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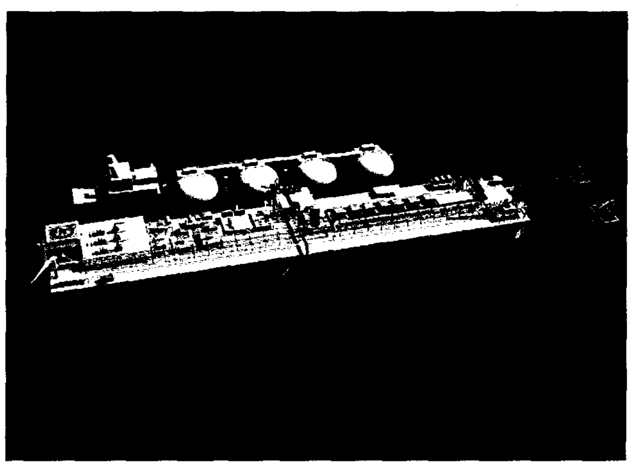
Section 2
Detailed Description of Proposed Action and Alternatives

USCG-2004-16860-30



2. Detailed Description of Proposed Action and Alternatives

2.1 Description of the Proposed Action

Gulf Landing LLC proposes to construct and install an offshore deepwater port and associated anchorages in the GOM, approximately 61 km (38 mi) south of Cameron, Louisiana, in West Cameron Block 213 (WC-213), in water depth of approximately 55 feet (ft), and within 3.2 km (2 mi) of an existing shipping fairway servicing the Calcasieu River and area ports (Figure 2-1). If approved, it is estimated that construction and installation of the Proposed Port would be completed by late 2008, and operations would begin in 2009. An outline of the general specification for the proposed Port is presented in Appendix E.

The proposed Port would consist principally of a Terminal to receive, store, and regasify LNG and up to five connecting pipelines to transport the gas from the Terminal to the existing existing natural gas pipelines located in the GOM. The Terminal would be 335 m (1,100 ft) long, 76 m (248 ft) wide, and 35 m (114 ft) (above the sea bottom). The Terminal would be capable of storing up to 200,000 cubic meters (m^3) (7,000,000 cubic feet [ft^3]) of gross LNG, with an operational net storage capacity of 180,000 m^3. The facility would vaporize and send out up to 1.2 Bcf per day (Bcfd) with an annual daily average of 1.0 Bcfd.

The Terminal would consist of two concrete gravity-based structures (GBSs) housing the LNG storage tanks, along with topside unloading and vaporization facilities, living quarters, and a ship-berthing arrangement. The Terminal would be able to receive LNGCs between 125,000 m^3 and 200,000 m^3 (4,414,000 ft^3 and 7,063,000 ft^3) capacities and unload approximately 135 LNGCs per year. LNGC arrival frequency would be planned to match specified Terminal gas delivery rates. All marine systems, communication, navigation aids, and equipment necessary to conduct safe LNGC operations and receiving of product during specified atmospheric and sea states would be provided at the proposed Port.

The regasification process would consist of lifting the LNG from storage tanks, pumping the cold liquid to pipeline pressure, subsequent vaporization across heat-exchanging equipment, and, finally, send-out through custody transfer metering to the gas pipeline network. No offshore gas conditioning would be required for the Terminal since the incoming LNG would be of pipeline quality.

Five offshore take-away pipelines, ranging from 16 to 36 inches (in) in diameter, would be constructed and would traverse a combined 65.7 nautical miles (NM). Each pipeline would transport gas from the Terminal to an existing transmission pipeline where it would deliver the gas to the onshore U.S. gas pipeline network. On average, Gulf Landing LLC expects the Terminal would vaporize and deliver 1.0 Bcfd of natural gas to the pipelines; with a peak daily send-out rate of 1.2 Bcfd.

2.2 Alternatives Analysis

A bedrock principle of NEPA is that an agency should consider reasonable alternatives to a proposed action. The Secretary may approve or deny an application[10] for a license under the Deepwater Port Act. In approving a license application, the Secretary may impose enforceable conditions as part of the license. Consistent with NEPA, in determining the provisions of the license, the Secretary may also consider

[10] For the application at hand, the No Action Alternative and denial of the license are considered to be the same.

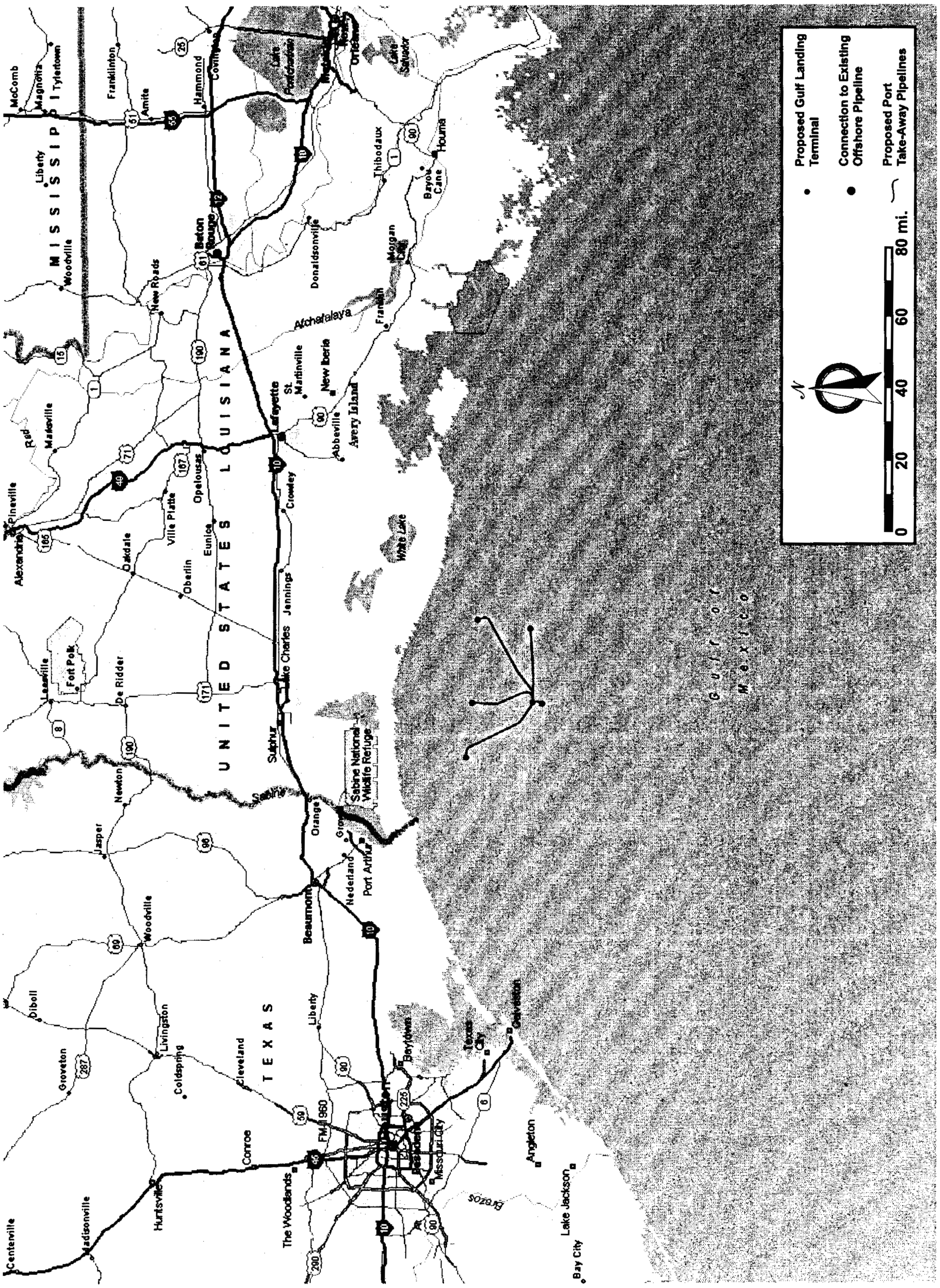


Figure 2-1. Location of Proposed Gulf Landing Terminal and Surrounding Area

alternative means to construct and operate a deepwater port. Alternatives for a natural gas deepwater port may extend to matters such as its specific location, methods of construction and platform layout, and technologies for storing and regasifying LNG. Considering alternatives helps to ensure that ultimate decisions concerning the license are well founded and, as required by the Deepwater Port Act, are in the national interest and consistent with national security and other national policy goals and objectives.

To warrant detailed evaluation by the USCG and MARAD, an alternative must be reasonable and meet the Secretary's purpose and need (see Section 1.2). To be considered reasonable, an alternative must be "ripe" for decisionmaking (any necessary preceding events have taken place), affordable, capable of implementation, and satisfactory with respect to meeting the purpose of and need for the action. The Secretary identified several potential alternatives to the proposed Port. The following identifies the alternatives for the Port, the alternatives found to be reasonable, the alternatives found not to be reasonable, and, for the latter, the basis for such finding. Alternatives considered but found not to be reasonable are not evaluated in detail in this EIS.

Alternatives concerning location, construction, and operation of a deepwater port for receipt and transfer of LNG must meet essential technical, engineering, and economic threshold requirements. Section 2.2.1 identifies these threshold requirements. When these are met, alternatives may be identified with respect to general systems for regasification units, LNG storage systems, and processes to vaporize LNG into natural gas for movement through pipelines. Sections 2.2.1 through 2.2.3 address the alternatives regarding these matters. Where open-rack vaporizer (ORV) technology is proposed, alternatives concerning designs for seawater intake and discharge, as well as means to avoid the intake of marine life, become relevant. These alternatives are addressed in Sections 2.2.4 and 2.2.5. Alternatives for the location of a deepwater port and pipeline routes are discussed in Sections 2.2.6 and 2.2.7. Alternatives for the GBS Fabrication Yard Site are discussed in Section 2.2.8. Construction and operation of an oil deepwater port as an alternative for natural gas is addressed in Section 2.2.9.

Essential Port Requirements. The location, construction, operation, and decommissioning of a deepwater port for LNG must meet essential technical, engineering, and economic requirements to ensure that a project is environmentally sound, economically viable, responsive to vessel and facility operating needs, and compliant with governing standards. The following discuss these major requirements.

- *Facility throughput.* Throughput capacity is a critical consideration in determining the economic feasibility of a project. To be economically feasible, the type of regasification unit and its location must have the ability to receive approximately 135 LNGC port calls per year and have a peak natural gas send-out rate of approximately 1.2 Bcfd.
- *Take-away capacity.* Transportation of a normal send-out rate of 1.0 Bcfd of natural gas requires either the construction of new export pipelines and/or the use of existing pipeline infrastructure to deliver the product to the U.S. natural gas distribution network. One or more pipelines of sufficient size are required to connect the LNG terminal to existing gas transmission pipelines, and access to those existing pipelines must be available.
- *Ability to accept a range of LNG qualities.* Natural gas is a combustible mixture of hydrocarbon gases, the primary constituent of which is methane. Natural gas originating in various regions of the world varies in its chemical components (i.e., the proportional content of methane, ethane, propane, butane, and other gases). A regasification terminal and associated pipelines must have the capability to handle a wide range in LNG quality.
- *Working storage.* A key technical and economic factor for a project is the ability to deliver consistent volumes of natural gas into the connected transmission pipeline network. A terminal sized to deliver 1.0 Bcfd of natural gas to its export pipelines requires a net on-site storage

capacity of 180,000 m^3. This storage capacity, amounting to about a 4-day supply, relieves the operator from difficulties associated with very high and very low throughput.

- *Ability to handle large LNGCs.* For economic reasons, a project must be able to handle LNGCs having cargo capacity ranging from 125,000 to 200,000 m^3 of LNG. This LNGC size range includes most LNG ships currently in operation worldwide or anticipated to be constructed in the near future. Offloading LNGCs would be at an average rate of approximately 12,000 m^3 per hour (m^3/hr).
- *Decommissioning.* A project must include economic and engineering plans for decommissioning the facility at the end of its operating life.

2.2.1 Regasification Unit Alternatives

The Secretary has considered a variety of deepwater port concepts for regasification units. These can be generally divided into operational models reflecting either continuous base load operations or intermittent operations. Operational models that include storage capacity for LNG would generally be used for continuous base load operations. Operational models that do not include storage for LNG would generally be used for intermittent operations. Both types of regasification units would include systems for docking and unloading of LNG vessels and systems for vaporization of the LNG for delivery to onshore markets via undersea pipelines.

Continuous Base Load Operations. Regasification units that include storage capacity for LNG may be either stationary structures or floating, storage, and regasification units (FSRUs). Stationary structures with storage capacity for LNG may be either GBSs or platforms supported by pilings or other methods used in the offshore oil and gas production industry. Due to the requirements for an appropriate depth of water for safe navigation of the LNG vessel and considerations of the cost of construction of larger structures, GBS terminals would generally be limited to water depths between 40 and 200 ft. GBS structures must also be located in areas where the sea floor is relatively level or gently sloping, lacking in geological hazards, and with satisfactory sediments to support the foundation and weight of the structure. The installation of a GBS structure would generally result in disturbance to a greater area of the sea floor than other types of stationary structures. Other types of stationary structures may be located in deeper water, but would have similar constraints with respect to avoiding areas with geological hazards. Floating structures with storage capacity generally require an anchoring system and sufficient water depth (generally greater than 200 ft) to accommodate the technology required for a flexible pipeline connection between the unit and the seafloor pipeline.

Intermittent Operations. Regasification units that do not include storage capacity for LNG may include a variety of stationary structures to support regasification processes or they may require that the LNG delivery vessels support the regasification process. In either case, the LNG is not stored at the deepwater port but is immediately converted into natural gas for delivery to a seafloor pipeline. This operational model can include either stationary or floating methods of mooring the LNG vessel and delivering the natural gas to the pipeline. Stationary mooring and delivery methods would be much like those required for the continuous base load operational model. Floating moorings would typically involve a buoy with associated anchoring systems to connect a pipeline to the LNG vessel. Due to the limitations imposed by specialized materials and engineering requirements to handle the extremely cold LNG, floating moorings would not likely be used in the transfer of LNG. Floating moorings would more likely be associated with vessels that are designed to support the LNG regasification process onboard the vessel. Floating mooring and delivery methods would generally require water depths of 200 ft or greater to accommodate the flexible pipeline connection between the unit and the seafloor pipeline for the delivery of natural gas from the vessel. Since the regasification process generally is slower than the vessel-unloading process, intermittent operating concepts normally require LNG delivery vessels to be moored for longer periods of time while the LNG is being regasified for delivery to the pipeline. Longer mooring times would reduce the frequency of LNGC visits to the deepwater port. Furthermore, these intermittent deliveries of LNG would mean that the regasification process at the port would also be operating in an intermittent fashion.

The Secretary does not give preference to either operational model. Instead, the Secretary will rely upon the LNG industry to determine the appropriate operational model to serve its intended market. Likewise, the determination as to whether the deepwater port is stationary or floating is an individual business decision for an applicant. The Secretary believes that any of these operational models for regasification units can be acceptable in terms of safety, operability, availability, and environmental protection. Therefore, the Secretary will evaluate the merits of each application on a case-by-case basis and require each applicant to provide a rational and objective analysis of alternative concepts.

2.2.2 Storage System Alternatives

Three LNG storage systems are potentially available for regasification units based on the GBS operational model. Gulf Landing LLC will employ one type of these three tank systems:

Prismatic Membrane Tank System. A membrane tank system would consist of primary and secondary barriers, insulation, and support arrangements to the inner concrete surfaces of the GBS. The primary liquid and vapor barrier would consist of a corrugated stainless steel membrane serving as the LNG tank bottom and walls. The secondary barrier would run behind the membrane. In the event of a primary barrier failure, the secondary barrier would contain any leaked LNG. Polyurethane foam panels placed between the secondary barrier and the concrete walls of the GBS would provide insulation. The tank would have a suspended, glasswool insulated, aluminum roof. The membrane type of system has been used for the storage of both LNG and other products in onshore tanks, employing design differences dependent on the intended application. Additionally, the prismatic membrane tank system has been commonly used aboard LNG vessels.

Self-supporting 9 Percent Nickel-steel Cylindrical Tank System. A 9 percent nickel-steel system would consist of a self-standing steel cylindrical tank. The LNG would be contained in a 9 percent nickel-steel container, surrounded by loose perlite insulation around the walls and perlite concrete beneath the floor.[11] The cylindrical tank system represents the more standard onshore design used extensively in LNG storage facilities. It has been used in more than 100 onshore tanks worldwide. Similar to the prismatic membrane tank system, this tank system has been commonly used aboard LNG vessels.

Self-supporting Prismatic Tank. A self-supporting tank system would consist of a cylindrical or round tank with internal stiffeners (bulkheads). The freestanding tank would rest on a large number of reinforced epoxy/plywood blocks supported by the bottom of the concrete GBS hull. The tank, insulated externally with polyurethane materials, would bear both the thermal and structural loads. Two ocean-going LNGCs using this type of tank have been built to date.

In its application for the deepwater Port license, Gulf Landing LLC has postulated use of the prismatic membrane tank system but, at the time of application submission, had not finally selected the type of tank system ultimately to be employed. The Secretary notes that selection of the storage system is not likely to have significant environmental consequences because none of the types of systems affect the facility's footprint, pose air or water emissions, or affect normal Terminal support activities such as helicopter traffic or supply boat visits. The Secretary retains his authority, however, to evaluate other aspects of the type of tank to be used, such as a system's safety and operational (maintenance) requirements.

[11] Perlite is a generic term for naturally occurring siliceous rock. Crude perlite contains 2 to 6 percent water. When rapidly heated to more than 1,600 degrees Fahrenheit, it expands and becomes a lightweight material with outstanding insulation qualities.

2.2.3 Vaporization Unit Alternatives

The Applicant considered four types of LNG vaporizer systems for potential use at the proposed deepwater Port.

- ORVs, which use unheated water or sea water at ambient temperature as the warming agent to regasify LNG. As the name implies, the heat exchangers in an ORV are open to the surrounding environment and, therefore, can only be operated on a very stable platform.
- Submerged combustion vaporizers (SCVs), which burn fuel (a portion of the regasified natural gas product or diesel) to heat water in a closed loop submerged heating system, which in turn warms the LNG in the regasification process.
- Intermediate fluid vaporizers (IFVs), which use an intermediate fluid other than water (typically propane) in an enclosed system to revaporize LNG.
- Shell and tube vaporizers (STVs), are designed to use once-through warming water, steam, or water glycol as the heating medium to revaporize LNG. STVs are designed primarily for use on ships or floating platforms. The STV heat exchangers are not as efficient as an ORV, however, they are not open to surrounding environment (closed in a tube) and can operate effectively on a moving platform or ship.

The use of IFVs in onshore terminals is usually discounted due to their higher operating cost and the safety issues associated with the storage and possible release of the intermediate revaporization fluid. STVs using seawater have been considered, but this concept has not yet been proven. STVs using glycol and hot water have been successfully employed in site-specific instances, but they only become feasible alternatives when advantage can be taken from an existing heat or steam source. Based on an assessment of these conditions, the Secretary supports the decision to remove these IFV and STV systems from further consideration for this Application.

Based on assessments of currently available LNG regasification technologies practical for implementation offshore conducted for this and previous applications, the Secretary accepts ORV and SCV technologies as the most appropriate for a fixed regasification terminal in the GOM. Both of these systems represent proven technology. Each has inherent safety, environmental, and resource management attributes (see below). The Gulf Landing Application identifies an ORV system as the Preferred Alternative. The following identifies key factors taken into consideration by the Secretary.

System Descriptions. An ORV uses pumped and treated ambient seawater as the heat source for vaporizing the LNG into gas. An ORV consists of two horizontal headers connected by a series of vertical heat-transfer tube panels made of aluminum alloy. LNG enters the bottom header and moves up through the tubes, while seawater flows down along the outer surface of the tube panels in a once-through mode. Vaporized gas is collected and removed from the top header. Sodium hypochlorite is usually injected at the suction of the seawater pump to prevent marine growth on the water intakes and inside the warming water system. The seawater, cooled by the process of warming the LNG, is collected in a trough and sent by gravity to the water outfall, which is at the opposite end of the GBS from the seawater intake to avoid recirculation of cold water.

In an SCV, pressurized LNG is vaporized in a stainless steel tube coil immersed in a bath of hot water that is heated by combusting natural gas. The burning takes place in a distributor duct that is immersed in the water bath. The products of combustion are exhausted directly into the water bath, which is used as the heat transfer medium for vaporizing the LNG in the tube coil. This vaporization process consumes vaporized LNG product as fuel. Each SCV requires a high-pressure, electric-motor-driven air blower to support the combustion process and to force the combustion flue gas through the water bath. Burning natural gas for the SCV process would generate approximately 40 m^3 (10,570 gal) of low pH (acid) water, which would require chemical treatment to neutralize the acid (raise the pH) before discharge.

Costs. The cost comparison for an ORV system and an SCV system included capital expenditure costs and operational costs. Costs common to either system were disregarded (e.g., GBS and port construction, unloading equipment, surge tanks, LNG piping, metering, power generation, etc). It has been determined that the GBS structure proposed by the Applicant would be adequate to accommodate either system configuration. Capital expenditure costs include design, fabrication, and procurement of regasification systems components that would be installed on top of the GBS (equipment, instrumentation, steel, concrete, and electrical components and transportation of bulk material items). Operational costs include the number of annual operating hours, electrical costs, fuel costs, and maintenance costs. Operational costs are calculated at net present value over a 30-year period. The net present value calculations recognize include appropriate electricity, fuel gas, equipment, and chemical cost escalators. Salient assumptions are also taken into account (e.g., frequency of replacing components such as water pumps, blowers, or chemical injectors).

The total cost comparison of initial capital expenditures as defined above are similar for an ORV or and SCV system. It would cost approximately $4,992,707 to redesign the proposed Port for operation with SCV.

Operating costs for an SCV system would exceed costs of an ORV system by an estimated $24,406,398 per $46,962,344 per year and $732,191,940 to $1,408,870,320 over the 30 operations of the proposed Port. The determinant of this additional cost relates to the cost of using approximately 2.2% of the natural gas produced to operate the SCV warming water system. In calculating low end costs for an SCV system, the very conservative value of $3.00 per million British thermal units was assigned to the LNG that would be used to provide the heat source for the SCVs. The higher end costs reflect a natural gas value of $6.00 per million British thermal units. The spot market price for natural gas reported on June 7, 2004 was $6.38. Inflation and use of higher values for the LNG that would be used in the process would render an SCV system even more expensive in comparison to an ORV system.

Equipment Reliability. Each train of an ORV consists of a seawater intake pump and shell-less tube heat exchanger requiring regular cleaning. Very little instrumentation is required for either protection or control. Seawater pumps are based on well-proven designs. Seawater treatment, other than biocide injection and coarse filtration, is not required.

Each train of an SCV consists of a direct-fired water bath heater and a blower. The water bath heater has a fuel gas supply, ignition and combustion system, temperature control, and protective instrumentation. Large units also may require closed loop, forced-circulation-burner cooling water systems. Consideration must be given to protecting the system from tube rupture. That is, the SCV is an enclosed unit, and rapid phase transition of LNG on contact with water would not have an easy relief path. Water must be continuously withdrawn during operation since it is a product of combustion. Additional auxiliary utility systems would consist of a water make-up system for startup, and a water bath neutralization system. These require maintenance greater than that required for an ORV and are subject to failure resulting in real or nuisance trips and additional downtime. Blowers tend to require more maintenance than seawater pumps. Compared to ORVs, overall reliability of SCVs is expected to be lower.

Electrical Power Generation and Distribution. The ORV case electrical load is approximately 21.8 megawatts (MW), and the SCV case electrical load is approximately 23.8 MW. As the SCV case requires two more high voltage motors than the ORV case, supporting the SCV case would require additional switchgear/motor control, interconnects, and cabling. The two cases are not significantly different; neither provides an obvious advantage over the other in this category.

Effects on Water Quality and Marine Life. The ORVs proposed by the Applicant would use up to 126.8 million gallons per day (MGD) of sea water to vaporize LNG. Discharge water returned to the GOM would average approximately 10 degrees Celsius (°C) (18 degrees Fahrenheit [°F]) below ambient seawater temperature and would contain 0.5 parts per million (ppm) sodium hypochlorite (used to prevent biofouling). Modeling of the cool water plume anticipated from the use of ORVs at the proposed site indicates that at a distance of 100 meters (m) (328 ft) from the discharge point, the discharge water temperature along the sea floor would be 1 °C (1.8 °F) or less below the ambient water temperature. Sodium hypochlorite concentrations at the same distance would be less than 0.05 ppm.

Use of ORVs includes consideration of entrainment (carrying of organisms with the natural water) and impingement (the retention of larger fishes and other organisms on screens placed across the intakes). Entrainment generally affects smaller organisms including planktonic eggs and larvae of fishes and invertebrates. Once drawn into the system, entrained organisms are subject to mechanical damage by physical contact with pipes, screens, pumps, and other components. In addition, use of sodium hypochlorite as a chemical treatment to retard biofouling within the intake system poses toxicity risks to entrained organisms. Organisms entrained in the intake water would be expected to experience a 100 percent mortality rate. Age-1 equivalent calculations conducted for this EIS (Section 4.2) indicate that entrainment impacts associated with the ORV operations would not be signifigant.

Impingement occurs when mesh screens or other barriers block larger organisms entering the intake system. Screens are used to prevent larger debris from damaging pumps and other parts of the intake system. The intake design will allow most free swimming organisms to escape the intake.

Use of SCVs with a closed loop warming water system would not require continuous intake and discharge of 136 MGD of warming water. Other water requirements for GBS operations would be similar to operations with an ORV. Burning natural gas for the SCV process would generate approximately 40 m^3 (10,570 gal) of low pH (acid) water per hour, which would require chemical treatment to neutralize the acid (raise the pH) before discharge.

Effects on Air Quality. Compared to ORVs, SCVs would involve increased air emissions due to the combustion of natural gas to warm the sea water. The estimated annual emissions from the SCVs alone, exclusive of electrical generators supplying their power, would be 299 metric tons (MT) of nitrogen oxide (NO_x) per year, 156 MT of carbon monoxide (CO), 355,810 MT of water, and 434,879 MT of carbon dioxide (CO_2). Emissions of NO_x from the SCVs could be reduced, if necessary, by the addition of emissions controls such as selective catalytic NO_x reduction equipment. This, however, would not affect the additional water vapor and CO that is produced. Alternatively, ORVs do not produce any air emissions to vaporize the LNG. As previously described, both ORVs and SCVs would consume approximately the same amount of electrical power to operate their respective pumps and equipment. Therefore, CO that is produced as a result of electrical power generation would be the same for either system.

Safety. ORVs might require the periodic use of divers to clean and maintain screens around the warming water intake, or, in the case of the proposed Port, a crane would be used to lift the redundant stand-by intake screens to the surface for cleaning and maintenance. Small leaks in the warming tubes could occur, resulting in a potential hazard to onboard personnel. However, due to the lack of enclosed (confined) spaces, and the lack of any combustion or open flame, ORVs pose little explosive danger. SCVs might have similar gas leaks and are a potential ignition source for the gas. By design, SCVs have enclosed (confined) spaces, which could pose an explosion risk. Design and engineering can mitigate the SCV risks in the offshore environment, but equipment and personnel separation is still limited to the size of the structure.

Energy Requirements and Efficiency of Energy Use. SCVs consume a percentage of the natural gas product to warm the water used to vaporize the LNG, whereas ORVs do not. Thus, SCVs would substantially reduce the overall energy efficiency of the Port in terms of its ability to supply the maximum amount of natural gas to the U.S. market. Estimates indicate that ORVs that use sea water warmed by solar radiation are 20 times more energy-efficient than SCVs. The natural gas burned to vaporize LNG at the Terminal is essentially lost to U.S. consumers.

Table 2-1 presents a comparison of advantages and disadvantages associated with using ORVs or SCVs for LNG vaporization.

Overall, the Applicant has found ORVs to be preferable to SCVs in terms of environmental protection, use of energy resources and efficiency, cost, maintenance, and safety in the following areas:

- SCVs would result in a significant increase in the level of CO, NO_x, acidic water, and water vapor emissions from the facility. These emissions could be managed within the current environmental regulatory regime, but they do not exist with ORVs.
- SCVs would significantly reduce the overall energy efficiency of the installation due to a 20-fold increase in energy usage over ORVs. This increased energy use translates into increased operating costs of the installation.
- SCVs represent a potential ignition source in the process area. While this risk is potentially manageable, it is a risk that does not exist with ORVs.

The Secretary recognizes that selection of means to vaporize LNG depends on case-by-case evaluation, to include consideration of how a given system's design and operating conditions would fit within the overall scheme of a project. The Secretary does not give preference to the use of any particular regasification technology. The Secretary believes that either ORV or SCV technologies can be made acceptable in terms of safety, operability, availability, and environmental protection. The Secretary relies on applicants to demonstrate consideration of potential technologies, with associated environmental protection measures, including an evaluation of best available technology in achieving the necessary level of environmental protection.

The Applicant has conducted a reasonable evaluation of alternatives and reached a rational conclusion that, for the purposes of the proposed Port, ORVs present the superior technology to vaporize LNG. In relation to this application, the Secretary believes that the use of ORV technology would be advantageous compared to SCV technology. The Applicant selected ORV technology because it is a widely used and highly proven technology, is a simple process (highly reliable), and has low fuel-usage requirements and resultant reduced operating costs. The Applicant has also made sound arguments on the basis of safety and availability of means to ensure protection of the environment. Having fully reviewed the Applicant's evaluation of regasification technologies, the Secretary adopts the Applicant's analysis and, accordingly, eliminates those alternative regasification technologies from further consideration in this EIS.

Table 2-1. Comparison of ORV and SCV Systems

Factor	ORV	SCV
Total costs (initial installation, maintenance, and operation over a 30-year period)	Baseline Costs	Similar Baseline costs. Redesign Costs for the Applicant to change to an SCV system approximately $4,992,707. Additional costs to burn natural gas to operate the SCV warming water system estimated to be between $24,406,398 and $46,962,344 per year ($732,191,940 to $1,408,870,320 over the 30 operations of the proposed Port).
Equipment reliability	Higher	Manufactures specifications indicate blowers would require more regular maintenance than ORV seawater pumps. Natural gas boilers would require additional maintenance and monitoring associates with the acids produced in the system and the risk management of an ignition source. Threshold for emergency shutdown increased.
Electrical power	No advantage (Similar to SCV).	No advantage (Similar to ORV).
Effects on water quality and marine life	Higher effect. Cold-water discharge can affect local ecology. Potential for entrainment and impingement of marine life. Use of biofouling inhibitor required (discharge to environment).	Lower effect. Requires minimal raw water intake and discharge.
Effects on air quality	Relatively low overall emissions.	Higher effect. Estimated additional air emissions from SCV: N_2 2,213,931 MT per year; CO_2 434,879 MT per year; NO_x 299 MT per year; and CO 156 MT per year. Increased NO_x emissions can require specific mitigation. Increased potential air quality hazards to personnel on facility.
Safety	Divers may be needed for cleaning and maintenance of intake screens. Leaks to atmosphere can occur and pose fire hazards.	Potential ignition source and fire/explosion hazard. Blower hazards/personnel exposure. Increased chemical handling and exposure associated with water treatment systems. LNG under greater pressure—internal leaks would escape via vent system.
Energy efficiency	No LNG product used in process.	20 times more energy used by the facility; U.S. market loses approx 2.2 percent of product that is used to vaporize the LNG

Source: GL 2003a

The Secretary recognizes that other deepwater port operating concepts, designs, throughput rates, or locations could result in identification of another regasification technology being deemed advantageous. Conclusions with respect to ORV technology are neither an endorsement of the use of ORV nor an unfavorable determination to future applicants whose proposals might be based on use of SCV or other technology in the marine environment.

2.2.4 Seawater Intake and Discharge Design Alternatives

Configuration and design of the proposed deepwater Port to use ORV technology to regasify LNG necessitates consideration of alternatives for intake and discharge of sea water in order to minimize impacts on the environment. Use of sea water to heat LNG must deal with two circumstances. First, low intake flow rates result in a greater temperature change in warming water. This results in colder water being released into the environment. Second, high-intake flow rates result in less temperature change in the warming water. This can lead to an increased potential for marine life impingement and entrainment and more water being treated and discharged into the environment.

Optimizing the seawater intake system for ORV use involves determining the most advantageous combination of the following variables:

- Volume, velocity, and rate of seawater intake.
- Reduction of discharge water temperature below ambient seawater temperature.
- Discharge rate and discharge pipe configuration.
- Optimum spacing between intake and discharge to prevent entrainment or recirculation of cool water into the intake.

Two additional factors that must be considered pertain to ambient seawater temperature and guidelines for sea water used in the ORV processes (effluent).

- During the winter season, the mean seawater temperature in the GOM can reach as low as 10 °C (50 °F). Reducing the temperature of this water by 10 °C (18 °F) as a result of its use in the ORV process has the potential to result in formation of ice with the process system and other operational upsets.
- The World Bank Group guidelines for process wastewater provide that effluent should result in a temperature increase of no more than 3 °C (5.4 °F) at the edge of the zone where initial mixing and dilution takes place. Where such a zone is not defined, there should no more than a 3 °C (5.4 °F) increase in temperature 100 m (328 ft) from the discharge point.[12] (World Bank 1998).

To aid in determining the most advantageous combination of intake and discharge scenarios, the Applicant performed modeling of designs having various intake volumes, velocities, and discharge configurations.[13] Table 2-2 shows eight design combinations. Design Number 5, in which 136 MGD of sea waterwould be used for ORV processes and would be discharged through three pipes in a single diffused design, would result in a temperature differential of 1.1 °C (1.98 °F) at a distance of 100 m (328 ft) from the discharge point.

[12] World Bank guidelines presume process wastewater is warmer than receiving waters. In the absence of governing standards or guidelines addressing situations in which wastewater is *cooler* than receiving waters, the Applicant has sought to preclude the discharged seawater's being not more than 3 °C (5.4°F) warmer *or cooler*.

[13] The Cornell Mixing Zone Expert System ("CORMIX") was used to identify far-field effects. Plume behavior in the near-field was modeled using the Offshore Operators Committee model.

The Secretary finds the Applicant's decision to proceed based on the results of the modeling to be acceptable. Further detailed analysis on alternative intake and discharge regimes would not be reasonable and, hence, such other alternatives are not evaluated in detail in this EIS.

Table 2-2. Various Intake and Discharge Scenarios

Design No.	Intake Volume (MGD)	Potential Fish Larvae Entrained (million/d)	ΔT at Discharge (°C)	Velocity at Discharge (m^3/s)	Discharge Configuration	ΔT 100m from Discharge (°C)	Potential Seafloor Area with ΔT of 1 °C (acres)[1]
1	380	2.38	-10.0	16.66	6 x 58" pipes	-1.0	543
2	380	2.38	-5.5	16.66	6 x 58" pipes	-2.6	111
3	179	1.12	-11.1	4.6	5 x 58" pipes	-6.4	56
4	179	1.12	-11.1	17.1	5 x 30" pipes	-2.0	35
5	127	0.80	-10.0	5.6	Single port diffused	-1.1	5.7
6	127	0.80	-10.0	5.6	25 ports on 95 m pipe	-0.6	6.7
7	197	1.23	-10.0	8.6	Single port diffused	-4.0	8.1
8	197	1.23	-10.0	8.6	25 ports on 96 m pipe	-0.6	6.3

Source: GL 2003a
Notes: [1] Based on "worst case" current and water column stratification conditions.
MGD – million gallons per day
million/d – million per day
m^3/s – cubic meters per second

2.2.5 Marine Life Exclusion System Alternatives

To minimize the potential for impingement and entrainment of marine organisms in the warming water uptake, the Applicant identified three types of marine life exclusion systems for potential use at the proposed deepwater Port. These systems were an aquatic filter barrier (AFB) system (Gunderboom type system), wedgewire screen barriers (0.5-millimeter (mm) [0.019-in] mesh), and wedgewire screen barriers (6.35-mm [0.25-in] mesh).

AFB System. This system is effectively a large net around the intake structure. It would consist of two sheets of a fine polyethylene/polypropylene mesh fabric. Each fabric layer would be about 3.18 mm (1/8 in) thick. The fabric would be porous with very fine openings through the fabric threads. A 3.18-mm (1/8-in) twine netting with openings about 1 inch square would be fixed between the two layers of fabric and support the inlet fabric side against drag of the water flow. The outlet fabric side would have vent pockets through which filtered water would pass into the clear water basin.

Based on an intake velocity of 0.15 meters per second (m/s) (0.5 feet per second [ft/s]) at the screen face, a flow of 32,000 m^3/h (1,129,920 ft^3/h) requires a filtration surface of 3,502 square meters (m^2) (37,700 square feet [ft^2]). The most practical method of installing this amount of fabric in an offshore environment is panel-mounting the fabric. Panels would be mounted in channels around the perimeter of a jacket structure. The panels would rise above water level and be seated in a frame near the base of the jacket, forming an intake basin within the jacket.

As proposed for Gulf Landing, such an AFB system would consist of four independent platform structures (two around each intake). Each net (jacket) would have a total of 24 panels measuring 6.6 m (20 ft) wide by 19.7 m (60 ft) high panels. These panels would extend above mean sea level to account for wave and tide action and would extend downward to 3 m (10 ft) above the sea floor, where they would fit into specially designed receiving channels. The bottom 3 m (10 ft) of the jacket structures would be enclosed using metal plating.

Setting large AFB fabric panels in the GOM environment would be a challenge. No data are available on the reliability of the panel-wedging system. Potential frequency of fabric fouling by debris is unknown. In addition, AFB fabric would not be expected to survive a hurricane or severe winter storm.

This type of system with the small mesh size (0.5-mm [0.019-in]) has not been previously installed and operated in the offshore marine environment. The complications associated with designing, installing, and operating prototype equipment might result in poor overall performance of the system due to downtime and failures of the system. Marine biofouling of fabric over time is also potentially a major issue. Complete replacement of an AFB system based on storm damage and damage from floating objects is estimated to be required every 2 years.

The total cost for design and installation of an AFB system at Gulf Landing is estimated to be approximately $70 million. This cost estimate excludes maintenance and regular storm damage, and fouling damage replacement costs. Because the life expectancy of such a system in the offshore waters of the GOM cannot be estimated, the potential cost of this system over the life of the project is thought to be very high.

Wedgewire Screen Barriers. Wedgewire screens are cylindrical filters made by winding wire around cylindrical support rods forming a series of gaps between the wires. Flow is from the outside to inside. A flow distribution device inside the screen is provided to keep even flow over the entire screen surface. Marine life exclusion is suggested to be a function of screen gap, gap velocity, and current velocity past the screens. The screens can be furnished in a "T" design with horizontal screen cylinders feeding a central "T" with a down-facing branch outlet. An alternate is a drum screen in which the screen cylinder is vertical and flow is down into a lower connection pipe.

Wedgewire screens are designed to reduce entrainment by both physical exclusion (blocking) and by exploiting hydrodynamics. Physically, marine organisms are excluded when the mesh size is smaller than the organism in question. Hydrodynamic exclusion results from the maintenance of a low through-slot velocity, which, because of the circular configuration, is rapidly dissipated, allowing organisms to escape or be pushed away from the flow field.

Screens are subject to becoming fouled and plugged with floating material in the marine environment. They also are prone to damage by large floating objects and storms. Drum screens set on an intake manifold below a jacket structure were evaluated, since this design would facilitate removal and reinstallation of screens for inspection, cleaning, or damage repair. A screen size of 183 cm (72 in) in diameter with 218 cm (86 in) of screen length was evaluated. This size was assumed to be a reasonable compromise between a constellation of small screens and the largest screens that would be more affected by sea conditions during removal and reinstallation.

Wedgewire Screen Barriers (0.5-mm [0.019-in] mesh). Since there is a maximum screen length and a fixed wire size between each gap, a reduced screen gap results in reduced flow area. This means more screens are required with a 0.5-mm (0.019-in) screen gap than with a larger gap to maintain the 0.15-m/s (0.5-ft/s) flow velocity. Twenty-two screens are required for a 32,000-m^3/h (1,129,920-ft^3/h) flow with a 0.5-mm (0.019-in) screen size. The 0.5-mm (0.019-in) gap screens were assumed to be pulled to the surface every 2 months for cleaning and replaced every 6 years. Actual required surface cleaning frequency would be determined by operating experience.

The 0.5-mm (0.019-in) gap screens would prevent entrainment of all adult mobile species. However, eggs and larvae might be impinged onto the screen, which will result in damage and significant mortality of the eggs and larvae. It would therefore not have the desired effect of minimizing the impact on these species.

A structure housing one intake collection manifold and eight screens was assumed for both the 6.35-mm (0.25-in) mesh screen and the 0.5-mm (0.019-in) mesh alternative. The 0.5-mm (0.019-in) mesh screen requires six structures housing a total of 48 screens. Each structure requires compressed air for in-place "hydro-burst" backwash of loosely adhering material plugging from the screen face. Each structure also requires a high-pressure water blast for cleaning screens of barnacles and tightly adhering materials after retrieving the screens to the surface.

These screens are less robust than larger mesh screens and complete replacement of wedgewire screens due to storm damage and damage from floating debris is estimated to be required every 3 years.

Wedgewire Screen Barriers (6.35-mm [0.25-in] mesh). Seven screens are required for the 32,000 m^3/h (1,129,920 ft^3/h) flow requirement using wedgewire screens with a 6.35-mm (0.25-in) gap. However, eight screens are assumed to allow 16 percent fouling before one intake line would have to be shut down for screen cleaning. The 6.35-mm (0.25-in) screen alternative requires two structures housing a total of 16 screens. The 6.35-mm (0.25-in) gap screens are estimated to require a water blast cleaning once a year.

The initial cost for a wedgewire screen system using a mesh size of 6.35-mm (0.25-in) is estimated to be approximately $15 million. The larger mesh size allows a more robust screen than amaller mesh sizes and complete replacement of these screens due to damage from storms and floating debris is estimated to be necessary every 6 years.

Selection of Alternative. The AFB approach would involve use of unproven technology in the offshore marine environment. Moreover, costs associated with initial installation and ongoing operations are disproportionate to potential benefits. For these reasons, use of AFB is eliminated from further consideration.

Literature research conducted by the Applicant found that fine-mesh wedgewire screens reduce entrainment and virtually eliminate impingement damage to fish and other marine organisms. One study of freshwater situations showed that cylindrical wedgewire screens incorporating 0.5-mm (0.019-in) mesh eliminated entrainment of fish eggs in the 1.8 to 3.2 mm (0.07 to 0.13 in) size ranges. Testing of 1.0 to 2.0 mm (0.04 to 0.08 in) wedgewire screens in St. Johns River, Florida, showed that mesh sizes of this diameter reduced entrainment by 99 percent and 62 percent, respectively, over conventional power plant screens with mesh sizes of 9.5 mm (3/8 in).

Based on the overall cost of all of these systems and that no GOM performance data are available to compare the cost of any of these marine life exclusion systems with the benefit of potential impact reduction, the Applicant proposes to develop and employ an exclusion system based on the use of cylindrical wedgewire with a gap size of 6.35 mm (0.25 in). This mesh size, in conjunction with locating the intake cage at the bottom of the water column, represents a reasonable compromise between the 9.5-mm (3/8-in) mesh commonly in use today for power plant intakes and the 0.5-mm (0.019-in) mesh, which, while potentially more effective at screening out fish eggs, has a considerably greater biofouling potential and an unknown benefit in the OCS waters of the GOM. This exclusion system would be evaluated through a monitoring program to be conducted by the Applicant. The intake structures would be designed in such a way that finer-mesh screens could be added later if the monitoring program shows they are warranted.

The Secretary finds this approach suitable to reducing potential impacts on marine life. In light of the Applicant's documentation of its prudent efforts to avoid adverse effects, it does not appear that further detailed evaluation of alternative means to exclude marine life would result in material benefit. Accordingly, detailed evaluation of such alternatives is not presented in this EIS.

2.2.6 Location Alternatives

The Applicant considered various scenarios for locating an LNG regasification terminal off the U.S. Atlantic and Gulf Coasts. The advantage identified for potentially locating an LNG port on or near the U.S. Atlantic Coast would be the proximity to major east coast natural gas markets. However, a significant disadvantage would be the lack of existing offshore infrastructure that would provide favorable project economics and flexibility for transmission of product to market. The GOM has substantial natural gas transport infrastructure and capacity already in place. In addition, the Gulf Coast has an industrial base geared to offshore oil and gas exploration and development, which will be of significant benefit to the Applicant in the construction and operation of an LNG regasification terminal in the northern GOM. In addition the GOM provides relatively higher water temperatures that allow the option for the more efficient ORV system. Based on the relative differences regarding gas transmission flexibility afforded by existing infrastructure, economics, and environmental considerations, the Applicant selected the GOM as the geographic focus for subsequent siting studies.

Specific Siting Requirements. The location for an LNG terminal must also satisfy a number of site-specific considerations, many of which vary depending on the nature of the final site selected. Considerations relevant to the inquiry include the following:

- *Water Depth.* Water depth is a critical factor in evaluating potential LNG terminal locations. The water depth requirement is based on the premise that dredging would not be conducted for the purpose of bringing ships into the offshore terminal. Thus, the minimum water depth for the offshore terminal is required to accommodate the expected draft of the largest LNGCs calling at the terminal, plus an additional under-keel clearance (distance between the vessel's hull and the ocean floor) that would also take into account the ship's movement up and down with the tide and waves. Ultimately, a minimum water depth of approximately 15 to 16.8 m (49 to 55 ft) is needed to meet these requirements for an LNG terminal.
- *Soil Conditions/Geotechnical.* The geotechnical properties of the sea floor alone can range from critically important in the case of bottom-founded systems, to nearly irrelevant in floating systems. A concrete GBS must be sited in a location with satisfactory geological conditions and a stable sea bottom to support a large structure and to avoid archaeological sites and shallow hazards.
- *Navigation Safety/Shipping Access.* Due to the large size of LNGCs, the proximity of the LNG terminal to navigation fairways is an important siting criterion. The typical modern LNGC of 138,000 m^3 capacity (currently available) is approximately 300 m (975 ft) in length and 43 m (143 ft) in width, with a draft of approximately 12 m (39 ft). It is anticipated that future LNGCs

will be larger, upwards in size of 200,000 m^3 cargo capacity. To ensure a safe transit, the approach into and departure from the offshore LNG terminal must be free from surface and subsurface obstructions. Safe navigational access is a key requirement of the selected location. The USCG has formally designated a number of shipping fairways and harbor approaches in the GOM. These fairways are described at 33 CFR 166.200. These regulations, moreover, do not permit the placement of platforms or other obstructions that might interfere with shipping within the limits of the fairway. As a result, LNGCs should have safe navigational access into LNG terminals in close proximity to these existing shipping fairways. Offshore locations that do not have convenient access to, or are a considerable distance from, shipping fairways will pose a greater safety risk. In addition to unimpeded shipping access, the terminal location should also have a sufficiently large area free of surface and subsurface obstructions (including pipelines) to serve as a dedicated vessel anchorage. Although the proposed operations do not involve routine anchoring of LNGCs, an adequate anchorage near the LNG terminal is an important safety feature. Infrequently, LNGCs have mechanical, scheduling, or other problems that might require the ship to anchor for a period of time. If possible, the terminal location should be situated so that an appropriate anchorage can be used.

- *Safety and Security.* The terminal location should be situated to minimize safety risks while simultaneously allowing adequate security. Although it is helpful to site the terminal near an existing shipping fairway to promote convenient LNGC access, the selected location must not be so close to the edge of the fairway that it will interfere with the navigation of other vessels or pose an increased risk of collision from passing ships. Also, the facility location should be in an area with a low density of nearby offshore structures both to enhance navigation safety and to minimize the risk to other OCS operators in the event of an inadvertent release of LNG. The location on the OCS eliminates the need for the LNGCs to transit into and out of congested ports and waterways to discharge LNG cargo, thereby reducing the risk of collision or grounding in inshore waters. The terminal location should also be suitable for placement of a safety/security zone extending outward from the terminal 500 m (1,641 ft) in all directions. This size of safety/security zone is consistent with the provisions of 33 CFR 147, which authorizes the USCG District Commander to establish safety zones 500 m (1,641 ft) in all directions surrounding OCS facilities. Under provisions of the Deepwater Port Act, vessels will not be permitted to enter this safety/security zone without the express permission of the terminal operator or the USCG.

- *Availability of Offshore Blocks.* The GOM is a mature oil and gas province with an active oil and gas leasing program administered by MMS. Offshore blocks are leased for the exploration and extraction of minerals from the OCS. There are currently more than 8,000 active leases in the central and western GOM. Due to the active offshore development program, availability of unleased offshore blocks (or blocks with minimal facilities and operations that might be affected) in the vicinity of any prospective project site is an important siting consideration. Ideally, the project location would be a currently unleased OCS block with a low potential for economically recoverable mineral reserves.

- *Use of Existing Offshore Pipeline Infrastructure.* The project location should minimize the need for building lengthy new export pipelines while making maximum use of nearby underutilized gas transmission pipelines. The concept of connecting the LNG terminal to the existing offshore gas pipeline distribution network is one of the primary economic drivers for the project. Construction of lengthy segments of new offshore or onshore pipelines would be expensive and could seriously impair the economic viability of the project. The site should have access to one or more existing pipelines with sufficient available capacity to transport up to 1.2 Bcfd of natural gas. It is also desirable to have access to other nearby pipelines owned by various entities and serving multiple markets. This provides market flexibility and ensures opportunities for onshore storage of the natural gas if needed during periods of low demand.

- *Potential Conflicts with Other OCS Users.* The project location should minimize impacts on other users of the OCS. Many diverse groups use the waters and sea floor of the OCS, including mineral exploration and production companies, commercial and recreational fishermen, the military, commercial shipping, and recreational boaters. To the extent possible, the terminal location should avoid areas that are vital to any of these groups. Placing the terminal location near an existing shipping fairway might eliminate the need to have additional shipping fairways designated by the USCG, and subsequently prevent new restrictions from being placed on current leaseholders in the affected blocks. Attempting to locate the terminal on an unleased block with low potential for economically recoverable mineral reserves seeks to preserve blocks with higher potential for future exploitation. To the extent possible, the terminal location should minimize the footprint of the terminal and associated ship access routes such that the smallest possible number of lease blocks is affected.
- *Environmentally Sensitive Areas.* The location and associated pipelines should avoid environmentally sensitive areas. The selected alternative should avoid biologically important zones such as hard bottom, pinnacles, coral reefs, and chemosynthetic communities. The location should avoid any marine protected areas such as the Flower Garden Banks National Marine Sanctuary or similar protected areas. Making maximum use of the existing offshore gas pipeline network also has the advantage of avoiding the environmental effects of installing new pipelines across coastal beaches, wetlands, and other potentially sensitive inshore environments.

The Applicant's site selection process discussed here covers only sites considered for the GBS alternative selected for its Preferred Alternative. Other locations were screened during the selection process when FSRU and platform-based designs were still under consideration. However, since those systems were screened out from selection for this project, only potential GBS sites are discussed here.

In light of the prerequisite that regasified LNG from offshore be delivered into the existing natural gas transmission network, the starting point for a site-selection study must be to identify commercially viable takeoff points in the geographic target area. In general, the Applicant sought to identify major pipelines (16 in or greater) with suitable tie-ins, available capacity, and within 20 mi of each candidate block. Unleased offshore blocks for the GBS were selected near the 15 to 20 m (49 to 66 ft) water depth contour.

The Applicant identified potential locations for siting of a GBS in eight lease blocks along the Gulf Coast: Mobile Block 909, West Delta Block 58, West Delta Block 54, Ship Shoal Block 183, Eugene Island Block 162, South Marsh Island Block 276, West Cameron Block 183 (WC-183), and WC-213. For these eight locations, a two-step process was used to determine the most promising sites. The first step was to reduce the potential locations to a short list of technically feasible locations, using engineering, operational, and economic criteria. The intention was to arrive at a short list of technically feasible locations with respect to vessel accessibility and geotechnical conditions for each site. In the second step, additional and more detailed criteria were used to select a preferred location for the Proposed Action.

Evaluation Step 1. For the eight sites evaluated, shipping accessibility and soil conditions were considered initial screening criteria, with the following results:

- *Mobile Block 909.* While this site is near many shipping lanes, it was eliminated from further consideration because of proximity to wildlife refuges and wilderness areas (potential air emissions) and weaker soil conditions at the site.
- *West Delta Block 58, West Delta Block 54, Ship Shoal Block 183, Eugene Island Block 162, and South Marsh Island Block 276.* These sites were eliminated from further consideration because of challenging shipping access.

- *WC-183*. This site was retained for further evaluation based on its having fair access to a shipping channel and acceptable (stiff clay) geotechnical conditions.
- *WC-213*. This site was retained for further evaluation based on its having good access to shipping lanes and geotechnical conditions (sands) rated as reasonable to good.

Evaluation Step 2. Selection of the final sites for detailed evaluation was based on the technical feasibility of each site, as determined by a number of factors including availability of the block, pipeline accessibility, environmental impacts/constraints, soil/sediment conditions, shipping access, and operational safety (e.g., hurricane operation). Upon consideration of these factors, both sites were found acceptable. Overall, the Applicant has identified the site in WC-213 as its preferred site for the GBS primarily due to its excellent access to and from an established fairway, good soils (i.e., providing a good foundation for a GBS facility), water depth, anchorage, and its slightly farther offshore location than WC-183. The various factors for WC-213 and WC-183 are summarized in Table 2-3.

The Secretary respects applicants' expertise to identify those LNG deepwater port locations that represent viable business opportunities and relies on applicants to present reasonable and objective consideration of alternative locations to support their license applications. In light of the preceding discussion of alternative locations, this EIS evaluates in detail the potential use of WC-213 and WC-183 for the siting of the Applicant's proposed deepwater Port.

Table 2-3. Alternative Terminal Locations Site Feasibility

Location	Positive Factors	Negative or Neutral Factors
West Cameron Block 183	Good operational safety. Good pipeline access. Shorter total pipeline routes.	Poor temporary anchorage areas. Relatively poor water depth for berthing at facility, especially if scour protection by stone rubble is required. Block is leased; conflict with intended use by leaseholder. Fair access to shipping lanes, but with numerous platform structures in the path. Acceptable soil conditions, but turning to more clay. Acceptable environmental impact (slightly closer to shore).
West Cameron Block 213	Good soils. Good water depth. Good temporary anchorage options. Good operational safety. Excellent shipping lane access. Good pipeline access.	Acceptable environmental impact (slightly farther offshore).

2.2.7 Alternative Pipeline Routes

A variety of factors are involved in determining appropriate pipeline routes and connections for delivery of natural gas to onshore distribution systems. Sufficient available capacity must be identified if existing pipelines are to be used. The lengths and numbers of pipeline routes influence economic viability and the potential for environmental impacts. Construction procedures and new pipeline routes must be selected to avoid geological hazards, prevent impacts on existing OCS structures and pipelines, and avoid creating hazards to fishing or other offshore activities. Requirements for new pipeline routes can influence the economic viability and the potential for environmental impacts from a proposed deepwater port.

The Applicant considered several alternative take-away pipeline routes from WC-213 in developing the Preferred Alternative. The pipe diameter and length and potential acres of bottom that would be disturbed during the construction of each of these alternative take-away pipelines are presented in Table 2-4.

Table 2-4. Potential Take-Away Pipelines for a Terminal in West Cameron Block 213

Pipeline	Pipe Required (mi)	Pipe Diameter (in)	Acreage of Disturbed Sediment (ac)
A	20.0	36	507
B	13.0	24	303
C	17.2	30	422
D	1.7	16	41
E	13.8	20	332
F	56.6	36	1,372
G	1.4	30	34
H	5.3	30	129

Source: GL 2003a

Gulf Landing LLC has proposed to employ five pipelines (A, B, C, D, and E) as take-away options for the natural gas revaporized at the LNG regasification Terminal. Geohazard and archaeological surveys have been conducted for these routes. This combination of pipelines and routing meets the essential requirements of the project.

Pipeline routes F, G, and H were not selected because they had no economic or environmental advantages. There were problematic issues idenitifed with these receiving pipelines.

2.2.8 GBS Fabrication Yard Site Alternatives

The Gulf Landing GBS units would be formed from two caissons of prestressed, reinforced concrete. As fabrication in GOM waters would not be practicable, the GBS units would be fabricated on land, floated, and towed to the Terminal site for installation. Creation of a purpose-built "graving dock" for construction of the proposed GBS caissons would be required.

Gulf Landing LLC has not finalized its decision on where to build the GBS units. A final site selection would be based on numerous factors; environmental considerations and permitting requirements would be important decision criteria.

The Applicant's selection of the site for fabrication of the GBS units is a discrete stage of the project for which there will be supplemental NEPA analysis for decisionmaking (40 CFR 1502.2 and 1508.28). While a majority of the Gulf Landing LLC application is ready for decision, matters affecting the location of the proposed construction of the GBS units has not been resolved. That aspect of the Proposed Action is, therefore, not ready for decision. As a result, analysis specific to the proposed Terminal fabrication site will be presented in a separate, supplemental NEPA document that will include an analysis of reasonable alternatives and cumulative impacts of the entire previously unanalyzed actions (40 CFR 1508.28). The requirement to conduct site-specific and cumulative analyses of the proposed Terminal fabrication site prior to construction in a separate NEPA document will be a condition of the license for the Gulf Landing deepwater Port should such license be issued. The subsequent supplemental analysis may take the form of a separate EIS or other form of NEPA analysis.

Construction of the Gravity Based Structures will most likely be accomplished at a shore-based fabrication site. The Applicant has not proposed a site for construction of the GBSs and has not provided details of the construction process to be used. Construction of the GBSs is likely to involve construction of a specialized dry-dock, or graving yard. The GBSs will be fabricated in the graving yard, either simultaneously or sequentially. They will then be outfitted with the equipment necessary to support LNG offloading, regassification, and deliver the gas to the pipeline systems.

At a minimum the analysis will identify and evaluate applicable Federal, state and local regulatory and permitting requirements as well as potential impacts to all appropriate resources. Selection of a construction site outside of the United States would require additional assessment of the applicable requirements for that nation. A quantitative inventory and impacts assessment of these parameters is site specific and cannot be reasonably completed prior to identifying specific site alternatives. The impacts evaluated for onshore construction may include

- Water Quality (including drinking water resources)
- Biological Resources (terrestrial and wetland habitats; endangered, threatened and species opf some regulatory concern)
- Costal Zone Management Act Consistency
- Cultural Resources
- Socioeconomic resources
- Recreation
- Transportation
- Air Resources
- Land Use
- Cumulative and Other Impacts

2.2.9 Oil Deepwater Ports

The Secretary is to promote both oil and natural gas deepwater ports equally, without comparison or preference to either. While oil deepwater ports are possible, only one has been constructed. The USCG has not received any other applications for oil deepwater port licenses since the first port was constructed 30 years ago. Also, the Deepwater Port Act places strict limits on the number of oil deepwater ports the Secretary can license, based on the concept of "application area" at 33 U.S.C. 1504(d) allowing only one facility in a very large geographic area. Finally, as opposed to natural gas, there are many competing options for importing oil. For example, onshore oil terminals are numerous and nearly ubiquitous on the coast. By comparison, there are only four operating onshore LNG facilities in the United States. As a consequence of this and other provisions, the Secretary believes that there will be very few applications for oil deepwater ports. Therefore, analysis of oil deepwater ports was eliminated from further consideration.

2.3 No Action Alternative

This document refers to the continuation of existing conditions of the affected environment, without implementation of the Proposed Action, as the No Action Alternative. Inclusion of the No Action Alternative is prescribed by CEQ regulations and serves as a benchmark against which Federal actions can be evaluated.

Under the No Action Alternative, the Secretary would deny the license application and the project would not proceed. The additional infrastructure proposed by Gulf Landing LLC would not be built and brought on line to satisfy natural gas demand. Other license applications concerning proposals to satisfy demand for natural gas might be submitted to the Secretary, or other means might be used to satisfy the Nation's energy demands, such as expansion or establishment of onshore LNG ports. Because the demand for energy in the United States is predicted to increase, consumers may have fewer and potentially more expensive options for obtaining natural gas supplies in the near future. It is possible that existing natural gas infrastructure supplying the proposed market area could be developed in other ways unforeseen at this point, including the further development of natural gas sources in North America and construction of associated pipeline projects. In some cases, potential customers of natural gas could select available energy alternatives such as oil, coal, wind, solar, hydro or biomass to compensate for the reduced availability of natural gas. However, it is purely speculative to predict the resulting action that would be taken by the end users of the natural gas supplied by the project and the associated direct and indirect environmental impacts.

2.4 Alternatives Selected for Detailed Evaluation

The Deepwater Port Act provides for the Secretary's action to authorize and regulate the "... *location*, ownership, construction, and operation of deepwater ports"[14] (emphasis added). The Secretary has applied the purpose and need for the Proposed Action and carefully considered various alternatives. He determined that alternative locations in the GOM were appropriate for further consideration. Within the GOM, the Secretary applied his aforementioned criteria to identify possible sites (see Section 1.2). Most important in that analysis were safety, protection of the environment, and economic viability.

Alternatives to be evaluated in detail in this EIS are the Applicant's proposal for siting of the deepwater Port in WC-213, an alternative deepwater Port location in WC-183, and the No Action Alternative.

2.5 Identification of the Preferred Alternative

40 CFR 1502.14(e) instructs EIS preparers to "Identify the agency's preferred alternative or *alternatives*, if one or more exists, in the draft statement and identify such alternative in the final statement *unless another law prohibits the expression of such a preference*" (emphasis added). Since the Secretary will either grant (with or without conditions) or deny the license, the Preferred Alternatives are the Proposed Action (WC-213) and the No Action Alternative. However, identifying the Preferred Alternative could be interpreted as predecisional to the issuance of a license prior to the Secretary's assembling, reviewing, and analyzing all of the relevant information pertaining to the license application, as required under the Deepwater Port Act. Therefore, the Secretary will defer identification of the Preferred Alternative until a decision is made whether or not to grant a deepwater port license and will indicate the Preferred Alternative in the Record of Decision issued under the Deepwater Port Act.

[14] 33 U.S.C. 1501(a)(1)

2.6 Detailed Description of the Proposed Action

This section provides a detailed description of the Applicant's proposal to construct and operate an LNG deepwater port.

Information in this section is based on the proposed Port being in the Applicant's preferred location, WC-213 (see Figure 2-1). An alternative location for the proposed Port would be WC-183. The offshore facility components for the alternative would be very similar and in some cases identical to those described for a terminal in WC-213. Because of its location near a shipping fairway, water depth, unimpeded carrier access, soil profile, and leasehold status, WC-213 is the location identified as the Applicant's Preferred Alternative. Accordingly, this block has been the focus of all geohazard, cultural resources, and pipeline right-of-way surveys. No new geophysical or cultural resource surveys have been conducted in WC-183. For this EIS, available historical data from an adjacent area (WC-182) have been used to characterize the geology, soils, and cultural resource potential in the block for the alternative location. Figure 2-2 shows the proposed and alternate Gulf Landing Terminal locations and take-away pipeline routes and the surrounding OCS features. Figure 2-3 shows the proposed Gulf Landing Terminal and vicinity.

2.6.1 Facility Description

The proposed Terminal would consist of two fixed concrete GBS caissons and include the following:

- LNG storage within each GBS caisson
- Scour protection
- LNGC mooring provisions
- LNG unloading arms
- LNG transfer and high-powered pumps
- LNG vaporizers
- Sales gas heaters
- Fiscal meters
- Utility systems
- Accommodations and helideck
- Safety and security systems
- Escape and emergency systems
- Power generation plant
- Control room, workshop, and laydown areas
- Seawater intake and outfall structures
- Navigational aids
- Pipeline risers

Figure 2-4 shows a plan view of the proposed Gulf Landing Terminal. Figure 2-5 shows an aerial view of the proposed Gulf Landing Terminal.

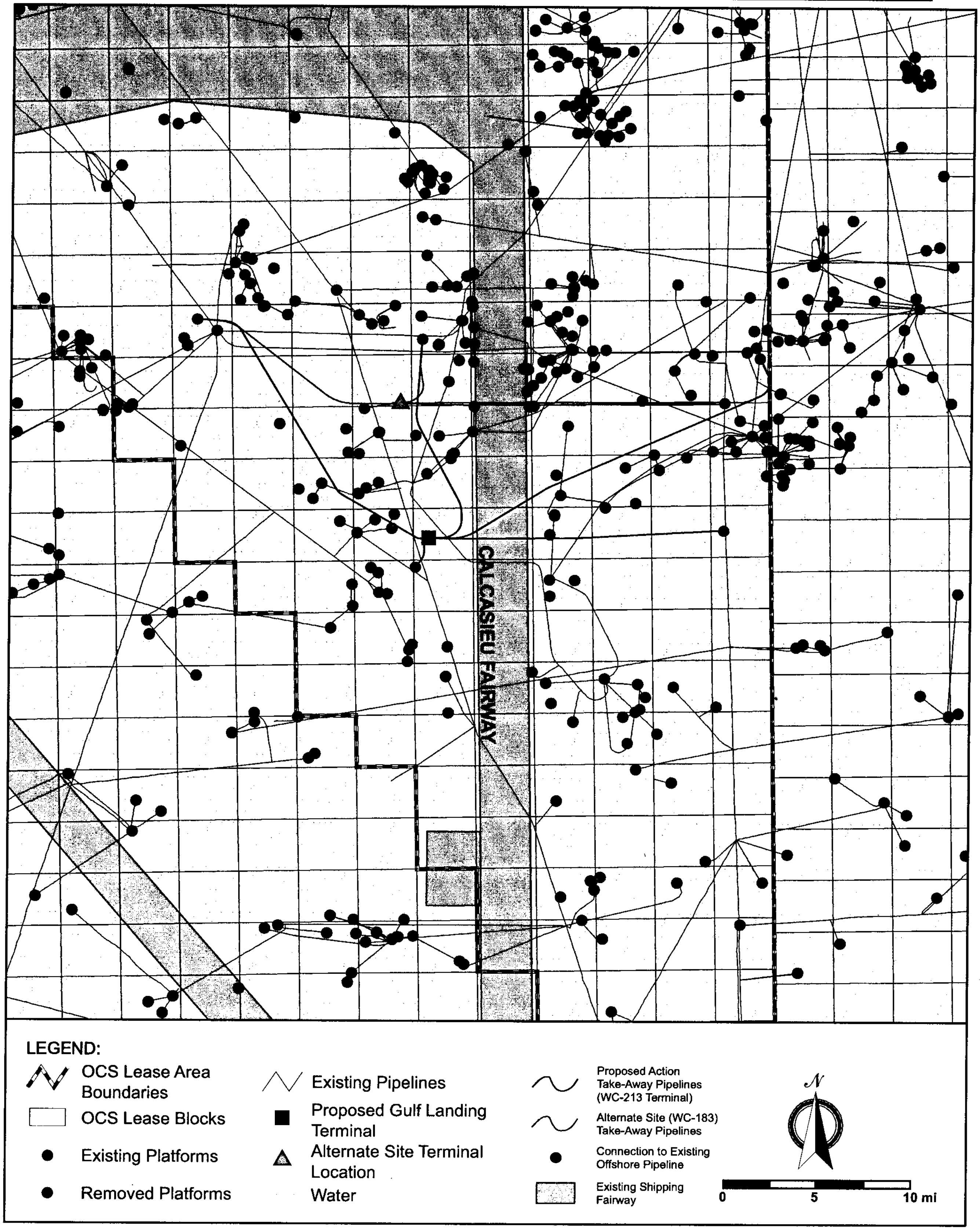


Figure 2-2. Proposed and Alternate Gulf Landing Ports and Surrounding OCS Features

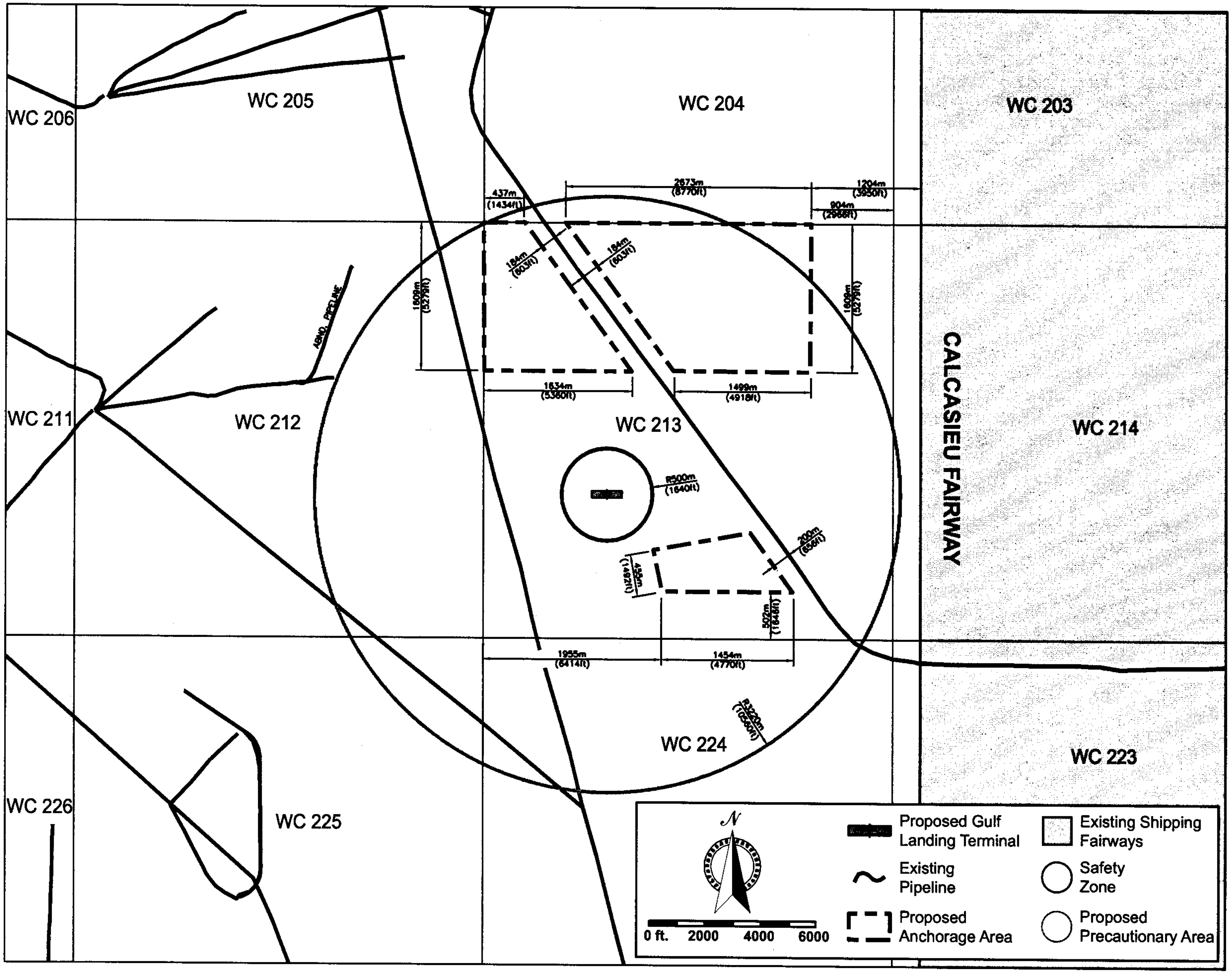


Figure 2-3. Proposed Gulf Landing Terminal and Vicinity

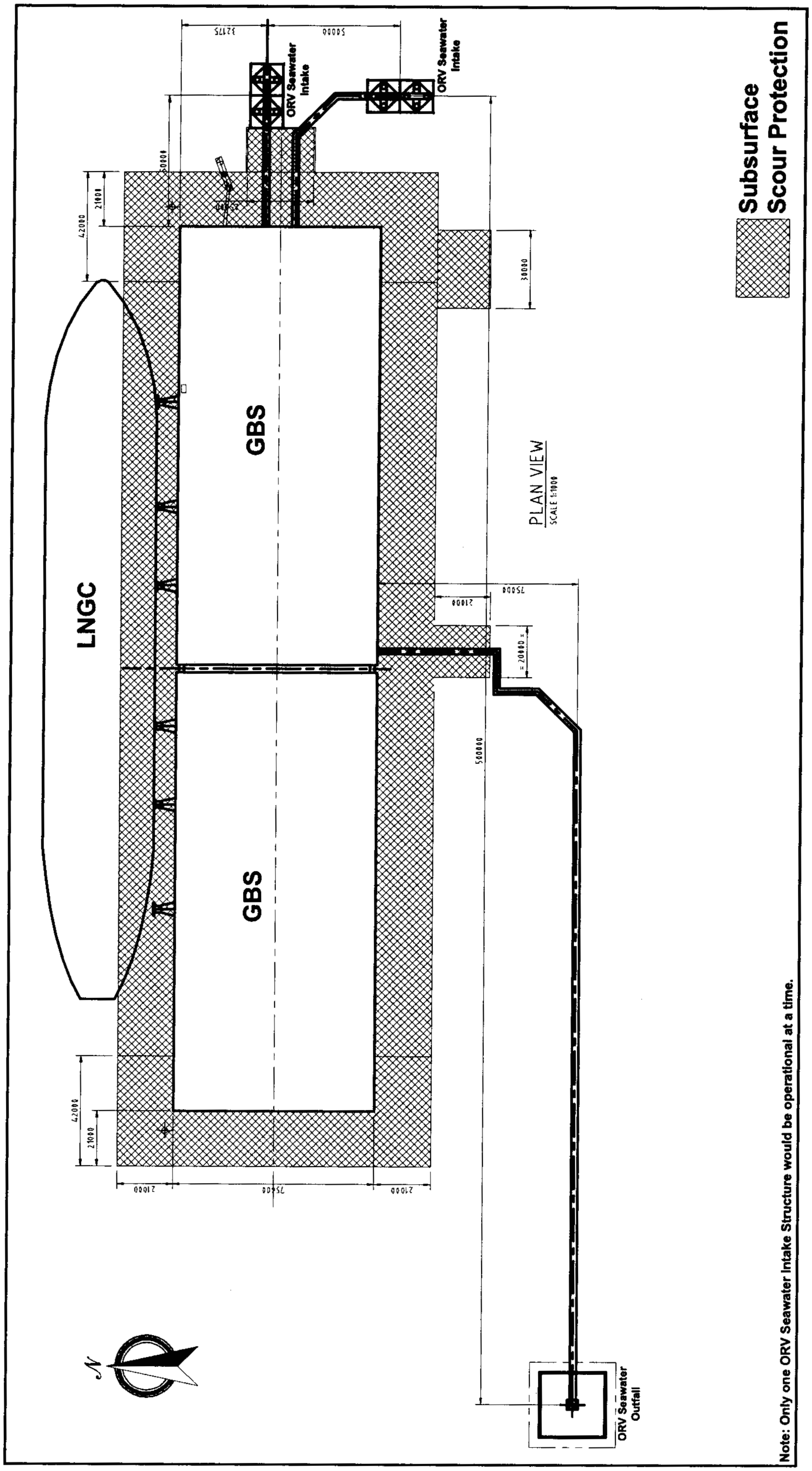


Figure 2-4. Proposed Gulf Landing Terminal Plan View

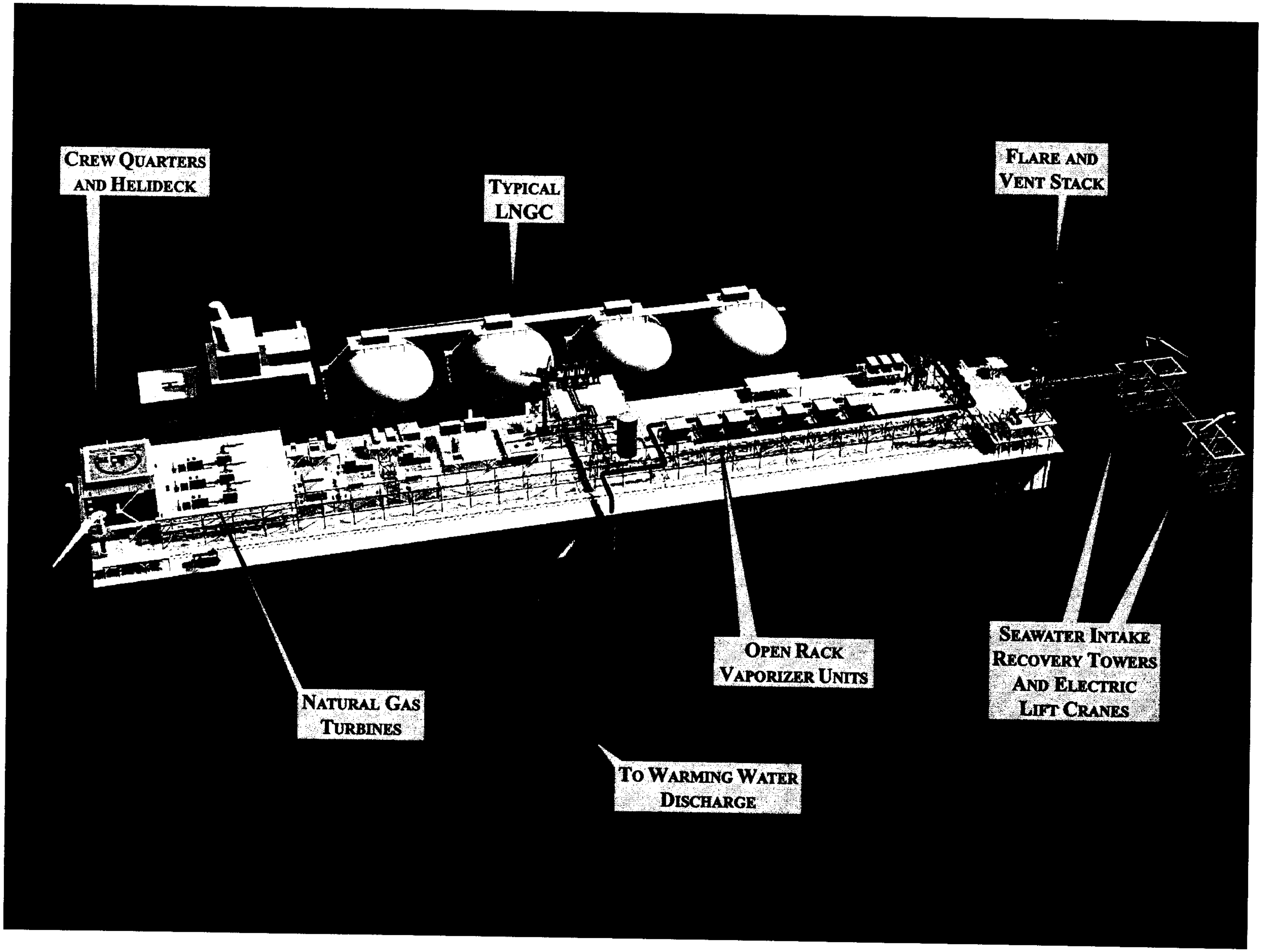


Figure 2-5. Aerial View of Proposed Gulf Landing Terminal

Terminal Functions. The Terminal would provide several basic functions including carrier berthing, carrier unloading, LNG storage, LNG vaporization, gas metering and delivery, power generation and other utilities, and personnel quarters as described in the following:

- *LNGC Berthing.* The Terminal would accommodate berthing, unloading, and unberthing of standard worldwide trading LNGCs and LNGC designs anticipated in the near future. The size range of LNGCs that the Terminal could accommodate would be from 125,000 to 200,000 m3 cargo capacity. Facility design would accommodate offloading approximately 135 LNGCs per year (approximately 1 LNGC every 2.7 days). Berthing would be accomplished with the aid of four tugboats. Each tugboat would meet the incoming LNGC and stay on-station until the LNGC has safely departed the Terminal. It is anticipated that the tugboats would be in addition to the existing tug fleet in Cameron, Louisiana. Cameron is a major port of call for the offshore oil and gas industry and the area also supports two menhaden processing plants (GL 2003b). The tugboats would each make a maximum of 135 trips to and from the Terminal each year. The facility would be operated 24 hours per day, 7 days per week, 365 days per year. It is anticipated that berthing, transfer of the LNG from the LNGC to the Terminal, and unberthing would take between 22 and 30 hours per LNGC.LNGC Unloading. LNGCs would berth directly alongside the GBS structure to unload. The GBS would be equipped with fenders and quick-release hooks to facilitate mooring operations. Unloading would be side by side using unloading arms located on the GBS loading Terminal. These would be physically separated from the LNGC. The design-unloading rate of the Terminal would be up to 12,000 m3/h with an anticipated average unloading rate of 10,000 m3/hr requiring between 12.5 and 20 hours to offload each LNGC. In between vessel arrivals, a small flow of LNG recirculation would be required from downstream of the loading arms to the storage tank to keep the LNG system "cold," (i.e., "ready for service" to avoid thermal shock between carrier unloading cycles).
- *LNG Storage.* The LNG would be stored in tanks located and supported inside the two concrete GBS caissons. The combined LNG storage capacity of the two tanks would be 180,000 m^3, the equivalent of approximately 3.8 Bcf of natural gas (working or net capacity).

LNG Vaporization. The deck of the concrete GBS would support the Terminal processing and metering equipment. The vaporization equipment would include the LNG low-pressure in-tank pumps, high-pressure pumps, vaporizers, seawater intake pumps, and sales gas heaters. The LNG would arrive on the facilities from the LNGC and loading area where it would be pumped into the Terminal storage tanks. The LNG would then be pumped to the process facilities using low-pressure in-tank pumps. High-pressure pumps would pump the LNG to a pressure of up to 1,450 pounds per square inch (psi) (100 bar). The pressurized LNG would be vaporized via ORVs to natural gas ready for distribution. Figure 2-6 shows a schematic of the proposed basic process design.

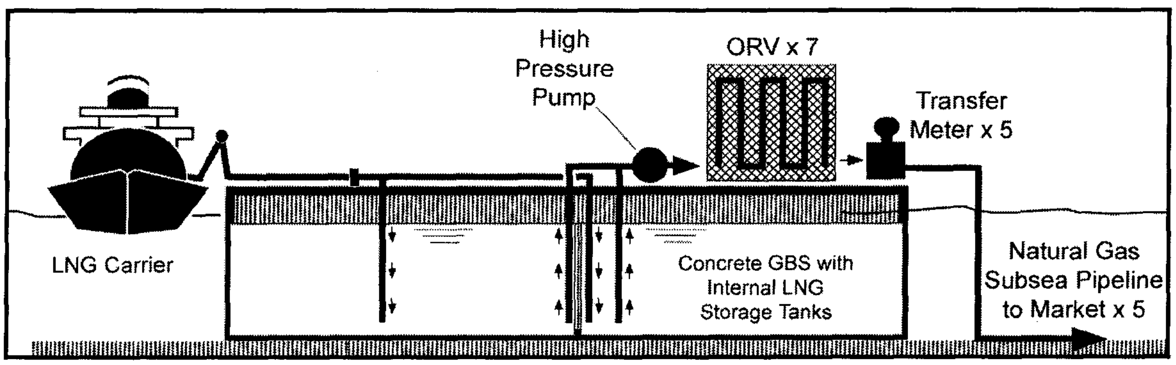


Figure 2-6. Proposed Gulf Landing Basic Process Design

- *Gas Export and Metering.* The vaporized LNG would be metered and delivered into the offshore transportation grid using a combination of the five lateral pipelines extending from the Terminal. There would be five metering stations, each consisting of one or more standard-size nominal meter tubes to suit the capacity of the lateral pipeline. A spare meter tube and meter would be available on the Terminal for replacement purposes. The pipeline laterals would consist of various lengths of outer diameter pipe dependent on the design capacity, pressure drop considerations, and length of pipeline to the interconnection point. MMS would have oversite for Gas Export and metering issues.
- *Main Power Generation.* The Terminal electrical power requirements would be provided by two turbine generator sets. There would be one spare generator set installed. Fuel for the turbines would be provided from vaporized LNG via a fuel gas system. Two of the turbines would be dual fuel, capable of burning diesel oil for Terminal start-up or during emergencies. The Terminal would store 224,500 gallons (gal) (850 m^3) of diesel oil in a single storage tank. This tank would provide an approximate 7-day supply for critical services.
- *Sea Water for Vaporization.* Sea water would be used as the heating medium for the ORVs to vaporize the LNG in a once-through mode. Seawater lift pumps would deliver the sea water to the vaporizers from the seawater intake structure. As shown in Figures 2-4 and 2-7, the Applicant has proposed two intake structures. The proposed operating design would collect 100 percent of the Terminal's raw sea water from one intake with a redundant intake out of service. Operation of the intakes would be rotated regularly for cleaning and maintenance of intake screens.

  Each intake structure would have eight cylindrical 0.25-in gap wedgewire intake screens to minimize entrainment. A recovery tower would be constructed around each intake structure (Figure 2-7). These towers would be approximately 34 m (112 ft) tall reaching approximately 17 m (56 ft) above the sea surface. The top of each tower would be equipped with a crane used to lift the screens to the surface for maintenance and repair when not in use. The towers would be connected to the Terminal with a bridge.

  Based on calculations presented by the Applicant, the total estimated average annual daily intake of raw sea water at the operative intake structure would be 136 MGD with the Terminal regasifying 1.0 Bcfd of natural gas with a maximum seawater intake of 152 MGD at a regasification rate of 1.2 Bcfd. The intake velocity would be approximately 0.32 ft/s at 136 MGD and 0.38 ft/s at 152 MGD. The intake screens would be approximately 5 m (16 ft) off the sea floor (Figure 2-7).

  A sodium hypochlorite solution between 2 and 5 ppm would be injected at the suction of the seawater pump to prevent marine growth in the warming water system. The maximum sodium hypochlorite concentration in the warming water outfall discharge would be 0.5 ppm.

  The cooled sea water is collected in a trough and sent by gravity to the water outfall, which is approximately 2 m above the sea floor on the opposite end of the GBS from the seawater intake to avoid recirculation of cold water (Figure 2-7). As shown in Figure 2-7, the cooling water outfall diffusers will discharge vertically. The Applicant's model assumes that the temperature of the water at the discharge point would be approximately 10 °C (18 °F) below the ambient seawater temperature. In the absence of a cross current, the discharge temperature plume would be an umbrella shape. The Applicant's modeling results indicate that 100 m from the discharge manifold, the temperature of the plume would be well within the World Bank Criteria of 3 °C (37.4 °F) of ambient seawater temperature (GL 2003b).

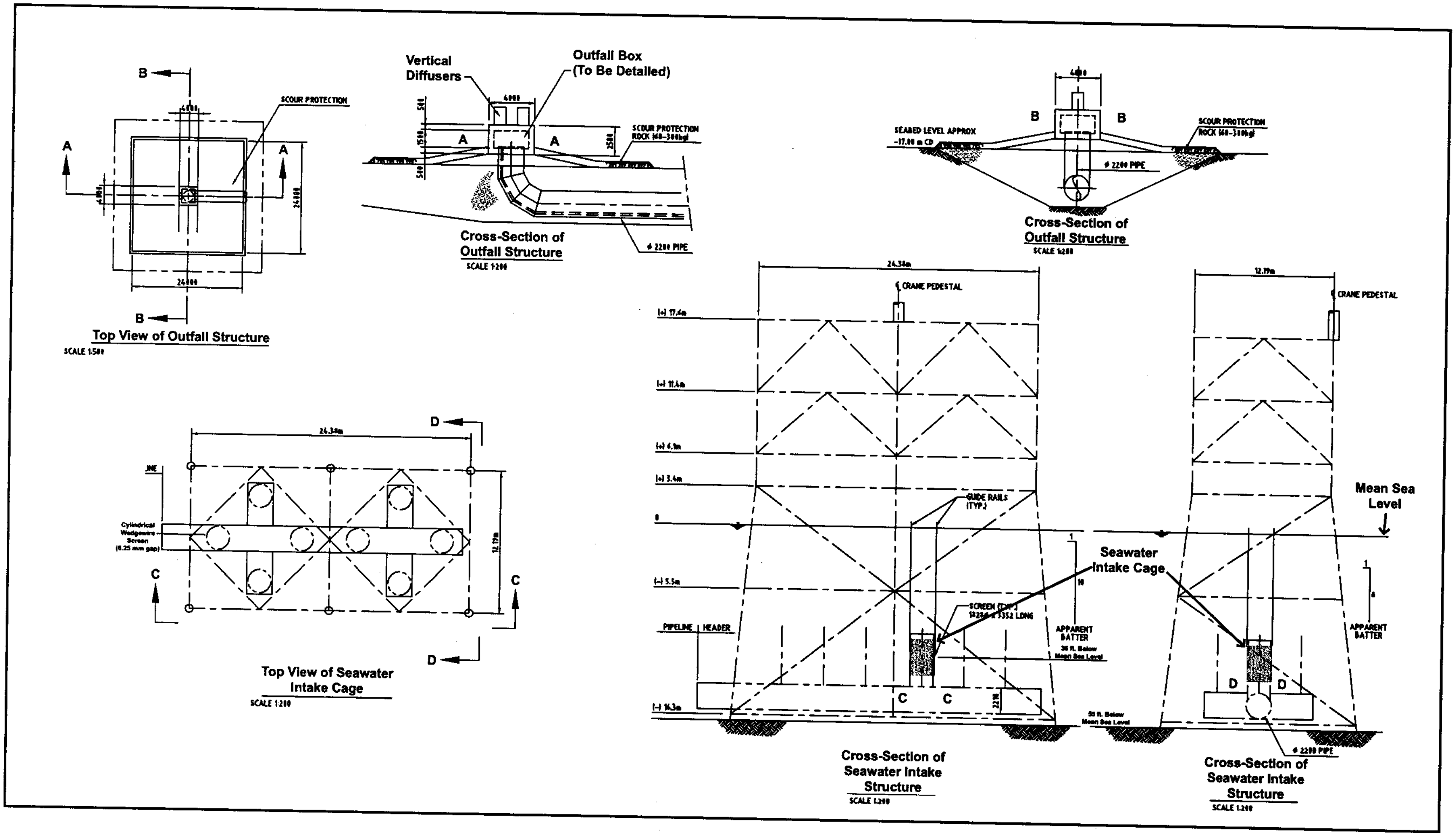


Figure 2-7. Proposed Gulf Landing Terminal Intake and Outfall Schematics

- *Supply & Support*: It is anticipated at this time, that one contracted vessel will make one trip per week to and from the Terminal to transport supplies and personnel and remove materials as needed. It is anticipated that contracted helicopters will transport personnel and small supplies to the Terminal three times per week. The supply vessels and helicopters will be contracted from existing onshore support service facilities currently operating in the OCS. No new vessels, helicopters, or onshore infrastructure would be required to support the operations and maintenance of the Gulf Landing deepwater Port.
- *Solid Waste and Debris.* Solid waste and debris generated in all phases of the proposed Port (construction, operations, and decommissioning) would be collected aboard the generating entity (tugboat, supply vessel, or the GBS Terminal) and ultimately transported to shore for disposal in an approved disposal site. All contractors and suppliers would be required to have waste management plans in place that include identification of the ultimate repository for collected waste. For these reasons, only the accidental release of trash and debris has been carried forward through the environmental analysis.*Personnel Quarters.* Personnel quarters sufficient to support approximately 20 persons, would be located on the GBS structure with appropriate segregation and protection from hydrocarbon hazards associated with LNG offloading, storage, pumping, vaporization, and metering equipment. The personnel quarters building would consist of individual deck levels for sleeping, galley and messing, recreation, control room and offices, equipment and communications control rooms, workshops and storage areas, and helicopter operations. It would provide fully self-contained accommodations for operations personnel, including occasional short-term accommodations for offshore maintenance and gas pipeline staff. A helicopter deck meeting the necessary regulatory requirements would be located above the quarters building.

Facility Layout. Design of the facility's layout accords highest priority to safety and operability. The separation distance between the hydrocarbon systems and the accommodations module would be maximized by placing the accommodations on the west end of the GBS and the processing equipment on the east end of the structure. This would result in a separation distance between the accommodations and the hazardous systems of approximately 150 m (492 ft). The accommodations module would be located above ballast areas of the GBS and not above the LNG storage tanks. The accommodations module would also be segregated from LNG storage within the GBS by the containment system and the concrete deck.

The personnel quarters would be aligned with the LNGC accommodations, as the LNGC would berth on the north side of the Terminal with its bow typically heading east (direction of the generally prevailing current). The helicopter deck would be located on top of the personnel quarters, and the westerly location of the personnel quarters would enable an upwind helicopter approach during the governing wind direction.

Escape capsules would be provided near the accommodations module. To improve the reliability and availability of lifeboats being successfully launched in an emergency, muster points and lifeboat stations, each capable of accommodating 100 percent of the personnel at the Terminal, would be provided on different sides of the Terminal near the accommodations. An alternate refuge would be provided at the east end of the Terminal to act as a muster and evacuation point for major accident scenarios that prevent all personnel from reaching the accommodations and primary muster areas. This alternate refuge would be equipped with communications equipment and an additional escape capsule.

For safety reasons, the amount of LNG moved external to the storage tanks would be minimized. The main hydrocarbon equipment would be clustered on the eastern GBS caisson, enabling short process lines. All process equipment including the recondenser vessel would be able to drain directly into the

LNG storage tanks. The low-pressure liquid header would be on the south side of the process equipment, and the high-pressure gas header would be on the north side of the process equipment.

The risers and metering skid would be at the eastern end of the Terminal because of the direction of the send-out lines. The water intake system would be off the Terminal structure and connected to the eastern GBS caisson by means of two pipes. The outfall system would also be off the Terminal structure and run from the eastern GBS caisson as well.

Safety systems and utilities would be placed between the accommodations module and hydrocarbon processing facilities to further act as a barrier between the safe and hazard ends of the installation. The vent/flare would be on the southeast corner of the eastern GBS caisson.

The main functions of the GBS structures would be to accommodate the LNG storage tanks; to safely support the accommodations, LNG vaporization plant, and other process equipment and utilities; and to safely enable LNGCs to berth directly alongside the GBS. The Terminal would be composed of two pre-stressed and reinforced concrete structures. The structures would be built onshore, towed to the site, and set down on the sea floor using well-proven construction methods and technology that have been commonly and successfully used in the offshore oil and gas industry for decades. The concrete deck level would be about 18 m (60 ft) above the water (Chart Datum), ensuring that no wave overtopping or green water would occur in operational environmental conditions.

The two GBS caissons would be placed end to end. The structural layout would consist of a repetitive grid of plane walls and slabs. Longitudinal and transverse skirts located underneath the base slab would extend below the mud line in order to achieve adequate bottom stability and prevent the GBS from sliding or shifting. Between the storage tanks and the outer wall and bottom of the GBS would be a grid of cells: These would be used for ballasting the GBS during transportation to the site and to ground and secure the GBS foundation. In addition, the peripheral so-called "buffer belt" around the LNG tank would provide protection to the storage tanks in the event of a vessel impact.

LNG Facilities. The following describes the proposed LNG process facilities.

- *Boil-Off Gas.* Natural gas vapor is formed due to heat ingress into the storage tank, heat introduced into the tank during ship unloading, heat ingress from the LNG recirculation lines, and by changes in the fluid composition when LNG is offloaded into the storage tanks from LNGCs. This vapor is referred to as boil-off gas (BOG). BOG would be used to balance the pressure in the LNGC while unloading, based on differential pressure. Excess BOG would be routed to the BOG compressor.
- *Boil-Off Gas Compressor.* Under normal conditions, the BOG would be compressed by the BOG compressor and routed to the recondenser. There would be one spare BOG compressor fitted to ensure continuity during periods of BOG compressor maintenance or equipment failure. During hurricanes, the Terminal would be unmanned, and gas send-out would cease. All noncritical operations would be shut down, topsides hydrocarbon systems depressured and drained, and as a result, excess BOG would then be flared.
- *Recondenser.* The recondenser would be used to recondense all of the BOG and provide enough pressure and surge volume at the suction of the high-pressure LNG send-out pumps. The main flow of the LNG from the in-tank pumps would be routed directly to the bottom of the recondenser vessel. The BOG would be recondensed by mixing it with a portion of the cold LNG being pumped out of the LNG storage tanks. The recondensed BOG would mix with the LNG inside the bottom section of the recondenser and then be routed to the regasification trains. The

recondenser would be designed to consume all of the BOG generated in the GBS, including ship-unloading vapors.

- *LNG In-Tank Pumps.* The LNG in-tank pumps would transfer LNG from the LNG storage tanks to the process facilities. The low-pressure in-tank pumps would be centrifugal submerged motor pumps installed in vertical pump wells inside the storage tank.

- *LNG High-Pressure Pumps.* High-pressure pumps would bring the required maximum flow rate of LNG to a pressure of 1,450 pounds per square inch gauge (psig) (100 bar). Each pump would be directly coupled to an ORV. The pumps would be designed for cryogenic service and have a kickback line and open-vent line back to the recondenser. There would be one spare high-pressure pump fitted.

- *ORVs.* The LNG flows from each high-pressure pump would be passed to an ORV, where the LNG would be vaporized at high pressure. Sea water would be used as the heating medium for the ORVs to vaporize the LNG. Figure 2-8 shows a schematic of an ORV. The sea water would be delivered using pumps. There would be one spare seawater pump installed. An electrochlorination or sodium hypochlorite injection unit would prevent marine growth on the seawater lines. The LNG would be fed through aluminum tubes while sea water flows from the top of the vaporizers over the tubes in which the vaporization takes place. The approach temperature (the difference between outlet temperature and the seawater intake temperature) would be a maximum of 10 °C (18 °F). There would be one additional ORV installed as a spare.

- *Sales Gas Heaters.* The send-out gas would be heated to mitigate the possibility of hydrate formation in the take-away pipelines. There would be two sales gas heaters in normal operation, with one additional heater installed as a spare. The heating medium would be water based. Waste heat would be recovered from the electrical power generation exhaust gases in the waste-heat recovery unit, using a water-based heating medium. During very cold weather, a small supplementary boiler would provide additional heating required to prevent hydrate formation in the export pipelines.

- *LNG and Gas Quality Measurement.* Custody transfer for the LNG discharging from the LNGC would be based on ship-level measurements to determine volume and online gas chromatography measurements to determine composition. The LNG chromatograph would be located downstream of the loading arm prior to the tank inlet. A dome sampler, which collects a composite sample over the entire unloading period, would be used. Export gas would also be analyzed by gas chromatography; the gas sampling point would be on the sales gas heater.

- *Send-Out Gas Distribution and Metering.* After heating, the gas export stream would be divided amongst up to five take-away pipelines. Each pipeline would have its own pressure reduction station and two or more custody transfer meters to accommodate the export flow-rate.

- *LNG Circulation System.* All significant lengths of cryogenic piping and equipment would remain cold during normal operation by the presence of LNG. Lines where this is not possible (e.g., the vapor return line) would be designed for thermal cycling. Recirculation would be established from the LNG storage tanks from the low-pressure LNG send-out header to the unloading manifold and directly back into the tanks. Compared to a conventional LNG import terminal, the heat ingress (and hence the required rate of LNG circulation) would be fairly limited due to the short distance between the LNGC and the storage tanks.

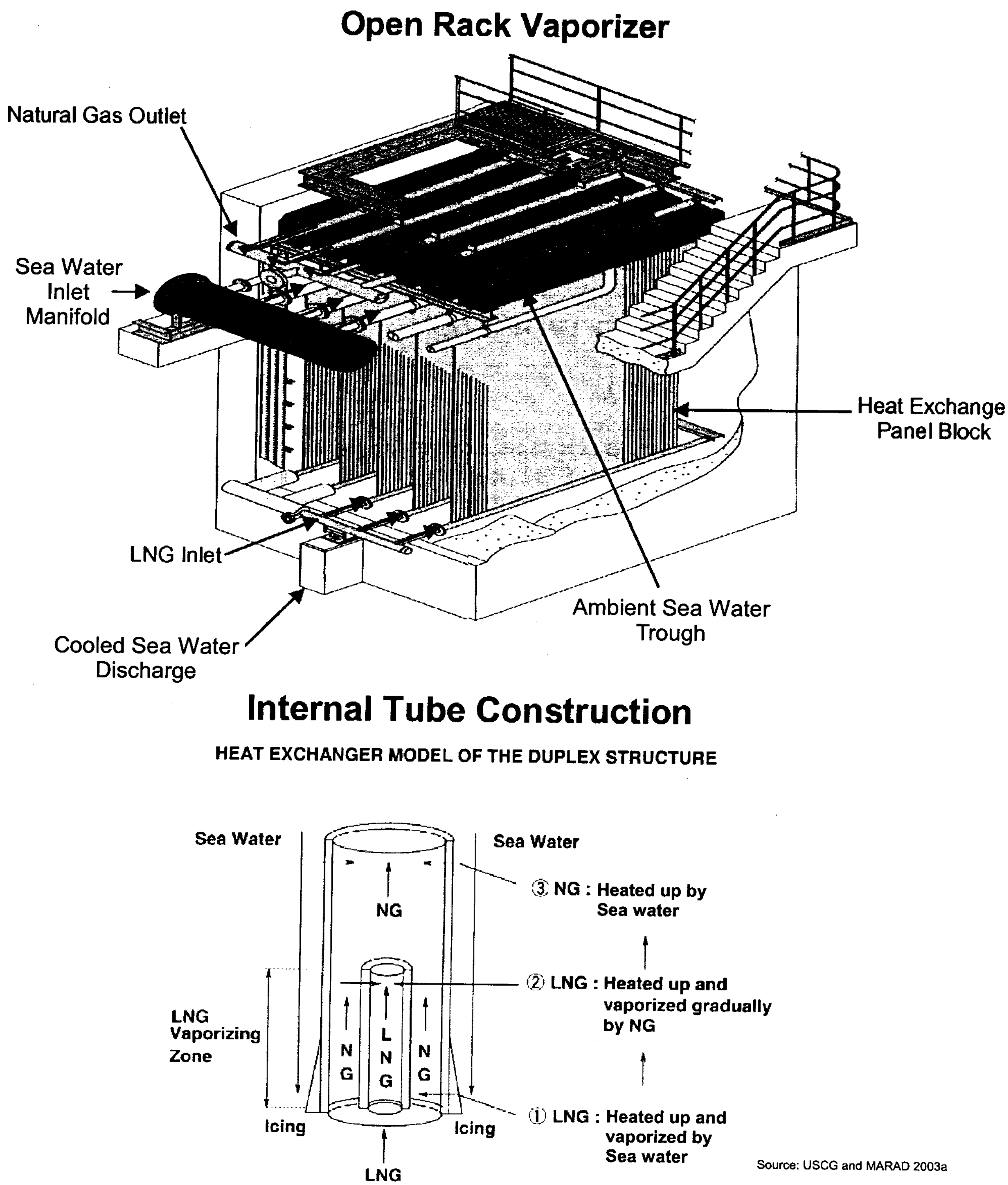


Figure 2-8. ORV Schematic

- *Relief System.* Under normal operating conditions, the facility would have no flaring or venting; any BOGs would be recondensed to LNG and routed to the high-pressure LNG pumps. For emergency conditions, there would be three emergency relief headers, a flare header, a low-pressure emergency vent header, and a high-pressure emergency vent header. A self-igniting flare would be provided to safely dispose of emergency process releases. Use of the ignitable flare concept would minimize the overall greenhouse gas emissions to the atmosphere of the facility through the elimination of continuous fuel gas sweep and pilot lights on the flare tips. In case of abandonment of the facility during hurricane situations, send-out of natural gas into the take-away pipelines would be discontinued. In these situations, topsides hydrocarbon equipment would be depressurized and drained, and subsequently tank boil-off would be routed to the flare.

Pipelines. The five take-away pipelines would operate at pressures appropriate to maximize safety and efficiency and would be buried to meet the regulatory standards of cover. The combined length of the five pipelines would be approximately 105.7 km (65.7 mi). Table 2-5 and Figure 2-9 show details of the five proposed pipelines.

The pipelines would be in water depths varying from 12.2 to 18.3 m (40 to 60 ft). The pipelines would be constructed of American Petroleum Institute (API) 5 liter (L), pipe having a specified minimum yield stress (SMYS) of 52,000 psi (358.5 mega Pascal [MPa]) or greater. The pipelines would be constructed in accordance with 49 CFR 192.327(g) and 192.612(b)(3) requiring all natural gas pipelines in the GOM to have a minimum of 0.91 m (36 in) of cover for normal excavation and 0.46 m (18 in) of cover for rock excavation, except for pipelines crossing shipping fairways that must be buried with 3 m (10 ft) of cover. For undersea stability, the pipeline would have an appropriate weight concrete coating. The corrosion protection system would include a thin film external coating and sacrificial anodes for cathodic protection.

Table 2-5. Proposed Gulf Landing Take-Away Pipelines

Pipeline	Pipe Required (mi)	Pipe Diameter (in)	Acreage of Disturbed Sediment (acres) (200 ft ROW)	Approximate Pipeline Volume (ft^3)
A	20.0	36	507	26,900
B	13.0	24	303	11,440
C	17.2	30	422	18,920
D	1.7	16	41	997
E	13.8	20	332	10,120

Source: GL 2003a

Notes: ROW – Right of Way (construction)
mi – miles
in – inches

2.6.2 Operations

Gulf Landing LLC has submitted with its license application a Draft Marine Operations Manual for the conduct of daily activities of the proposed Port. The draft manual is subject to approval as part of the license application process. If the license application is approved, commencement of operations would be contingent upon an approved final operations manual.

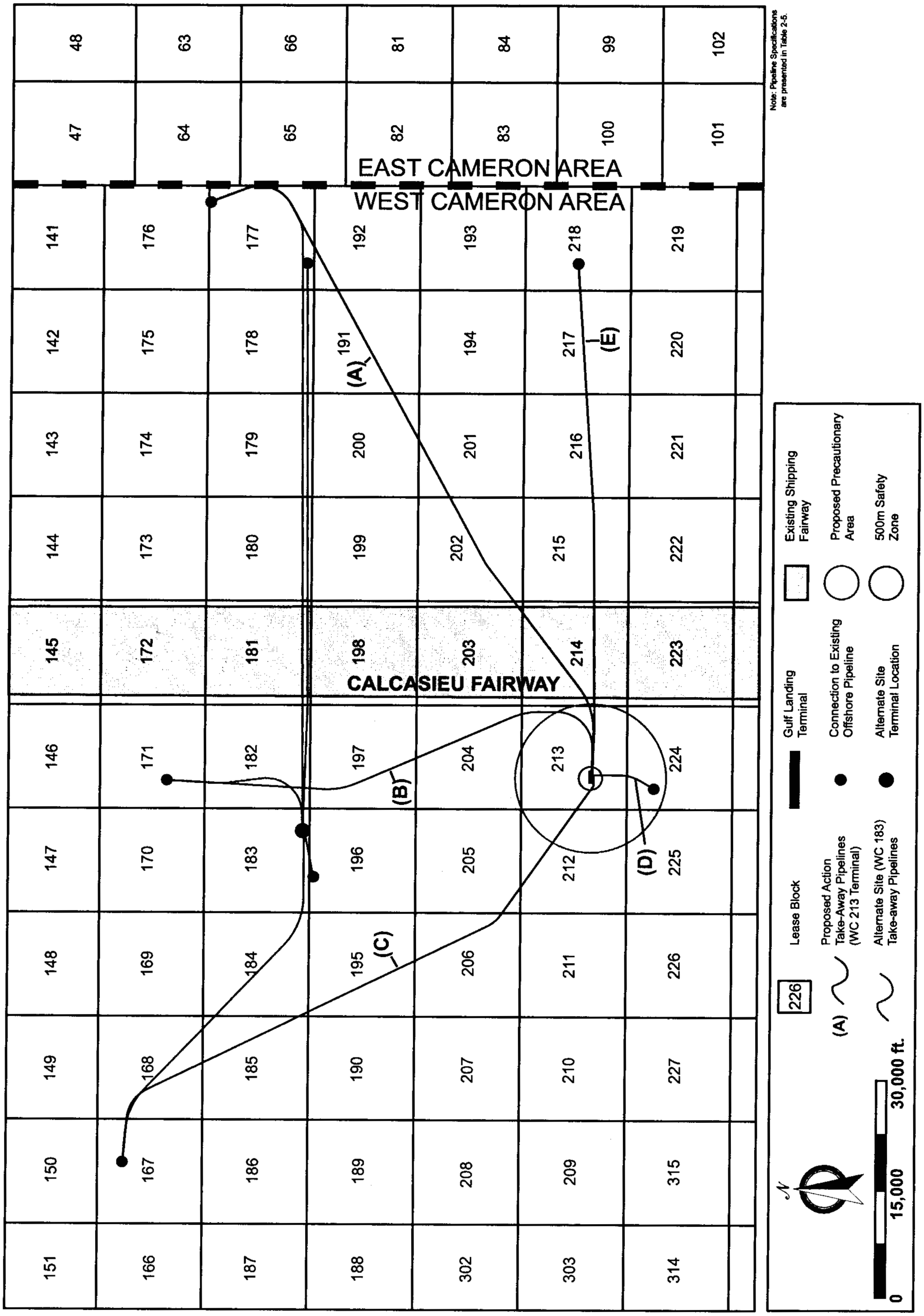


Figure 2-9. Proposed and Alternate Gulf Landing Ports

As required by 33 CFR 148, 149, and 150,[15] the Applicant must provide Engineering and Operations Manuals to the USCG for approval. These manuals must address, in specific detail, the following major components:

- Project Background
- Pollution Prevention Equipment
- Lifesaving Equipment
- Firefighting and Fire Protection Equipment
- Aids to Navigation
- Design and Equipment
- Personnel
- Vessel Navigation
- Oil Transfer Operations
- Operations
- Workplace Safety & Health
- Reports and Records
- Safety Zones
- Facility Security

A logbook would be placed on board the Terminal to record and document all activities and operations involving the Terminal, such as weather conditions (2-hour intervals), LNGCs alongside (including arrival and departure times), cargo received and offloaded, helicopter activities, personnel onboard, other vessels alongside the Terminal (including the reason for their presence), personnel injuries and sicknesses, and equipment/mechanical downtime. The date and time of all drills (e.g., lifeboat, fire, and safety) would also be recorded. Any pollution and overboard discharges would be recorded in the logbook.

All transfer operations involving oil, waste, sewage, or other controlled materials would be recorded in the oil record book. This log would be permanently kept in the Terminal's control center.

Marine Ships, Vessel Routes, and Anchorage. The Applicant has proposed that LNGCs would use GOM fairways south and east of the Terminal. Navigational aids are installed along established fairways. The need for additional navigational aids to mark an applicant's proposed Recommended Route would be reviewed by the USCG and MARAD. A racon (radar signaling) device would be installed on the Terminal. It is assumed that under most circumstances, LNGCs would approach the Terminal from the Calcasieu Pass Fairway approximately 2.2 mi east of the proposed Terminal. No structures are located between the fairway and the Terminal, further, it is unlikely that new ones would be constructed given the distance from the Terminal to the shipping lanes. The proposed Terminal location has been selected to avoid proximity to such structures. Traffic to the Terminal is expected to receive approximately 135 LNGCs per year (approximately one LNGC every 2.7 days).

[15] As modified, as appropriate, by *Deepwater Ports; Proposed Rule*: Vol. 67, *Federal Register* No. 104, Thursday, May 30, 2002, pp 37,920–963.

Gulf Landing LLC has suggested three anchorage areas north and south of the Terminal (Figure 2-3). These anchorage areas would be used to stage LNGCs if weather conditions prevented berthing or if unforeseen delays resulted in one LNGC arriving before another has disengaged from the Terminal. Typical Terminal operations would not require LNGCs to anchor. The Applicant's proposed anchorage areas are substantially within the Applicant's proposed Precautionary Area. The Terminal's proposed Precautionary Area would have a radius of approximately 3.2 km (2 mi) from the Terminal and will require International Maritime Organization (IMO) approval. The final designation of anchorage areas and anchoring procedures for the Proposed Port will be subject to USCG review and approval throught the required Port Operation Plan.

There are a number of prohibited areas, clearly marked on navigation charts, designated in the GOM. Transiting vessels may cross these areas but under no circumstances may they anchor, drill for oil, or lay a pipeline through them. No such prohibited areas are near the Terminal or the Applicant's proposed Recommended Route to the Terminal.

Safety and Security. As noted earlier in this section, where applicable, this EIS will consider safety but does not function as the final safety screening. All aspects of Port safety, including transportation routes near oil and gas production facilities, and facility security will be addressed in the Port Operations Manual and Facility Security Manual, both which will require USCG approval prior to initiation of Port operations.

Gulf Landing LLC has proposed demarcation of a Safety Zone and a Precautionary Area around the proposed Terminal to support safe and efficient port operations. As described in Section 4.7, a Safety Zone and a Precautionary Area would likely correspond to recognized navigation zones as designated on NOAA nautical charts.

- *Safety Zone.* This zone would extend 500 m (1,640 ft) outward from the mooring buoy and could be designated under USCG regulations for Deepwater Port Safety Zones. No traffic unrelated to Port operations would be authorized in this area.
- *Precautionary Area.* The Applicant has described this zone as extending approximately 3.2 km (2 mi) from the Terminal. If approved by IMO, the Precautionary Area would be printed on new NOAA charts and serve as a notice to mariners of potential LNGC and other port operations in the area. The Precautionary Area would have no enforceable restrictions to vessel movement.
- In addition to the Draft Marine Operations Manual, the Applicant has submitted a Draft Facility Security Plan (FSP). The purpose of the FSP would be to provide Gulf Landing personnel with security responsibilities with a systematic approach to securing Gulf Landing assets, protecting personnel working on or at the Gulf Landing Terminal from man-made threats such as terrorism. The FSP would be included as an integrated part of the Port Operations Manual. Components of the FSP would include:

2.6.3 Onshore Construction and Offshore Installation

Fabrication of the GBS Unit. The two caissons forming the GBS structure would be constructed onshore in a purpose-built graving dock. The GBS construction scope would include the installation of the LNG containment system and the installation/integration of the topside facilities equipment.

The caisson construction effort would employ both skilled and unskilled labor crafts. Total numbers might range from 750 to 2,000 depending on the mix of existing regional skill levels. The location of the graving dock and associated activities (including socioeconomic factors) will be assessed in follow-on supplemental NEPA documentation and a deepwater port (DWP) license. A detailed assessment of potential environmental impacts associated with onshore construction will be documented by supplemental NEPA documentation required by the License.

Positioning of the GBS Unit and Topside Fabrication. Each GBS caisson with its associated facilities would be towed from the graving dock to the Terminal site and positioned using several large tow vessels. Additional smaller vessels might be required during the tow from the construction yard to open water and then again during the installation of each caisson.

The installation process for the entire GBS would last an estimated 3 to 4 months, depending on the details of the final design. The amount of required solid ballast and scour protection will determine the overall installation time required. The topside facility tie-in work would be performed concurrently with the installation of the solid ballast and scour protection. The proposed scour protection would consist of gabions installed around the entire base of the GBS structure. The proposed Gulf Landing Terminal and associated scour protection is shown in Figure 2-4.

The offshore installation equipment would be sourced mainly from U.S.-based operators or contractors with offices in the United States. Derrick barges, support tugboats, and supply vessels would be obtained from standard GOM equipment fleets.

It is anticipated that established contractors along the U.S. Gulf Coast would perform topside facility fabrication. This work effort would provide an estimated employment level of between 500 and 1,000 workers over the construction period. The operational Terminal would be expected to support a crew of up to 60 people, including ad hoc visitors and maintenance personnel, and, with shift requirements, it would be expected to provide permanent employment to approximately 100 people. These individuals would come from the local Gulf Coast offshore labor pool and should not result in any significant population shifts.

Take-away Pipelines. The installation of the natural gas take-away pipelines would be an independent element of the construction of the facility. Pipeline installation could occur during the summer prior to GBS installation. The installation process would probably be performed during the summer months (June to September) to take advantage of calm weather. Pipes would be laid on the bottom using a pipelay barge and buried to a depth required by MMS regulations in water from 40 to 60 ft in depth. It is anticipated that a hydrojetting sled would be used to dig the trench into which the pipeline would settle. As shown on Table 2-5, construction of the pipeline installation trenches would disturb an area approximately 100 ft on each side of the pipelines. These types of pipeline trenches naturally refill within a matter of months.

Gulf Landing LLC conducted a pipeline routing study during preliminary engineering. The five take-away pipeline routes were identified based on an analysis of readily available existing data about subsea hazards, pipeline and cable crossings, and other obstructions. A shallow hazard survey of the preliminary routes was then completed to confirm actual conditions, and adjustments were made as necessary to optimize constructability and minimize environmental impacts. Before initiating construction activities, a detailed preconstruction hazard survey would be completed to identify any underwater hazards in the pipeline placement paths and the exact location(s) of any additional subsea cable or pipeline crossings. Should any hazards be identified, they would be avoided, or other appropriate mitigative measures would be applied (e.g., use of concrete mats to provide pipeline separation).

Installation of the pipelines could begin after GBS is in place, or could be installed ahead of the GBS arrival. Installation time per mile of each pipeline would vary with diameter and route location. It is anticipated that it would take a total of 5 months (150 days) to complete construction of all 65.7 mi of pipeline. The pipelines would be installed using shallow draft lay barges and a crew drawn from the region. Based on the water depth and pipe sizes involved in the project, it is anticipated that each pipe would be installed using two barges and a number of support vessels. Typical construction barges for this type of installation would be between 350 and 500 ft long and have 8-anchor lines. The anchor lines would be reset at approximately 2,000-ft intervals.

The first barge would be a conventional lay barge configured for S-lay operations. Figure 2-10 presents a schematic showing a typical S-lay installation method. The crew would weld precoated joints of pipe to the string, radiographically inspect the welds, apply joint coating, and install anodes. The pipe string would then be moved into the water off the rear of the barge as it moves forward. Installation of the pipeline would have an unsupported span from the lift-off point on the barge's stinger to sea floor. This span would be maintained in proper configuration by a combination of stingers connected to the lay barge stern and tension equipment on the lay barge. The second barge would be the jetting/trenching barge, which would cut the trenches and then cover the pipe with the required material, generally a minimum of 3 ft of sediment.[16] Emergency procedures for adverse weather conditions and various installation situations would be developed to provide for the safety of construction crews and the pipeline during installation.

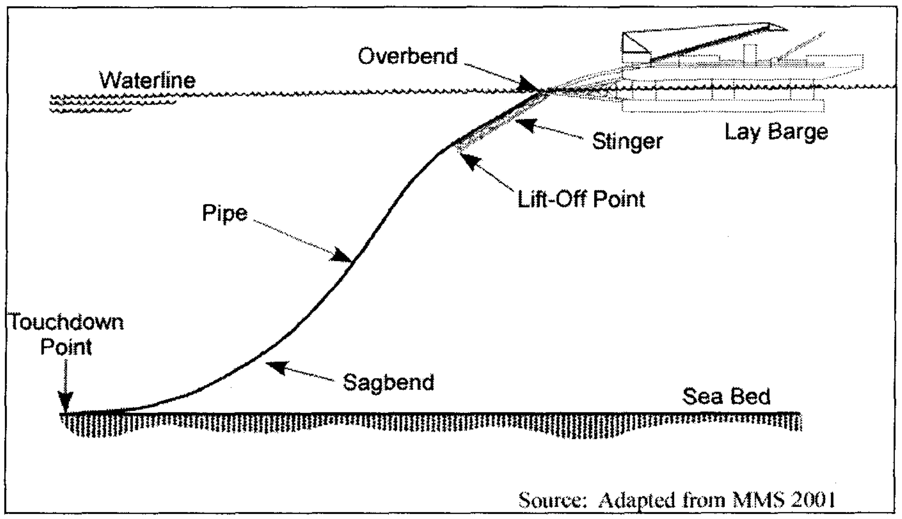


Figure 2-10. Typical S-Lay Installation Method

The take-away pipelines for the LNG regasification Terminal would be closed ended and kept dry during construction, eliminating the need for biocides to prevent marine growth inside them. Once ready to be connected to the Terminal facility, they would be hydrotested using untreated raw sea water, emptied, and then dried with nitrogen. Installation of all five of the natural gas take-away pipelines proposed for the Port would be expected to take approximately 5 months.

Hydrostatic Testing. All pipelines including the system pipelines on the GBS and the five take-away pipelines would undergo a hydrostatic integrity testing after installation and before being placed in operation. The pipelines would be designed to withstand stresses during installation, testing, and operations. The five take-away pipelines would be coated with the appropriate concrete weight-coating for undersea stability. The corrosion protection system for all underwater pipelines would include a thin film epoxy external coating and sacrificial anodes.

[16] Concerning pipeline construction, 49 CFR 192.327(g) and 192.612(b)(3) mandate that all natural gas pipelines in the GOM have 36 in of cover for normal excavation and 18 in of cover for rock excavation.

The riser sections of the pipelines would be pre-installed on the GBS and tested onshore using fresh potable water as the test medium. After completion of the pressure test, the riser sections would be drained and left void prior to the GBS being towed offshore.

The proposed take-away pipelines would then be tested in accordance with the requirements of 49 CFR 192.503, 192.505, and 192.619(a)(2)(ii). The pipelines and risers would be designed for a maximum allowable operating pressure of 1,440 psig (99.28 bar). Hydrostatic testing of the five take-away pipelines would be conducted using raw sea water as the test medium; test pressures would be held for 8 hours.

Hydrostatic testing of the take-away pipelines would involve approximately 41,584 m^3 (10,990,000 gal) of sea water drawn from and returned to the GOM. The intake and discharge sites would be the Terminal and the pipeline interconnection sites respectively.

Initial velocities and flow rates for filling of the pipelines have been estimated based upon Bernoulli's equation and are provided in Table 2-6. Initial velocities and flow rates would be the maximum fill rates of the pipelines. The discharge of hydrostatic test water would be made in accordance with the terms of the general discharge permit governing operations of this type in the GOM. The discharge rate would be limited to approximately 2,000 gallons per minute (GPM).

Table 2-6. Initial Velocities and Flow Rates During Filling of Pipeline for Hydrostatic Testing

Pipeline	Volume m^3 (gal)	Velocity m/s (ft/s)	Flow Rate m^3/s (ft^3/s)
A	19,660 (5,194,000)	0.67 (2.2)	0.41 (14.5)
B	5,685 (1,502,000)	0.67 (2.2)	0.19 (6.6)
C	11,719 (3,096,000)	0.67 (2.2)	0.28 (9.9)
D	336 (88,760)	1.49 (4.9)	0.18 (6.4)
E	4,184 (1,105,000)	0.61 (2.0)	0.11 (4.0)

Source: GL 2003a

Notes: m^3 – cubic meter
gal – gallons
m/s – meter per second
ft/s – feet per second
m^3/s – cubic meter per second
ft^3/s – cubic feet per second

These initial flow rates would be sufficient to produce both entrainment and impingement impacts on marine species present in the area. The potential for entrainment and impingement impacts would be mitigated somewhat because these initial water velocities would decrease rapidly as the pipelines fill. Placement of the uptake for hydrostatic testing water near the bottom of the sea floor would minimize entrainment and impingement impacts.

Dewatering of the five proposed take-away pipelines would be performed by "pigs" (mechanical devices used for internal cleaning and inspections of pipelines) placed in the "hot taps" or connecting points of the lines and pushed back toward the platform by the line pack gas. Displaced water would be disposed of per appropriate authority requirements. The velocities and density of this displaced sea water should be insufficient to produce any impacts on marine species in the discharge area. No chemicals or biocides would be added to this hydrostatic testing water. Required permits, for disposal of the water would be obtained prior to performing all dewatering activities.

2.6.4 Decommissioning

The proposed Port would be designed for a 30-year service life. At the end of that period, the Port would be decommissioned.

All assets would be designed such that, upon reaching the end of their useful life, they could be decommissioned either by dismantling and removal or by abandonment in accordance with applicable statutory requirements and existing standards. Structures would be removed; pipelines would be left in place. The site would be left in a safe and environmentally acceptable condition following all requirements listed in MMS Gulf of Mexico OCS Region Notice to Lessees and Operators No. 98-26, *Minimum Interim Requirements for Site Clearance (and Verification) of Abandoned Oil and Gas Structures in the Gulf of Mexico.*

Should explosives be used during decommissioning of the Terminal, they would be of a type normally used for decommissioning of facilities in the GOM at that time. Prior to decommissioning, the underwater portion of the structures would be evaluated to determine the nature and extent of habitat developed during the operational life of the facility. In consultation with appropriate Federal agencies, a decommissioning plan would be agreed upon. Should explosives be used to decommission the Terminal, appropriate agencies would be informed of relevant impact zone models, types and weights of explosives, possible effects on listed species, and actions to be taken to eliminate or reduce effects on listed species.

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