were excluded from Broadwater's initial siting study have been raised. Two specific onshore locations are Block Island and Plum Island. As previously stated, onshore options with the exception of Shoreham, New York were considered non-viable and were eliminated based on a variety of factors.

A pipeline from Block Island would likely be offshore and would be approximately 87 miles in length to reach a subsea interconnection with the IGTS system. A pipeline from Plum Island would likely be offshore and would be approximately 55 miles in length to reach a subsea interconnection. In both instances, a nearshore pipeline crossing would be required that would have significant environmental impact on the sensitive nearshore environment. Further, to meet the draft requirements for LNG carriers, construction of a jetty and LNG carrier berthing facilities would be required (along with potential dredging to a depth to accommodate LNG carrier drafts), which would further increase the impact.

As discussed above, in both instances, a pipeline (whether offshore or situated on Long Island) greater than 40 miles in length would be required. An intermediate compressor station would be required to offset pressure losses in the transmission pipeline. Siting this compressor station, whether onshore or offshore, would be difficult in view of the environmental constraints and population density on Long Island.

10.6.2 Defining the Project Study Area

As a final step in the evaluation process to identify a suitable site for the Project within the Sound, Broadwater conducted a comparative analysis that incorporated information from the site selection workshop and presented a detailed environmental screening of the remaining eight sites to differentiate sites based on available engineering and environmental data. Broadwater identified specific resource constraints for each site and made a determination of whether or not to carry sites forward. This analysis also incorporated various straight-line pipeline alternatives for connection with the IGTS for each of the remaining sites, which is a critical consideration in determining the optimum location for the LNG terminal. Data analyzed included:

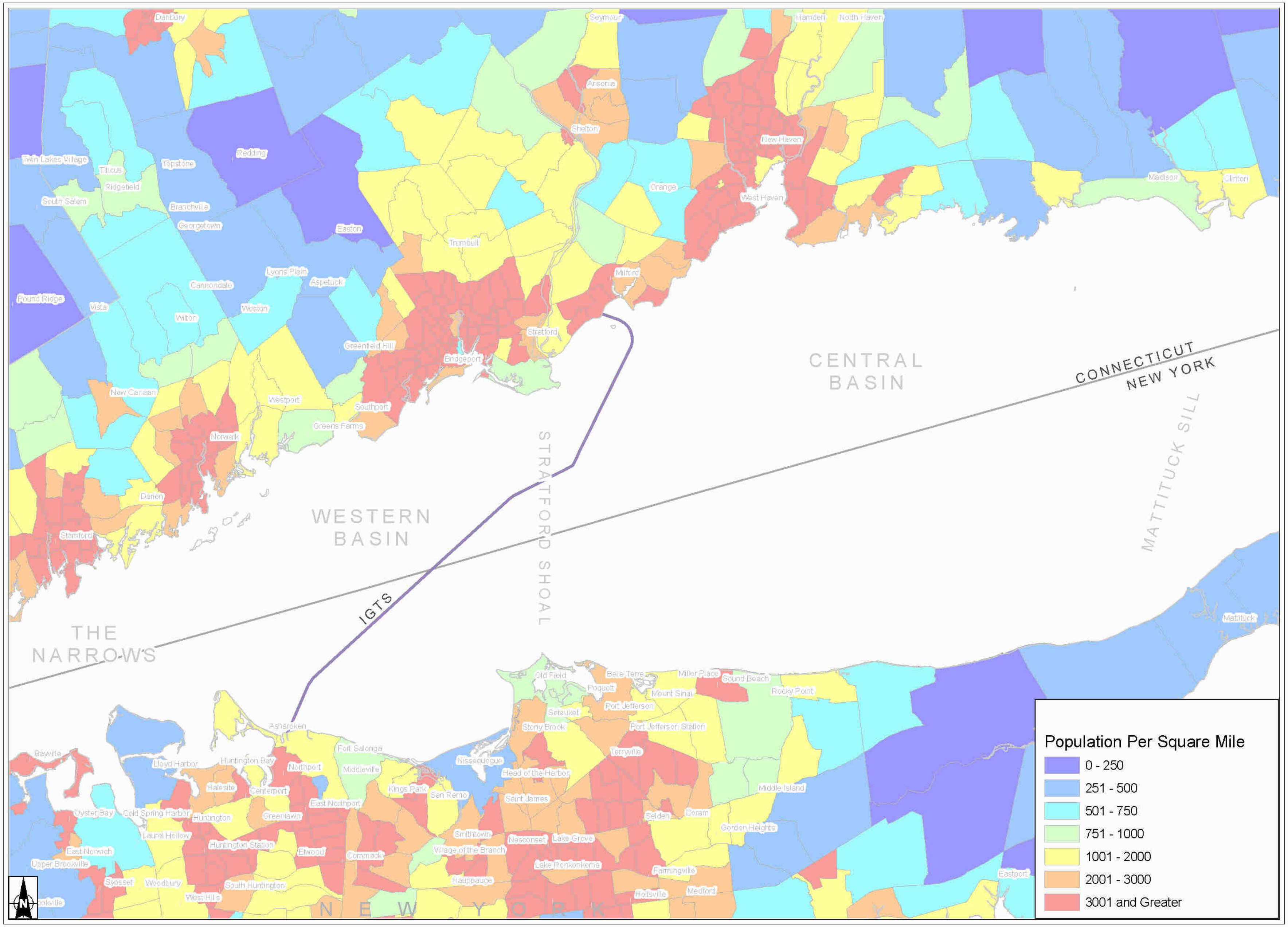
- Water quality;
- Water temperature;
- Soil conditions;
- Air emissions;
- Water discharges;
- Sediment quality;

- Marine ecology/sensitive habitats;
- Noise impact;
- Visual impact;
- Coastal zone consistency;
- Safety issues;
- Land use compatibility;
- Pipeline distance;
- Regulatory implementability; and
- Population density.

The remaining onshore terminal option at Shoreham was eliminated by Broadwater due to the proximity to a densely populated area, the nearshore environmental impacts associated with the construction of a jetty to accommodate berthing, and the likely need for dredging to accommodate LNG carrier approaches to the berth. Figure 10-9 indicates the density of population that exists along the Long Island shoreline. As this figure demonstrates, the sites within the central portion of Long Island Sound result in little or no impact on populations in either Connecticut or Long Island.

As a result of the evaluation, it was determined that the GBS option carried significant environmental challenges with respect to impacts on the seafloor and proximity to populated areas. Overall, the FSRU option was determined to be the most viable and environmentally sound technology alternative for the Region because of the following factors:

- Less impact on the seafloor than GBS technology;
- Less visual impact than a GBS facility;
- Improved ability to berth LNG carriers due to the ability of the FSRU to orient in response to the prevailing wind, wave, and current conditions;
- Ability to be sited far enough offshore (in deeper waters than GBS) to avoid populated areas and limit nearshore impacts; and
- Increased flexibility in siting compared with the GBS because an FSRU facility can be sited in a variety of water depths.



Source: U. S. Geological Survey Open-File Report OFR 00-304, 2000.

Figure 10-9 Population Densities Adjacent to Long Island Sound

From the engineering analysis it was determined that the preferred location for the FSRU was in the immediate vicinity of the IGTS pipeline. By siting in the immediate vicinity of the IGTS pipeline, the length of a connecting pipeline is limited, thereby providing operational efficiencies such as avoidance of gas transmission pressure and temperature losses inherent in longer pipelines. However, from an environmental standpoint, such a location is not optimal due to the decreased width of the Sound in this location, potentially increasing impacts on recreational and commercial boating traffic and being closer and having a greater overall potential impact on Long Island and Connecticut populations.

Evaluation of publicly available data resulted in the determination that coastal population density and marine use begins to fall off east of Shoreham relative to the western Sound. From an environmental and safety standpoint, a more centralized site in the Sound is preferred because it maximizes the distance from shore and therefore lessens impacts on populated areas and the current offshore uses of the Sound. Siting in the central Sound also avoids the more contaminated sediments associated with the higher population densities in the western portions of the Sound.

Several sites in New York waters in the central portion of the Sound were identified and evaluated because a significantly greater proportion of natural gas demand in the Region is associated with natural gas markets in New York, which the Project will serve over its operating life.

On June 3, 2002, in direct response to proposed energy development projects in Long Island Sound, the State of Connecticut issued a Moratorium on energy related projects (Moratorium C.G.S. § 25-157). In issuing the Moratorium, the State adopted legislation prohibiting state agencies from approving applications "relating to electric power line crossings, gas pipeline crossings or telecommunication crossings of Long Island Sound." The State's Moratorium on energy projects, which was set to expire after one year, was extended until June 3, 2005; however, the State of Connecticut General Assembly failed to extend the Moratorium and it expired on June 3, 2005.

In light of these events, Broadwater evaluated the potential of expanding its Project area to include Connecticut waters for siting of the FSRU. The proposed FSRU is centrally located within the Sound. To consider a site in Connecticut, the selected site would need to demonstrate environmental, engineering, and socioeconomic preference with respect to the existing site. Due to existing established shipping routes, a potential site north of the existing site in Connecticut would need to be approximately 3 miles north of the current site. This would result in a closer distance to the nearest shore in shallower water resulting in greater adverse environmental and socioeconomic impacts.

Broadwater determined that siting the FSRU in Connecticut waters offers no advantages, as the FSRU's proposed location is optimal from a number of socioeconomic, environmental, and engineering considerations. It would, therefore, not be reasonable to open the evaluation to include sub-blocks in Connecticut waters of Long Island Sound.

Through a further weighing of the environmental and engineering considerations, a broad area within the central/eastern portion of the Sound in New York State waters was identified as providing the preferred location for siting an FSRU (*see* Figure 10-10). The identification of such an extensive study area required that a more detailed analysis of the potential alternatives in this area be conducted. An expanded study area was subsequently developed to capture potential areas for pipeline siting. The final Project study area with the pipeline component added is illustrated in Figure 10-11. Pipeline alternatives are discussed in detail in Section 10.7.

As noted below, the final study area was divided into blocks of approximately equivalent sizes for comparison purposes and was used to identify the preferred site location.

10.6.3 Final FSRU Evaluation and Site Selection

As previously noted, based on a number of environmental and engineering considerations, the preferred location for the Project is an area off the coast of Long Island in the Sound ranging from 3 miles off the coast out to the New York State – Connecticut State lines offshore of Suffolk County, New York (*see* Figure 10-10). This section provides the final alternative analysis of the identified Project study area, which was used to select the site for placement of both the FSRU and the subsea pipeline.

10.6.4 Siting Requirements

Important aspects of the actual construction of the Broadwater FSRU are not only environmental concerns but also physical requirements. The FSRU facility will be designed to withstand wind and wave action. However, because the data collected to date is largely applicable to wide- ranging Sound conditions, the use of existing metocean data is not a discriminating factor in selecting either an FSRU location or pipeline route within Long Island Sound.

To provide a basis for comparing FSRU siting locations within the Sound, Broadwater established sub-blocks within a smaller subset of the entire Project study area. The sub-block constraints were established through a number of socioeconomic, environmental, and engineering considerations. The northern, eastern, and southern boundaries of the subset correspond with the established boundaries of the overall Project study area. The western boundary of the FSRU study area was established in recognition of the higher population densities that occur within the western portion of the Sound with potential land use, recreational marine use, socioeconomic and environmental impacts. Within the FSRU study area, 12 distinct sub-blocks of similar size were delineated to provide a more defined analysis for this desktop study. These sub-blocks are identified on Figure 10-12.

As presented in Figure 10-12, no sub-blocks were mapped along a central corridor through the FSRU study area. This gap accounts for a typical (known) shipping route characterized as having traditionally high vessel traffic and the existence of a submarine telecommunications cable. To avoid impacts on this historic shipping route and the cable, Broadwater removed this area from consideration. A similar shipping route is located north of the sub-blocks in Connecticut waters.

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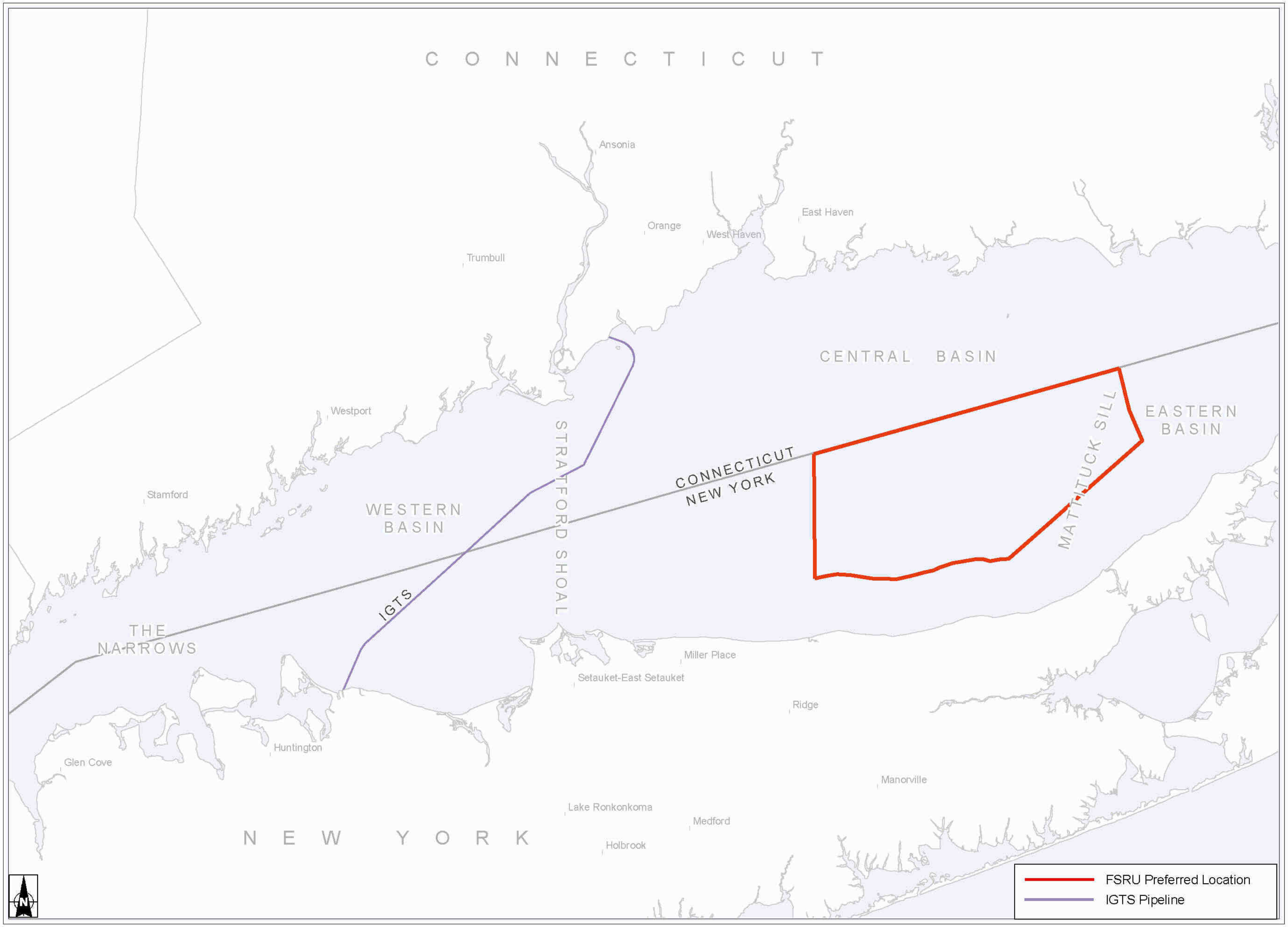
\\BUFSDL4\GIS\Pensacola\LNG\BROADWATER\Maps\MXD\Resource_Reports_Final\RR10\Fig10-10 Preferred Siting Loction.mxd 01/17/06



Source: U. S. Geological Survey Open-File Report OFR 00-304, 2000.

0 2.5 5 10
Miles

Figure 10-10 Preferred Location for Siting an FSRU

BW002495

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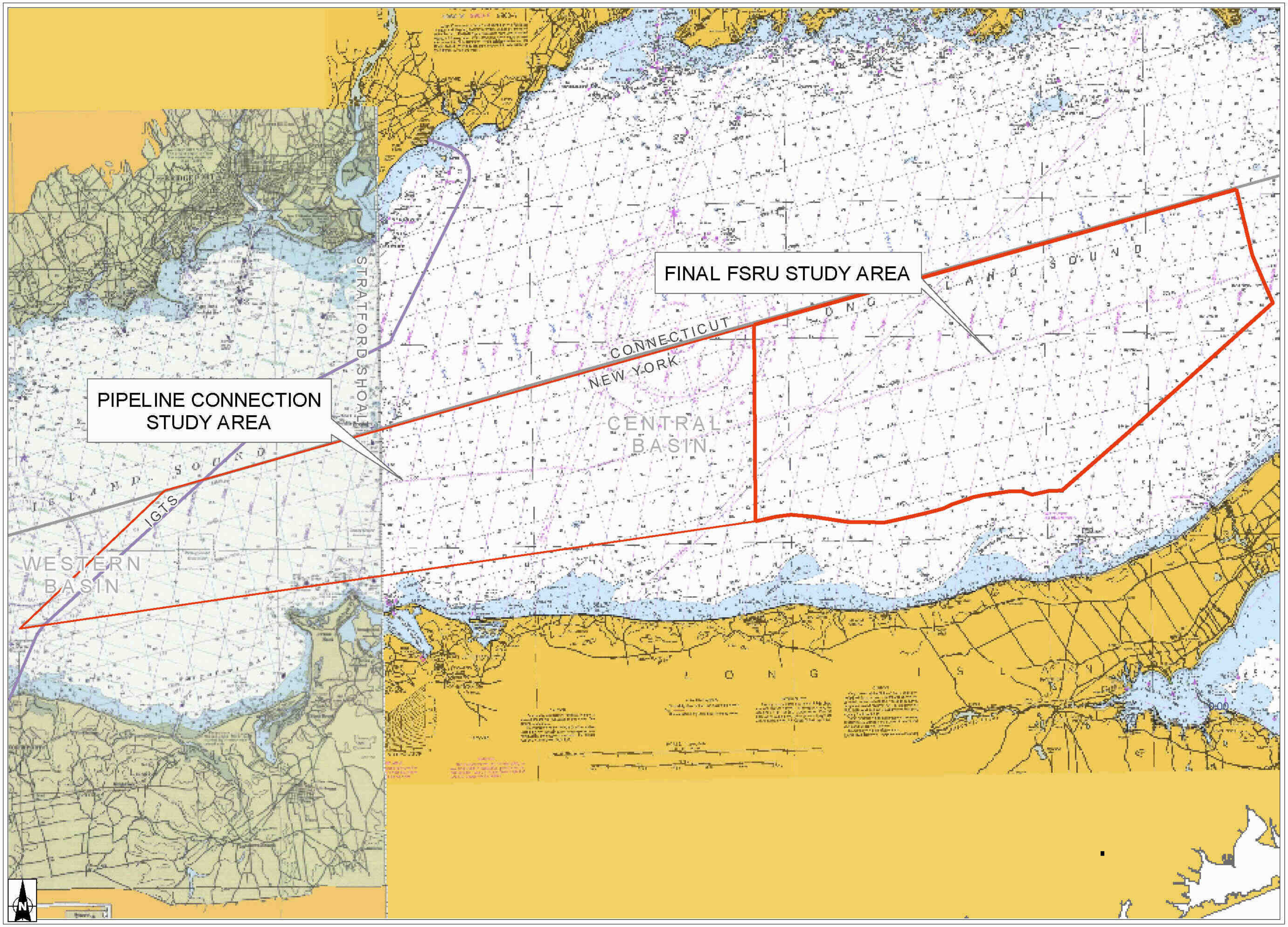

Source: NOAA Charts 12354 (July, 2003), and 12363 (July 15, 2000).

0 2.5 5 10
Miles

Figure 10-11 Final FSRU Study Area and Pipeline Connection Study Area

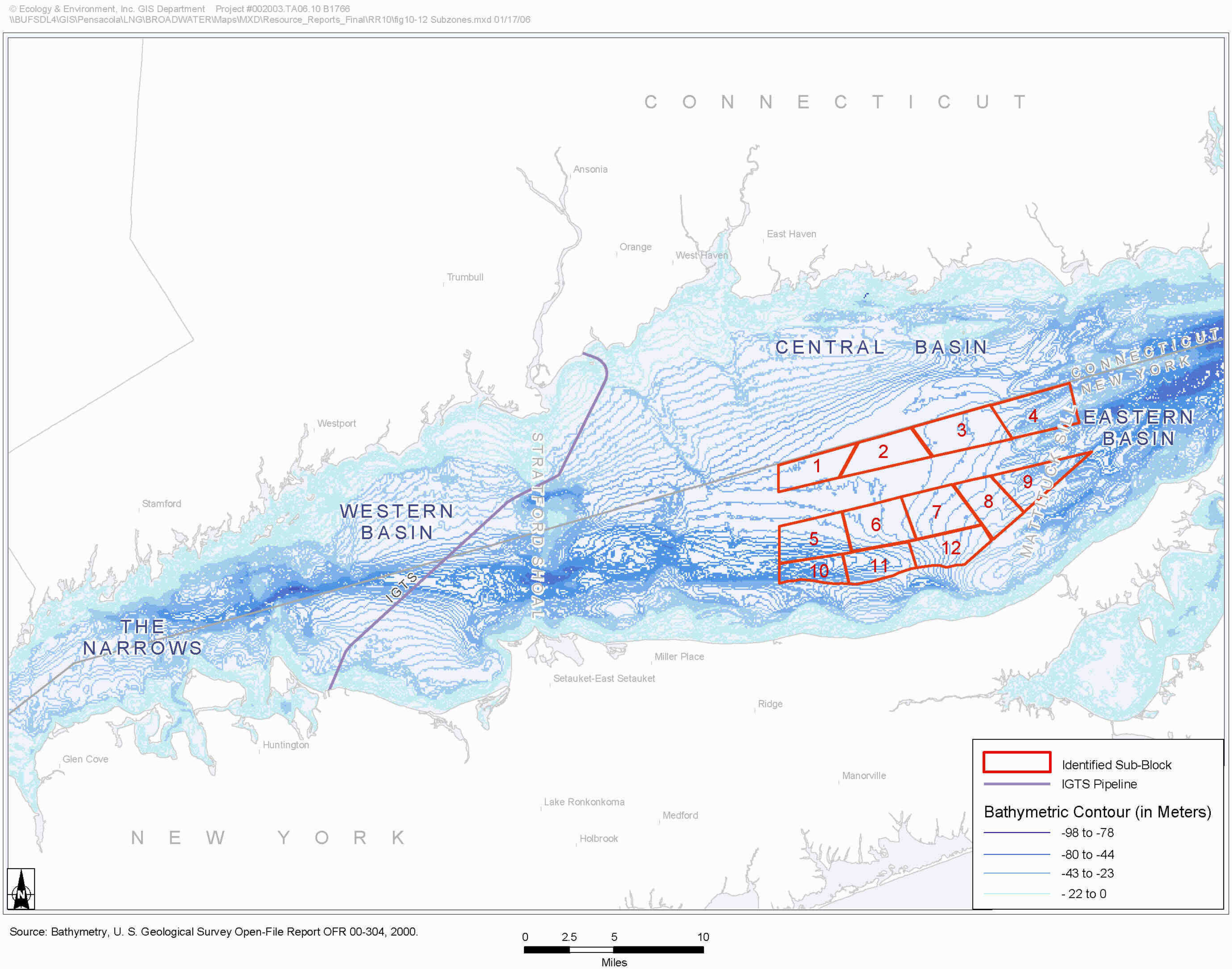

Figure 10-12 Identified Sub-Blocks within the FSRU Study Area

BW002497

10.6.4.1 Area Requirements

The potential restrictions placed on activities around the FSRU if a safety zone is established are an indirect but significant consideration in siting the Project. Sites located in areas with other existing marine uses, such as shellfish harvesting, and commercial fishing and recreational fishing and boating would restrict the continued operation of these uses. The FSRU also needed to be located away from primary shipping routes to avoid disruption to existing vessel traffic.

10.6.4.2 Identification of Preferred Sub-Blocks

Following the establishment of the sub-blocks, Broadwater initiated an analysis, based on the information collected to date, to differentiate the sites based on environmental, socioeconomic, and engineering considerations, and to eliminate those that were considered to have increased impacts with no corresponding benefits. Specifically, if individual factors were present that suggested potentially greater impacts in any of the 12 identified sub-blocks within the study area, those sub-blocks would be eliminated from further consideration.

Based on oceanographic data collected, Broadwater eliminated Sub-Block 4 from further consideration. The significant bottom topography, coupled with the proximity to The Race, exposes this site to potential extremes in currents and wave patterns (The Race is the eastern entrance to Long Island Sound, between Fisher's Island and Gull Island, including Valiant Rock). These extremes could significantly impact the ability of the facility to operate without disruption. The bottom contours and bed load transport characteristics of the sediment also indicate a potential for scouring conditions. Based on these considerations, Sub-Block 4 was eliminated.

Sub-Block 12 is almost entirely located within a lightering zone, which raises safety concerns. Therefore, Sub-Block 12 was eliminated from consideration. Sub-Blocks 7 and 8, while intersecting partially with the lightering zones, appear at first review to have suitable areas north of the lightering zones.

Sub-Blocks 9, 10, and 11 are the minimum 3 miles from shore. While achieving a minimum buffer distance to address perceived safety concerns, the proximity to shore raises significant socioeconomic, land use, and recreational issues that could not be reasonably mitigated. As such, these three Sub-Blocks were eliminated.

Based on this initial fatal flaw review, five of the 12 sub-blocks were eliminated from further review. Sub-Blocks 1, 2, 3, 5, 6, 7, and 8 were carried forward in the review process.

10.6.4.3 Alternatives Analysis

Each of the remaining seven alternative sub-blocks were then evaluated in relation to existing data to determine the preferred siting location for the FSRU. Primary criteria used to determine the preferred site included the socioeconomic, environmental, and engineering considerations described below.

10.6.4.3.1 Land Use and Socioeconomics

Based on the preliminary evaluation of the Project area, Broadwater identified land use and socioeconomic issues as critical siting criteria. In reviewing the alternatives carried forward, Sub-Blocks 1, 2, and 3 are preferable to the remaining four sub-blocks (5, 6, 7, and 8) as a result of increased distance from shore, the respective reduction in potential impacts on adjacent communities in terms of noise and visual resources, and the distance provided from a public safety standpoint. Each of these sub-blocks is approximately 9 miles from the shore at the closest point. In comparison, the other four remaining sub-blocks are less than 5 miles from shore, with Sub-Block 8 as close as 3 miles from the shoreline of Long Island. Proximity to the shore also would have a greater impact on smaller recreational boat traffic that tends to be closer to the shoreline. Recognizing that larger vessels navigate the majority of the Sound, locating an FSRU terminal in the central, widest portion of the Sound minimizes navigational impacts because vessels could avoid a safety zone established for the FSRU.

10.6.4.3.2 Commercial Fisheries

Another key concern for Broadwater is the potential impact on commercial fishing. Fishing activity increases to the west of the study area and, based on available information, the seven sites considered are all subject to relatively high fishing activities. Although densities begin to decline in the eastern portion of Sub-Block 3 and Sub-Block 8, siting of the FSRU at either of these locations would increase the pipeline routing by approximately 8 to 10 miles over any of the remaining sub-blocks and would have a corresponding increase on bottom disturbance and the potential to adversely impact fisheries. Based on consultation with local fishermen, this extension of the pipeline and FSRU to the east would also encroach on existing finfish trawling areas that are avoided by siting further to the west. Therefore, from strictly an environmental impact minimization standpoint, since fishing habitat is similar through all of these seven sub-blocks, the optimal solution would be to minimize the pipeline length, which would indicate a preference for Sub-Blocks 1 and 5. However, given that pipeline lengths would be similar for both sub-blocks, and that limiting land use and socioeconomic impacts is critical for Project siting, preference was given to Sub-Block 1 over Sub-Block 5 since Sub-Block 1 is located further from shore than Sub-Block 5.

Although preference was given to Sub-Block 1 based on the these primary considerations, further evaluation against the remaining data collected was required to ensure no other data would contradict the conclusions based on land use and socioeconomic and commercial fishing interests.

10.6.4.3.3 Soil and Water Quality

Soil and water quality issues were not considered significant discriminating factors based on the data collected. It was generally expected that some sediment contamination potentially exists throughout the Sound based on the historic levels of input to the Sound and existing data. Based on the existing sampling data available, slightly elevated levels of contamination are found in the sub-blocks being considered. The highest levels of contamination are in Sub-Blocks 1 and 5, which conforms to the general trend of contamination increasing toward the western portion of the Sound. This is also consistent with the depositional nature of the sediments underlying this portion of the Sound. The contamination levels between the sites under consideration do not vary significantly enough to justify moving the preferred sub-block away from Sub-Block 1. Field surveys conducted in the spring of 2005 (*see* Environmental Sampling Report in Resource Report 2) demonstrated that no significant contamination exists at the preferred site in Sub-Block 1.

10.6.4.3.4 Bathymetry

In terms of bathymetry, Sub-Block 1 (in addition to Sub-Blocks 2 and 3) is considered optimal due to its relatively flat topography. Geophysical surveys conducted in the spring of 2005 confirmed that Sub-Block 1 is suitable for terminal siting.

10.6.4.3.5 Marine Hazards and Obstructions

No other data collected and evaluated has siting implications that would indicate a preference for any of the other sub-blocks over Sub-Block 1. Based on field geophysical, archaeological and geotechnical surveys, no identified marine hazards or obstructions occur within Sub-Block 1 and no known cultural resources have been identified. Siting in any of the other six sub-blocks under consideration would have additional engineering constraints due to the existence of subsea utilities such as an MCI cable corridor and the FLAG Atlantic-1 North cable, as well as a potential conflict with the proposed Islander East pipeline.

10.6.4.3.6 Vessel Traffic

Project siting considered potential conflicts with identified waterways and existing vessel traffic patterns. Sub-Blocks 1, 2, and 3 are situated between two identified waterways. Historic travel corridors extend from the east and west of the Sound toward Connecticut ports and pass to the north. Through traffic and vessels scheduled for New York ports will generally pass to the south of these areas. Based upon reasonable assumptions regarding the size of the safety zone to be established by the USCG, Broadwater believes that the siting of the FSRU in these sub-blocks can be successfully accomplished without adversely affecting navigation. While Sub-Blocks 6 and 7 would be further away from primary routes of travel, these sub-blocks would result in the siting of the FSRU much closer to shore which increases potential socioeconomic concerns and would require additional crossings of existing subsea utility lines. Sub-Blocks 7 and 8 would also likely have higher traffic volumes due to the presence of a lightering zone, which infringes on both of these sub-blocks.

10.6.5 Conclusions

Based on these comparisons and screening procedures, Broadwater concluded that the offshore option, using FSRU technology, is the most viable, environmentally sound, economically feasible, and safest approach to providing a long-term, reliable natural gas supply to the Region. Based on the alternatives analysis between each of the viable sub-blocks, Broadwater identified Sub-Block 1 as the preferred location for an FSRU LNG terminal. A pipeline between mid-Sub-Block 1 to a proposed subsea interconnection with the IGTS between MP 17 and MP 23.5 was determined to be constructible, based on engineering and environmental assessments completed by Broadwater. Broadwater established specific coordinates (latitude and longitude) for the FSRU mooring tower and the IGTS interconnector (beginning and end control points) based on coarse engineering criteria that were satisfied from observations made during a March 2005 reconnaissance survey. Following the detailed geophysical and geotechnical surveys, the exact location was finalized. Considerations included siting the hot tap at a location with suitable soils for connection spool lowering, placement, and support, where there was no evidence of scour, and where the existing IGTS pipeline was at a maximum depth. Other considerations included maximizing the distance from the FLAG Atlantic 1-North fiber optic cable and locating the tie-in as far north as possible to reduce pipeline length. The FSRU location was sited in an area of flat bottom topography, outside of recognized fish trawling lanes, and as far west in the sub-block to reduce pipeline length. Broadwater then set out specific pipeline route alternatives for assessment.

10.7 PIPELINE ROUTE ALTERNATIVES

Broadwater's pipeline route selection process involved identifying general constraints and opportunities presented for various pipeline route alternatives, avoiding undesirable areas, and maintaining the engineering and economic feasibility of the pipeline. Physical, environmental, engineering, regulatory, and construction issues were considered, and the preferred pipeline route selected by Broadwater represents an appropriate balance of these considerations. The area considered for the preferred pipeline route is identified in Figure 10-11.

From the FSRU location, Broadwater identified two siting options for the pipeline taking gas away from the FSRU: one interconnecting with the IGTS interstate pipeline via a subsea interconnection in the Sound and the second interconnecting with the IGTS pipeline on land. Broadwater eliminated an interconnection with the IGTS pipeline on land from consideration due to environmental impacts. An onshore tie-in would require a shore crossing with increased coastal zone and land construction impacts. The following sections present the alternatives considered for interconnecting the FSRU to the IGTS pipeline.

10.7.1 Basic Siting Requirements

The following factors were considered during the pipeline route selection process:

- Public safety;
- Environmental impacts;
- Land-use constraints;
- Restricted areas;
- Engineering constraints;
- Hazards and obstructions;

- Pipeline integrity;
- Cost efficiency; and
- Regulatory implementability.

The route selection process also addresses other key constraint factors inherent in pipeline construction and operation by avoiding or minimizing geographic and regulatory restrictions:

- Population concentrations;
- Fish spawning areas;
- Wildlife and endangered species habitats;
- Historical and archeological sites;
- Restricted areas such as national parks;
- Existing utilities;
- Areas of potential erosion;
- Bedrock;
- Excessively steep slopes;
- Seismic conditions;
- Existing corridors;
- Temporary and permanent access;
- Construction schedules; and
- Marine traffic routes and anchorages.

The proposed pipeline terminates at a subsea interconnection on the existing IGTS pipeline that runs between Milford, Connecticut and Northport, New York. The following factors were considered for the selection of the precise location of the subsea mechanical connection on the existing pipeline:

- Locate the subsea mechanical connection within New York State or Connecticut waters (i.e., furthest along the length of the IGTS [flow is toward Long Island] without going onshore) to take advantage of an improved match between hydraulic flow characteristics of the two pipelines, providing better overall pipeline performance;

- Locate the subsea mechanical connection outside any designated shipping lanes, anchorage areas, restricted areas, lightering areas, or disposal areas;

- Locate the subsea mechanical connection away from commercial fishing areas to the extent possible;

- Locate the subsea mechanical connection away from environmentally sensitive areas to the extent possible;

- Select an area with stable sea bottom conditions;

- The top of the existing IGTS should be at least three feet below the surrounding seabed and the area should not exhibit indications of current/past tidal scour; and

- Locate the subsea mechanical connection on the IGTS on an area of the pipeline that is confirmed to be suitable for the installation of the mechanical fitting.

10.7.2 Control Points

Control points are set points along a pipeline route that normally include the start and end point for the pipeline. These points dictate the routing options of a pipeline. The control points for the Broadwater marine pipeline route are the FSRU location (center of the tower system) and the IGTS pipeline subsea interconnection location.

10.7.2.1 Pipeline System Hydraulic Examination

Design and operational limits on the existing IGTS pipeline along with peak flow conditions were considered when identifying engineering constraints that impact pipeline hydraulics. When coupled with the send-out conditions of the LNG terminal, the results of the study identified a maximum pipeline length constraint of approximately 40 miles. A length greater than 40 miles would require additional pipeline compression at a self-standing compressor station offshore, resulting in impact on the Sound.

10.7.2.2 FSRU Location

Based on feedback from the fishing community, the preferred location for an FSRU is the northwest corner of Sub-Block 1 and is considered the initial starting control point for all pipeline route considerations.

10.7.2.3 IGTS Tie-in Location

The IGTS pipeline tie-in location area was determined by utilizing some of the factors listed above to create a 6.5 mile "target area" on the IGTS pipeline that falls between MP 17 and MP 23.5, as measured along the IGTS Long Island Sound Crossing, with MP 0 being the Connecticut shore. Based on coarse engineering criteria (*see* Section 10.6.5), a tie-in location has been selected to serve as the end-of-line point for all pipeline route considerations. Based upon detailed surveys, MP 18.2 was chosen as the preferred interconnection point.

As presented in Section 10.7.3.5, following the expiration of the Connecticut Moratorium on energy projects in the Sound, consideration was also given to potential tie-in locations within Connecticut waters. An approximate 4-mile target area was identified based on desktop review of sediment data, shell fishing leases and proximity to the Connecticut coastline. The results of this investigation are documented in the referenced section.

10.7.3 Subsea Pipeline Routing Alternatives

Potential subsea pipeline routes were evaluated using all available information, and the constraints present with respect to the location of the FSRU and existing IGTS as previously discussed. Routes considered in this comparison are described below and shown on Figures 10-13 through 10-16.

- **Route 1.** This route is 21.5 miles in length and is the farthest distance from either the Long Island or Connecticut shorelines.

- **Route 2.** This route is 21.7 miles in length and has been designed to avoid the harder bottom substrates in other areas of the Stratford Shoals. The routing maintains a straight-line approach to the extent possible while accounting for substrate conditions and known wreck locations. Route 2 is considered the preferred route in consideration of the environmental, engineering, and socioeconomic factors as discussed above with respect to pipeline siting.

- **Route 3.** This route is 22.3 miles in length and generally runs in a straight line from the proposed FSRU to a point near the Stratford Shoals, at which point it heads south to avoid the shoals and connect to the IGTS. To avoid the gravelly substrates of the Shoals, this alternative traversed the identified Port Jefferson historic dredge disposal area and requires two crossings of the Flag Atlantic-1 North Trans-Atlantic fiber optic cable.

- **Route 4.** Route 4 is 23.5 miles in length and runs from the proposed FSRU southwest near the Long Island shoreline. Route 4 is the longest proposed pipeline alternative and comes in the closest to the Long Island shoreline.

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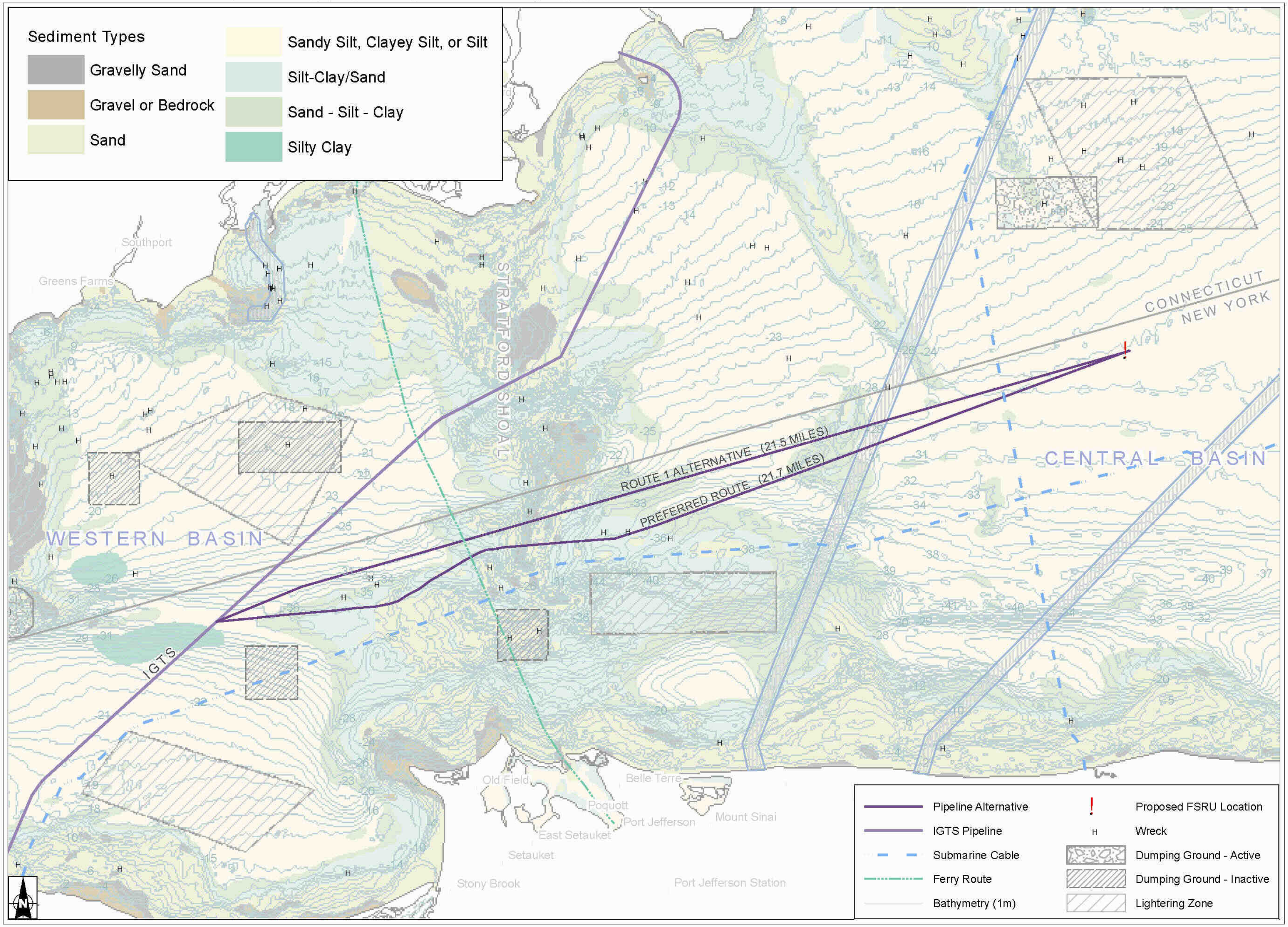
\\BUFSDL4\GIS\Pensacola\LNG\BROADWATER\Maps\MXD\Resource_Reports_Final\RR10\fig10-13 constraints with straight line(rte1).mxd 01/17/06



Source: Bathymetry/Sediments, U. S. Geological Survey Open-File Report OFR 00-304, 2000.
Marine Use, NOAA Electronic Nautical Charts 12354 and12363, 2004.

0 2.5 5 10
Miles

Figure 10-13 Route 1 Alternative

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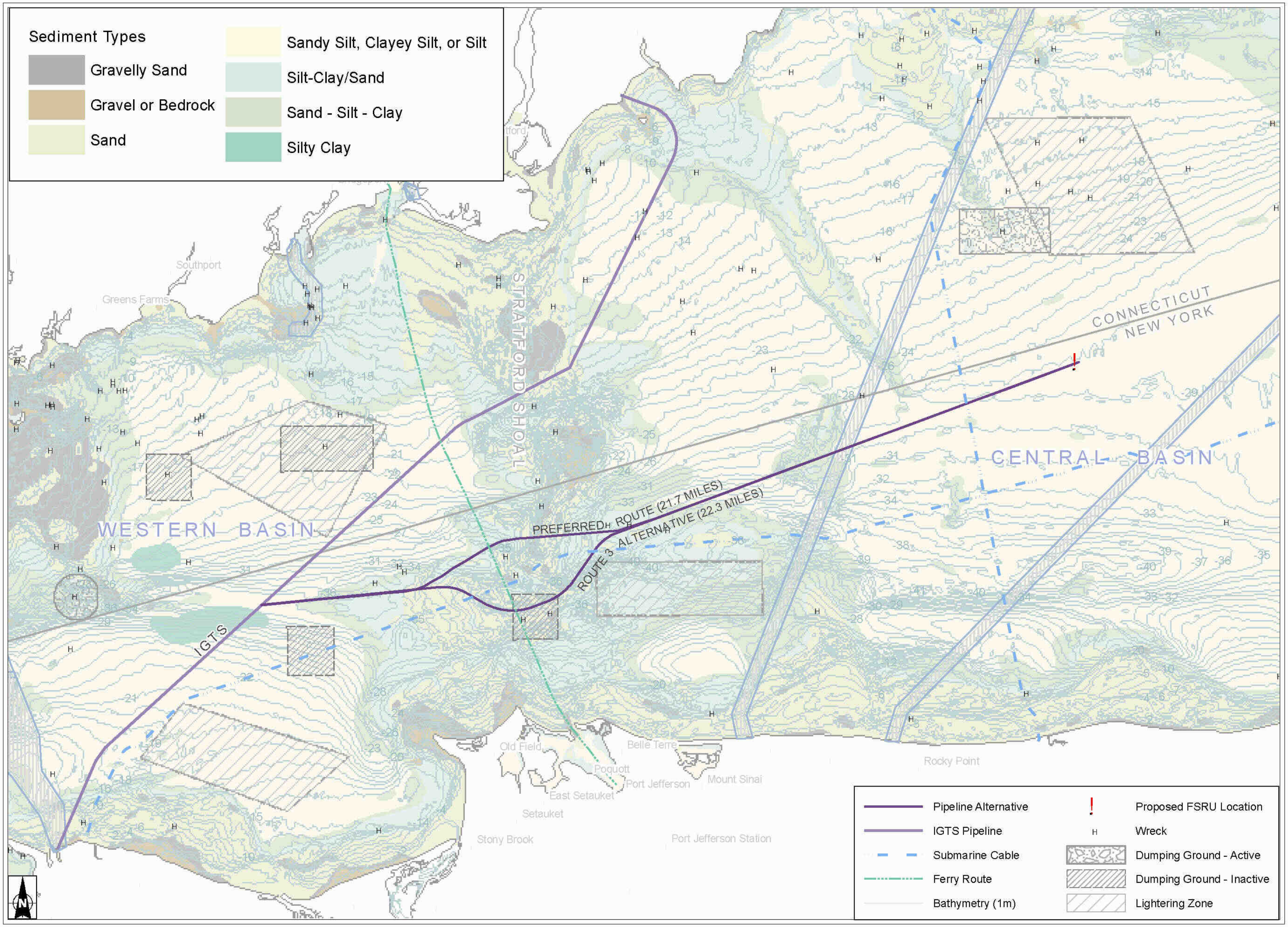
\\BUFSDL4\GIS\Pensacola\LNG\BROADWATER\Maps\MXD\Resource_Reports_Final\RR10\fig10-14 constraints with Port Jefferson line alt(rte 3).mxd 01/17/06



Source: Bathymetry/Sediments, U. S. Geological Survey Open-File Report OFR 00-304, 2000.
Marine Use, NOAA Electronic Nautical Charts 12354 and12363, 2004.

0 2.5 5 10
Miles

Figure 10-14 Route 3 Alternative

BW002506

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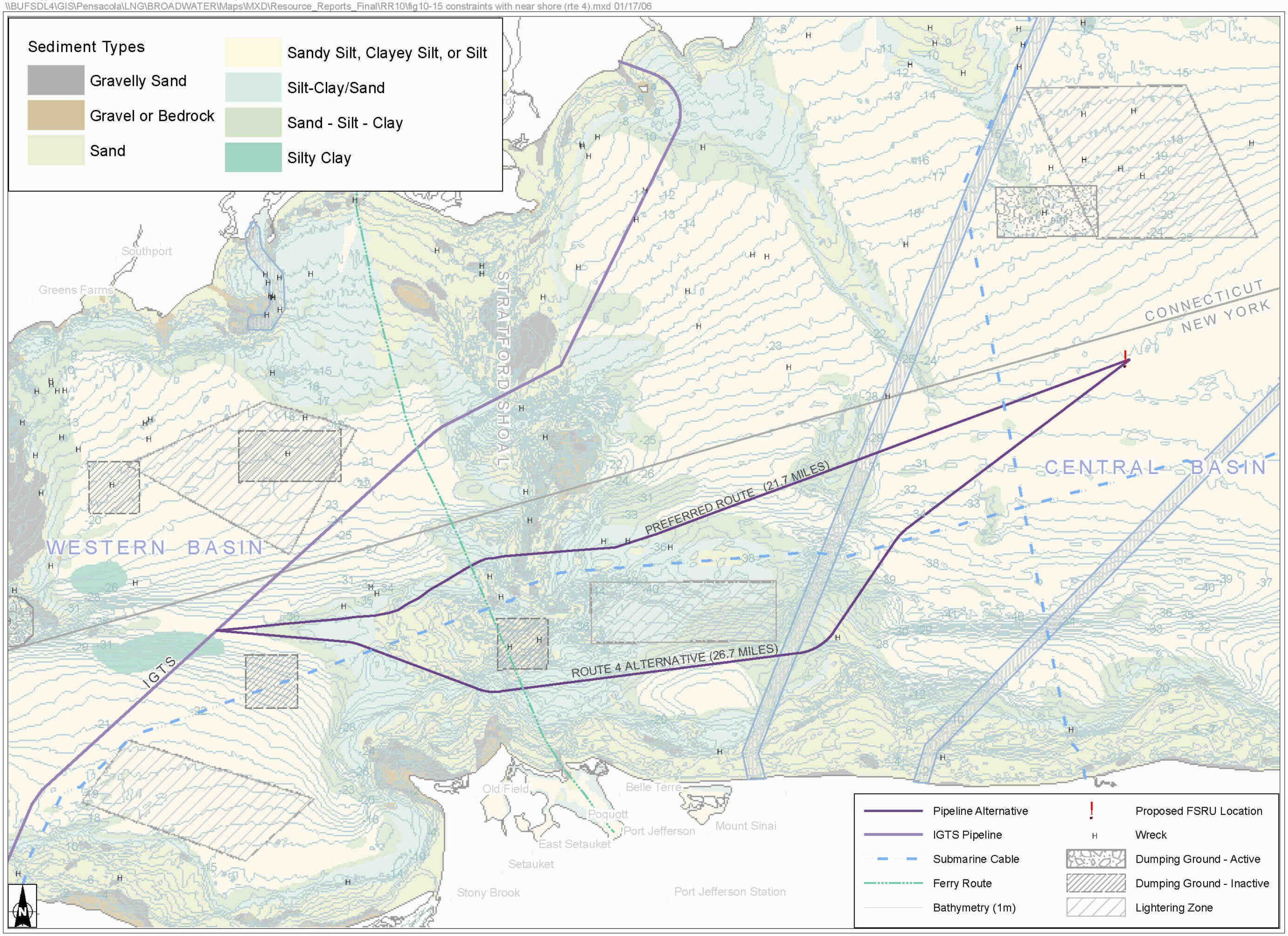
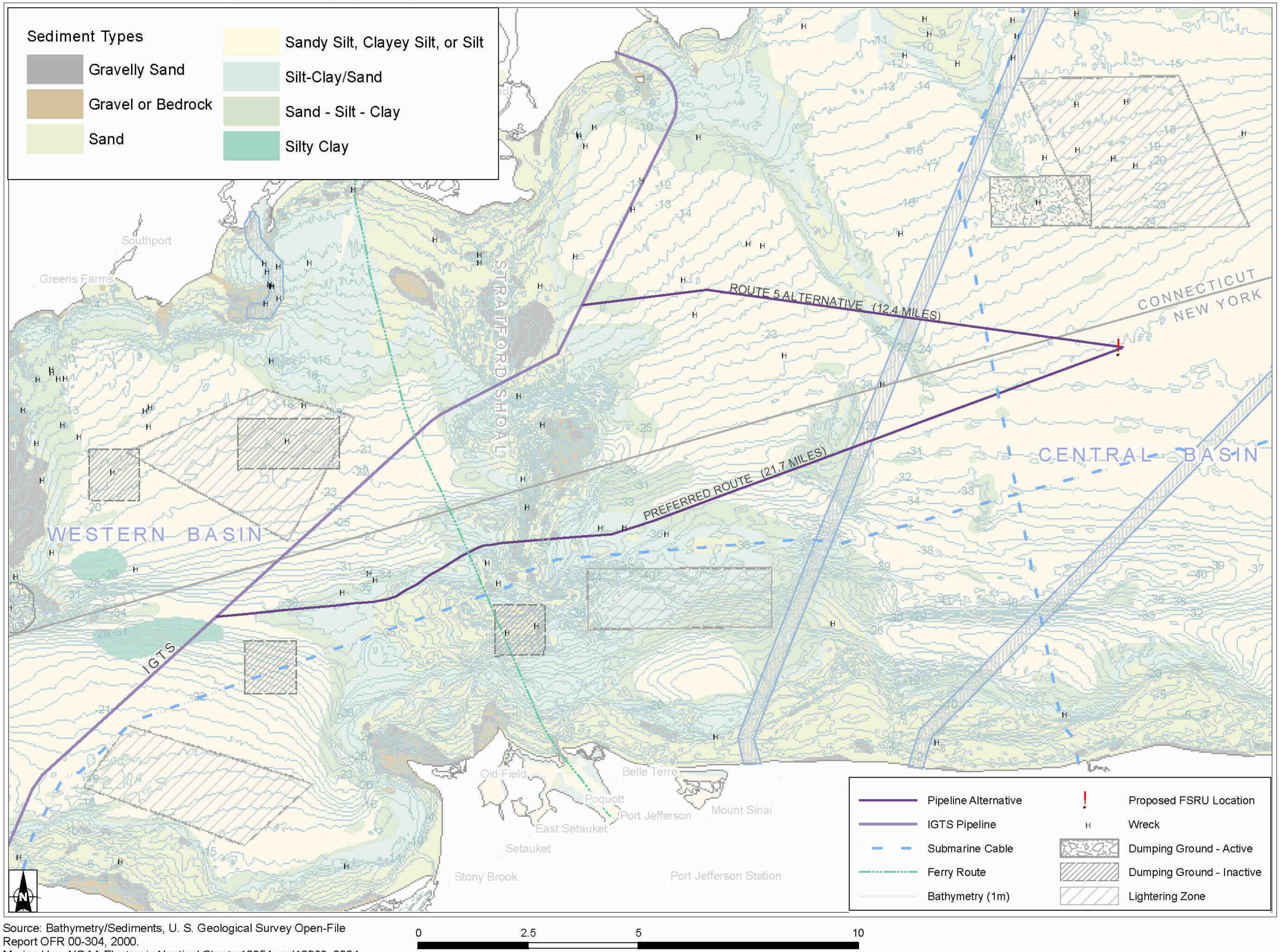
\\BUFSDL4\GIS\Pensacola\LNG\BROADWATER\Maps\MXD\Resource_Reports_Final\RR10\fig10-15 constraints with near shore (rte 4).mxd 01/17/06



Source: Bathymetry/Sediments, U. S. Geological Survey Open-File Report OFR 00-304, 2000.
Marine Use, NOAA Electronic Nautical Charts 12354 and12363, 2004.

Figure 10-15 Route 4 Alternative

BW002507



Source: Bathymetry/Sediments, U. S. Geological Survey Open-File Report OFR 00-304, 2000.
Marine Use, NOAA Electronic Nautical Charts 12354 and12363, 2004.

Figure 10-16 Route 5 Alternative

- **Route 5.** Route is 12.4 miles in length, runs from the FSRU northwest into Connecticut, and terminates at the IGTS in Fairfield County, Connecticut. Route 5 is the shortest proposed pipeline alternative and traverses closest to the Connecticut shoreline.

10.7.3.1 Subsea Pipeline Alternatives Analysis

The analysis and supporting tables below present a comparison of some of the key environmental and engineering considerations and conditions along the proposed marine pipeline routing alternatives that led to the selection of Route 2 as the preferred alternative. Alternative Routes 1 through 4 start at the FSRU site and end at the same location on the IGTS pipeline. Route 5, which is the shortest alternative, starts at the FSRU site but terminates at a tie-in with Iroquois that is located within Connecticut. Route 4 is located south of Route 2 and is the longest of all the routes. Route 1 is located to the north of the preferred alternative.

10.7.3.2 Route 1

Route 1 is the farthest route from either the Long Island or Connecticut shoreline, which at its closest point is 4.5 miles from Long Island. This route is slightly north of and 0.2 miles shorter than Route 2. Route 1 is the shortest New York alternative route from the FSRU. Although these routes run close to each other, there are some significant differences. The primary difference between the two routes is that Route 1 traverses portions of the Stratford Shoal Middle Ground that could require blasting for installation, while Route 2 crosses the Shoals farther to the south where gravels and sands predominate. This accounts for the differences in sediment types and bathymetry encountered. Route 1 is compared to Route 2 in more detail in Table 10-10 below.

Table 10-10 Comparison of Route 2 and Route 1

Parameter	Route 2	Route 1
Length (miles)	21.7	21.5
Nearest Distance to Shore (miles)	3.7	4.5
Bathymetry Depth (meters)	-18 to -39	-12 to -43
Submarine Cable Crossing	2	2
Within 1 mile of Inactive Dumping Sites	1	1
Within 1 mile of Lightering Area	1	0
Distances to Wrecks (within 1 mile)	9	6
Distance to Nearest Wreck (feet)	350	1215
Ferry Route Crossing	1	1
Sediment Types (miles traversed)		
Gravelly Sand	0.4	0.4
Sand	1.8	1.4
Sandy Silt, Clayey Silt, or Silt	8.7	8.8
Sand- Silt-Clay	4.9	9.1

Table 10-10 Comparison of Route 2 and Route 1

Parameter	Route 2	Route 1
Silt-Clay/Sand	6.0	1.8
Sediment Environments (miles traversed)		
Deposition	11.3	16.2
Erosion	1.7	2.4
Sorting	8.7	2.9

Source: USGS 2000; NOAA 2004a, 2004b.

Route 1 would require crossing a portion of the Stratford Shoals which, based on geophysical investigations, has shallow rock that may require blasting. Therefore, this route was not selected as the preferred route.

10.7.3.3 Route 3

Route 3 was identified as an option to avoid crossing the harder substrates of the Stratford Shoals altogether. Due to the presence of the FLAG Atlantic-1 North Trans-Atlantic fiber optic cable that runs on a general east-west trend through the Sound, this alternative could not be sited immediately to the south of the Stratford Shoals but, rather, requires that the routing be moved approximately one mile south to provide safe crossing of the cable. Because of this relocation farther to the south, Route 3 traverses an identified historic dredge disposal site offshore from Port Jefferson. While contacts with the USACE and United States Environmental Protection Agency (EPA) have not identified any specific recent dredge disposal activities that have utilized the area, it is identified and recognized on the National Oceanic and Atmospheric Administration (NOAA) navigation charts for Long Island Sound. The rerouting of this alternative to account for the two additional cable crossings adds approximately 0.6 miles in length to the pipeline, and results in the routing encroaching on a recognized shipping fairway toward Northport. Due to potential conflict with shipping lanes, the need for two additional cable crossings, and the uncertainty regarding contamination of the dredge disposal site, this route was not considered preferred. Route 3 is compared to Route 2 in more detail in Table 10-11 below.

Table 10-11 Comparison of Route 2 and Route 3

Parameter	Route 2	Route 3
Length (miles)	21.7	22.3
Nearest Distance to Shore (miles)	3.7	2.3
Bathymetry Depth (meters)	-18 to -39	-23 to -59
Submarine Cable Crossing	2	4
Within 1 mile of Inactive Dumping Sites	1	2 (1 transects)
Within 1 mile of Lightering Area	1	1
Distances to Wrecks (within 1 mile of)	9	9

Table 10-11 Comparison of Route 2 and Route 3

Parameter	Route 2	Route 3
Distance to Nearest Wreck (feet)	350	504
Ferry Route Crossing	1	1
Sediment Types (miles traversed)		
Gravelly Sand	0.4	0
Sand	1.8	4.1
Sandy Silt, Clayey Silt, or Silt	8.7	8.7
Sand- Silt-Clay	4.9	4.9
Silt-Clay/Sand	6.0	4.5
Sediment Environments (miles traversed)		
Deposition	11.3	10.8
Erosion	1.7	4.5
Sorting	8.7	7.0

Source: USGS 2000; NOAA 2004a, 2004b.

10.7.3.4 Route 4

Route 4 was evaluated against Route 2 for several significant parameters. Route 4 is the longest alternative being considered since a straight-line approach is not possible while avoiding identified marine obstructions. Route 4 runs to the south of Route 2, closer to the Long Island shoreline in order to avoid a large lightering area. The nearshore alternative also requires two additional crossings of buried cables. A significant difference between the two alternatives is the bathymetry encountered and the number of wrecks within one mile of the projected pipeline routes. Route 4 would be constructed in much shallower waters for portions of the route, potentially impacting more sensitive nearshore marine habitats. At its nearest point Route 4 is approximately 1.2 miles from the New York shoreline. Along Route 2, nine wrecks are within one mile, whereas Route 4 only encounters one wreck within one mile, which is 805 ft from the pipeline. Route 4 is compared to Route 2 in more detail in Table 10-12 below.

Table 10-12 Comparison of Route 2 and Route 4

Parameter	Route 2	Route 4
Length (miles)	21.7	23.5
Nearest Distance to Shore (miles)	3.7	1.2
Bathymetry Depth (meters)	-18 to -39	-12 to -43
Submarine Cable Crossing	2	4
Within 1 mile of Inactive Dumping Sites	1	2
Within 1 mile of Lightering Area	1	1
Distances to Wrecks (within 1 mile of)	9	1

Table 10-12 Comparison of Route 2 and Route 4

Parameter	Route 2	Route 4
Distance to Nearest Wreck (feet)	350	805
Ferry Route Crossing	1	1
Sediment Types (miles traversed)		
Gravelly Sand	0.4	0
Sand	1.8	2.30
Sandy Silt, Clayey Silt, or Silt	8.7	9.51
Sand- Silt-Clay	4.9	5.40
Silt-Clay/Sand	6.0	6.29
Sediment Environments (miles traversed)		
Deposition	11.3	11.0
Erosion	1.7	1.60
Sorting	8.7	10.9

Source: USGS 2000; NOAA 2004a, 2004b.

Broadwater did not select Route 4 as the preferred alternative due it its longer length, additional cable crossings, and proximity to the Long Island shoreline, which could result in greater nearshore impacts to marine resources.

10.7.3.5 Route 5

As discussed in Section 10.6.2, siting the FSRU in Connecticut waters offers no advantages over the FSRU's proposed location in New York waters of Long Island Sound based on socioeconomic, environmental, and engineering considerations; therefore, it would not be reasonable to pursue options for siting the FSRU in Connecticut waters. It is, however, reasonable to consider an alternative pipeline route from the proposed FSRU terminal site to the IGTS pipeline located partly in Connecticut waters, as this would provide for the shortest possible route owing to the location and orientation of the IGTS pipeline crossing of Long Island Sound relative to the preferred FSRU location.

Route 5 is the shortest possible route from the proposed FSRU terminal site to any location along the IGTS at 12.4 miles. The primary differences between Route 5 and the preferred alternative is the length of the route and the jurisdictions entered. Route 5 is 9.3 miles shorter than Route 2. Additionally, Route 5 starts at the FSRU location in Suffolk County, New York, proceeds on a northwesterly direction into New Haven County, Connecticut, and terminates at the IGTS in Fairfield County, Connecticut. The tie-in at the IGTS is the closest location on the route to the Connecticut shoreline. Route 5 intersects with two cable crossings but does not cross the ferry route or come within 1 mile of a dumpsite or lightering zone. The route passes through shallower water than the other alternatives, with the deepest depths encountered being -105 ft (-32 m). Route 5 comes within 1 mile of only two wrecks, the closest of which is 0.28 mile (0.45

km) from the proposed pipeline route. Because of its apparent preference based strictly on pipeline length, Route 5 required the most detailed environmental evaluation to assess its potential impacts.

Three primary environmental and socioeconomic considerations were identified in conjunction with Route 5 that lead to a conclusion that Route 2 is the preferred alternative: (1) potential sediment contamination; (2) proximity to shore and shellfishing beds; and (3) potential commercial shipping impacts.

The proposed IGTS interconnect for Route 5, and for any potential tie-in in Connecticut waters north of the Stratford Shoal Complex, is located in Long Island Sound waters influenced by Housatonic River discharges. The Housatonic River, which has been highly industrialized, is one of the primary freshwater sources into the Sound. Due its historic utilization for industrial purposes, significant contamination was been discharged from the river. The inshore waters of Connecticut are generally recognized as being influenced by the urbanization in larger cities such as New Haven and Bridgeport.

The United States Geological Survey (USGS) has evaluated the sediments for the entire Sound with sediment samples collected between 1996 and 2000, and it has developed an extensive database of contamination levels throughout the Sound. A subset of data from this larger data set was evaluated to compare levels of contaminant concentrations along Route 2 and Route 5. The USGS sediment sample results evaluated are presented in Figures 10-17 through 10-23, which show graduated levels of contamination for six different metals and the bacteria clostridium using color-coding to indicate contaminant ranges. As is apparent from these figures, areas of the Sound immediately offshore of urban areas, including New Haven, tend to function as sinks for contamination being discharged from onshore and upriver facilities.

Individual sample locations 29-01, 30A-01, and 27-02 were evaluated based on their proximity to the potential IGTS tie-in location along Route 5 as shown in Figure 10-24. These samples exhibit higher concentrations of heavy metals including chromium, copper, lead, mercury, nickel and zinc along a greater percentage of Route 5 when compared to the sediments along Route 2. The sample concentrations are shown in more detail in Table 10-13 below. Sediment metal concentrations along Route 5 exceed the ecological guidance value for the Effects Range Low utilized by the New York State Department of Environmental Conservation for evaluating marine and estuarine sediments for negative effects[3]. Based on the USGS data set, it is clear that the sediments along Route 5 exhibit higher levels of metals contamination than the sediments along Route 2. While these elevated metals concentrations do not preclude construction of the pipeline, by avoiding areas of higher contamination, impacts can be minimized. The closer proximity of Route 5 to coastal areas and shellfish beds presents a greater potential for transport of contamination via sediment dispersion to these areas.

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[3] Guidance values used for comparison to sediment contaminant concentrations were Effects Range Low (ER-L) and Effects Range Median (ER-M) which are utilized by state and federal agencies as aquatic sediment guidelines including USGS (the source of the contaminant data) and NYSDEC. CTDEP guidance values for aquatic sediment are not available.

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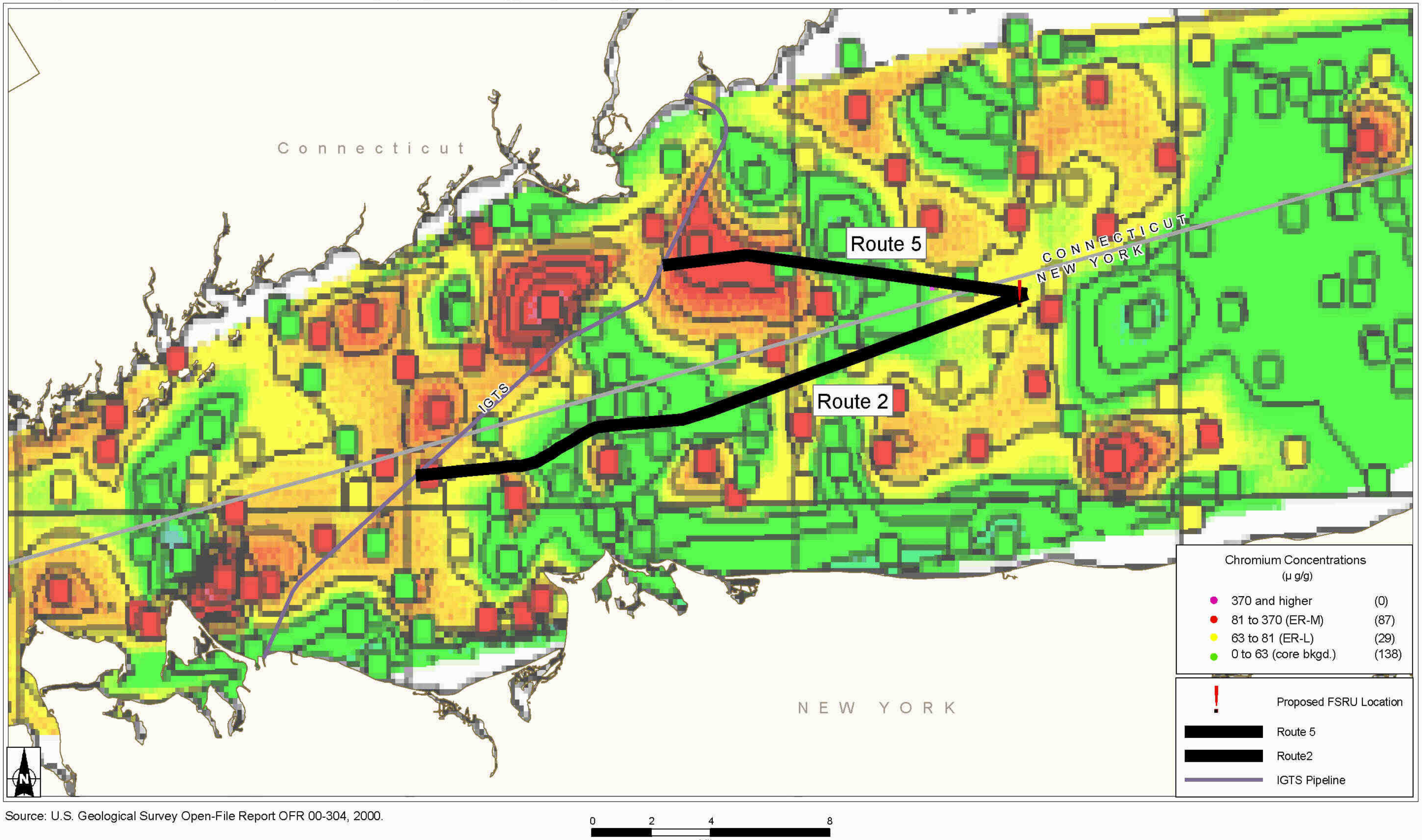
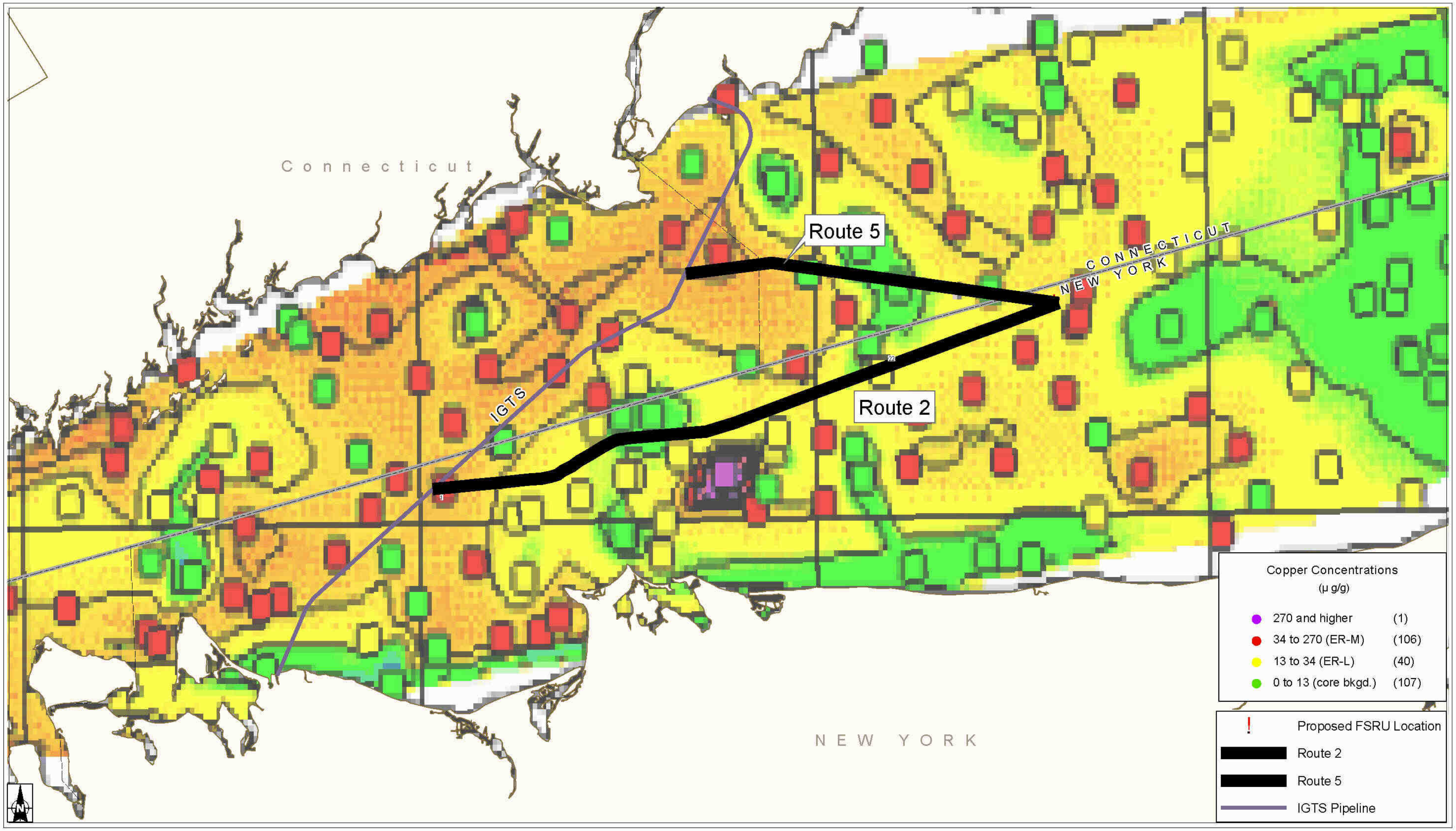


Source: U.S. Geological Survey Open-File Report OFR 00-304, 2000.

Figure 10-17 Chromium Concentrations Within Long Island Sound



Source: U.S. Geological Survey Open-File Report OFR 00-304, 2000.

0 2 4 8
Miles

Figure 10-18 Copper Concentrations Within Long Island Sound

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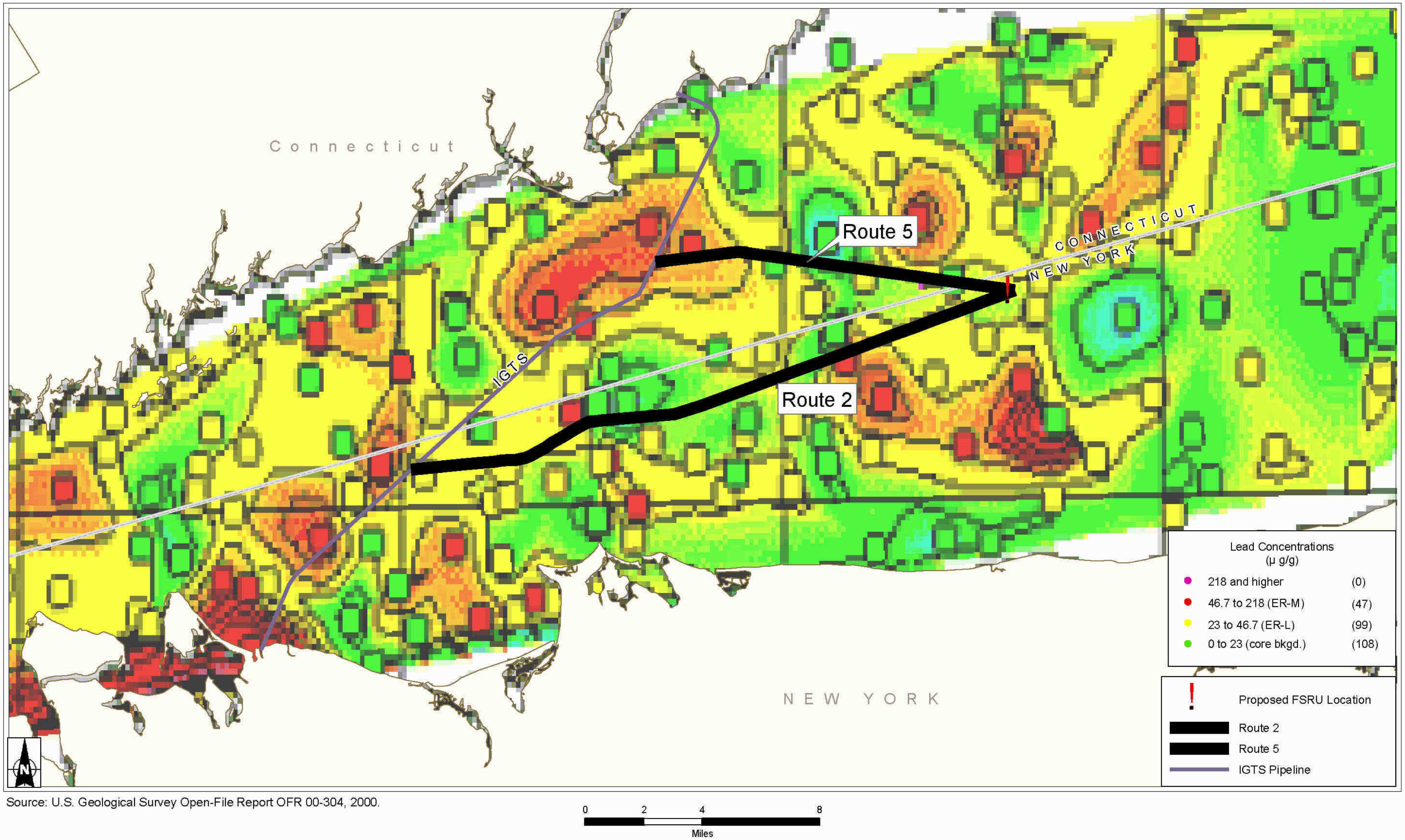
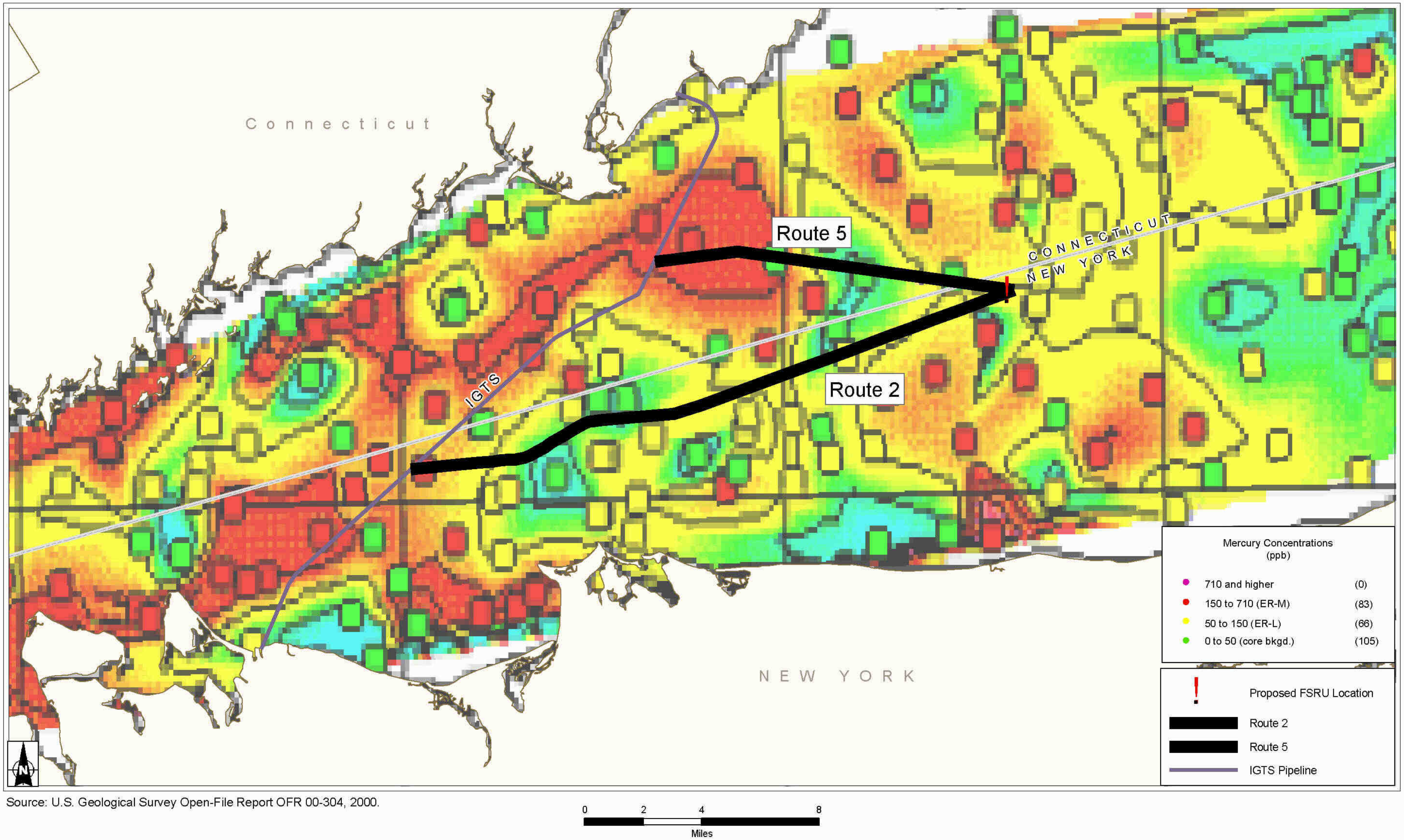


Source: U.S. Geological Survey Open-File Report OFR 00-304, 2000.

Figure 10-19 Lead Concentrations Within Long Island Sound



Source: U.S. Geological Survey Open-File Report OFR 00-304, 2000.

Figure 10-20 Mercury Concentrations Within Long Island Sound

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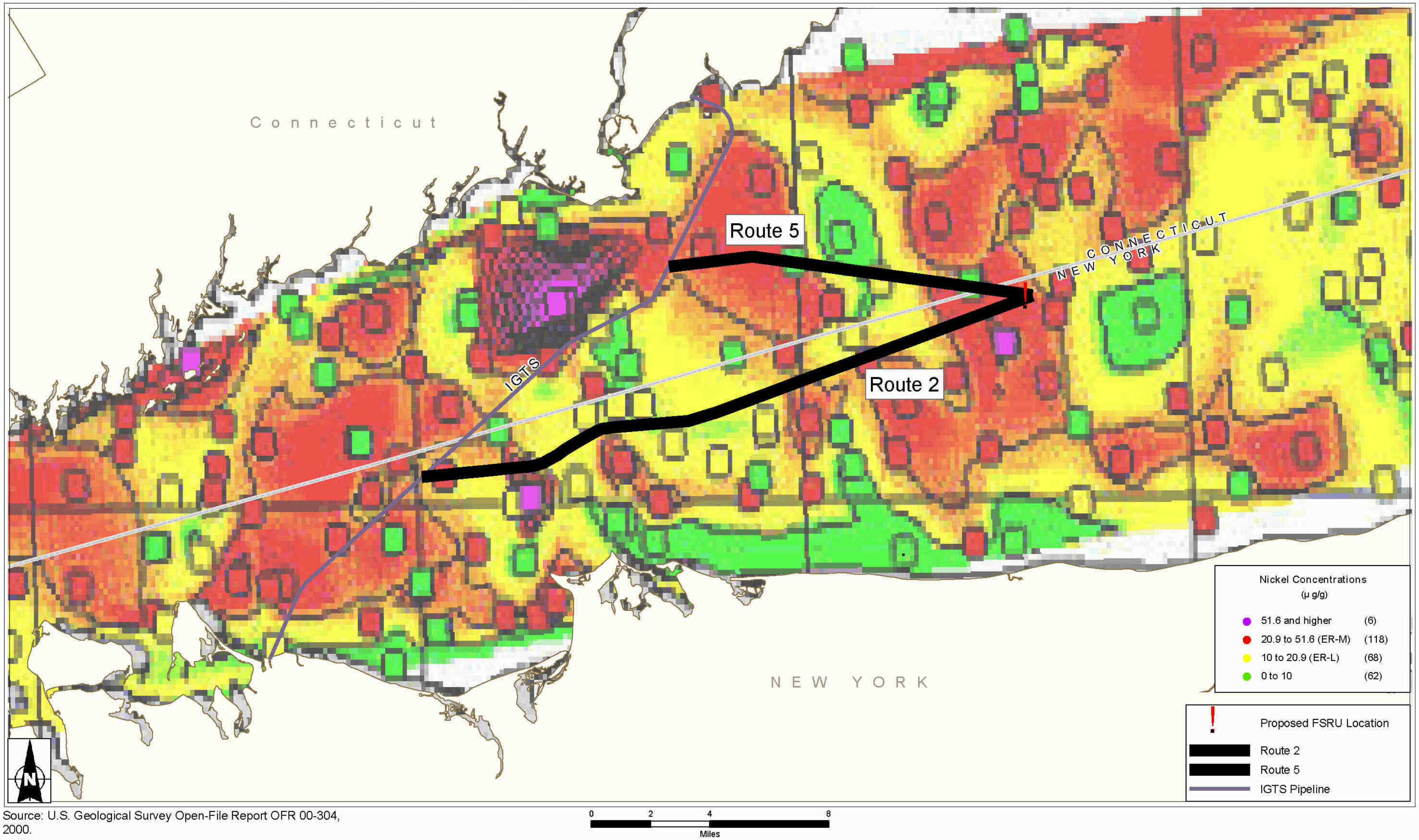

Source: U.S. Geological Survey Open-File Report OFR 00-304, 2000.

Figure 10-21 Nickel Concentrations Within Long Island Sound

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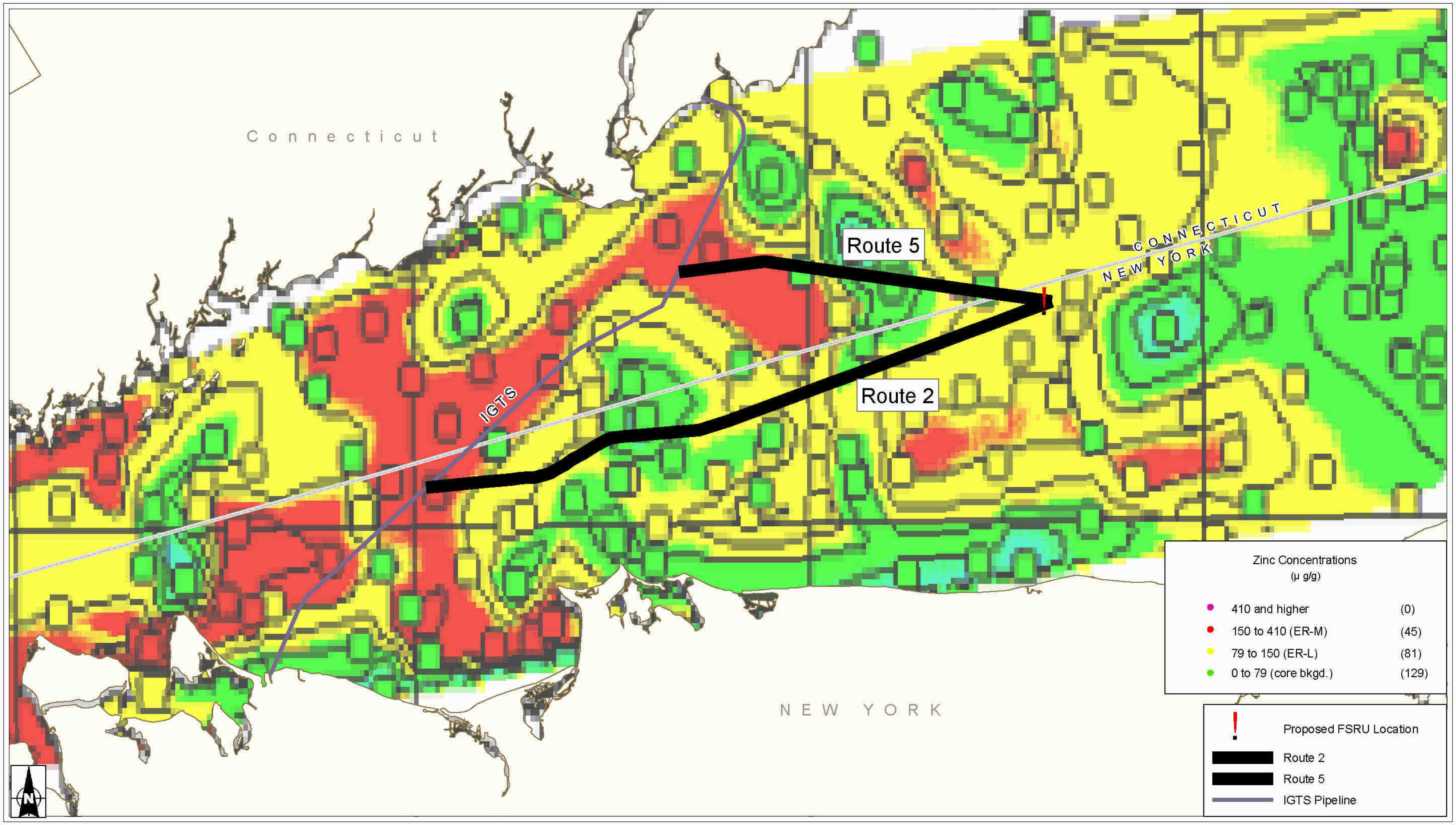


Source: U.S. Geological Survey Open-File Report OFR 00-304, 2000.

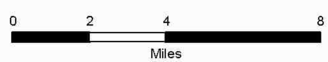
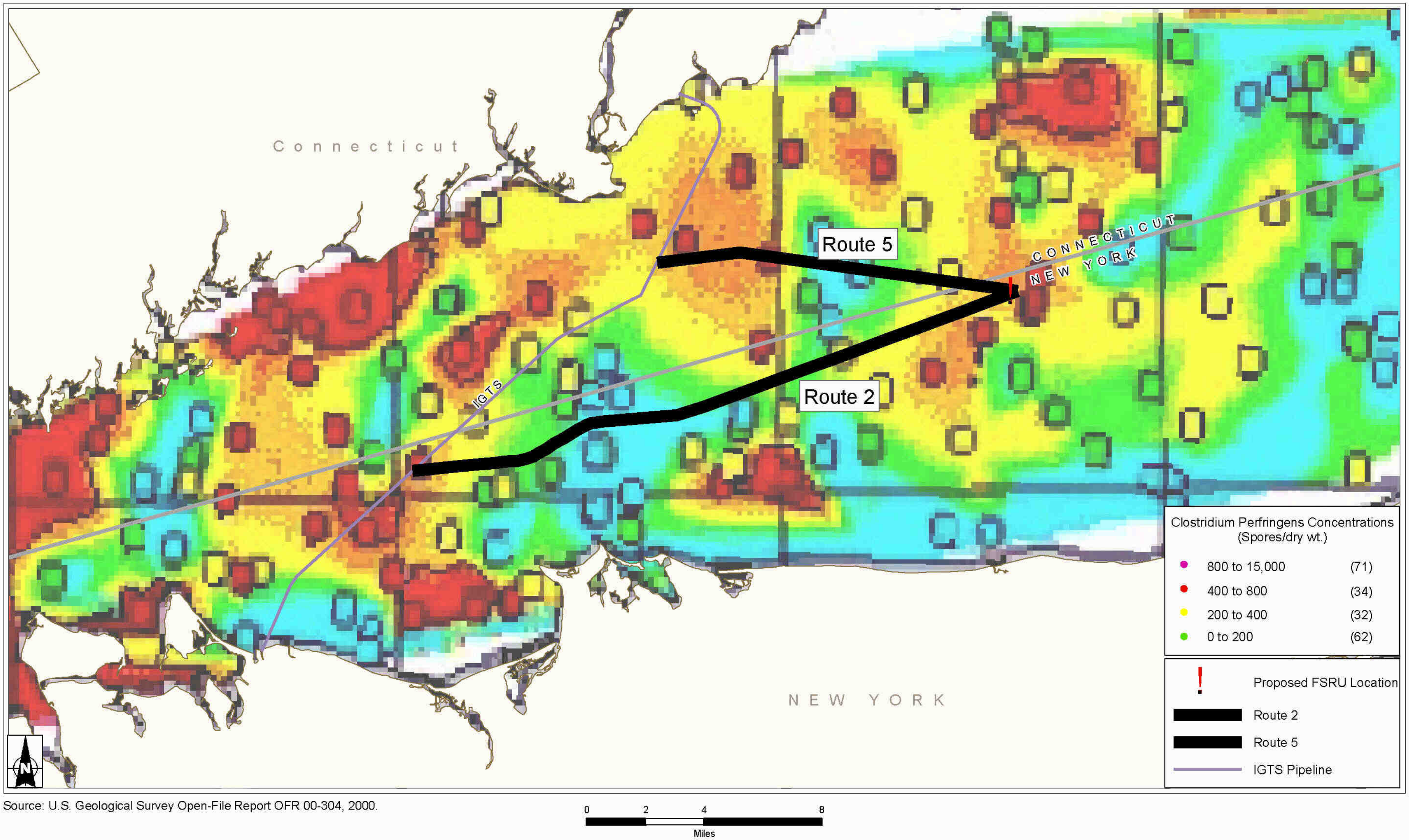


Figure 10-22 Zinc Concentrations Within Long Island Sound



Source: U.S. Geological Survey Open-File Report OFR 00-304, 2000.

Figure 10-23 Clostridium Perfringens Within Long Island Sound

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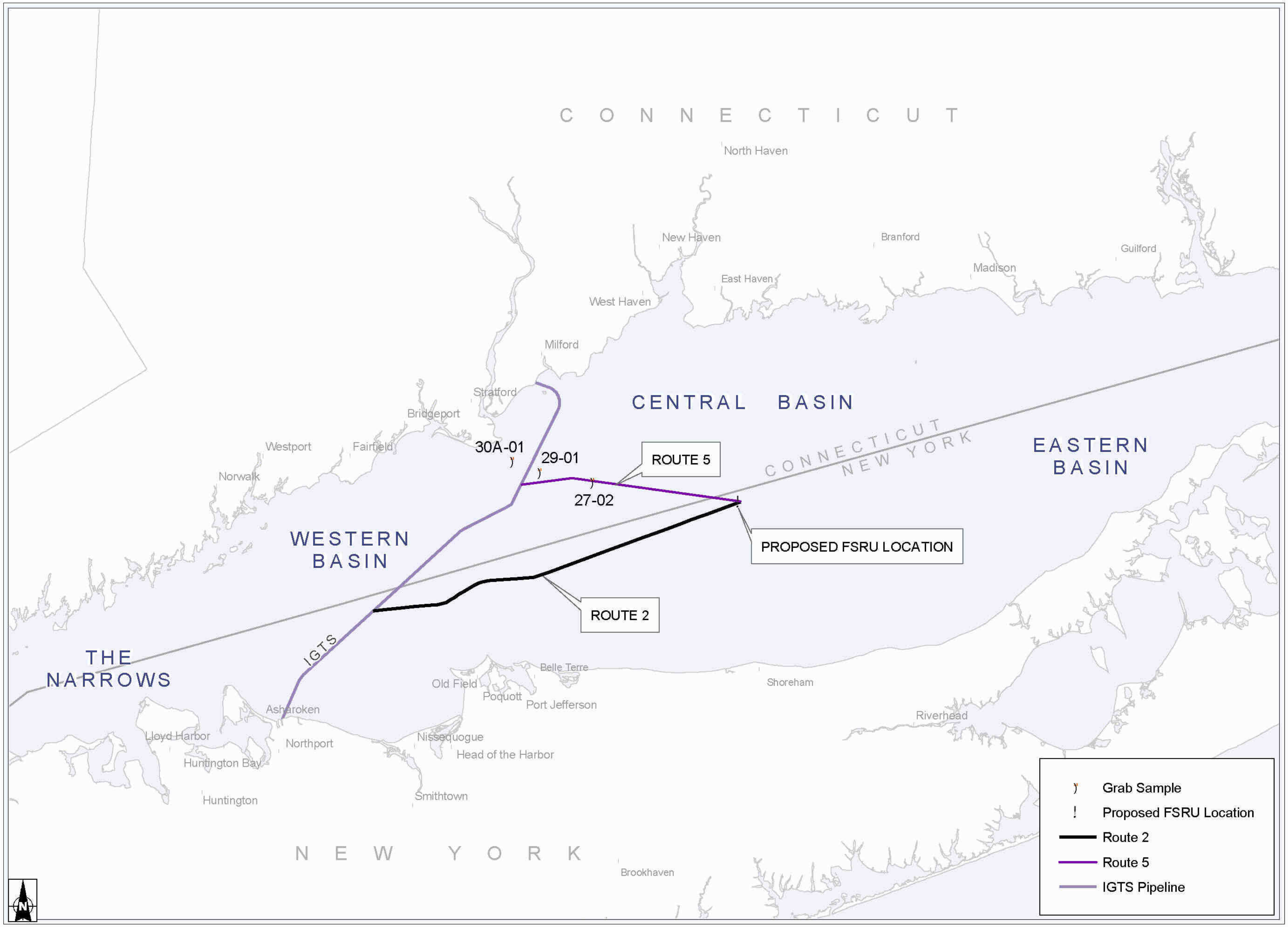

Source: U. S. Geological Survey Open-File Report OFR 00-304, 2000.

0 2.5 5 10
Miles

Figure 10-24 USGS Grab Samples Analyzed for Metal Concentrations in Long Island Sound

BW002521

Table 10-13 USGS Sediment Concentrations Along Route 5

Contaminant	Sediment Screening Value		USGS Sample Locations		
	ERL	ERM	29-01	30A-01	27-02
Chromium	81	370	154	94	134
Copper	34	270	89	84	62
Lead	46.7	218	62	74	45
Mercury	0.15	0.71	250.8	234.6	238.5
Nickel	20.9	51.6	34	31	34
Zinc	150	410	168	161	158

Source: USGS 2000.
Sediment Screening Value: Long, E. R. et al 1995.
(ERL = Effects Range Low, ERM = Effects Range Median)

Sediment samples have also been collected for other projects in Long Island Sound in the vicinity of Route 5. This includes sediment samples collected for the Biological Assessment (BA) for the Iroquois Gas Transmission System: East Long Island Extension. Sediments collected from eight Connecticut sample stations were analyzed for inorganic and organic constituents. Results were compared to the New York State Department of Environmental Conservation's (NYSDEC's) ER-L and ER-M criteria for evaluating contaminated marine sediments. Exceedances of the NYSDEC ER-L criteria for inorganics included arsenic, copper, mercury, and nickel. Polycyclic aromatic hydrocarbons (PAHs) and polychlorinated biphenyls (PCBs) also were detected at each sample location, and exceedances of the NYSDEC ER-L criteria for organics occurred for p,p'-DDD at one station. None of the samples exceeded the NYSDEC ER-M criteria.

Broadwater also performed a site-specific field sampling effort in April 2005 to collect sediment core data along the preferred alternative Route 2 to evaluate any potential sediment contamination that may be present along the actual pipeline route to the depth of pipeline installation. Data collected as part of the sampling effort included positive results for metals in sediment samples. However, when compared to NYSDEC ER-L and ER-M criteria for marine sediments, there were no exceedances of any criteria. Dioxins, PAH, PCBs and pesticides were also evaluated as part of the sampling effort but were not detected in any samples (*see* Resource Report 2, Water Use and Quality).

The sediment data trends are an important factor in the alternatives evaluation since all other historical data sets collected along Route 5 and near the Connecticut shoreline exhibits exceedances of ecological screening criteria for metals and some level of contamination for other constituents including PAH, PCBs and pesticides. Exceedance of sediment criteria would lead to a greater impact on water quality, benthic communities and fish species during pipeline installation if Route 5 were the preferred alternative due to the disturbance of contaminated sediments and the introduction of these contaminants into the water column.

Other concerns for Route 5 include the level of vessel traffic in this area on approach to the Connecticut shoreline during pipeline installation. Foreign commercial shipping in the area of Route 5 mainly involves vessels arriving and departing the ports of Bridgeport and New Haven, Connecticut since these ports can support deeper draft vessels. These are the busiest ports along the Connecticut coastline with the greatest number of total arrivals for vessels, including barges and freight ships, based on data provided by the USCG for 2003-2005 Vessel Arrivals. With this level of vessel traffic, commercial shipping activity would likely be interrupted during installation of the pipeline along Route 5.

Broadwater did not select Route 5 as the preferred alternative based on the sediment contamination present in this area (*see* Table 10-12), number of cable crossings and closer distance to shore, which could result in greater impacts to marine and coastal resources. Route 5 is compared to Route 2 in more detail in Table 10-14 below.

Table 10-14 Comparison of Route 2 and Route 5

Parameter	Route 2	Route 5
Length (miles)	21.7	12.4
Nearest Distance to Shore (miles)	3.7	2.7
Bathymetry Depth (meters)	-18 to -39	-12 to -32
Submarine Cable Crossing	2	2
Within 1 mile of Inactive Dumping Sites	1	0
Within 1 mile of Lightering Area	1	0
Distances to Wrecks (within 1 mile of)	9	2
Distance to Nearest Wreck (feet)	350	0.28 mi.
Ferry Route Crossing	1	0
Sediment Types (miles traversed)		
Gravelly Sand	0.4	0
Sand	1.8	0.39
Sandy Silt, Clayey Silt, or Silt	8.7	9.99
Sand- Silt-Clay	4.9	1.66
Silt-Clay/Sand	6.0	0.33
Sediment Environments (miles traversed)		
Deposition	11.3	11.2
Erosion	1.7	0
Sorting	8.7	11.4

Source: USGS 2000; NOAA 2004a, 2004b.

In addition to the environmental considerations, an interconnection with the IGTS system as shown for Route 5 would result in a decrease in the hydraulic capability to maximize deliveries to the New York City and Long Island markets. While Route 5 would result in a shorter pipeline to the IGTS interconnect point, this point would be considerably further north than the interconnect point for Route 2. Table 10-15 summarizes the relative lengths from the FSRU location to the IGTS Hunts Point meter station (in New York City) and to the South Commack meter station on Long Island. It is apparent from the table that while the total distances traversed are similar, gas flows must pass through a higher proportion of 24-inch pipeline for the Route 2 alternative. For the path to the Hunts Point meter station, gas flows must pass through an additional 11.2 miles of 24-inch pipeline. The same is true for the South Commack meter station.

Table 10-15 Pipeline Route Length Comparison

		Route 2 (NY)		Route 5 (CT)	
Segment	Pipeline Diameter	Pipeline Length (miles)	% of Route Length	Pipeline Length (miles)	% of Route Length
FSRU to IGTS Hunts Point M/S (New York)	30"	21.7	33%	12.4	18%
	24"	45.0	67%	56.2	82%
	Total	66.7	100%	68.6	100%
FSRU to IGTS South Commack M/S (Long Island)	30"	21.7	56%	12.4	31%
	24"	17.1	44%	28.2	69%
	Total	38.8	100%	40.6	100%

As a result of the gas having to be transported a greater distance in a smaller diameter pipeline, there is a greater pressure drop for the Route 5 alternative compared to Route 2. For example, in the case of deliveries to the Hunts Point meter stations, the gas would have to travel an additional 11.2 miles through the smaller 24-inch Iroquois pipeline. As a result of the greater pressure drop in the Route 5 alternative, the ability to deliver gas volumes to either the Hunts Point or South Commack meter stations using the Route 5 alternative is significantly reduced compared to the Route 2 alternative. Broadwater's hydraulic analysis of the Iroquois system indicates that, based upon a terminal delivery pressure of approximately 1440 psi, there would be a 36% reduction in the physical delivery capability to the Hunts Point meter station under the Route 5 alternative, compared to the Route 2 alternative. Similarly, the physical delivery capability to the South Commack meter station would be reduced by 42%.

These results are based upon the physical delivery capability provided from the FSRU without any added facilities on the Iroquois system while accommodating both forecast IGTS transportation contracts and incremental flow from the Project. Broadwater's hydraulic analysis of the Iroquois system suggests that for the Route 5 alternative to match the physical delivery capability of the Route 2 alternative, approximately 20 miles of 24-inch subsea pipeline loop, as well as approximately 11,500 horsepower of additional compression would be required at the Northport meter station site on Long Island. These additional facilities would result in a substantial additional environmental impact that can be avoided by selecting the Route 2 alternative.

10.7.4 Recommended Route

Based on all evaluation criteria considered to date, a thorough comparison of the factors that affect routing, and the results of the geotechnical and geophysical surveys, Route 2 is the preferred pipeline route alternative.

10.7.5 Summary

The selected primary configuration of Sub-Block 1 and Route 2 for the FSRU location and the pipeline, respectively, is attributed to certain factors, which include:

- The preferred sub-block and route are favored with regard to the reduced proximity to populations and areas of intense marine activities, reduced complexity in the construction and operation of the pipeline, and reduced proximity to sensitive environmental resources;

- By establishing the Project in the central portion of the Sound, the Project is largely avoiding the inshore areas that support a significant shellfishery;

- The use of FSRU technology provides greater flexibility in siting of the LNG facility;

- The FSRU would be placed near the designated shipping routes for access by LNG carriers;

- The FSRU would be located in the central portion of the Sound where deeper waters are present, resulting in reduced local current velocities and, therefore, more reliable operations;

- The FSRU would be located in an area with adequate water depth for providing sufficient operational safety margins;

- The bottom topography in the preferred sub-block is suitable for the location of the FSRU;

- The preferred sub-block is located approximately nine miles from the nearest shore, which maximizes the safety buffer for onshore locales;

- The preferred sub-block and route are not impacted by lightering zones and dumping grounds;

- By locating the FSRU and pipeline well offshore, the respective reduction in potential impact to adjacent communities in terms of noise and visual resources would be a realized benefit;

- The preferred sub-block and pipeline route are implementable from a regulatory standpoint; and

- The preferred pipeline route reduces the number of crossings of third-party communication and power cables.

Through the iterative process developed for this alternatives analysis, supported by extensive field surveys, the selection of Sub-Block 1 and the associated subsea pipeline Route 2 represent Broadwater's preferred alternatives for location of the FSRU and the route of the pipeline.

10.8 LNG TERMINAL EQUIPMENT/TECHNOLOGY ALTERNATIVES

Following the selection of the FSRU as the preferred alternative, Broadwater also evaluated equipment/technology that would be used onboard the FSRU for consistency with the criteria listed in Section 10.2. The results of Broadwater's analysis are presented below.

10.8.1 Proposed Vaporization Technology Alternatives

Four vaporization technologies were evaluated:

- Submerged Combustion Vaporization (SCV);
- Seawater-Warmed Vaporization;
- Shell and Tube Vaporization (STV); and
- Air-Warmed Vaporization, where ambient air temperature heats the LNG.

Broadwater determined that both SCV and STV vaporization technologies would require primary and secondary air pollution control technology to reduce emissions to levels consistent with state requirements for Suffolk County. Broadwater chose STV technology as the most suitable technology based on its capability to be equipped with effective emission control devices to lower air emissions to levels consistent with state requirements.

A description of all vaporization technologies considered is provided below.

10.8.1.1 Submerged Combustion Vaporization

SCV technology vaporizes LNG as it passes through a heat exchanger submerged in a water bath. In the SCV, natural gas is burned to produce heat for the water bath such that the water bath is maintained at temperatures between 60°F and 105°F. The exhaust gas from the combustion process is bubbled through a fresh water basin or bath by which the heat from the gases is transferred to the water. LNG is then routed through a matrix of stainless steel coils which are immersed in the bath. The LNG is hence vaporized by the removal of heat from the water. The water therefore acts as an intermediate heat transfer fluid. Waste heat from the gas turbine exhausts may also contribute to the water heating process, by water system circulation and providing approximately 10% of the total heating duty.

SCVs are a reliable, widely used, and proven technology with high thermal efficiency (up to 98%) due to the direct exhaust gas quench, which also condenses most of the water from products of combustion. SCVs typically consume approximately 1.5% of the send-out natural gas from the terminal and use electricity to run air blowers.

Since water is also a natural product of combustion, this is condensed during water bath bubbling and the SCV becomes a net producer of water. For an average send-out of 1.0 bcfd, the SCV system would produce approximately 173,000 gallons of combustion water per day. This water is clean, but slightly acidic and would require caustic treatment before discharging overboard.

From an air emissions perspective and without emissions control systems being applied, exhaust NO_X and CO content is comparatively high at 40 ppm and 80 ppm respectively. SCVs do, however, have a high global or overall efficiency when operated in this condition.

Emission control systems can be applied to SCVs such that NO_X emissions can be reduced by 90%, however the resultant emissions remain comparatively high compared to STVs and the SCV system efficiency advantage is lost, since the exhaust gas requires additional energy input in order to treat it for NO_X removal.

SCV technology is currently in use at LNG terminal facilities at Elba Island, Georgia, and Lake Charles, Louisiana, and is approved for use at the Cameron LNG project located near Hackberry, Louisiana.

10.8.1.2 Seawater-Warmed Vaporization

Seawater may be used as a heat source for LNG vaporization, through a process known as open-rack vaporization (ORV). The volume of seawater required for this technology is a function of the allowable decrease in seawater temperature. If seawater temperature is above approximately 63°F degrees, seawater can typically serve as the sole vaporization technology for a terminal. However, when seawater temperatures drop to between 50°F and 63°F, supplemental heat is typically required.

Seawater vaporization is widely used at LNG terminal facilities and was approved for the Port Pelican and Gulf Landing offshore deepwater LNG terminals in the Gulf of Mexico and is proposed for use by the Pearl Crossing offshore deepwater LNG terminal in the Gulf of Mexico.

It should be noted that the NOAA Fisheries Department (NOAA Fisheries) opposes use of seawater-warmed vaporization technology based on concerns with potential impacts on aquatic species. Agency technology preference and data collection considerations, along with the relatively cool water temperature in the Long Island Sound, precluded Broadwater from further consideration of this technology. Use of ORVs on the Broadwater FSRU would also require the operation of other supplemental heating methods for those periods from late fall to early spring when the water temperatures in the Sound would not be sufficient to support ORV usage.

10.8.1.3 Shell and Tube Vaporization

STV vaporization technology involves a heat exchanger in which tubes containing LNG pass through a counter-current of heat exchange medium, such as a water-glycol solution. Due to the lower thermal efficiency of the gas-fired heaters (85% to 90%), STVs consume slightly more fuel of the send-out natural gas from the terminal) than SCV technology. STVs are heated by the combustion of natural gas and, therefore, produce air emissions, particularly NO_X. To address this issue, Broadwater has selected SCR technology to reduce the emissions from STVs. When combined, these technologies provide superior emissions control with a comparable thermal efficiency. Table 10-16 provides a comparison of the thermal efficiencies and emission rates.

Table 10-16 Technical Comparison of SCV and STV Vaporization

	SCV	STV	SCV with SCR	STV with SCR
Thermal efficiency (%)	99%	93%	91%	91%
Global efficiency (%)	96%	92%	89%	90%
NO_x emissions (ppmv)	40	15	4	2.5
CO emissions (ppmv)	80	50	10	5

STV technology will be used in the recently approved Vista del Sol LNG Terminal in San Patricio County, Texas. 111 FERC ¶ 61,432 (2005). STV technology was approved for terminal because it is a “reliable, widely used, and proven technology” that can be “constructed with effective and proven emission control devices to reduce air emissions….” (Vista del Sol LNG Terminal Final Environmental Impact Statement, Docket No. CP04-395, at 3-20).

10.8.1.4 Air-Warmed Vaporization

Under this technology, ambient air heated vaporizers, in either a natural draft mode or a forced draft mode, would be used to vaporize LNG. No air emissions or water would be generated during the vaporization process. However, SCVs or STVs would also be required to provide a heat source during winter months. The Petronet LNG facility in India has commissioned ambient air-heated vaporizers. However, operating experience is not available for this technology. Given the lack of experience with ambient air heated vaporization and the need to construct 100 percent standby technology, Broadwater has eliminated this technology from further consideration.

10.8.1.5 Summary

The use of STVs equipped with suitable SCR emissions control equipment allows for the lowest achievable emissions rate at thermal efficiencies comparable for SCVs with similar emissions control equipment. For this reason, STVs were chosen as the preferred vaporization technology for the Project.

10.8.2 Mooring System Alternatives

The FSRU must be securely connected to the send-out gas pipe via a permanent mooring structure allowing the FSRU to weather vane with the weather conditions. The mooring structure must be sufficiently robust to accommodate the load of the FSRU in all expected weather conditions.

The mooring structure must in addition to securing the FSRU, also facilitate and support the natural gas send-out pipeline and its utility systems. Two alternatives were investigated:

- External turret mooring system; and
- Yoke mooring system.

10.8.2.1 External Turret Mooring

The External Turret Mooring system comprises a steel box type structure that can be close or extended some distance from the bow or stern of the FSRU, providing a foundation for a rotating bearing arrangement and a turret.

The bearing accommodates a fixed chaintable to which mooring chains and fluid transfer hoses are attached. The chain legs are anchored to the seabed either by anchors or piles. Product and utility connections are made between the facilities on the tanker and the seabed via a swivel stack in the turret, allowing the tanker to weathervane around the fixed part while continuing production.

This system is suited to greater water depths of approximately 50 m minimum and requires 6 or more leg anchor systems, for which horizontal catenary anchor cables can be required up to 3,200 ft (1,000 m) from the turret, depending on actual water depth. Due to greater water depth, these systems tend to be used further offshore.

10.8.2.2 Yoke Mooring System

A yoke mooring system is connected to a jacket (tower), which is piled to the seabed. The jacket is a four legged tubular steel structure of square horizontal cross-section with legs in each of its four corners. At the base of the jacket there is a square mud mat, the corners of which are connected to the jacket legs. At each of the four mud mat corners, there is a pile guide through which skirt piles are driven. A central column or 'king post' is located at the top of the jacket onto which the turntable is mounted. The turntable structure or "topsides module" houses the swivel stack, and is connected by means of a slewing bearing to the top of the king post. This allows the FSRU vessel together with the mooring yoke to weathervane around the piled jacket. Located within the jacket is the pipeline riser that connects to the remainder of the pipeline on the sea floor. The pipeline riser will be secured to the inside jacket leg by bolted clamps to provide protection against any waterborne impacts.

The mooring yoke consists of a rigid triangular tubular structure which is connected at the jacket end by a roll and pitch articulation to the turntable, and at the vessel end by two mooring legs, to the mooring support structure mounted on the vessel's bow.

The mooring yoke, which is partially filled with water ballast, is suspended from the two mooring legs that hang vertically when the system is in equilibrium with the vessel at rest. When the vessel moves because of environmental effects, the ballast weight in the mooring yoke is raised and thus creates a restoring force that acts to bring the vessel back to the equilibrium position. Any movements of the vessel (roll, pitch, yaw, surge, heave, sway) with respect to the jacket are allowed for by articulations at each end of the mooring legs, at the mooring yoke/turntable connection, and by the main slewing bearing. The mooring system configuration is such that the mooring yoke is suspended above the normal water level.

The transfer of all utilities and send-out gas between the tower and FSRU is achieved through a series of flowlines and umbilicals that are suspended between the mooring support system and turntable structure.

Structures of this type are more suited to shallow water depths of approximately 15 to 30 m and hence can be used nearer to shore, such as in the Long Island Sound environment. The four-leg piled jacket (tower) does not require additional anchoring and hence has a reduced sea bed impact.

Because the jacket and mooring yoke provide the requisite support structure with a minimum amount of area on the sea floor, the overall system was selected as the preferred alternative for the Project.

10.8.3 Nitrogen Supply Alternatives

In order to meet the anticipated downstream pipeline gas quality requirements, nitrogen blending will be utilized, up to a maximum of 4% of the sales gas stream. Nitrogen is injected upstream of the recondenser to meet the heating value and flame stability requirements (Wobbe Index) of the send-out gas. The nitrogen injection rate is proportional to the gas send-out rate.

Two nitrogen injection technologies were evaluated:

- Cryogenic nitrogen plant; and
- Membrane nitrogen plant.

10.8.3.1 Cryogenic Nitrogen Plant

This type of plant produces nitrogen by air distillation. Supply air is compressed to approximately 9 bar (130 psi) by dedicated air compressors and water is separated out by cooling and separation. The air is filtered and dried before entering the cold box and distillation column where reflux heat exchange is applied and nitrogen gas is produced and stored in a buffer tank.

This technology is suited to the generation of high capacity, high purity production of nitrogen gas. The footprint and distillation column height is comparatively large. Operability and maintenance requirements are comparatively high, having long start up and shut down periods and a need for periodic defrosting of the air separation unit(s). The system can be affected by FSRU motions and is therefore less suited to marine application without modifications.

10.8.3.2 Membrane Nitrogen Plant

Membrane systems produce nitrogen by forced separation across hollow fiber membranes since the permeation rates for oxygen and nitrogen differ. Air is compressed to approximately 9 bar (130 psi) and filtered before entering the membrane cartridges where gas separation occurs. Waste gas is vented and the nitrogen produced is collected in and supplied from a buffer tank.

Membrane systems are widely used in marine applications without modification and are suited to small/medium capacity and low/medium purity applications. Maintenance down time is low, plant availability is high and operability is good. Power consumption for membrane systems is marginally higher than cryogenic plant and the membrane renewal interval can be 6 to 10 years. This can be achieved without interruption to process due to an "N+1" sparing provision; therefore, a spare unit will be available.

For the reasons noted, a membrane nitrogen plant was chosen as the preferred technology for Broadwater.

10.8.4 Ballast Transfer System

Broadwater assessed the feasibility of providing a ballast system that would allow transfer of ballast water between the FSRU and the LNG carriers during LNG transfer operations in order to minimize total ballast water intake.

As proposed by Broadwater, the FSRU and each LNG carrier that delivers its cargo are responsible for the separate and independent management of ballast water. Under typical operations, the LNG carrier would take on ballast water to offset the offloading of the LNG. At the same time, the FSRU would be discharging ballast water as it accepted LNG volumes from the LNG carrier.

Under the proposal described above, when unloading LNG from the LNG carrier to the FSRU, ballast water would be simultaneously transferred from the FSRU to the LNG carrier. This would reduce the volume of water that the LNG carrier would have to obtain from Long Island Sound. A ballast handling system of the type described was determined to be infeasible for the following reasons:

- Broadwater intends to accept LNG deliveries from the existing worldwide LNG carrier fleet. There are currently no LNG carriers configured to accept ballast water from another facility. It could be possible to modify the ballast handling systems of LNG carriers to accept ballast water; however, this would be a potentially complex undertaking since providing a new connecting manifold to the existing ballast piping would require a deck penetration, which would require concurrent strengthening to prevent the introduction of structural weaknesses and may require changes to the existing ballast piping specification.

- Coupling and decoupling of the ballast transfer system could introduce air into the ballast handling system, with resulting water hammer effects that would be detrimental to the system.

- From a safety perspective, there are a number of issues with such a proposal. First, the ballast transfer system would represent another connection between the FSRU and LNG carrier besides the liquid and vapour loading arms. In the event of a emergency shutdown, LNG transfer operations and ballast transfer operations would have to be synchronized to avoid instability. Second, the loading arms are equipped with emergency release couplers that will release in event of an LNG carrier mooring failure, or when the carrier moves towards the extreme limits of the loading arm range of operation. A similar system would be required for the ballast transfer system. Third, ballast transfer operations would represent the addition of another interface activity between the LNG carrier and FSRU, which would increase operational complexity as the number of operations to be managed would increase.

For these reasons, Broadwater does not view a ballast transfer system as a viable alternative.

10.9 PIPELINE CONSTRUCTION ALTERNATIVES

10.9.1 Pipeline Installation Alternatives

Broadwater evaluated specific construction methodologies for the installation of the subsea pipeline. These are discussed below.

10.9.1.1 Conventional Marine Pipeline Installation

Deepwater pipeline construction typically uses two barges working in tandem or sequentially to install the pipeline: the lay barge and the bury barge. The lay barge welds the pipeline together and sets it on the seafloor. The bury barge tows a subsea pipeline plow or jet sled which excavates a trench under the pipeline and lowers the pipeline to complete the installation. It is common for the lay barge to be used as the bury barge.

Under typical construction scenarios, these barges are moored via an eight to twelve point mooring system, and propelled by winches attached by cable to the anchors. The maximum extent of the mooring anchor array would be approximately 2,500 feet to the front and back of the barge and 2,000 feet to either side. As the lay barge and bury barges advance, anchor handling tugs (AHTs) lift the anchors from the sea floor and reposition them at approximately half-mile intervals in the direction of movement. The barges change position relative to the anchors as the cables are taken up and let out.

Broadwater is proposing conventional pipeline construction as the preferred methodology, using an eight-point or more anchoring design for the lay barge and the bury barge.

A criticism of conventional anchor-moored lay barges is the possibility of inordinate and/or permanent marking or scarring of the seabed by the anchors and by cable sweep. Such seabed impressions made during the course of the work will gradually infill with natural sediment migration. The time required for the seabed to return to its original state will depend on the sediment type and tidal currents. Broadwater is aware of no documented evidence that would substantiate claims of unacceptable long-term impacts either from placement of the anchor itself or by sweep of the cable, particularly as may be related to a recently completed IGTS Eastchester Extension project constructed in Long Island Sound during the 2002-2003 season.

10.9.1.2 Dynamically Positioned Vessel Marine Pipeline Installation

As stated in Section 10.9.1.1, deepwater pipeline construction typically uses two barges working in tandem or sequentially to install the pipeline: the laybarge and the bury barge. The laybarge welds the pipeline together and sets it on the seafloor. The bury barge tows a subsea pipeline plow or jet sled, which excavates a trench under the pre-laid pipeline to lower it below the seabed and complete the installation. It is common and more economical for the laybarge to also be used as the bury barge after the pipeline is laid.

Broadwater considered the use of a dynamically positioned (DP) laybarge to lay and lower the subsea pipeline.

DP laybarges are purpose-built to lay marine pipelines in challenging environments. Most DP laybarges are not designed or intended for pipeline lowering (i.e., to pull a subsea plow or jet sled). Other specialized offshore tug/supply ship (non-anchor propelled) type vessels exist to tow a subsea pipeline plow or jet sled. The worldwide fleet of specialized offshore tug/supply ship type vessels used for pipeline lowering is foreign built and flagged, and owned and operated by non-U.S. contractors.

United States cabotage laws, specifically the Jones Act (Section 27 of the Merchant Marine Act of 1920), place restrictions on the use of foreign vessels in pipeline construction within U.S. coastal waters. The U.S. Customs Service has ruled that a vessel that performs dredging activities (creating a pipeline trench and lowering a pipe is considered dredging) in U.S. waters is required to comply with the Jones Act. For Broadwater, this means that the bury barge must be qualified under the Jones Act, meaning that the vessel must be built in the U.S., be owned and controlled by U.S. citizens (no less than 75% controlled), and be manned by a U.S. crew. Of the currently available U.S. owned, controlled, and manned fleet of vessels suited to serve as a bury barge for the Broadwater subsea pipeline, none are DP vessels.

DP laybarges do not use anchors for positioning, but rather use a series of thrusters and GPS (global positioning system) technology to advance and hold station during pipe lay operations. The use of DP laybarges is relatively new to the pipeline industry and is usually limited to deeper water locations in extreme environments or to locations where a preponderance of existing pipeline systems or other seabed obstacles prohibit or discourage use of a conventional anchor-moored laybarge. They are generally large, ocean-going surface vessels (up to 1,000 feet in overall length) with a dedicated crew and workforce, limiting opportunities for local employment during construction (especially foreign owned and flagged DP laybarges), and their unit cost of construction would be in the range of 3 to 5 times greater than for a conventional laybarge.

For the Broadwater Project, it is believed that bottom disturbance using a DP laybarge would generally be reduced to the area in the immediate construction and lowering corridor. The use of a DP laybarge would also minimize the possibility of placing an anchor or dragging an anchor or cable into an existing utility cable, existing pipeline, or other features of concern—although the risk of this occurring with a conventional anchor-moored laybarge is minimized with thorough planning and careful execution using appropriate monitoring, supervision, and controls. In fact, to minimize disturbance impacts resulting from conventional installation, Broadwater has adopted the use of midline buoys on the quarter anchor cables as the preferred installation method.

Table 10-17 provides a comparison of the installation methods (laybarge and bury barge combinations) potentially available to Broadwater for laying and lowering the pipeline.

Table 10-17 Summary of Potential Bottom Disturbance Impacts from Pipeline Installation

Installation Method[1]	Pipelay (acres)	Lowering[2] (acres)	Total (acres)	Comment
1) Pipelay and lowering by conventional laybarge	950 *(3,750 without midline buoys)*	1,070 *(3,060 without midline buoys)*	2,020 *(6,910 without midline buoys)*	8-point mooring, 3 anchor sets/mile for 1 lay, and 2 plow passes with midline buoys on the quarter anchor cables
2) Pipelay by DP laybarge and lowering by conventional laybarge	0[3]	1,520[4]	1,520[5]	Conventional laybarge used to pull the plow using 8-point mooring, 3 anchor sets/mile, for 2 plow passes, with midline buoys on the quarter anchors

1 Assumes worst-case scenario for multiple passes of anchor sweep, with anchor sweep evenly spaced between prior sets, thus minimizing overlap (i.e., maximizing disturbance) between successive passes.

2 For all cases, trenching is via subsea plow except at tie-ins and utility crossings.

3 While the acreage is assumed to be zero for the purposes of this analysis, conventional equipment will be required to lay the pipeline across Stratford Shoal, resulting in some disturbance impact due to anchor cable footprint and sweep, which has been neglected in this analysis. Due to the imprecise information available for the impact of prop wash on the bottom, the impact acreage from DP laybarge use cannot be estimated.

4 Impacts of first plow pass = 950 acres. Anchor sweep of second pass has 40% overlap of previously disturbed sediment.

5 Plus disturbance at the Stratford Shoal due to pipelay by conventional laybarge, plus disturbance from DP laybarge prop wash.

Dynamic positioning requires a series of thrusters on the vessel bow and stern that holds the vessel in place during pipeline installation. Because anchors are not needed, seabed impacts associated with mooring may be avoided, as Table 10-17 demonstrates. However, other potential impacts are associated with DP laybarges. DP laybarge prop wash may have short-term impacts on the water column and on the seafloor where shallow water depths result in increased water perturbations and, therefore, increased sedimentation. Determining the impacts from prop wash requires conducting prop wash numerical modeling studies for the range of water depths and sediments along the pipeline route on a vessel-specific basis. Because Broadwater does not consider use of a DP laybarge a viable option, as discussed below, Broadwater has not undertaken these studies.

Typically, a DP laybarge large enough to install the Broadwater pipeline requires a minimum water depth of 60 feet. The water depth across the central part of Stratford Shoal does not meet that minimum requirement. If a DP laybarge were engaged to lay the pipeline, Broadwater would also have to employ a conventional laybarge to lay the pipeline across Stratford Shoal. If both DP and conventional laybarges are used, the actual reduction in the impacts through use of the DP laybarge is potentially significantly diminished.

Although the use of a DP laybarge may be technically feasible for laying about 95% of the Broadwater pipeline (not including the section crossing Stratford Shoal), there are other considerations that make the exclusive selection of a DP laybarge a nonviable option. DP laybarges have proven economical for large pipeline projects in offshore environments due to the length of the pipeline installation where significant economies of scale come into play. However, construction of the Broadwater pipeline is a small project by offshore construction standards. At only 21.7 miles long and constructed during the winter months, the Broadwater pipeline would be considered a small project with disproportionate logistical complexities compared to the DP laybarge project undertakings seen to date around the globe. Broadwater expects that DP laybarge contractors would be attracted to the Broadwater Project only under the guarantee of very high and uncompetitive levels of remuneration—a factor that would be significantly compounded if conventional laybarge contractors were prohibited from working on the project. This factor, coupled with the high demand for DP laybarges and multi-purpose construction vessel worldwide, leads Broadwater to believe that its project would not be attractive to a DP laybarge contractor, particularly when required to compete with conventional laybarge contractors.

The four existing and one proposed DP laybarges technically capable of laying the Broadwater subsea pipeline are identified in Table 10-18. Some of these vessels are multi-purpose construction vessels, and all are in high demand. Their utilization on Broadwater would be constrained by both cost and availability. In any case, Broadwater could not competitively bid the construction of the pipeline and achieve the optimum contractual terms with appropriate operational requirements (e.g., schedule) and price if conventional laybarge contractors, including U.S.-owned contractors, were prohibited from working on the Project.

Table 10-18 Available DP Laybarges

Owner/Operator	Vessel/Barge	Flag
Allseas	*Solitaire*	Panama
Allseas	*Audacia* (planned for 2006)	TBD
Global Industries	*Hercules*	Vanuatu
McDermott	*DB 16*	United States
Stolt	*Seaway Polaris*	Panama

In conclusion, due to cost, contractual, logistical, legal, and labour considerations, Broadwater does not consider the exclusive use of a DP laybarge to be a practicable alternative for laying the subsea pipeline.

10.9.2 Pipeline Lowering Alternatives

Broadwater evaluated the post-lay subsea plow, the post-lay subsea jet sled, and pre-lay dredging as alternative methods for trench excavation and lowering of the pipeline. These alternatives are discussed below.

10.9.2.1 Post-Lay Subsea Plow

A subsea plow physically cuts the seafloor and casts excavated spoil on the side of the trench, pushing sediment approximately 25 feet (8 m) to either side of the trench. The width of the trench would be approximately 25 feet (8 m) at the seafloor surface. In a post-lay method, the subsea plow would be positioned over the pipeline and would ride along the seafloor on pontoons. Compared to the subsea jet sled and dredging methods, sedimentation and increased turbidity are limited with the subsea plow, and it has been identified by resource agencies as the preferred installation technique. As such, subsea plowing is Broadwater's preferred installation technique.

10.9.2.2 Post-Lay Subsea Jet Sled

A subsea jetting sled uses high pressure water to liquefy and rapidly remove the sea floor under the pipeline. Cohesive soils and clays are typically the easiest soils to jet and usually maintain a relatively narrow trench with vertical walls. For much of the pipeline route the trench produced would be approximately 40 feet wide at the top. Non-cohesive silts and sands would result in wider trenches with more gradually sloping walls. Jetting is known to cause greater disturbance to sediments and to disperse sediments over a much larger volume of the water column than the subsea plow due to the liquefaction of the soil.

10.9.2.3 Pre-Lay Dredging

Pre-lay dredging involves the excavation of the trench before the laybarge installs the pipeline. Depending on water depth, either a specialized spud barge containing a heavy duty excavator (suitable for the shallower waters of Stratford Shoal) or a barge-mounted clamshell dredge (suitable for deeper waters along the pipeline route) would be used to shape the trench. The laybarge would then lower the pipeline into the pre-excavated trench in a continuous operation.

Compared to post-lay lowering methods, a larger trench width is required for the pre-lay method to ensure successful placement of the pipeline into the pre-excavated trench; a 40-foot-wide box cut is assumed. The side slopes should slump to leave a 2:1 side slope, an approximate top width of 54 feet, and a bottom width of 26 feet to install the pipeline. Due to the shallower water depths through Stratford Shoal, it is expected that the trench spoil from Stratford Shoal would be recovered to a hopper barge and then disposed of at an existing dumping site in Long Island Sound. For the remainder of the route, it is assumed that trench spoil would be side-cast to a spoil pile or piles on one or both sides of the trench.

The impacts for each lowering method, including the trench and spoil areas (i.e., the direct footprint of the trench plus immediately adjacent areas along the trench) are compared in Table 10-19.

Table 10-19 Comparison of Pipeline Lowering Methods

Method	Typical Trench Width at Top	Typical Total Construction Width	Volume of Excavated Sediment[1]	Total Area of Impact[2]
Post-Lay Subsea Plow	25 feet	75 feet	354,320 cubic yards	2,235 acres
Post-Lay Subsea Jet Sled	40 feet	100 to 300 feet[3]	627,290 cubic yards	2,560 acres
Pre-Lay Dredging	54 feet	100 to 200 feet	1,214,160 cubic yards	2,450 acres[4]

1 Includes the primary trenching method plus manual excavations to effect pipeline lowering at tie-ins and utility crossings.
2 Based on average total construction widths.
3 Source: Institute for Sustainable Energy 2003.
4 Not including disposal of some 40,000 cubic yards of spoil from Stratford Shoal at an approved dump site in Long Island Sound.

Due to the anticipated increased impact from the use of a post-lay jet sled or pre-lay dredging for pipeline lowering, Broadwater has eliminated these methods from consideration.

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