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Deepwater Port License Application for the Main Pass Energy Hub™ Project

Volume I
General (Public)

February 2004

Submitted by:
Freeport-McMoRan Energy LLC

FREEPORT-MCMORAN ENERGY

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February 27, 2004

Rear Admiral Thomas H. Gilmour
Commandant (G-M)
United States Coast Guard
2100 Second Street SW
Washington, D.C. 20593

Attn: Commander Mark Prescott

Re: Main Pass Energy Hub™
Application for a License for a Deepwater Port

Dear Admiral Gilmour:

Pursuant to the Deepwater Port Act of 1974, as amended (DWPA), and using for guidance the United States Coast Guard's (USCG's) January 6, 2004 Temporary Interim Rule,[1] Freeport-McMoRan Energy LLC (FME; the applicant) hereby files an application for a license to construct, own and operate a deepwater port, Main Pass Energy Hub™ (MPEH™), for the purposes of receiving, vaporizing, conditioning, storing and transporting, into the country's natural gas pipeline infrastructure liquefied natural gas (LNG) and constituent liquids derived from the conditioning process, as more fully described in the application.

Description of Proposed Project

MPEH™ is designed to deliver an average of 1.0 billion standard cubic feet per day (bscfd) and a peak of 3.0 bscfd of pipeline-quality natural gas, and a peak of 85,000 barrels per day (bbls/d) of natural gas liquids (NGL). The proposed deepwater port will be located in the Gulf of Mexico (GOM) on the Outer Continental Shelf (OCS) approximately 16 miles offshore southeast Louisiana at Main Pass Block 299 (MP 299). The water is approximately 210 feet deep at the deepwater port site. The project involves the reuse of four large existing platforms and three smaller bridge support platforms along with the interconnecting bridges formerly used in sulphur mining operations at MP 299. In addition to reusing the existing fixed platforms and interconnecting bridges, the proposed project also involves:

- Installing two new fixed platforms at MP 299 with six tanks capable of storing a combined total of 145,000 cubic meters (m^3) of LNG;

[1] Temporary Interim Rule with Request for Comments proposed at *69 Federal Register* 724 (January 6, 2004): hereafter the Temporary Interim Rule.

- Installing a pipeline junction platform at Main Pass Bock 164 (MP 164) to provide for natural gas metering equipment to support connections to existing, nearby natural gas pipelines;
- Installing two new semisubmersible floating units to act as dolphins in a patent-pending Soft Berth™ System for LNG carrier mooring;
- Installing open rack vaporizers (ORVs) capable of vaporizing a maximum of 1.6 bscf of LNG per day;
- Installing a plant capable of conditioning up to 1.0 bscfd of natural gas with recovery of ethane, propane, and butane to reduce the gross heating value (GHV) rating of the sales gas to meet pipeline sales specifications;
- Constructing three new salt cavern-based natural gas storage caverns that will each have a working gas capacity of 9.3 bscf to act as temporary storage for vaporized natural gas;
- Installing approximately 192 miles of natural gas and NGL export pipelines; and
- Installing miscellaneous additional facilities and equipment to assist with power generation, LNG unloading, gas compression, material handling, personnel accommodations and other support functions.

The deepwater port and the majority of the pipeline components will be located offshore on the OCS. The proposed project includes the construction of four new pipelines. A 36-inch diameter natural gas pipeline will extend northeast for approximately 92.7 miles to connect the deepwater port to existing gas distribution pipelines near Coden, Alabama. Approximately 5 miles of this pipeline segment is proposed for construction onshore in Alabama (above the mean high water line). A junction platform will be installed along this pipeline route at MP 164 to provide a connection point for proposed, short 16-inch diameter interconnecting laterals tied-in subsea to existing transmission lines. A second new 16-inch diameter natural gas pipeline will originate at the deepwater port and extend east for two and a half miles to Main Pass Block 298 (MP 298), and tie into an existing pipeline. A third new natural gas pipeline, 20 inches in diameter, will extend south-southwest for approximately 51.5 miles connecting to existing natural gas transmission pipelines at South Pass Block 55 (SP 55). A fourth 12-inch diameter pipeline will carry NGL derived from natural gas conditioning at the deepwater port. This pipeline will originate at the deepwater port and extend approximately 45.7 miles westerly into Louisiana inland waters, and make a connection with an existing NGL facility near Venice, Louisiana.

The proposed deepwater port is being designed to accommodate LNG carriers of up to 160,000 m^3 capacity. The deepwater port will be located approximately 5 miles from an existing designated shipping fairway with nearby water depths ranging from 140 to 230 feet. The location provides convenient access for LNG carriers without the need to formally designate new shipping fairways or channels. To enhance safety, the proposed deepwater port operations manual will include a detailed description of necessary support vessel escorts of the LNG carriers, the required use of professional mariners, and formal ship berthing and departure procedures.

Construction of the deepwater port will diversify the supply of natural gas in the eastern half of the GOM by providing alternative sources of supply. It is probable that the LNG received at the deepwater port will come from overseas LNG sources under long-term contract and spot market cargoes. As indicated above, the vaporized natural gas will be delivered into existing gas transmission pipelines located on the OCS and onshore Alabama. The gas will then be redelivered by shippers into the national gas pipeline distribution grid through connections with other major interstate and intrastate pipelines. The proposed project will be capable of delivering significant volumes of natural gas into the nation's gas distribution network and will assist in meeting the increasing demand for this important commodity.

Commissioning of the deepwater port is anticipated in December 2007. Construction is expected to take approximately 34 months. All of the new platforms and most of the specialized modules can be built in existing United States construction yards. Some specialized modules and equipment may be built overseas. The deepwater port will be designed, constructed, and operated in accordance with applicable codes and standards.

This proposed project is somewhat unusual in that it also involves the jurisdiction of the Federal Energy Regulatory Commission (FERC) with respect to the 5 miles of natural gas pipeline extending landward of the mean high water mark in Alabama, near the town of Coden. FME will submit an application to the FERC under Section 7 of the Natural Gas Act to authorize construction of this component of the project.

Contents Enclosed

Per instructions from representatives of the USCG, FME is delivering two (2) hardcopy originals with two (2) electronic copies on CD-ROMs and, under separate cover, four (4) complete hardcopies of the deepwater port license application. Each application in hardcopy consists of four (4) volumes. Volume I, labeled "General" consists of the application components that are releasable to the public. Volume II, labeled "Environmental Evaluation" consists of an environmental report that is also releasable to the public. Volume III, labeled "Attachments," which is being filed under seal, consists of certain confidential and proprietary technical information regarding the design of the deepwater port. Volume IV, labeled "Financial," which also is being filed under seal, consists of certain confidential financial information being provided only to the USCG and the Maritime Administration (MARAD). The accompanying CD-ROMs are similarly labeled with the exception that CD 1 contains the electronic equivalent of Volumes I and II combined. FME hereby requests that the USCG treat Volumes III and Volume IV (hard copies), and, corresponding CDs 2 and 3 (Attachments and Financial, respectively) as confidential and proprietary information and not disclose such information to the public.

A check for $350,000 (U.S.) made payable to the United States Treasury is enclosed as an application filing fee. This filing fee is being submitted pursuant to Section 148.125(a) of the Temporary Interim Rule.

The contents of the application are arranged in the order as provided in Section 148.105 of the Temporary Interim Rule. This application is based on FME's good faith interpretation of the requirements of the Temporary Interim Rule; therefore, FME requests the ability to modify or supplement the information supplied in its original application, in the event it is necessary to do so, without impeding the application processing timeline.

FME is also forwarding under separate cover three (3) copies of the following survey reports:

- "Hydrographic Survey and Sub-Surface Features Assessment, Proposed Port Facility, Block 299, Main Pass Area," February 19, 2004, Report No. 2404-1038A, prepared by Fugro GeoServices, Inc. (FGSI) and "Hydrographic Survey and Sub-Surface Features Assessment, Proposed Platform, Block 164, Main Pass Area," February 2004, Report No. 2404-1038, prepared by FGSI;

- "Geotechnical Characterization of Sediments, Main Pass Energy Hub Facilities Offshore Louisiana and Alabama, Gulf of Mexico," Report No. 0201-5170, February 2004, prepared by Fugro McClelland Marine Geosciences, Inc. (FMMG);

- "Main Pass Energy Hub™ Deepwater Port License Application, Pipelines," February 2004, prepared by Project Consulting Services, Inc.;

- "Archeological, Engineering and Hazards Survey, Block 299 to 164, Main Pass Area and from Block 164, Main Pass Area to Block 819, Mobile Area, and Two Proposed 16-inch Gas Pipelines, Block 164, Main Pass Area, Gulf of Mexico," Report No. 101224, February 2004, by FMMG;

- "Archeological, Engineering and Hazards Survey in Mississippi Sound Area (Alabama State Waters), Block 107 to Block 34 (Landfall in Coden, Alabama)," Report No. 101225, February 2004, by FMMG;

- "Archeological, Engineering and Hazards Survey, Block 299 Main Pass Area to Block 55, South Pass Area, Gulf of Mexico," Report No. 2403-1340, January 2004, prepared by FMMG;

- "Archeological, Engineering and Hazards Survey, Block 299 to Block 298, Main Pass Area, Gulf of Mexico," Report No.101224-MP298PL, January 2004, prepared by FMMG; and

- "Archeological, Engineering and Hazards Survey, Block 299, Main Pass Area, Gulf of Mexico to Dynegy Gas Plant, Venice, Louisiana," Report No. 2403-1382, February 2004, by FMMG.

All surveys were conducted under Section 148, Subpart E of the USCG's Temporary Interim Rule. The surveys are being filed under seal as they contain information of a confidential and proprietary nature.

Services and Correspondence

The names, titles, and mailing addresses of persons to whom correspondence and communications concerning this filing should be directed are as follows:

All Correspondence
David C. Landry[2]
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A statement certifying that the information in the application is true is included in the application and is being provided pursuant to Section 148.105(cc) of the Temporary Interim Rule.

Respectfully submitted,
Freeport-McMoRan Energy LLC

David C. Landry

Enclosures

[2] Primary contact for all correspondence and non-legal service.
[3] Pimary contact for legal service.

Deepwater Port License Application
Main Pass Energy HubÔ Project

Submitted in four volumes as follows:

<u>Volume I</u>: **General (Public), including license application and appendices (*herein*)**

<u>Volume II</u>: **Environmental Evaluation (Public)** ***(under separate cover)***

<u>Volume III</u>: **Attachments (Confidential)** ***(under separate cover)***

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Acronyms and Abbreviations

°C	degrees Celsius
°F	degrees Fahrenheit
2GLB	2nd Generation Lay Barge
3GLV	3rd Generation Lay Vessel
ABS	American Bureau of Shipping
ACHP	Advisory Council on Historic Preservation
ACI	American Concrete Institute
ADEM	Alabama Department of Environmental Management
AIS	Automated Information System
AISC	American Institute of Steel Construction
API	American Petroleum Institute
applicant, the	Freeport-McMoRan Energy LLC (also FME)
ARPA	automated radar plotting aid
ASME	American Society of Mechanical Engineers
AWOS	Automated Weather Observing System
AWS	American Welding Society
BA	biological assessment
BASS	Bennett & Associates, LLC
bbls/d	barrels per day
bcf	billion cubic feet
bcfd	billion cubic feet per day
BO	biological opinion
BOG	boil-off gas
BS	bridge support
bscf	billion standard cubic feet
bscfd	billion standard cubic feet per day
Btu/scf	British thermal units per standard cubic foot
CCTV	closed circuit television
CFR	Code of Federal Regulations
cm	centimeter
CO_2	carbon dioxide
COTP	Captain of the Port
CPI	corrugated plate interceptor
CTI	Crescent Technology, Inc.
CZMA	Coastal Zone Management Act
CZMP	Coastal Zone Management Program
DCS	distributed control system
deepwater port, the	Main Pass Energy Hub™, the subject of this application
DIGP	Dauphin Island Gathering Partners
DLN	dry low-nitrogen oxide
DRE	destruction/removal efficiency
DSV	diver support vessel
DWPA	Deepwater Port Act of 1974, as amended

Acronyms and Abbreviations, continued

EE	Environmental Evaluation
EEZ	exclusive economic zone
EFH	essential fish habitat
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EPA	United States Environmental Protection Agency
EPIRB	emergency position-indicating rescue beacon
ESA	Endangered Species Act
ESD	emergency shutdown
ETA	estimated time of arrival
F&G	Fire and Gas
FAA	Federal Aviation Administration
FCC	Federal Communications Commission
FCI	Flow Control Industries
FERC	Federal Energy Regulatory Commission
FFFP	film-forming fluoroprotein
FGSI	Fugro GeoServices, Inc.
FME	Freeport-McMoRan Energy LLC, the applicant
FMMG	Fugro McClelland Marine Geosciences, Inc.
FPZ	fire protective zone
ft/s	feet per second
GHV	gross heating value
GOM	Gulf of Mexico
gpd	gallons per day
gpm	gallons per minute
Gulf South	Gulf South Pipeline Company LP
Gulfstream	Gulfstream Energy Services, Inc.
HDD	horizontal directional drill(ing)
hi-ex	high expansion
HLV	heavy lift vessel
HP	high-pressure
I/O	input/output
ISA	Instrumentation, Systems and Automation Society
km	kilometers
kw	kilowatt
LAN	local area network
LDNR	Louisiana Department of Natural Resources
LNG	liquefied natural gas
LP	low-pressure
m^3	cubic meters
m^3/hr	cubic meters per hour
MAOP	maximum allowable operating pressures
MARAD	Maritime Administration
MCC	Motor Control Center
MDEQ	Mississippi Department of Environmental Quality
mgd	million gallons per day
MHz	megahertz
MMR	McMoRan Exploration Co.

Acronyms and Abbreviations, continued

MMS	(United States Department of the Interior) Minerals Management Service
mmscf	million standard cubic feet
mmscfd	million standard cubic feet per day
MP	Main Pass
MPEH™	Main Pass Energy Hub™
MPRSA	Marine Protection, Research, and Sanctuaries Act
MSFCMA	Magnuson-Stevens Fishery Conservation and Management Act
MSL	mean sea level
mT	metric ton
MTU	main terminal unit
MW	megawatts
NEC	National Electric Code
NEMA	National Electrical Manufacturers Association
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NGL	natural gas liquids
NHPA	National Historic Preservation Act
NOAA	National Oceanic and Atmospheric Administration
NOAA Fisheries	National Oceanic and Atmospheric Administration Marine Fisheries Service
NO_X	nitrogen oxide
NPDES	National Pollutant Discharge Elimination System
NRHP	National Register of Historic Places
OCIMF	Oil Companies International Marine Forum
OCS	Outer Continental Shelf
OPA 90	Oil Pollution Act of 1990
ORV	open rack vaporizer
OSCLA	Outer Continental Shelf Lands Act
P&A	plug and abandon
PA&A	Public Address and Alarm
PB ESS	PB Energy Storage Services, Inc.
PCS	Project Consulting Services, Inc.
PLC	programmable logic controller
ppm	parts per million
PSC	Public Service Commission
psi	pounds per square inch
psig	pounds per square inch gauge
PTL	Project Technical Liaison Associates
RACON	radar beacon
RO	reverse osmosis
ROV	remotely operated vehicle
RPT	rapid phase transition
RTD	resistance thermal device
RTU	remote terminal unit
SART	search and rescue transponder
SCADA	Supervisory Control Automated Data Acquisition
SCBA	self-contained breathing apparatus

Acronyms and Abbreviations, continued

scf/hr	standard cubic feet per hour
SCR	Selective Catalyst Reduction
SIGTTO	Society of International Gas Tanker and Terminal Operators
SOLAS	Safety of Life at Sea
Southern Natural	Southern Natural Gas Company
SP	South Pass
SWLB	shallow-water lay barge
TCFE	trillion cubic feet equivalent
TEG	tri-ethylene glycol
Temporary Interim Rule	Temporary Interim Rule with Request for Comments proposed at 69 Federal Register 724 (January 6, 2004)
terminal, the	Main Pass Energy Hub™
TETCO	Texas Eastern Transmission Corporation
TMR	triple modular redundant
U.S.C.	United States Code
UHF	ultra high frequency
UPS	uninterruptible power supply
USACE	United States Army Corps of Engineers
USCG	United States Coast Guard
USFWS	United States Fish and Wildlife Service
UV/IR	ultraviolet/infrared
VAC	volts alternating current
VDU	video display unit
VESCO	Venice Energy Services Company
VHF	very high frequency
VOC	volatile organic compound
WHO	World Health Organization
WSD	Working Stress Design

Volume II:
Environmental Evaluation (Public)

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1 Introduction

Freeport-McMoRan Energy LLC (the applicant, referred to herein as FME) is filing an application for a license pursuant to the Deepwater Port Act of 1974, as amended (DWPA) and using for guidance the United States Coast Guard's (USCG's) January 6, 2004 Temporary Interim Rule,[1] to construct, own, and operate a deepwater port off the coasts of Louisiana, Mississippi, and Alabama. As more fully described within this application, FME proposes to construct the Main Pass Energy Hub™ (MPEH™) as a deepwater port to receive, vaporize, condition, store, and transport liquefied natural gas (LNG) and constituent liquids derived from the processing.

The proposed deepwater port will be located in the Gulf of Mexico (GOM) on the Outer Continental Shelf (OCS) approximately 16 miles (25.7 kilometers [km]) offshore southeast Louisiana at Main Pass Block 299 (MP 299). It will be located in approximately 210 feet (64 meters) of water depth and will be designed to accommodate LNG carriers up to 160,000 cubic meters (m^3).

The proposed location is a former sulphur mining facility and the project will utilize four existing platforms along with associated bridges and support structures with appropriate modifications and additions as part of the deepwater port. Two new platforms will be constructed to support LNG storage tanks and a patent-pending Soft Berth™ System will be used to berth LNG carriers. Living quarters to routinely accommodate 50 personnel will be provided. The deepwater port is designed to deliver an average of 1.0 billion standard cubic feet per day (bscfd) and deliver a peak of 3.0 bscfd of pipeline-quality natural gas, and a peak of 85,000 barrels per day (bbls/d) of natural gas liquids (NGL).

The proposed action includes the installation of approximately 192 miles (309 km) of natural gas and NGL transmission pipelines. The deepwater port and the majority of the pipeline components will be located on the OCS.

A 36-inch (91.4-centimeter [cm]) diameter natural gas pipeline will originate at the deepwater port and extend northeast for approximately 92.7 miles (149.2 km) to connect the deepwater port to existing gas distribution pipelines near Coden, Alabama. Approximately 5 miles (8 km) of this pipeline segment is proposed for construction onshore in Alabama (above the mean high water line). A proposed metering platform to be installed at Main Pass 164 (MP 164) will be located on this 36-inch (91.4-cm) pipeline route and will provide a tie-in location for two lateral transmission lines. These laterals will be 16 inches (40.6 cm) in diameter and approximately 300 feet (91.4 meters) long extending to proposed subsea tie-ins to existing natural gas transmission lines.

A 16-inch (40.6-cm) diameter natural gas pipeline will originate at the deepwater port and extend east for 2.5 miles (4.0 km) to Main Pass 298 (MP 298), and tie into an existing natural gas transmission pipeline. A 20-inch (50.8-cm) diameter natural gas pipeline will extend south-southwest for approximately 51.5 miles (82.9 km) connecting to existing natural gas transmission pipelines at South Pass 55 (SP 55).

A 12-inch (30.5-cm) diameter pipeline will carry NGL derived from natural gas conditioning at the deepwater port. This pipeline will originate at the deepwater port, extend 45.7 miles (73.5 km)

[1] Temporary Interim Rule with Request for Comments proposed at *69 Federal Register* 724 (January 6, 2004): hereafter the Temporary Interim Rule.

westerly into Louisiana inland waters, and make a connection with an existing NGL facility near Venice, Louisiana.

MP 299 will sit atop a salt dome approximately 2 miles (3.2 km) in diameter (Figure 1). An on-site total gas storage capacity of 28 billion cubic feet (bcf) will be provided in three salt caverns underlying the deepwater port. This storage capacity will allow the deepwater port to provide a more measured and consistent delivery of natural gas volumes into the pipeline system, thereby relieving pipeline operators from the difficulty of managing alternating periods of very low and very high throughput. The ability to deliver consistent volumes of natural gas into the connected transmission pipeline(s) was identified as a key technical and economic requirement for the project.

Figure 1. Main Pass Energy Hub ä Conceptual Arrangement

FME is seeking a deepwater port license at this time to accommodate the country's growing need for infrastructure to accommodate new sources of imported LNG. As amply stated within the Energy Information Administration's (EIA's) *Annual Energy Outlook 2004*, in coming years LNG is expected to play a greater role in providing natural gas to the nation as domestic production declines. The FME MPEH™ deepwater port is being proposed with several principles in mind and a set of characteristics that make the project feasible, including:

- **Environmentally friendly.** Natural gas is a clean-burning fuel whose utilization has been encouraged;
- **Existing facilities.** Reuse of existing offshore facilities reduces the requirement for large capital outlays for construction of new offshore terminal platforms;
- **Salt dome underlay.** MP 299 is underlain by a 2-mile (3.2-km) diameter salt dome, which enhances the project's suite of service offerings by adding storage capacity;

- **Proximity to shipping fairway.** The 5-mile (8-km) proximity to shipping fairways will allow LNG carriers to maintain navigation within established fairways near the deepwater port;

- **Proximity to shore.** The 16-mile (25.7-km) distance to shore will allow for ease of access to support vessels, while minimizing the environmental impact and eliminating shipping congestion common at onshore locations;

- **Access to pipeline network.** The abundant infrastructure in the north-central GOM provides numerous options to access existing infrastructure;

- **High throughput capacity.** The terminal will have the capacity to process and export a peak of 3 billion cubic feet per day (bcfd);

- **Conditioning.** The terminal will have the capacity to condition natural gas and accept supply from a variety of sources; and

- **Water Depth.** The terminal is located in sufficient water depth to accomodate the largest LNG carriers in service and contemplated.

Commissioning of the deepwater port is scheduled for December 2007. Construction is expected to require approximately 34 months to complete. All the new platforms and most of the specialized modules can be built in existing United States fabrication yards. Some specialized modules and equipment may be built overseas. The deepwater port will be designed, constructed, and operated in accordance with applicable codes and standards. The terminal will have an expected service life of approximately 30 years.

2 *§148.105(a)* Applicant, Affiliate, and Consultant Information

2.1 *§148.105(a)(1)* Identities of the Applicant, Affiliate(s), and Consultant(s)

Applicant:	**Freeport-McMoRan Energy LLC**
Address:	1615 Poydras Street New Orleans, LA 70112
Telephone Number:	(504) 582-4000
Citizenship:	The applicant is a Delaware Limited Liability Company. All officers and directors of Freeport-McMoRan Energy LLC are United States citizens.
Principal Business Activity:	The applicant was formed for the business purposes of owning assets formerly used in sulphur businesses and

	owning an interest in a joint venture that produces oil reserves at Main Pass and is pursuing alternative uses at Main Pass.
Consultants:	Information on the consultants presently working on the MPEH™ project is contained in Section 4 of this application, entitled "Engineering Firms."
Affiliate of Applicant:	**McMoRan Exploration Co.**
Address:	1615 Poydras Street New Orleans, LA 70112
Telephone Number:	(504) 582-4000
Citizenship:	McMoRan Exploration Co. is a Delaware Corporation. All officers and directors of McMoRan Exploration Co. are United States citizens.
Principal Business Activity:	McMoRan Exploration Co. is the parent company of the applicant and was formed for the business purposes of the exploration, development, and production of oil and gas.
Consultants:	This affiliate has no consultants presently working on the project.
Affiliate of Applicant:	**McMoRan Oil & Gas LLC**
Address:	1615 Poydras Street New Orleans, LA 70112
Telephone Number:	(504) 582-4000
Citizenship:	McMoRan Oil & Gas LLC is a Delaware Limited Liability Company. All officers and directors of McMoRan Oil & Gas LLC are United States citizens.
Principal Business Activity:	McMoRan Oil & Gas LLC is a sister company of applicant and also is owned 100% by McMoRan Exploration Co. McMoRan Oil & Gas LLC was formed for the business purpose of oil and gas exploration.
Consultants:	This affiliate has no consultants presently working on the project.

2.2 *§148.105(a)(2)* Identities of Applicant's Subsidiaries and Divisions

The name, address, and principal business activity of the applicant's affiliate(s) who participated in the decision to apply for a license to build a deepwater port are provided in Section

2.1. No other subsidiaries or divisions of applicant or applicant's affiliates participated in the decision to build a deepwater port.

2.3 *§148.105(a)(3)* Affiliate Relationship(s) to Applicant

McMoRan Exploration Co. (MMR) is the parent company and 100% owner of the applicant. McMoRan Oil & Gas LLC is a sister company of the applicant, also owned 100% by MMR.

2.4 *§148.105(a)(4)* Corporate Officers and Directors

Table 2-1 provides the names and titles of the officers and directors of the applicant and each affiliate.

Table 2-1
Corporate Officers and Directors of Applicant and Affiliates

Applicant: Freeport-McMoRan Energy LLC	
Officers	
James R. Moffett	Co-Chief Executive Officer
Richard C. Adkerson	Co-Chief Executive Officer and President
Dean T. Falgoust	Vice President
Glenn A. Kleinert	Vice President
David C. Landry	Vice President
D. James Miller	Vice President
C. Donald Whitmire, Jr.	Vice President
Kathleen L. Quirk	Vice President and Treasurer
Robert R. Boyce	Assistant Treasurer
Nancy D. Parmelee	Secretary and Chief Financial Officer
Douglas N. Currault II	Assistant Secretary
William H. Hines	Assistant Secretary
Affiliate: McMoRan Exploration Co. (Parent Company of Applicant)	
Officers	
James R. Moffett	Co-Chairman of the Board
Richard C. Adkerson	Co-Chairman of the Board
Glenn A. Kleinert	President and Chief Executive Officer
B. M. Rankin, Jr.	Vice Chairman of the Board
C. Howard Murrish	Executive Vice President
W. Russell King	Senior Vice President
Nancy D. Parmelee	Senior Vice President, Chief Financial Officer, and Secretary
Kathleen L. Quirk	Senior Vice President and Treasurer
John G. Amato	General Counsel
William L. Collier III	Vice President
Dean T. Falgoust	Vice President
D. James Miller	Vice President
C. Donald Whitmire, Jr.	Vice President and Controller – Financial Reporting
Robert R. Boyce	Assistant Treasurer
J. Martin Hall	Assistant Controller – Financial Reporting

Table 2-1
Corporate Officers and Directors of Applicant and Affiliates

Affiliate: McMoRan Exploration Co. (Parent Company of Applicant)	
Officers	
Douglas N. Currault II	Assistant Secretary
William H. Hines	Assistant Secretary
Directors	
James R. Moffett	Director
Richard C. Adkerson	Director
Glenn A. Kleinert	Director
B. M. Rankin, Jr.	Director
C. Howard Murrish	Director
Robert A. Day	Director
Gerald J. Ford	Director
H. Devon Graham, Jr.	Director
J. Taylor Wharton	Director
Morrison C. Bethea	Advisory Director
Gabrielle K. McDonald	Advisory Director
Affiliate: McMoRan Oil & Gas LLC (Sister Company of Applicant)	
Officers	
James R. Moffett	Co-Chief Executive Officer
Richard C. Adkerson	Co-Chief Executive Officer
Glenn A. Kleinert	President and Chief Operating Officer
D. James Miller	Vice President
Kathleen L. Quirk	Vice President
Robert R. Boyce	Treasurer
Nancy D. Parmelee	Secretary and Chief Financial Officer
Douglas N. Currault II	Assistant Secretary
William H. Hines	Assistant Secretary

2.5 *§148.105(a)(5)* Applicant's and Affiliates' Five-Year Histories

Applicant

Freeport-McMoRan Energy LLC was formed as Freeport-McMoRan Sulphur LLC in 1998. The name change to Freeport-McMoRan Energy LLC occurred September 29, 2003. Freeport-McMoRan Energy LLC has neither filed bankruptcy nor violated state or federal law in the last five years. Regarding outstanding litigation, refer to the following statement regarding MMR.

Affiliates

McMoRan Oil & Gas LLC

McMoRan Oil & Gas LLC was formed in 1998. McMoRan Oil & Gas LLC has neither filed bankruptcy nor violated state or federal law in the last five years. Regarding outstanding litigation, see following statement regarding MMR.

McMoRan Exploration Co. (MMR)

MMR was incorporated July 30, 1998. MMR has neither filed bankruptcy nor violated state or federal law in the last five years.

Regarding outstanding litigation:

- Freeport-McMoRan Sulphur LLC v. Mike Mullen Energy Equipment Resource, Inc. and Offshore Specialty Fabricators, Inc., No. 03-1496 (United States District Court, Eastern District of Louisiana). Offshore Specialty Fabricators, Inc. ("OSFI") has claimed a right to participate in any future proceeds that Freeport realizes from operations at the MPEH™. Freeport strongly denies this claim. Freeport has filed a summary judgment motion to dismiss this claim. The trial is scheduled for May 2004.
- Daniel W. Krasner v. James R. Moffett; René L. Latiolais; J. Terrell Brown; Thomas D. Clark, Jr.; B.M. Rankin, Jr.; Richard C. Adkerson; Robert M. Wohleber; Freeport-McMoRan Sulphur Inc. and McMoRan Oil & Gas Co., Civ. Act. No. 16729-NC (Del. Ch. filed Oct. 22, 1998). Gregory J. Sheffield and Moise Katz v. Richard C. Adkerson, J. Terrell Brown, Thomas D. Clark, Jr., René L. Latiolais, James R. Moffett, B.M. Rankin, Jr., Robert M. Wohleber and McMoRan Exploration Co., (Court of Chancery of the State of Delaware, filed December 15, 1998.) These two lawsuits were consolidated in January 1999. The complaint alleges that the directors of Freeport-McMoRan Sulphur Inc. breached their fiduciary duty to the stockholders in connection with the combination of Freeport Sulphur and McMoRan Oil & Gas Co. In September 2002, the court granted the defendants' motion to dismiss. The plaintiffs appealed to the Supreme Court of the State of Delaware. We will continue to defend this action vigorously.

Other than the proceeding discussed above, we may from time to time be involved in various legal proceedings of a character normally incident to the ordinary course of our business. We believe that potential liability from any of these pending or threatened proceedings will not have a material adverse effect on our financial condition or results of operations. We maintain liability insurance to cover some, but not all, of the potential liabilities normally incident to the ordinary course of our businesses as well as other insurance coverages customary in our business, with coverage limits as we deem prudent.

2.6 *§148.105(a)(6)* Lobbying Activities, 31 U.S.C. 1352

W. Russell King is Senior Vice President of MMR and also an attorney and registered lobbyist with the law firm of Jones, Walker, Waechter, Poitevent, Carrere & Denegre, L.L.P., with offices located at 499 South Capitol Street, S.W., Suite 600, Washington, D.C. 20003. Senator J. Bennett Johnston, Chairman of Johnston and Associates, LLC, 2099 Pennsylvania Avenue N.W., Suite 1000, Washington, D.C., 20006, is also a registered lobbyist.

Mr. King assisted FME in briefing various members of Congress and their staffs and various Executive branch officials and their staffs regarding MPEH™. Senator Johnston and his firm assisted in related efforts. In addition, the applicant and its affiliates, through their employees, officers, consultants and contract lobbyists, registered an interest in the proposed Energy Policy Act of 2003 with regard to how that proposed Act would have potentially affected the permitting of offshore natural gas deepwater port facilities.

While the approval of this application is pending, the applicant and its affiliates will continue in the above-described efforts regarding the MPEH™ project and the successor bill (if any) to the Energy Policy Act of 2003. To the extent that it is appropriate to provide additional briefings to Congressional and Executive branch staff, Senator Johnston and Mr. King may be involved.

3 *§148.105(b)* Experience Related to Deepwater Ports

3.1 *§148.105(b)(1)* Offshore Operations Experience

MPEH™ will be operated by staff experienced in offshore operations and maintenance and will be counseled by personnel experienced in handling LNG at onshore ports. FME's parent company, MMR, through its predecessor companies, has over 40 years of experience in operating oil and gas exploration and production, and sulphur exploration and production facilities in the OCS waters of the GOM. These predecessor companies transported oil and gas and molten sulphur via pipelines and marine vessels. In the case of sulphur transportation, the predecessor companies also owned the transporting vessels. These companies also drilled wells and operated them in order to create salt caverns and operated gas conditioning/processing facilities.

OPA 90 Compliance and Recent Decommissioning Activities

Over its history, MMR and its predecessors and subsidiaries have complied with United States Department of the Interior Minerals Management Service- (MMS-) enforced Oil Pollution Act of 1990 (OPA 90) Oil Spill Financial Responsibility requirements and platform decommissioning and lease site clearance requirements for the leases it has operated, including Oil and Gas Lease OCS-G 12362 and Sulphur and Salt Lease OCS-G 9372 covering MP 299. MMR has already decommissioned facilities at MP 299 in accordance with MMS requirements. Prior to those decommissioning activities, MMR's major decommissioning efforts consisted of its Caminada Mine facility decommissioning in 2002, and decommissioning of its Grand Isle Mine, in a "rigs-to-reef" project, in 1999. The Grand Isle Mine reefing project created the world's largest artificial reef off of Grand Isle Louisiana. The former sulphur mine, with over 1.5 miles (2.4 km) of bridgework, was composed of more than 29 structures ranging from 16 four-pile bridge supports to a 35-pile power plant. The reef is in 60 feet (18 meters) of water and has 30 feet (9 meters) of clearance. For safety of navigation, it is marked by five lighted buoys. MMR, through its subsidiary FME, is prepared to comply with similar requirements imposed on the MPEH™.

History of Applicant and Affiliates

MMR is a publicly traded independent oil and gas company. Through its wholly owned subsidiary, McMoRan Oil & Gas LLC (sister company to FME), it is engaged in the exploration, development and production of oil and natural gas offshore in the GOM and onshore in the Gulf Coast region. MMR, through McMoRan Oil & Gas LLC, focuses on deep gas opportunities underlying shallow waters of the OCS of the GOM. MMR believes that significant reserve potential is presented by the opportunity to pursue "deep shelf" (geological structures found below 15,000 feet [4.6 km] in shallow water depths) gas to be found in the large deep structures lying below reservoirs where significant natural gas production has already occurred. MMR is also pursuing, through its wholly owned FME subsidiary, the project to convert, into the MPEH™, the significant existing infrastructure associated with the discontinued offshore sulphur mining facility at MP 299.

The original MMR was founded in 1969. MMR was among the first companies to extend offshore the farmout concept (where it brought its exploration concepts to owners of offshore leases and, in exchange for an interest therein, drilled wells on the leases the owners farmed out to MMR).

In 1981, McMoRan Oil & Gas Co., a successor company, merged with Freeport Minerals Co. (founded in 1912), to form Freeport-McMoRan Inc., which pursued, among other activities, both oil and gas exploration and production and exploration for, and production of, sulphur. Below are summaries of the histories of the two operations and current status.

Oil and Gas Background

MMR and its predecessors have conducted oil and gas exploration, development and production operations principally in the GOM and the Gulf Coast region for more than 30 years. These operations have provided it with an extensive geological and geophysical database, as well as significant offshore technical and operational expertise regarding production and transportation of natural gas and liquids.

MMR was among the most active and successful operators in the GOM in the 1980s, drilling numerous wells and installing over 65 platforms to develop its discoveries, which proved up over 3 trillion cubic feet equivalent (TCFE) of oil and gas.

As part of an asset-restructuring program to raise new capital to exploit other significant business opportunities, MMR's successor, Freeport-McMoRan Inc., sold numerous assets in various transactions during the late 1980s and early 1990s. These asset sales included the vast majority of its producing oil and gas properties. Sale proceeds from these properties totaled approximately $1.3 billion.

In May 1994, Freeport-McMoRan Inc., created McMoRan Oil & Gas Co., with all of the new company's common stock distributed to the Freeport-McMoRan Inc., shareholders. The purpose of that transaction was to allow McMoRan Oil & Gas Co. to rebuild, with essentially the same management and exploration team, the oil and gas exploration business previously conducted by Freeport-McMoRan Inc.

As a result, McMoRan Oil & Gas Co. commenced operations with an extensive geological and geophysical database, as well as extensive technical and operational expertise, but with only a small group of exploration prospects and limited financial resources. McMoRan Oil & Gas Co. pursued a business plan of exploring for and producing oil and gas, primarily in the GOM and onshore in the Gulf Coast area, and began to develop a position of industry leadership in exploration of the deep shelf gas plays.

Sulphur Background

Freeport-McMoRan Energy LLC is the successor to a line of business that, until 2000, had been continuously operated since 1912. Freeport-McMoRan Sulphur LLC and its predecessors ("Freeport Sulphur") operated numerous sulphur mines, including several in the waters of the OCS of the GOM and Louisiana state waters. Freeport Sulphur commenced operations in 1960 from the first offshore sulphur mine (Grand Isle Mine), in 1968 from the second offshore mine (Caminada Mine, also located in the Grand Isle area), and in 1992 from the third offshore mine—Main Pass Mine (MP 299). MP 299 was North America's largest sulphur reserve, and its discovery led to the installation of the largest production facility in the GOM—costing more than $1 billion and consisting of 15 offshore platforms. Prior to these mines, Freeport Sulphur had commenced operations in inland state waters at its Grande Ecaille Mine (in 1933) and Garden Island Bay Mine (1953), as well as at numerous smaller mines along the Louisiana coast.

In its sulphur operations, Freeport Sulphur introduced numerous innovations in the production and transportation of sulphur, including the development of mines in marshy terrain near the mouth of the Mississippi River, the use of directional drilling (a critical technique for exploiting offshore sulphur deposits), and the development of technology for transporting molten sulphur, which earned the acceptance of United States sulphur consumers as an environmentally and economically superior method of transportation. Freeport Sulphur employed the Frasch method of solution mining sulphur, developed by chemist and engineer Herman Frasch around the beginning of the 20th century. The Frasch method involved injecting, via wells, superheated water into porous limestone, where sulphur deposits lay embedded, and the molten sulphur was pumped to the surface in liquid form. Freeport pioneered the use of superheated seawater in the process.

Freeport-McMoRan Sulphur LLC and its predecessors operated the largest molten (liquid) sulphur handling system in North America and had the capacity to transport and terminal over five million long tons of molten sulphur annually via land and the GOM and inland waterways.

Marine Vessel Experience

Freeport Sulphur operated two molten sulphur tankers, each having a capacity of approximately 25,000 tons. The two tankers had the combined capacity to transport 3.5 million long tons of sulphur per year across the GOM. Freeport Sulphur's inland barge system was capable of transporting over 1.0 million tons annually. Additionally, two 7,500-ton tankers were used to transport sulphur in its liquid form from the Main Pass mine's offshore production platform and were used in Gulf Coast service to transport sulphur from the company's terminals to its customers.

Terminal Operation Experience

Freeport Sulphur owned and operated five sulphur terminals in the United States, the largest of which was located at Port Sulphur, Louisiana. The Port Sulphur facility was a combined liquid storage tank farm and stockpile area for solid sulphur. Liquid sulphur was stored in steam-heated, insulated tanks having an aggregate capacity of approximately 110,000 long tons. The solid storage area held approximately 1.3 million long tons of solid sulphur. Because substantially all of the company's domestic customers consumed sulphur in liquid form, Freeport Sulphur delivered all of its production in liquid form. This reduced the need to re-melt the sulphur, conserved energy and reduced costs, and was an environmentally superior handling method.

Freeport Sulphur owned a high capacity sulphur smelter that enabled the conversion of solid sulphur into liquid sulphur to supplement mine production during periods of high demand and to cover shortfalls in mine production or in recovered sulphur purchases. Sulphur was transported from Port Sulphur by barge to customers' plants in Louisiana on the lower Mississippi River or along the Gulf Coast of Texas and Mississippi, or by tanker to the company's terminals in Tampa.

Freeport Sulphur’s other terminals were located in Tampa and Pensacola, Florida, and Galveston, Texas. There were two Tampa terminals, each of which had a liquid storage capacity of 90,000 long tons and were supplied with sulphur from Port Sulphur and Galveston by the company's sulphur tankers. Each of the Tampa facilities shipped molten sulphur to phosphate fertilizer producers in central Florida by tank truck. The Pensacola terminal had a storage capacity of 10,000 long tons and was used for the storage, handling and shipping of recovered sulphur purchases or transporting recovered sulphur for third parties. Molten sulphur was shipped by barge from the Pensacola terminal to either the Port Sulphur terminal or directly to lower Mississippi River customers.

The Galveston terminal had 75,000 long tons of liquid storage tanks and solid storage capacity of one million long tons. This terminal received sulphur from Freeport Sulphur’s Culberson mine by unit train, and recovered sulphur purchases by truck, barge or rail, and then shipped sulphur to local customers by truck or barge or to the Tampa terminals by tanker. The Galveston terminal also had the ability to load solid sulphur aboard large oceangoing vessels, giving Freeport Sulphur access to international markets

During 2000, low prices for sulphur and high prices for natural gas, a significant element of cost in sulphur mining, caused the MP 299 sulphur mining operations to become uneconomical. As a result, in July 2000, Freeport-McMoRan Sulphur LLC announced its plan to discontinue its sulphur mining operations. Production from the Main Pass sulphur mine ceased on August 31, 2000. Freeport-McMoRan Sulphur LLC then initiated a plan to sell its sulphur transportation and terminaling assets.

In March 2002, agreements were entered into for the dismantling and removal of all the platforms at Caminada (the only remaining sulphur mine besides Main Pass 299) and some of the sulphur mining platforms at MP 299. In June 2002, Freeport-McMoRan Sulphur LLC sold substantially all of the remaining assets that comprised its recovered sulphur transportation, terminaling, logistics and marketing (transportation and terminaling) business to a joint venture owned by unrelated parties.

Current Status

The current MMR was created on November 17, 1998, when McMoRan Oil & Gas Co. and Freeport-McMoRan Sulphur, Inc., combined their operations. As a result, McMoRan Oil & Gas LLC and Freeport-McMoRan Sulphur LLC, the successors to those companies, became MMR's wholly owned subsidiaries. Freeport-McMoRan Sulphur LLC's name was changed in 2003 to Freeport-McMoRan Energy LLC to reflect the change in the nature of its business.

Ongoing Operation on Main Pass Block 299 (MP 299)

The MP 299 salt dome has been the site of oil and gas, sulphur and brine production activity for over 35 years. The top of the salt dome is located approximately 1,800 feet (549 meters) below the surface waters of the GOM and it essentially underlies the entire top half of the block. ChevronTexaco, FME and K-Mc Venture 1 are the leaseholders on the block. ChevronTexaco owns and operates Oil & Gas Lease OCS-G 1316. FME owns and operates the Sulphur and Salt Lease OCS-G 9372, and operates the Oil and Gas Lease OCS-G 12362 (owned by K-Mc Venture 1).

The structures on the block are as follows:

- ChevronTexaco has eight production platforms (five located within the MP 299 block and three nearby on adjacent blocks) that surround the salt dome. These platforms are used to drill for and produce oil and gas from the geologic faults and traps that were formed when the salt plug pushed its way up from the Lou-Ann salt bed through the overlying sediments to near the surface. The first oil and gas exploration wells were drilled on the block in 1967. It is FME's impression and opinion that ChevronTexaco's oil and gas reserves on this lease are significant and their operations on the block will continue for the foreseeable future.

- K-Mc Venture 1 has three oil and gas production and processing platforms on the MP 299 block that are located near the center of the salt dome. These platforms are used to drill for and produce oil and gas from the salt dome's overlying caprock structure and the sands above it. The processing platform handles approximately 30,000 bbls/d of oil and associated production fluids from both the local MP 299 production and from other leases near the area. Production from this lease is expected to continue for the next 5 to 10 years.

- FME continues to own and operate five significant platforms (four are planned for use and one will be removed) and three minor platforms (bridge support) that are located over the salt dome. These platforms were previously used for Main Pass Mine sulphur and brine production, and they are now planned for use in the proposed MPEH™. One of the drilling platforms is currently in operation for brine production with monthly production of approximately 3,000 barrels. Brine production is a simple process whereby water is pumped into a cavity in the salt dome. The pumped in water pressures up the brine cavity and dissolves the some of the salt. The water becomes saturated with salt and the saturated salt water (brine) under pressure flows to the surface where it is collected and sold. Most of FME's platforms will be used for the MPEH™, and therefore, are expected to remain in service for the next 30 to 40 years.

Pipelines and electrical cables were laid down for the above operations. Because the water depth here is greater than 200 feet (61 meters), the pipelines and cables are not buried.

3.2 *§148.105(b)(2)* Contracted Affiliates' Marine and Offshore Construction Experience and Qualifications

No construction contracts for the deepwater port have been executed. FME expects to manage the MPEH™ project in house and will utilize contractors experienced in the design, fabrication, and installation of LNG terminals for the construction of the deepwater port.

FME has extensive experience in the construction of many types of marine and offshore facilities. During its history, FME successfully designed, built, installed, and operated many production platforms in the GOM.

The most recent and complex of these facilities was completed in 1992 at MP 299 (the site of the proposed MPEH™). The facility required 650,000 man-hours of engineering design effort and required 100,000 tons of steel. The lift and installation of the 5,450-ton power plant module was the largest single lift ever accomplished offshore in the Western Hemisphere. This $1 billion complex included 10 major drilling, production, power plant, and processing platforms. The complex was installed on top of the MP 299 salt dome to mine the estimated 100 million bbls of oil and 100 million tons of sulphur contained in the dome's caprock structure and overlying sands. At the heart of the complex was the Main Pass Mine facility, which included a series of 14 interconnected platforms, with bridges and elevated pipelines stretching over 1.5 miles (2.4 km) in 210 feet (64 meters) of water. The power plant module was capable of producing 12 million gallons per day (mgd) of 325-degree Fahrenheit (°F; 163-degrees Celsius [°C]) water at 300 pounds per square inch (psi), 1 million pounds per hour of 600-psi steam and 17.5 megawatts (MW) of electric power. The oil and gas processing facilities included the only offshore Claus/Amine unit for processing the sour oil and gas at the site. The oil and gas processing facility was designed to 80,000 barrels of sour production fluids and 25 million standard cubic feet per day (mmscfd) of sour gas. Approximately 1,500 wells were planned for drilling from six drilling platforms at the complex. Additional information on this project demonstrating the applicant's prior construction experience is included in the brochure provided as an appendix to this document.

4 *§148.105(c)* Engineering Firms

Table 4-1 summarizes the identities and contact information of each engineering firm currently involved with the technical details supporting the MPEH™ license application. Project experience for each firm is summarized in Volume III, Attachment 1 "Identities of Participating Engineering Firms and Contact Information" {*confidential*}. Additional engineering firms may be identified as the detailed design of the MPEH™ project progresses. In such instances, the applicant will provide notification to the USCG as additional engineering firms are contracted.

Table 4-1
Identity of Participating Engineering Firms and Contact Information

Name	Address	Citizenship	Telephone Number
Crescent Technology, Inc. (CTI)	1615 Poydras Street New Orleans, LA 70112	United States	504.582.4305
Ecology & Environment, Inc. (E & E)	368 Pleasantview Drive, Lancaster, NY 14086	United States	716.684.8060
Bennett & Associates, LLC (BASS)	1140 St. Charles Avenue New Orleans, LA 70115	United States	504.561.8912
J Ray McDermott, Inc.	757 North Eldridge Parkway Houston, TX 77079	United States	504.587.5000
Elmer-Roland Maritime Consultants	230 Pine Shadows Drive Houston, TX 77056	United States	713.621.3641
Aker Kvaerner, Inc.	7909 Parkwood Circle Houston, TX 77036	United States	713.988.2002
Randall & Dewey, Inc.	16800 Greenspoint Park Drive, Suite 300-S Houston, TX 77060	United States	281.774.2000
PB Energy Storage Services, Inc. (PB ESS)	11757 Katy Freeway, Suite 600 Houston, TX 77079	United States	281.496.5590
Brandsma Engineering	102 East 8th Street Durango, CO 81302	United States	970.259.3487
Project Technical Liaison Associates (PTL)	20119 Stuebner Airline, Suite C, Spring, TX 77379	United States	281.376.9128
Project Consulting Services, Inc. (PCS)	3300 West Esplanade Avenue South Suite 500 Metairie, LA 70002	United States	504.833.5321
Fugro McClelland Marine Geosciences, Inc. (FMMG)	6100 Hillcroft Street, Suite 400 Houston, TX 77081	United States	713.369.5600
Delmar Systems, Inc.	8114 West Highway 90 P.O. Box 129 Broussard, LA 70518	United States	337.365.0180

Note: See **Volume III, Attachment 1 {*confidential*}** for each firm's qualifications.

5 *§148.105(d)* Applicant's Citizenship, Incorporation, and Authority

FME is a Delaware Limited Liability Company. All officers of FME (see Table 2-1) are United States citizens.

Legal documents pertaining to the formation and organization of the company along with affidavits of citizenship from the president and each officer are provided in Volume IV, Attachment 1, {*confidential*}.

6 *§148.105(e)* Address for Service of Documents

The names, titles, and mailing addresses of persons to whom correspondence and communications concerning this filing should be directed are as follows:

All Correspondence
David C. Landry[2]
Vice President
Freeport McMoRan Energy LLC
1615 Poydras Street
New Orleans, LA 70112
Phone: (504) 582-4880
Fax: (504) 582-4339
Email: dave_landry@fmi.com

Legal Service
Douglas N. Curault II[3]
Assistant Secretary
Freeport McMoRan Energy LLC
1615 Poydras Street
New Orleans, LA 70112
Phone: (504) 582-8412
Fax: (504) 589-8412
Email: dcurrault@joneswalker.com

Technical and Environmental
William H. Daughdrill
Principal Environmental Scientist
Ecology and Environment, Inc.
11550 Newcastle Avenue
Baton Rouge, LA 70816
Phone: (225) 298-5094
Fax: (225) 298-5081
Email: wdaughdrill@ene.com

Technical and Environmental
John Seip
Environmental Specialist
Crescent Technology Inc.
1615 Poydras Street
New Orleans, LA 70112
Phone: (504) 582-4314
Fax: (504) 582-1810
Email: john_seip@fmi.com

[2] Primary contact for all correspondence and non-legal service.
[3] Primary contact for legal service.

7 *§148.105(f)* Proposed Location and Use of Deepwater Port

The deepwater port will be located approximately 16 miles (25.7 km) offshore southeast Louisiana on the federal OCS. Water at this location in MP 299 in the GOM is approximately 210 feet (64 meters) deep. A gas pipeline junction platform, also part of the deepwater port, is located in MP 164 approximately 40 miles (64.4 km) offshore Mississippi in the GOM. The location of the deepwater port is shown on Figure 2. The general layout of the deepwater port is shown on Figures 3 and 4. Overall site plans of the deepwater port are included in Appendix A.

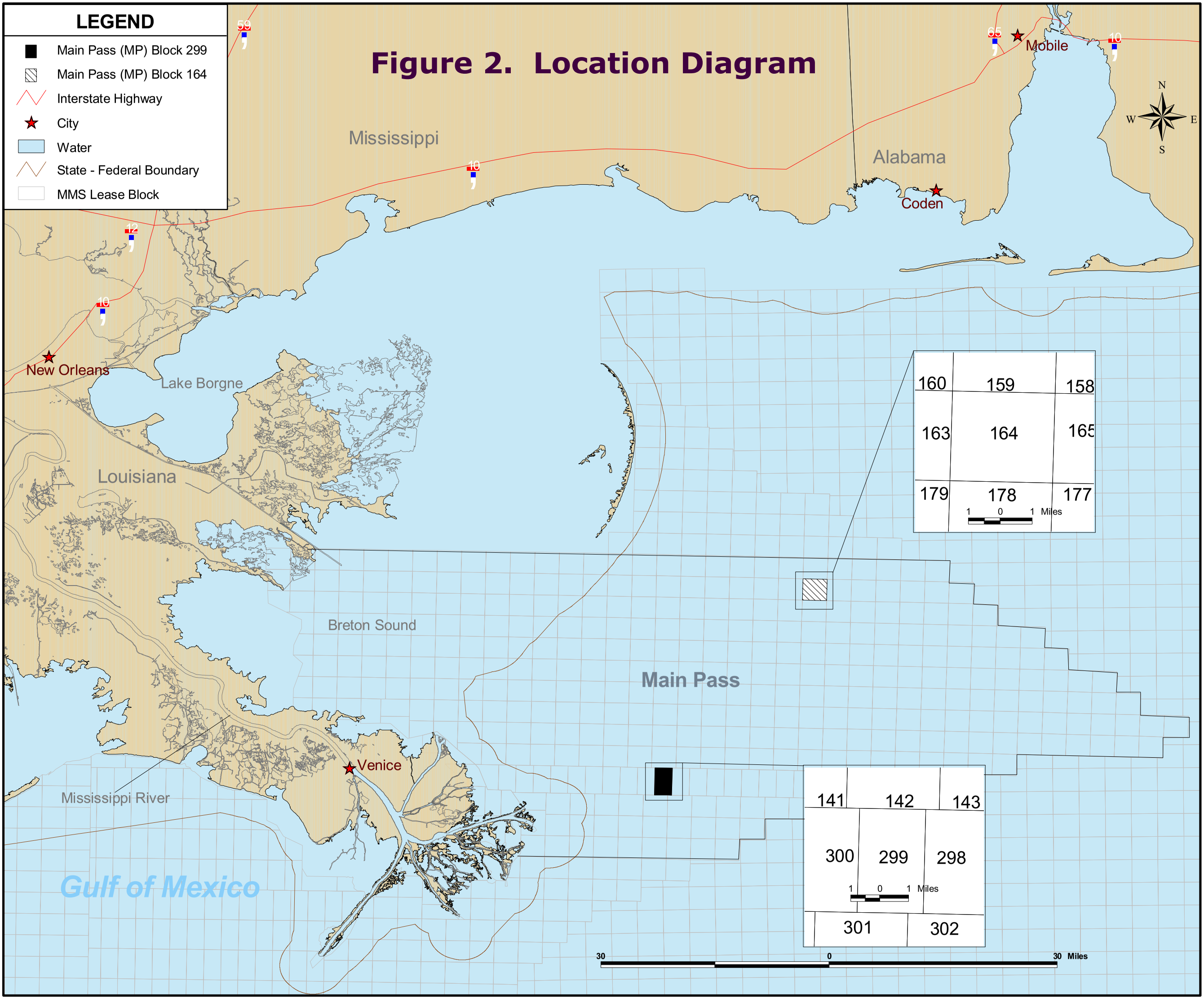
The deepwater port facilities consist of LNG storage tanks, LNG carrier berthing provisions, LNG unloading arms, low-pressure (LP) and high-pressure (HP) pumps, vaporizers, a gas conditioning plant, salt cavern gas storage, compression, dehydration, metering, utility systems, general facilities, and accommodations. Construction of the deepwater port consists of converting a portion of the former MP 299 sulphur mining operation and installing new structures, facilities, and pipelines. Specifically, the deepwater port construction will consist of converting two existing platforms, three existing bridge support platforms, and existing interconnecting bridge structures, then adding two new LNG storage platforms, new interconnecting bridges, new topsides equipment, a new semisubmersible-based LNG carrier berthing system, five new gas pipelines, a new pipeline junction platform, and a new NGL pipeline. In addition, two existing platforms will be used as storage for tri-ethylene glycol (TEG), spares, and other consumables.

The deepwater port will be designed to handle a nominal capacity of 7.0 million metric tons (mTs) per year of LNG or 350 bcf per year of gas. An overall process flow diagram is shown on Figure 5. The annual LNG throughput volume equates to a nominal vaporization capacity of 1.0 bcfd. The vaporization facilities will be designed for a peak capacity of 1.6 bcfd to provide additional supply during periods of peak demand. Block flow diagrams of the process facilities are included in Appendix B.

The deepwater port provides the following basic functions:

- LNG carrier berthing;
- LNG carrier unloading;
- LNG storage;
- LNG vaporization;
- Gas conditioning;
- NGL metering and export pipeline;
- Salt cavern natural gas storage;
- Natural gas compression;

Figure 2. Location Diagram



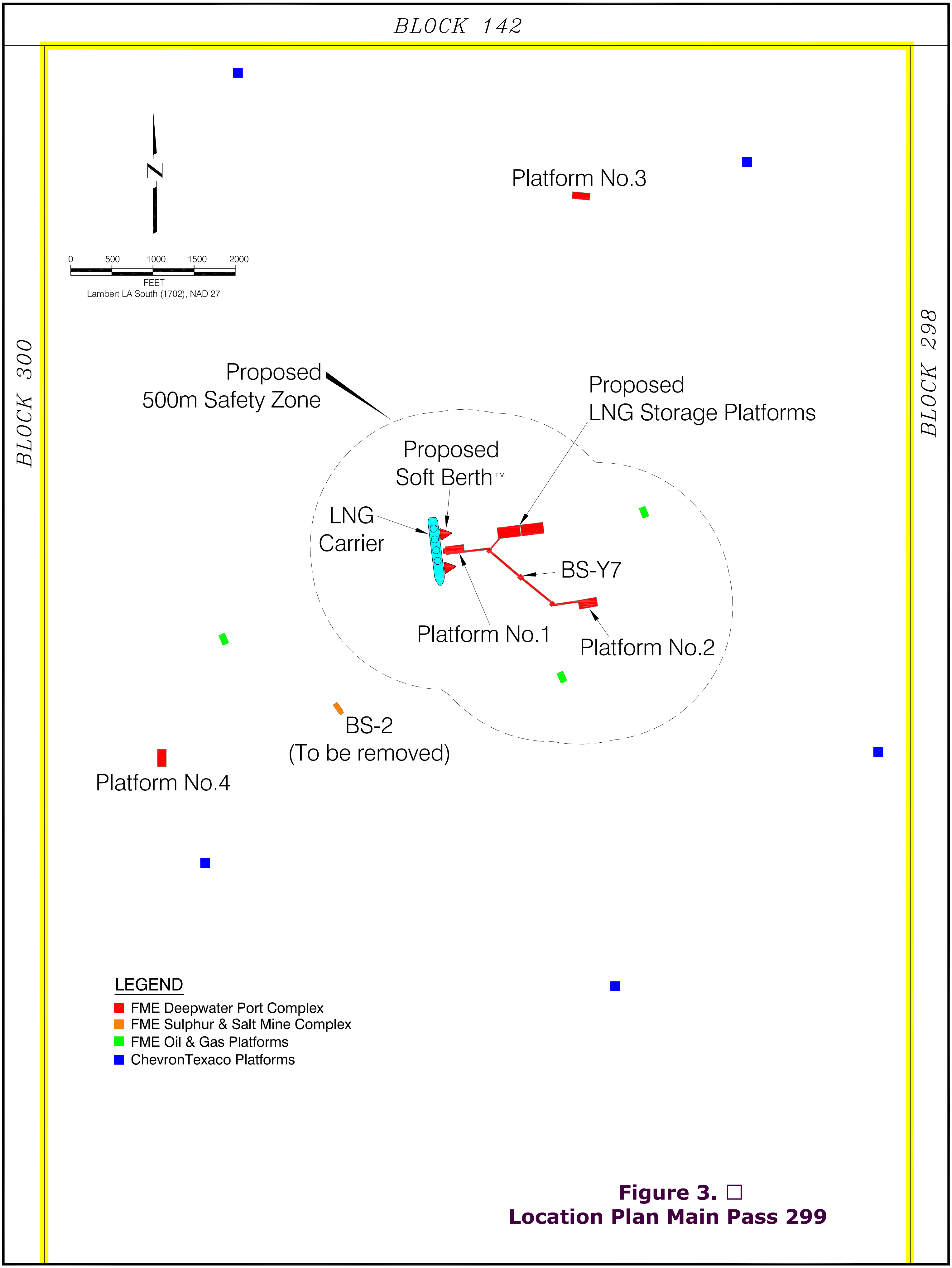
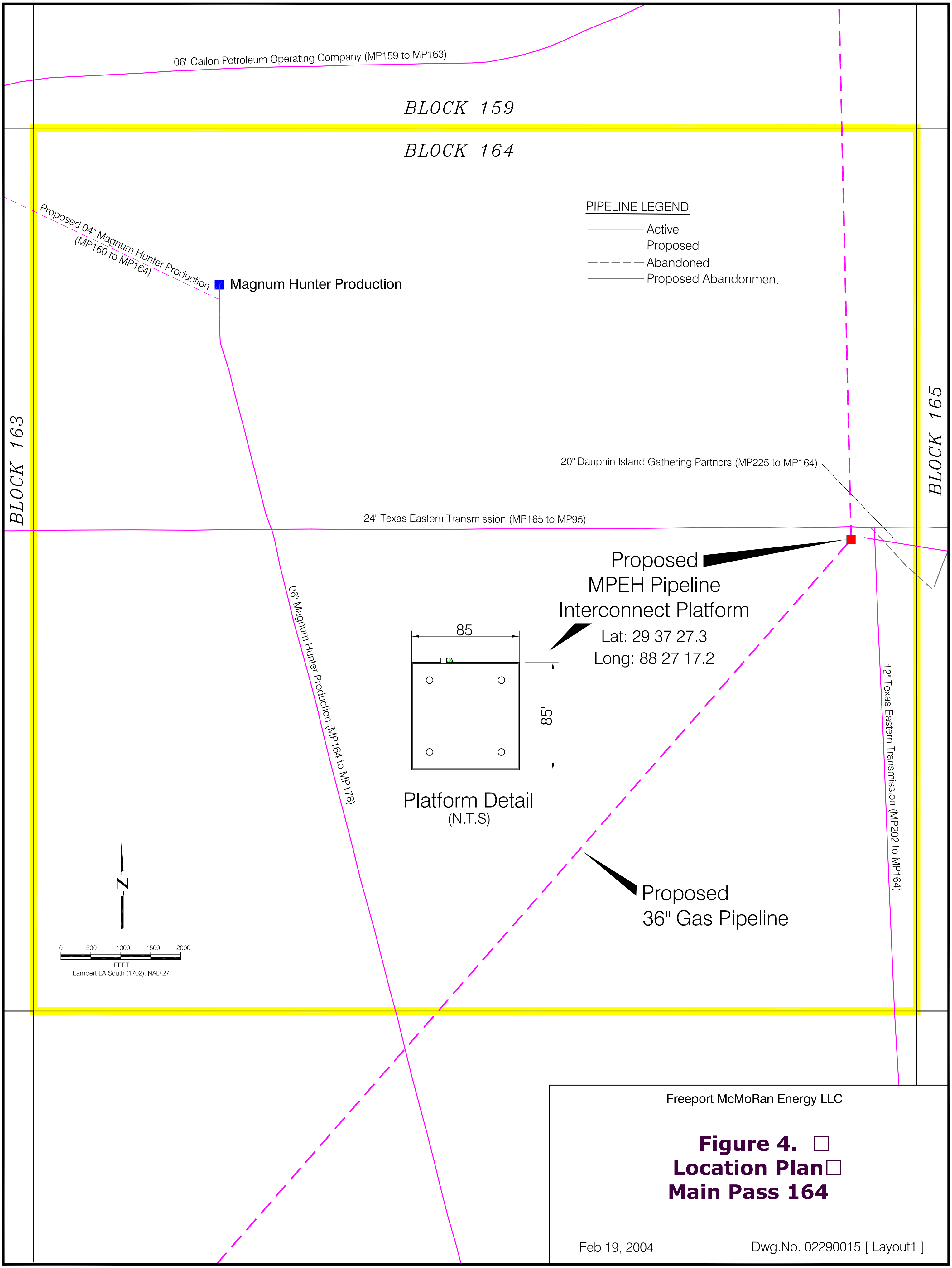


Figure 3.
Location Plan Main Pass 299



Freeport McMoRan Energy LLC

Figure 4.
Location Plan
Main Pass 164

Feb 19, 2004

Dwg.No. 02290015 [Layout1]

USE POWER POINT VERSION

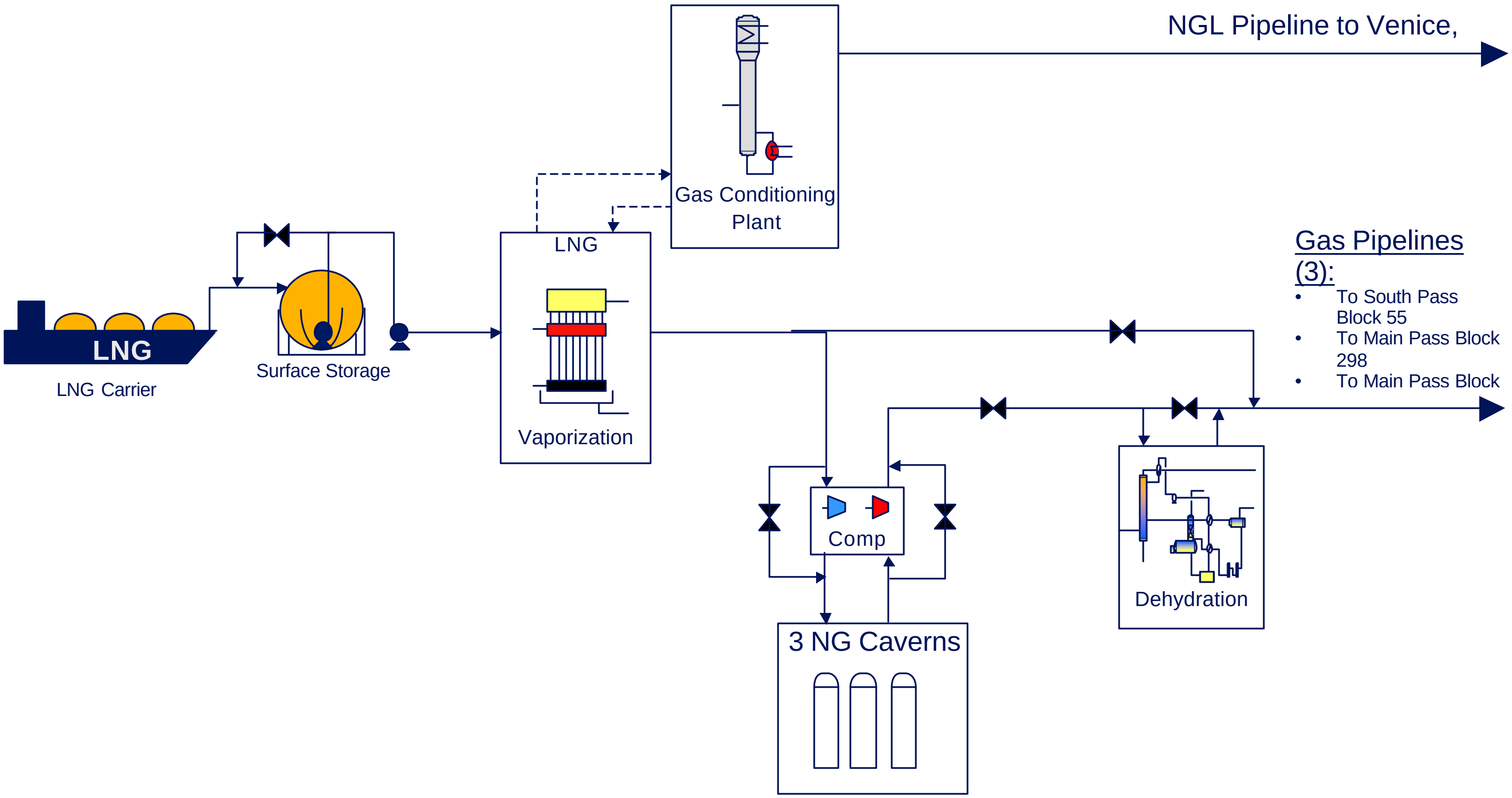


Figure 5. Overall Process Flow Diagram

- Natural gas dehydration system;
- Natural gas metering and export pipelines;
- Power generation;
- Storage facilities for spares and consumables; and
- Living quarters and helideck.

LNG Carrier Berthing

The terminal will use a Soft Berth™ System to berth LNG carriers. The Soft Berth™ System includes two semisubmersible-based dolphins, two auxiliary berthing buoys and associated mooring lines, and seabed anchor piles. The Soft Berth™ System allows the berthing of LNG carriers adjacent to Platform No. 1, the unloading of LNG to the platform at amidships, and the disconnection and egress of the LNG carrier after unloading. The two Soft Berth™ System dolphins are expected to be minimally sized semisubmersibles that incorporate mooring equipment, fairleaders, fenders, hawser attachments, ballast system, bridge support, and other miscellaneous items. In addition, auxiliary berthing buoys will be located near each dolphin (toward the LNG carrier bow and stern) to supplement LNG carrier berthing requirements. A layout of the Soft Berth™ System is shown on Figure 6. The access route for LNG carriers, along with other marine information relating to the proposed safety zone and proximity to fairways and anchorages is contained on Figures 7, 8, and 9.

LNG Carrier Unloading

The LNG carriers will berth alongside the Soft Berth™ System dolphins, which straddle Platform No. 1. The LNG unloading facilities are located on Platform No. 1. The unloading facilities will be designed to accommodate LNG carriers ranging in capacity from 60,000 m^3 to 160,000 m^3. LNG is unloaded from the carrier to the storage tanks through an LNG unloading arms package. The LNG unloading rate will be 10,500 to 12,000 cubic meters per hour (m^3/hr). The LNG unloading arms package consists of four 16-inch (40.6-cm) diameter unloading arms. The unloading arms will be similar to those used at existing onshore LNG terminals; however, the specific configuration will be designed to accommodate offshore ship movements at berth. During the absence of LNG carriers, LNG from the storage tanks will be re-circulated in the terminal unloading piping network to maintain temperatures (i.e., “ready for service”) for the next ship cycle and to minimizing the need for cool-down. LNG custody transfer measurement between ship and terminal will follow normal industry practice and take place on the LNG carrier.

LNG Storage

LNG will be stored in tanks located on two new, eight-legged, 12 skirt-pile, fixed platforms. The terminal will contain six USCG-approved LNG storage tanks (prismatic [SPB], Spherical [Moss] type, or any other acceptable containment system), each with an approximate gross capacity of 24,660 m^3 per tank. The total net capacity of the storage tanks is approximately 145,000 m^3. Three LNG storage tanks will be located on each new storage platform. The two LNG storage platforms will be bridge-connected to the processing facilities.

Figure 6.
Soft Berth System ™
Plan View

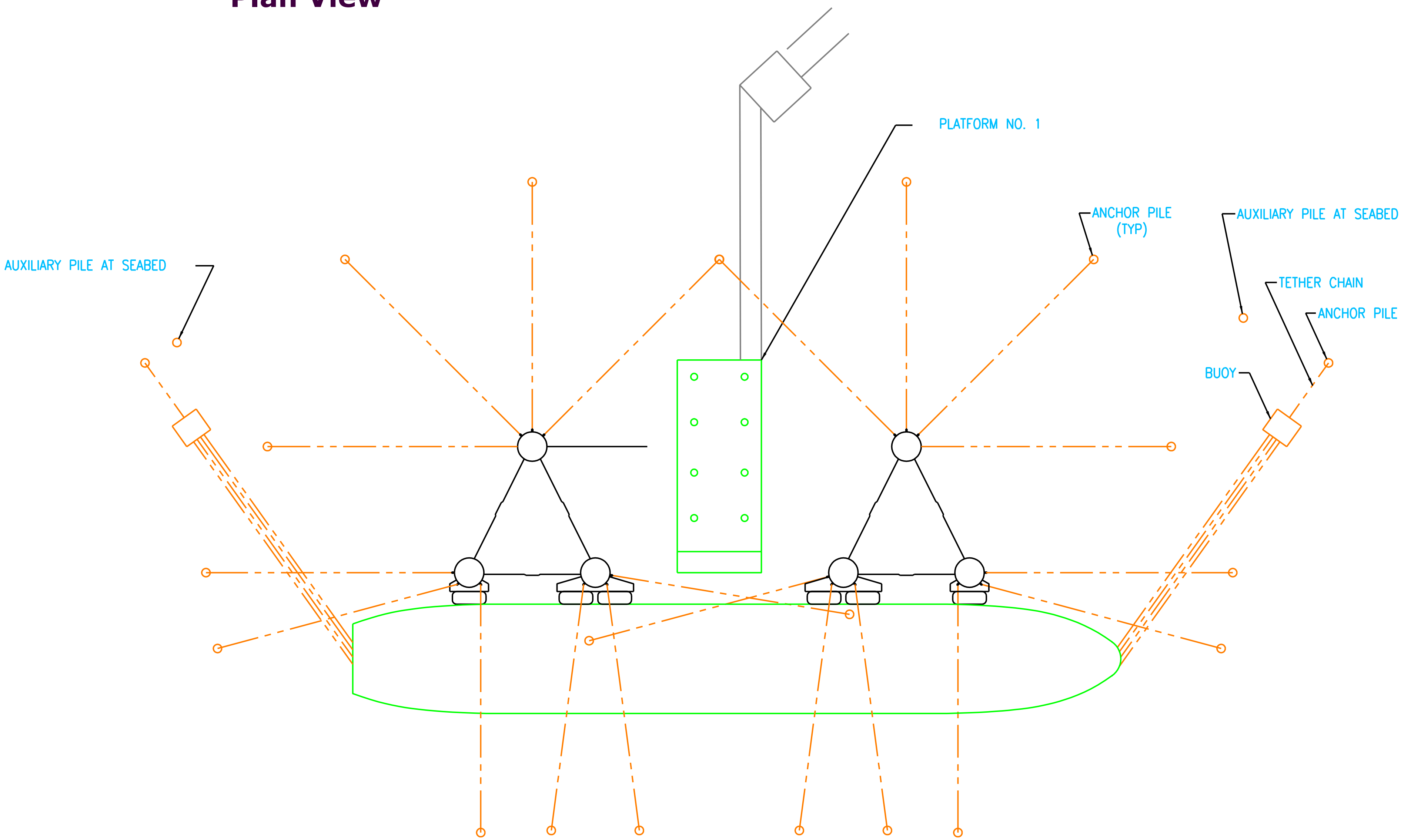


Figure 7. □
Recommended LNG Carrier Access Route from Safety Fairway □
Main Pass Energy Hub ™

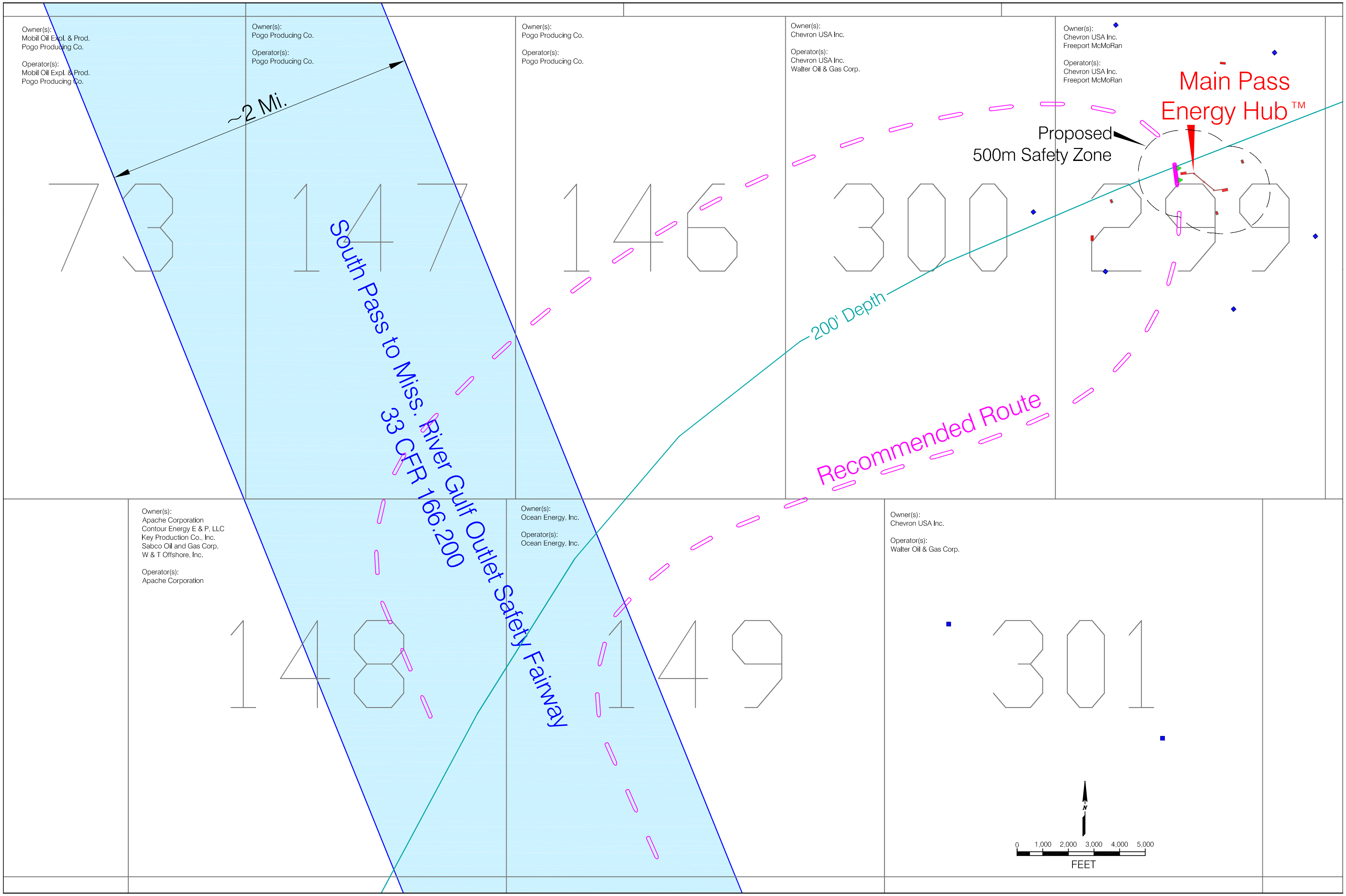


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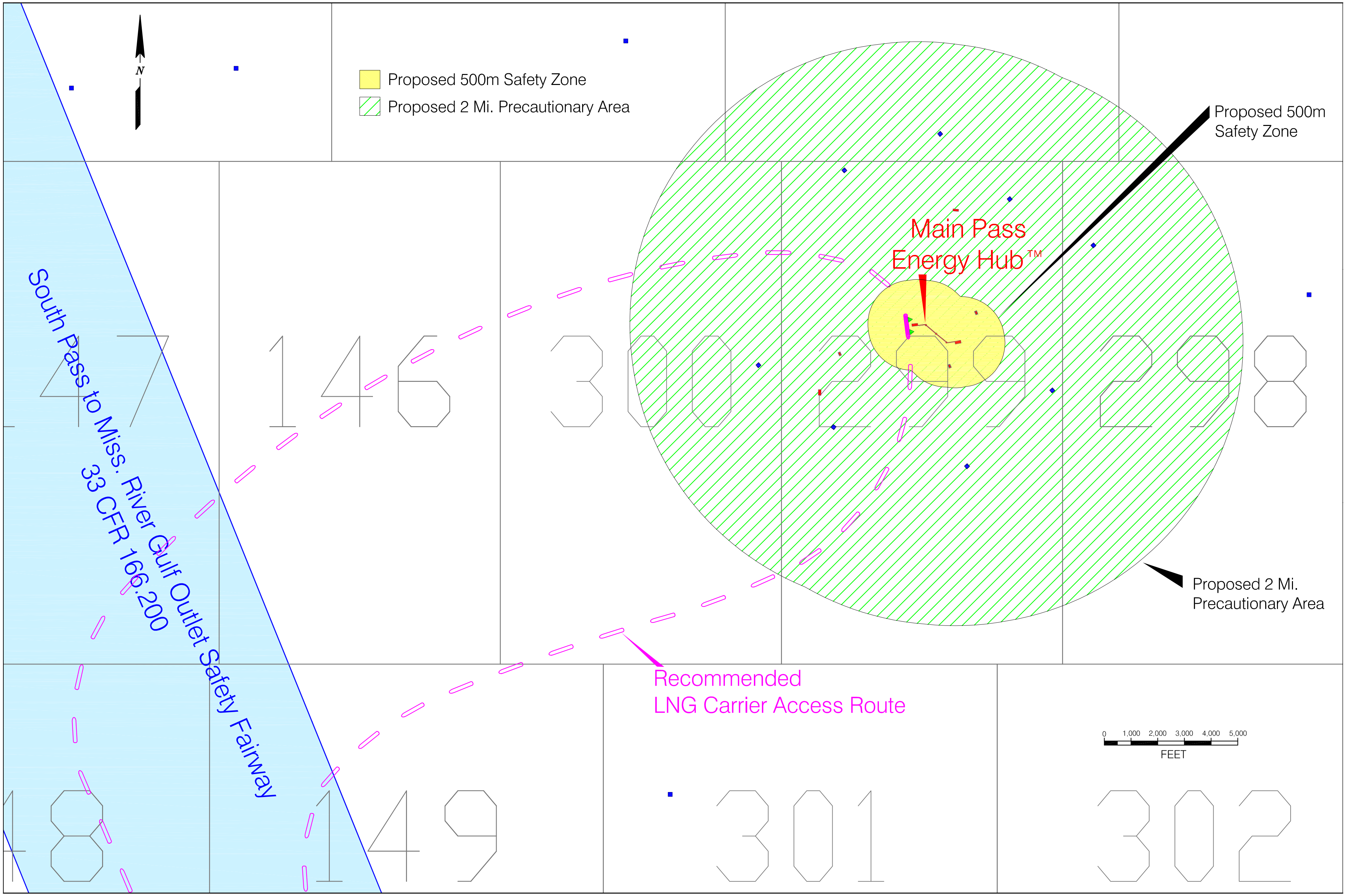
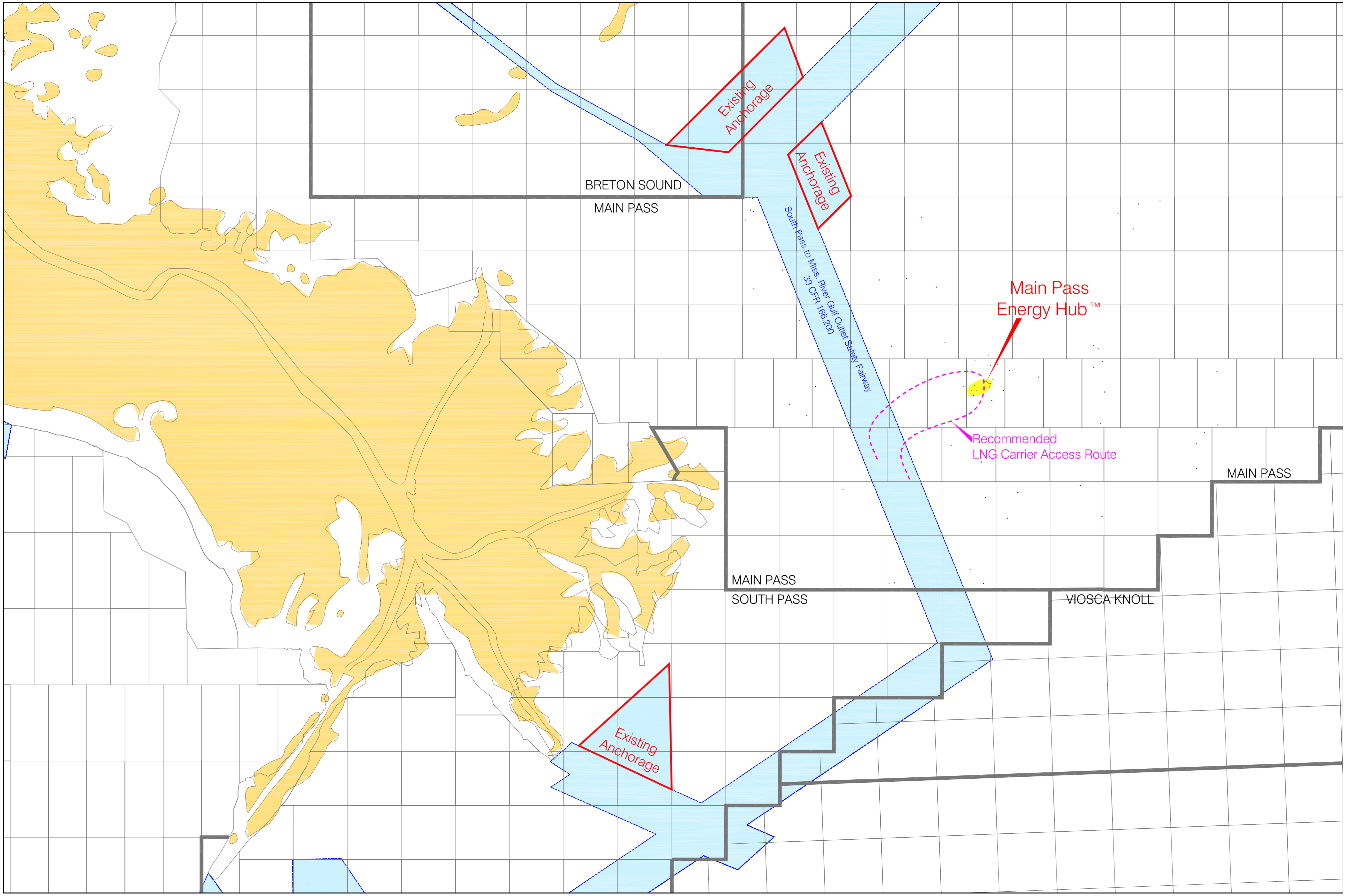
Figure 8.
Proposed Safety Zone and Precautionary Area
Main Pass Energy Hub ™



Dwg.No. 02290014 [Layout1]

Figure 9.
Proximity to Safety Fairways and Anchorages
Main Pass Energy Hub ™



Dwg.No. 02290012 [Layout2]

LNG Vaporization

The LNG vaporization facility consisting of boil-off gas (BOG) compression and re-condensation, LP LNG supply pumps, gas conditioning plant, HP LNG delivery pumps, vaporizers and seawater intake pumps is located on Platform No. 1.

The LNG will be pumped to the vaporization facilities via the LNG storage in-tank pumps to the suction of LP LNG supply and HP LNG delivery pumps. The HP LNG delivery pumps will pump the LNG to a pressure of up to approximately 1,800 pounds per square inch gauge (psig), which is at or above the required natural gas send-out pressure. The LNG will be vaporized in open rack vaporizers (ORVs) to natural gas, ready for storage in the salt caverns or metering and transportation via pipeline to market. Seawater will be the ORV heating medium for the LNG vaporization.

Gas Conditioning

For the terminal to meet the current gas pipeline gross heating value (GHV) specifications, a gas conditioning plant is required to condition the vaporized gas by extracting part of the ethane, propane, normal butane and iso-butane (butanes) in the LNG. Only part of the LNG stream will be processed in the gas conditioning plant, and the rest of the LNG stream will be bypassed and recombined with the "lean" LNG stream. The design capacity of the gas conditioning plant is equivalent to 1.0 bscfd of natural gas. The extracted stream consisting of ethane, propane, and butanes in the LNG will be exported onshore via pipeline.

NGL Metering and Pipeline

The gas conditioning plant will produce a Y-grade NGL that will be composed of ethane, propane, and butanes. Following measurement via check meter(s), the NGL will be transported via a 12-inch (30.5-cm) diameter pipeline from the deepwater port, a distance of 45.7 miles (73.5 km) westerly into Louisiana inland waters, and make connection with an existing NGL facility near Venice, Louisiana. NGL custody transfer will occur at the connection point near Venice, Louisiana.

Salt Cavern Natural Gas Storage

The deepwater port is situated above a large and well-defined salt dome. Salt has a unique combination of characteristics, making it an ideal rock for storage cavern construction. The deeply buried salt is generally impervious to liquid or gaseous hydrocarbons, has a compressive strength comparable to concrete, and can be easily mined by dissolution in water. Salt domes have been used to store natural gas along the United States Gulf Coast for over 30 years.

Three salt dome caverns will be constructed for the deepwater port for storage in the MP 299 salt dome from Platform No. 2. The gas storage caverns will be directionally drilled so that the center-to-center spacing between caverns will be a minimum distance of approximately 900 feet (274 meters). Each cavern will be capable of storing up to 9.3 billion standard cubic feet (bscf) of working gas at pressures of up to approximately 3,100 psig measured at the wellhead. Natural gas, which is regasified in excess of the pipeline demand, will be stored in the gas salt caverns. Likewise, whenever the regasification rate falls short of the pipeline demand, gas from the cavern will be supplied to the pipeline. A diagram of the salt cavern storage arrangement is shown on Figure 10.

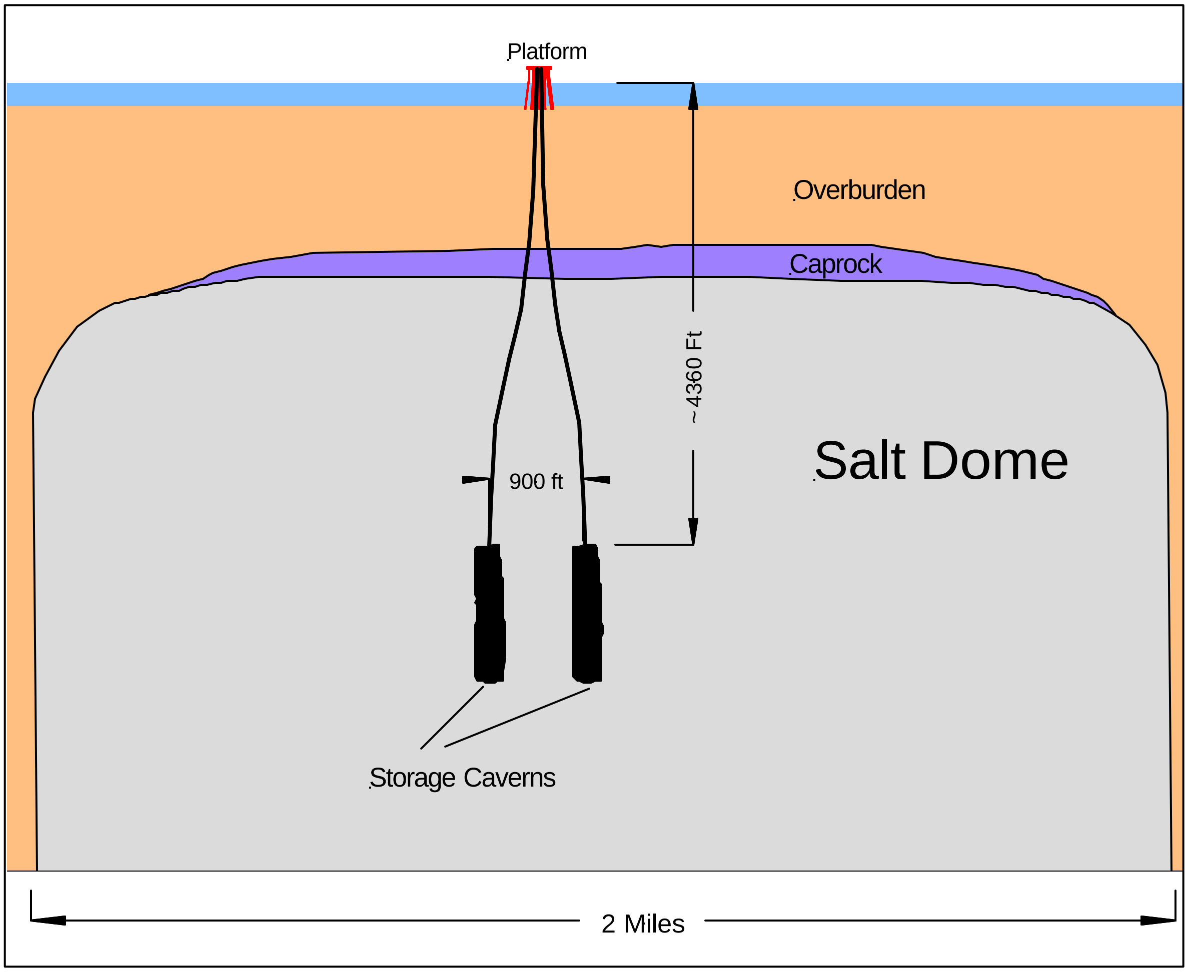


Figure 10. Salt Cavern Storage

Natural Gas Compression

The gas compression system will perform dual functions and will operate under the following events. First, in the event the LNG regasification rate is higher than the pipeline demand and the cavern pressure is higher than the pipeline send-out pressure, the compression system will increase the excess vaporized natural gas pressure to inject into the cavern. Second, in the event the LNG regasification rate is lower than the pipeline demand and the cavern pressure is lower than the pipeline send-out pressure, the compression system will boost the pressure of cavern gas to make up the shortfall in gas demand. Two 50% gas compression trains will be provided. The trains are generally operated in parallel to achieve the desired pressure and flow rate in each case, except for HP injection when the compressors operate in series.

Natural Gas Dehydration

The natural gas directly from the LNG vaporization plant is "dry" gas and does not need dehydrating. However, natural gas from the caverns may be water-saturated and will require dehydration in order to meet the pipeline specification of 7 pounds of water per million standard cubic feet (mmscf) of gas. TEG will be the selected dehydration medium. The dehydration unit will accept wet gas either directly from the caverns or from the gas compression system. The wet gas will be directed into the gas contactor where the gas and dehydration medium, TEG, will be contacted over structured packing. When the TEG comes in contact with the wet gas, water is absorbed from the gas into the TEG, resulting in “dry” gas exiting the contactor. The dry gas will be sent to a natural gas scrubber to allow the knockout of any TEG carried over from the gas contactor operation. The gas will then be sent to gas metering and pipeline transmission.

Natural Gas Metering and Export Pipelines

The natural gas departing the deepwater port will pass through check meters before entering the natural gas transmission pipelines. The majority of the export natural gas pipeline components will be located offshore on the OCS. A 36-inch (91.4-cm) diameter natural gas pipeline will extend northeast for approximately 30.8 miles (49.6 km) to connect the deepwater port to a new purpose-built junction platform located at MP 164. Departing the MP 164 junction platform will be two 16-inch (40.6-cm) diameter pipeline segments to tie in subsea to existing natural gas pipelines owned by Texas Eastern Transmission Corporation (TETCO) and Dauphin Island Gathering Partners (DIGP). Custody transfer for natural gas sold to TETCO and DIGP will occur on MP 164. In addition, the 36-inch (91.4-cm) diameter natural gas pipeline will continue approximately 61.9 miles (99.6 km) to Coden, Alabama. Approximately 5 miles (8 km) of this pipeline segment is proposed for construction onshore in Alabama (above the mean high water line). Custody transfer of natural gas sold to one of the three planned pipeline tie-ins, Gulf South Pipeline Company LP (Gulf South), Gulfstream Energy Services, Inc. (Gulfstream), and Transco, will occur in the vicinity of the tie-ins near Coden, Alabama. A second new 16-inch (40.6-cm) diameter natural gas pipeline will originate at the deepwater port and extend southeast for 2.5 miles (4.0 km) to MP 298, and tie into an existing natural gas pipeline owned by Southern Natural Gas Company (Southern Natural). Custody transfer for gas sold to Southern Natural will occur at MP 298. A third new natural gas pipeline, 20 inches (50.8 cm) in diameter, will extend south-southwest for approximately 51.5 miles (82.9 km) connecting to existing natural gas transmission pipelines at SP 55. Custody transfer for gas sold to existing pipelines at SP 55 will occur at SP 55.

Power Generation

Electrical power requirements will be generated by three 50% load capacity natural gas-powered turbine generators. Out of the three units, two will be for working operations and one will be an installed spare. Each power generation turbine will have capacity to generate approximately 19.5 MW of power (site rated). For normal terminal operations, gas to run the power generation turbines will be supplied by the fuel gas system from product natural gas. Three GE LM-2500 or equivalent turbines generators will be installed. All three power-turbine generators exhausts are treated for nitrogen oxide (NO_X) reduction in Selective Catalyst Reduction (SCR) units. A diesel engine-driven emergency generator will supply emergency backup power service.

Consumables and Spares Storage

Two existing platforms will be used for storage of consumables and spares. Platform No. 3 will be used for deck storage of containers, equipment, spares and other materials for the facilities operation and maintenance activities. Platform No. 4 will be used for the storage of TEG (used in the dehydration of gas stored in the salt dome caverns to pipeline specifications) and other operating chemicals. Additional deck storage for spares and consumables will be available on Platform No. 4 also.

Living Quarters and Helideck

Living quarters will be located on the existing bridge support Y7 (BS-Y7) located between Platform No. 1 and Platform No. 2. The living quarters will routinely accommodate 50 personnel, but can accommodate up to 94 personnel for brief periods, and includes offices, recreation, communications, and a galley. A jib crane will be provided for loading and unloading stores. In addition to the living areas, the living quarters will include the control room, offices, shop, warehouse, and laboratory spaces.

An existing helideck is located on BS-9 and can accommodate two helicopters. There will be a helideck located above the living quarters building and a further helideck is located nearby on Platform No. 3. There will also be a helideck at the pipeline junction platform at MP 164. All helidecks will meet the latest Federal Aviation Administration (FAA) and USCG rules and regulations for lighting and firefighting requirements.

8 *§148.105(g)* Financial Information

This section of the application provides financial information on the applicant FME, and its affiliates, MMR and McMoRan Oil & Gas LLC. The applicant is wholly owned by MMR.

8.1 *§148.105(g)(1)* Applicant and Affiliates Financial Information

Annual financial statements for FME and MMR for the years 2000, 2001, and 2002 (the last three full years for which statements are available) are contained in Volume IV "Financial" {*confidential*}. Also included are interim quarterly reports for the first, second, and third quarters of 2003 (the latest available interim quarterly reports) for FME and MMR.

8.2 *§148.105(g)(2)* Construction Cost Estimates

An estimate of the construction cost for the terminal is provided in Volume IV "Financial" {*confidential*}. Also included is an estimate of the cost to remove the marine components of the deepwater port, other than pipelines beneath the seabed.

8.3 *§148.105(g)(3)* Future Projections

Annualized projections for the first five years' operation of the deepwater port, along with projections at intervals throughout the life of the deepwater port are contained in Volume IV "Financial" {*confidential*}. This includes projected balance sheets, income statements, and operating expenses.

8.4 *§148.105(g)(4)* Proposals and Agreements

At the time of submittal of this deepwater port application, there are no agreements in place concerning the management and financing of the deepwater port. Should such agreements be entered into, copies will be made available to the USCG.

8.5 *§148.105(g)(5)* Throughput Reports

As the deepwater port is a proposed new facility (although it utilizes some existing structures) and is not yet in operation, there are no throughput reports for the year preceding the application for a deepwater port license.

9 *§148.105(h)* Construction Contracts and Studies

This section provides information on the applicant's intentions regarding construction contracts, information on the applicant's potential contractors, and on various studies that have been performed.

9.1 *§148.105(h)(1)* Construction and Operation Contracts

At this time, no contracts have been executed for the construction and operation of the deepwater port. It is not anticipated that contracts for construction and operation will be executed until after approval of this deepwater port license application. When construction and operations contracts are executed, copies will be made available to the USCG.

9.2 *§148.105(h)(2)* Deepwater Port Studies Conducted for or by the Applicant

9.2.1 §148.105(h)(2)(i) Completed or Ongoing Deepwater Ports Studies Conducted by or for the Applicant

Studies related to the concept selection, evaluation, engineering and design approach for the deepwater port are described in Appendix C "Summary of Deepwater Port Studies."

9.2.2 §148.105(h)(2)(ii) Other Construction-Related Studies

Studies related to the construction of the terminal are described in Appendix C, "Summary of Deepwater Port Studies."

9.3 *§148.105(h)(3)* Contractor Information

At this time, no contracts have been executed for the construction and operation of the deepwater port. It is not anticipated that contracts for construction and operation will be executed until after approval of this license application. When construction and operations contracts are executed, copies will be made available to the USCG along with the contractor firms' names, addresses, citizenships, telephone numbers, and qualifications.

10 *§148.105(i)* Compliance with Federal Water Pollution Requirements

10.1 *§148.105(i)(1)* Federal Water Pollution Control Act Amendments of 1972

Section 401 of the Clean Water Act (33 United States Code [U.S.C.] 1341(a)(1)) establishes the State Water Quality Certification program. This program applies to applicants for a federal license or permit that may result in a discharge into the navigable waters over which the state exerts concurrent jurisdiction with the federal government. The state water quality certification required by Section 401 of the Clean Water Act must be obtained before the federal license or permit may be issued. The water quality certification is required to consider whether the proposed discharge into navigable waters will comply with the applicable effluent limitations and water quality standards established pursuant to Sections 1311, 1312, 1313, 1316, and 1317 of Title 33 U.S.C. The applicant will comply with these requirements in accordance with the following section.

10.2 *§148.105(i)(2)* Request for Certification under 33 U.S.C. 1341(a)(1), if required

Because the MPEH™ project involves the construction of pipelines within the State waters of both Alabama and Louisiana, a request for Section 401 water quality certification will be included in the United States Army Corps of Engineers (USACE) dredge and fill permit applications submitted pursuant to Section 10 (Rivers and Harbors Act) and Section 404 (Clean Water Act). Only construction-related discharges are proposed to occur in waters subject to the jurisdiction of the States of Alabama and Louisiana. The information needed to evaluate the project will be included in the applications (ENG FORM 4345), along with appropriate technical, engineering, and environmental impact documentation. These dredge and fill permit applications submitted to the Mobile, Alabama, and New Orleans, Louisiana, district offices of the USACE are included in Appendix D.

In developing these applications, extensive consultation took place with state and federal resource agency officials in both Alabama and Louisiana to better understand agency needs and expectations on water quality and resource management issues. A summary of these consultations is provided in Section 29 of this application.

For discharges outside state waters, the water quality certification required by Section 401 of the Clean Water Act will be obtained from the administrator of the United States Environmental Protection Agency (EPA). These include both construction and ongoing operational discharges to the waters above the OCS. The ongoing operational water discharges from the deepwater port are proposed to occur on OCS blocks MP 299 and MP 164. These discharges will be the subject of a National Pollutant Discharge Elimination System (NPDES) permit application submitted to the EPA Region 6 in Dallas, Texas. This application will include the estimated volumes and characteristics of the proposed discharges, along with the results of water dispersion modeling for certain outfalls.

Results from the modeling of the LNG warming water discharges from the ORVs are included in this application. This NPDES permit application will be submitted to EPA Region 6 concurrent with this deepwater port license application. A copy of the NPDES permit application is provided in Appendix E.

11 *§148.105(j)* Coastal Zone Management

The proposed deepwater port will be located in the GOM on the OCS approximately 16 miles (25.7 km) offshore southeast Louisiana at MP 299. In addition to the deepwater port at MP 299, and metering platform at MP 164, the proposed project includes the construction of three new gas pipelines and one new NGL pipeline.

The NGL pipeline will enter the State of Louisiana, terminating near Venice, Louisiana. One of the gas pipelines will enter the State of Alabama, terminating near Coden, Alabama, and will come within 15 miles (24.1 km) of the State of Mississippi. The states of Louisiana, Alabama, and Mississippi have each been assumed by the applicant to be capable of qualifying as an "adjacent coastal State" in accordance with Section 3 of the DWPA (33 U.S.C. 1502). The applicant will submit a copy of this application to the following agencies in each state for consistency review.

Alabama Department of Environmental Management
Coastal Programs
4171 Commanders Drive
Mobile, Alabama 36615-1421
Attention: Mr. Allen Phelps

Alabama Department of Conservation and Natural Resources
State Lands Division
Coastal Section
23210 U.S. Highway 98, Suite B1
Fairhope, Alabama 36532
Attention: Mr. Jeff Jordan

Louisiana Department of Natural Resources
Coastal Management Division
P.O. Box 44487
Baton Rouge, Louisiana 70804-4487
Attention: Mr. Gregory DuCote, Coastal Resources Program Manager

Mississippi Department of Marine Resources
Coastal Ecology Office
1141 Bayview, Suite 101
Biloxi, Mississippi 39530
Attention: Mr. Mike Walker, Staff Officer

FME certifies to the best of its knowledge that the proposed action will be conducted in a manner consistent with the coastal zone management programs (CZMPs) of the adjacent coastal states.

12 *§148.105(k)(1),(2),(3)* Lease Block Information

Each lease block where any part of the proposed deepwater port or its approaches is located is listed in Table F-1 in Appendix F. Also included in this table are the ownership interest of each block and the present and planned use of each block. The blocks listed include all blocks crossed by proposed pipelines and blocks crossed during the access and egress of LNG carriers. Table F-2 in Appendix F provides a list of each pipeline or other right of way crossing along with the operator name. The blocks crossed by LNG carriers during access to and egress from the deepwater port are also shown on Figure 7.

Drawing number PC-PL-0001 also contained in Appendix F shows the lease blocks crossed by pipelines. Identification of the location of each pipeline right-of-way crossing is shown in survey plats in the pipeline route survey reports. Three copies of these reports, which are confidential, have been filed with this application under separate cover.

13 *§148.105(l)* Overall Site Plan

This section provides information on the drawings and plans of the deepwater port. The overall site plans are depicted on the following drawings contained in Appendix A.

Table 13-1
Overall Site Plans

Drawing No.	Title
02-29-0022	MPEH™ Conceptual Layout Schematic MP 299
AK-D-0001	Location Plan - General Arrangement MP 299
02-29-0018	Location Plan – MP 299 Platforms 3 and 4
02-29-0015	Structure Location Diagram – Main Pass 164
AK-D-0002	Air Emissions - Location Plan MP 299
02-29-0020	Air Emissions Location Plan – MP 299 Platforms 3 and 4
AK-D-0003	Water Discharges - Location Plan MP 299
02-29-0021	Water Discharges – Location Plan MP 299 Platforms 3 and 4
02-29-0023	Water Discharges – Location Plan MP 164
AK-D-0004	Navigation Aids Location Plan MP 299
02-29-0019	Navigation Aids Location Plan MP 299 Platforms 3 and 4
02-29-0017	Navigation Aids Location Plan MP 164

Detailed information on specific deepwater port components is provided in Volume III, Attachments {*confidential*} as described in the following sections.

13.1 *§148.105(l)(1)* Floating Structures

An integral component of the deepwater port is the Soft Berth™ System, which consists of two floating berthing dolphins, two berthing buoys, and associated mooring system to attach to the seafloor. The Soft Berth™ System is discussed further in Section 18.

13.2 *§148.105(l)(2)* Fixed Structures

The fixed structures, which consist of platforms, interconnecting bridges and associated support structures summarized in Table 13-2, are shown in the General Arrangement Drawings contained in Volume III, Attachment 2 {*confidential*}.

Table 13-2
General Arrangement Drawings

Drawing No.	Title
AK-D-0101	Platform No. 1 Top Deck Ship Offloading, Vaporization & Gas Conditioning
AK-D-0102	Platform No. 1 Mid Deck Ship Offloading, Vaporization & Gas Conditioning
AK-D-0103	Platform No. 1 Lower Deck Ship Offloading, Vaporization & Gas Conditioning
AK-D-0104	Platform No. 1 Elevation Ship Offloading, Vaporization & Gas Conditioning
AK-D-0201	Platform No. 2 –Drilling Deck (Upper) General Arrangement Plan
AK-D-0203	Platform No. 2 –Lower Deck General Arrangement Plan
AK-D-0204	Platform No. 2 –Elevation Drilling Deck General Arrangement Plan
AK-D-0401	Storage Platform No. 1 and No. 2 LNG Storage Tanks, General Arrangement Plan
AK-D-0402	Storage Platform No. 1 and No. 2 LNG Storage Tanks, General Arrangement Elevation
AK-D-0801	Platform BS-8 Bridge Support Platform Plan & Section
AK-D-0901	Platform BS-9 Bridge Support Platform Plan & Section
AK-A-0002	50-Man Living Quarters - 1st and 2nd Floor Plan
AK-A-0006	50-Man Living Quarters - West Elevation and HVAC Plan
PC-D-0100	MP 164 Main and Cellar Deck Plans
PC-D-0101	MP 164 Platform Piping Sections
61-06-0001	Platform No. 3 Lower Deck General Arrangement
61-06-0002	Platform No. 3 Upper Deck General Arrangement
71-06-0001	Platform No. 4 Lower Deck General Arrangement
71-06-0002	Platform No. 4 Upper Deck General Arrangement

Some typical structural arrangements of the fixed platforms are shown in the structural drawings in Volume III, Attachment 3 {*confidential*} and are summarized in Table 13-3.

Table 13-3
Structural Drawings

Drawing No.	Title
MD-STR-0001	Storage Platform Perspective
MD-PP1-2004	Platform No. 1 Truss Row "A" and "B"
MD-PP2-0001	Platform No. 2 Modifications
MD-Y7-0002	Platform BS - Y7 Modifications
MD-BS8-0001	Platform BS 8 Modifications
MD-BS9-0001	Platform BS 9 Modifications
MD-B10-0001	Bridge 10 Modifications
MD-B11-0001	Bridge 11 and 12 Modifications
MD-B13-0001	Bridge 13 Modifications
MD-B14-0001	Bridge 14 Conceptual Details
MD-JNC-0001	MP 164 Conceptual Details
61-00-0003	Platform No. 3 Isometric Assembly Elevation
71-00-0003	Platform No. 4 Isometric Assembly Elevation

13.3 *§148.105(l)(3)* Aids to Navigation

In addition to general deck lighting, the deepwater port will be equipped with navigation warning lights and aviation warning lights. The navigation warning lights will be provided as required by 33 Code of Federal Regulations (CFR) Part 149 Subpart E, Aids to Navigation. The locations of the navigation warning lights are shown on Drawing Number AK-D-0004, Navigation Aids Location Plan, contained in Appendix A. The locations of the MP 164 Junction Platform navigation warning lights are shown on Drawing Number 02-29-0019 also in Appendix A.

Aviation warning lights will be installed on the terminal flare booms and other tall structures (e.g., fixed cranes). These lights and their controller will meet all FAA and Federal Communications Commission (FCC) requirements. Alternating blue and yellow omni-directional taxiway lights will be installed to outline all heliport landing areas.

13.4 *§148.105(l)(4)* Manifold Systems

Manifold systems for the purposes of an LNG facility are interpreted as the process facilities. Block flow diagrams of the process facilities are contained in Appendix B of this volume. More detailed process flow diagrams are contained in Volume III, Attachment 4 {*confidential*}, and are also listed in Table 13-4.

Table 13-4
Process Flow Diagrams

Drawing No.	Title
AK-P-0021B	Overall Block Flow Diagram
AK-P-0051	LNG Unloading Arms
AK-P-0052	LNG Storage Tanks
AK-P-0053	LNG Storage Tanks
AK-P-0054	Boil-Off Gas Recovery

Table 13-4
Process Flow Diagrams

Drawing No.	Title
AK-P-0055	LP LNG Supply Pumps
AK-P-0056	Gas Conditioning Plant Train “A” and “B”
AK-P-0057	HP Sendout Pumps
AK-P-0058	LNG Vaporization (ORVs)
AK-P-0059	Product Sendout and Cavern Storage
AK-P-0060	Gas Compression
AK-P-0061	TEG Dehydration
AK-P-0081	Seawater System
AK-P-0082	Hot Oil system

Information on the electrical and instrumentation systems of the deepwater port is contained in the electrical and instrumentation drawings in Volume III, Attachment 5 {*confidential*}, and summarized in Table 13-5 below.

Table 13-5
Electrical and Instrumentation Drawings

Drawing No.	Title
AK-E-0001	Communications Concept Block Diagram
AK-E-0003	Terminal Electrical System One-Line Diagram
AK-E-0004	Leaching Electrical System One-Line Diagram
AK-I-0001	Conceptual Control System Block Diagram
AK-I-0002	Export Metering Block Diagram
AK-I-0003	Control System Wiring Philosophy

13.5 *§148.105(l)(5)* Onshore Storage Areas, Pipelines, and Refineries

The deepwater port will provide on-site storage for unloaded LNG. As LNG is vaporized, it will be either stored in salt caverns for future delivery or delivered directly via interconnecting laterals, to existing gas transmission pipeline systems. The interconnecting laterals will ultimately deliver their gas streams into the onshore national pipeline grid for transportation to the marketplace for commercial and residential consumption.

Natural gas, in its liquid or gaseous state, is not “refined;” however, natural gas may require removal of impurities that could harm pipeline infrastructure and/or meet tariff requirements, and to remove heavier hydrocarbons in the gas stream in order to prevent operational issues due to condensation within the pipeline, or to market extracted NGL as a commodity. For the deepwater port to meet gas pipeline GHV criteria, NGL may have to be extracted from the LNG prior to delivery into one or more pipeline interconnecting laterals. The NGL will be extracted offshore, metered, and transported via pipeline from the terminal to an onshore tie-in to an existing NGL pipeline system at Venice, Louisiana.

Details including diagrams and charts of the onshore systems served by the proposed deepwater port are provided in Volume III, Attachment 6 {*confidential*} and are listed in Table 13-6.

Table 13-6
Onshore Facilities

Drawing No.	Title
Attachment 6.1	Pipeline Connectivity Map
Attachment 6.2	Pipeline Diagram – Demand Side
Attachment 6.3	Venice Energy Services Company Gas Plant, Venice, Louisiana

14 *§148.105(m)* Site Plan for Marine Components

14.1 *§148.105(m)(1)* Overall Marine Components Site Plan

14.1.1 §148.105(m)(1)(i) Fixed and Floating Structures and Associated Components

The deepwater port will be located 16 miles (25.7 km) offshore southeast Louisiana, east of the Mississippi River Delta, at MP 299 in approximately 210 feet (64 meters) of water. The deepwater port will be primarily located at 29°16'03.15"N and 88°45'47.53"W and will be composed of five interconnected existing platforms (two main platforms and three smaller bridge support platforms), two nearby storage platforms for spares and consumables, and two new LNG storage tank platforms that also will be connected to the existing structures by bridges. Two new semisubmersible units and two berthing buoys that include the Soft Berth™ System are proposed for mooring adjacent to existing Platform No. 1 to act as a berthing and fendering system for LNG carriers calling at the deepwater port. The general layout of the deepwater port at MP 299 is shown on Figure 3.

In addition to the existing and proposed facilities at MP 299, a new four-pile gas-metering platform is proposed for construction at MP 164. This proposed metering platform will be located at 29°37'27.3"N and 88°27'17.2"W approximately 30.8 miles (49.6 km) northeast of the MP 299 terminal along the route of the 36-inch (91.4-cm) natural gas pipeline to Coden, Alabama. The proposed platform will be of standard steel-jacket construction with dimensions of approximately 85 feet by 85 feet (25.9 meters by 25.9 meters) at the upper deck. The water is approximately 150 feet (45.7 meters) deep at the location of this proposed gas-metering platform. No LNG carriers will call at this proposed unmanned platform. A detailed view of the location of the proposed gas-metering platform on MP 164 is provided on Figure 4.

Additional information on the orientation, size, and arrangement of the existing and proposed facilities at MP 299 is provided on the overall site plan drawings in Appendix A. Detailed information on offshore pipelines is contained in Section 20 of this application.

14.1.2 §148.105(m)(1)(ii) Ships' Routing Measures and Vessel Traffic Patterns in the Port Area

LNG carriers will berth adjacent to existing Platform No. 1, which is located approximately 5 miles (8 km) from the eastern edge of the South Pass to Mississippi River Gulf Outlet Safety Fairway. The recommended route to and from the deepwater port from the safety fairway is shown on Figure 7. The recommended route passes through OCS blocks, MP 149, MP 300, MP 299, MP 146, and MP 147. LNG carriers may approach the deepwater port from either the north or south, depending upon prevailing weather conditions and specific plans to discharge LNG from either the ship's port or starboard side manifolds. The LNG carrier will be tethered to three support vessels at all times while transiting to and from the safety fairway. These support vessels will be capable of rapidly stopping or turning the ship in the event of a loss of ship's power, steering, or other shipboard emergency.

The applicant does not propose to install any berthing buoys or other aids to navigation to mark the location of the recommended route for LNG carriers. The water in the vicinity of the deepwater port is between 140 and 230 feet (43 and 70 meters) deep. This depth of water makes it unnecessary to install aids to navigation to formally define a navigation fairway or channel. In addition, existing platforms in the vicinity provide fixed-radar reference points from which to accurately fix the LNG carrier's position. The recommended route is designed to provide adequate separation between the LNG carrier and existing fixed platforms in the area.

The applicant proposes that a 500-meter (1,640-foot) safety zone extend in all directions outward from the deepwater port. Once established, no vessel will be allowed to enter this safety zone without the express permission of the deepwater port vessel traffic supervisor or the USCG. In addition, to the 500-meter (1,640-foot) safety zone, the applicant also proposes that a 2-mile (3.2-km) diameter "precautionary area" be established surrounding the deepwater port. Such a precautionary area can be designated on navigation charts to notify other mariners to use caution in the vicinity of the deepwater port. Figure 8 shows the size and location of the proposed safety zone and precautionary area surrounding the deepwater port. No safety zone is currently proposed for the gas-metering platform at MP 164.

All fixed platforms and connection bridges that are part of the deepwater port will be marked with the obstruction lights required by 33 CFR Part 67. In addition, the high-intensity rotating beacon specified in 33 CFR 149.535 will be installed to distinguish the deepwater port from other surrounding offshore structures. Sound signals (fog horns) that meet the requirements of 33 CFR Part 67 will also be provided as required by 33 CFR 149.585. The proposed number and location of obstruction lights, fog horns, and other aids to navigation are shown in Appendix A on Drawings Nos. AK-D-0004 (Rev B) and PC-D-1401, "Navigation Aids Location Plans."

At least one radar beacon (RACON) that meets the requirements of 33 CFR 149.580 is proposed for installation on the deepwater port. This RACON will be capable of receiving signals from vessel radars and transmitting responding signals that appear as a brighter than normal target on the receiver's radar in Morse code. An Automated Information System (AIS) is also proposed for installation on the deepwater port. The AIS will transmit the name of the deepwater port and its position. This data will identify the deepwater port as a fixed marine facility to vessels in the area.

14.1.3 §148.105(m)(1)(iii) Anchorage Areas and Support Vessel Mooring Areas

The applicant proposes that LNG carriers use any of the numerous existing anchorages in the vicinity of the deepwater port. LNG carrier arrivals will normally be scheduled such that the ships will not have to anchor, but instead can proceed directly to the berth. In those rare instances when an LNG carrier might find it necessary to anchor, existing designated anchorages may be used. Two existing anchorages are designated at the intersection of Mississippi River Gulf Outlet and the South Pass to Mississippi River Gulf Outlet Safety Fairway approximately 12 miles (19.3 km) northwest of the deepwater port. Additional designated anchorages are located to the southwest at the entrances to the Mississippi River South Pass and Southwest Pass. No additional anchorages are proposed as part of the deepwater port. A map showing the location of the deepwater port in relation to two existing anchorages at the entrance to the Mississippi River Gulf Outlet channel is provided on Figure 9.

14.2 *§148.105(m)(2)* Hydrographic Survey of the Proposed Site

A number of hydrographic and archeological surveys of the MP 299 block have occurred since 1988 in connection with development of the oil, gas, and sulphur extraction facilities at the site. Recent hydrographic, archeological, and hazards surveys include:

- "Hydrographic Survey and Sub-Surface Features Assessment, Proposed Port Facility, Block 299, Main Pass Area," February 19, 2004, prepared by Fugro GeoServices, Inc. (FGSI);
- Hydrographic Survey and Sub-Surface Features Assessment, Proposed Platform, Block 164, Main Pass Area," February 2004, prepared by FGSI;
- "Archeological and Hazard Survey, Block 299, OCS-G-9372, Main Pass Area," August 1988, prepared by John E. Chance & Associates, Inc.;
- "Seafloor Subsidence Base-Line Survey and Interpretive Results, Main Pass Area, Block 299," Report 0201-0877, February 5, 1992, prepared by FMMG;
- "Freeport Sulphur Company, Monitoring Survey (OCS-G-9372) Block 299, Main Pass Area," November 1996, prepared by John E. Chance & Associates, Inc;
- "Freeport Sulphur Company, Monitoring Survey (OCS-G-9372) Block 299, Main Pass Area," December 1997, prepared by John E. Chance & Associates, Inc.;
- "Freeport Sulphur Company, Monitoring Survey (OCS-G-9372) Block 299, Main Pass Area," December 1998, prepared by John E. Chance & Associates, Inc.;
- "Freeport Sulphur Company, Monitoring Survey (OCS-G-9372) Block 299, Main Pass Area," November 1999, prepared by FGSI;
- "Average Annual Currents and General Oceanographic Data: Main Pass Block 299, 210 Mean Low Water Depth, Offshore Louisiana," dated February 1989, Re-issued February 2004, prepared by A.H. Glenn and Associates Services; and
- "Normal Wind and Wave Conditions and Storm Wave Persistence: Main Pass Block 299, 210 Mean Lower Low Water Depth: Offshore Louisiana, dated January 2004, prepared by A.H. Glenn and Associates Services.

Previous hydrographic surveys of the MP 299 block determined that the seafloor in the area ranges in depth from -202 feet (-62 meters) to -222 feet (68 meters). Bathymetric contours exhibit a slope to the southeast at an average rate of 7 feet (2.1 meters) per mile (0.07°) according to the John E. Chance & Associates, Inc.'s August 1988 report. Subsequent seafloor monitoring surveys have been consistent with these results with the exception of two seafloor depressions created as a result of sulphur extraction on the block. The 1999 seafloor monitoring survey by FMMG noted that one area of subsidence 6,000 feet by 3,800 feet (1,829 meters by 1,158 meters) measured -227 feet (-69 meters) at the deepest point. A second 200-feet (61-meter) diameter area of subsidence reached a maximum depth of -220 feet (-67 meters). These areas of subsidence were predicted to occur as a result of the sulphur extraction activities in the block.

Summary information on the reports listed above is included in Volume III, Attachment 7 {*confidential*}. Three copies of the following reports, which are confidential, have been submitted to the USCG under separate cover as part of this application:

- "Hydrographic Survey and Sub-Surface Features Assessment Proposed Port Facility, Block 299, Main Pass Area," dated February 2004, prepared by FMMG; and
- Hydrographic Survey and Sub-Surface Features Assessment Proposed Platform Block 164, Main Pass Area," dated February 2004, prepared by FMMG.

15 *§148.105(n)* Soil Data

A review of the geophysical survey data and available soils data to evaluate the general geological and geotechnical engineering characteristics of the ocean bottom and sub-bottom soils along the proposed pipeline routes and platform locations was performed. The review was directed toward determination of the suitability of the soil to accommodate the anticipated design load of each of the proposed facility components and the stability of the seabed when exposed to environmental forces.

Geophysical surveys were conducted using echo sounder, side-scan sonar and sub-bottom profiler. While drop core data at the proposed platform locations and pipeline routes were not available, records of previous soil borings were used to develop models of the expected seafloor soil conditions. The boring logs used, generally contained information concerning the soil classification, undrained shear strength of the cohesive soils, grain size of granular soils, soil unit weight, and sampler penetration resistance. The study involved the review of about 120 boring logs. In addition, foundation soil conditions at the deepwater port location in MP 299 were modeled in part from borings that had been drilled and sampled for the design of the original Main Pass sulphur mine facilities.

In general, the seafloor soil engineering properties are expected to be sufficient for pipeline support. During the detailed design of the pipeline from MP 299 to SP 55 the risk of seabed instability in the region between Viosca Knoll 942 and SP 55 due to future mudflows will be evaluated. Based on the magnitude and character of risk disclosed by the study, appropriate measures will be taken in pipeline design and installation to reduce the risk to acceptable levels.

In general, scour is not expected to be a factor for pipeline stability over most of the pipeline routes. However, during the detailed design of the pipelines, scour might be a factor for consideration in pipeline design during major tropical storms. The scour potential will be evaluated where appropriate based on tests of drop core samples and expected seafloor currents. Where the potential for scour is identified the risk will be mitigated by pipeline burial to appropriate depths below the seafloor.

In evaluation of the geothechnical engineering characteristics of the soils at the two proposed platform sites 17 borings in MP 299 and three borings in the vicinity of MP 164 were considered. The soil strength profiles deduced from the nearby soil borings suggest the foundation soils will provide sufficient foundation support for properly designed platform pile foundations in these two blocks. Scour effects, if any, are expected to be small and easily accommodated in the design of the foundation piles.

Additional information is contained in the report titled “Geotechnical Characterization of Sediments, Main Pass Energy Hub™ Facilities, Offshore Louisiana and Alabama Gulf of Mexico,” Report No. 0201-5170. Summary materials from this report are provided in Volume III, Attachment 8 “Soils” {*confidential*} and three copies of the full report have been submitted to the USCG under separate cover as part of this deepwater port license application.

16 *§148.105(o)* Archeological Information

The archeological survey of MP 299 conducted in 1988 by John E. Chance & Associates, Inc., noted the following:

> “The Pleistocene horizon which was exposed during the last glacial cycle is buried by at least 250 feet of relatively modern deposits, and possible prehistoric archeological features in this area are buried beyond a reasonable recovery depth. Block 299, Main Pass Area, should be considered a low probability zone for the occurrence or recovery of prehistoric archeological resources.
>
> The side scan sonar, pinger, and magnetometer records were used in conjunction with the facility maps to verify the positions of the numerous structures and wells in the lease.
>
> The scan sonar showed naturally occurring gas vents on the seafloor, but there were no indication of any possible shipwreck material in the area. The deep water would obviously preclude the possibility of any vessel having run aground. The geophysical data suggests that Block 299, Main Pass Area, is free of potential cultural resources.”

Recent shallow hazard and archeological surveys of the proposed project platforms and pipeline routes, conducted by FMMG and Panamerican Consultants in 2003 and 2004, include:

- “Archeological, Engineering and Hazards Survey, Block 299 to 164, Main Pass Area and from Block 164, Main Pass Area to Block 819, Mobile Area (Alabama’s 3 mile boundary), Gulf of Mexico,” Report No. 101224, February 2004, by FMMG;
- “Archeological, Engineering and Hazards Survey in Mississippi Sound Area (Alabama State Waters), Block 107 to Block 34 (Landfall in Coden, Alabama),” Report No. 101225, February 2004, prepared by FMMG;
- “A Phase I Cultural-Resource Survey of the Freeport-McMoRan Main Pass Energy Hub (MPEH) Pipeline, Mobile, Alabama,” February 20, 2004, prepared by Panamerican Consultants, Inc.;
- “A Phase I Cultural-Resource Survey of the Freeport-McMoRan Main Pass Energy Hub (MPEH) Pipeline, Plaquemines Parish, Louisiana,” Draft, February 20, 2004, prepared by Panamerican Consultants, Inc.;

- "Archeological, Engineering and Hazards Survey, Block 299 Main Pass Area to Block 55, South Pass Area, Gulf of Mexico," Report No.2403-1340, January 2004, prepared by FMMG;
- "Archeological, Engineering and Hazards Survey, Block 299 to Block 298, Main Pass Area, Gulf of Mexico," Report No.101224-MP298PL, January 2004, prepared by FMMG; and
- "Archeological, Engineering and Hazards Survey, Block 299, Main Pass Area, Gulf of Mexico to Dynegy Gas Plant, Venice, Louisiana," Report No. 2403-1382, February 2004, prepared by FMMG.

Summary information on the Panamerican reports and FMMG reports are provided in Volume III, Attachment 9 {*confidential*}. Three copies of the full FMMG reports, which are confidential, have been submitted to the USCG as part of this application under separate cover. Also refer to the "Hydrographic Survey Report" and other reports in Section 14.2 of this application.

17 *§148.105(p)* Vessel Operational Information

This section provides information related to vessel operations. Additional information is contained in Section 24 of this application.

Vessel Operations

The following is a synopsis of more detailed procedures outlined in the draft deepwater port operations manual (refer to Section 24 of this application). This section provides an overview of the typical vessel operations at the deepwater port.

Safety will be a core value at the deepwater port and all personnel involved in LNG transfer, storage, and vaporization will be expected to follow all safety guidelines. The LNG Carrier Captain, the Mooring Master, support vessel crews, and the Terminal Manager will be expected to work closely together during all aspects of LNG carrier operations. Only one LNG carrier at a time will be allowed to berth, and the LNG carrier will not approach until the Mooring Master has issued navigation and maneuvering instructions. The LNG carrier must be 100% operable and seaworthy prior to receiving approval to approach, and the LNG carrier must confirm that it meets additional requirements as described in the Operations Manual.

The boarding area for the Mooring Master will be at the point where the LNG carrier exits the traffic lane on its approach to the deepwater port. After boarding, the Mooring Master will familiarize the LNG Carrier Captain on all aspects of escort, security and berthing requirements and procedures at the deepwater port. After entering the LNG carrier's bridge, the Mooring Master will immediately confirm the LNG carrier's position, heading, speed, and look for local traffic before conducting his Master/Mooring Master conference. The Mooring Master will verify, via a pre-transfer checklist, that all equipment has been tested and inspected in compliance with United States regulations and Oil Companies International Marine Forum (OCIMF) recommendations. Berthing arrangements will be determined prior to arrival. If conditions onboard the LNG carrier, as outlined in the 96-hour estimated time of arrival (ETA) communication, require action or reconsideration of the berthing plan, decisions to alter the plan will be made by the Mooring Master with concurrence with the LNG Carrier Captain and Terminal Manager.

Environmental conditions, such as sea current, wind force, and wave direction, will influence the berthing plan. In most cases, the LNG carrier bow thruster and main engine will be used as necessary during berthing operations. As the LNG carrier approaches the deepwater port, the Assistant Mooring Master will station himself at the forecastle of the LNG carrier to advise the Mooring Master and LNG carrier crew in deploying mooring lines and operating deck equipment. The Mooring Master will make certain that support vessels are safely controlling the LNG carrier. If satisfied, the Mooring Master will (in accordance with the berthing plan) slowly close the distance between the LNG carrier and Soft Berth™ System. When within 50 feet (15.2 meters) of Soft Berth™ System, the LNG carrier will hold its position as breast lines are connected to the Soft Berth™ System. The Mooring Master will then maneuver the LNG carrier alongside the Soft Berth™ System, according to the berthing plan. A support vessel(s) will hold the LNG carrier in position until all remaining lines are heaved tight to required tension. At this point, the Mooring Master will ease off thrust forces of support vessel(s) and allow Soft Berth™ System and adjacent mooring buoys to accept LNG carrier mooring load.

After the LNG carrier is securely moored, the LNG Carrier Captain will confirm fire wires are rigged outboard of the LNG carrier at its bow and forward quarter. These wires are required during cargo transfers. An offshore embarkation ladder will also be rigged for immediate use by crewmembers in the event of an emergency. LNG carrier cargo transfer shall comply with all OCIMF procedures and recommendations and the appropriate requirements and regulations in Subpart B of 33 CFR Part 127. Before commencement of cargo or vapor transfers necessary information will be communicated to all concerned. This will include confirmation that the LNG carrier is ready in all respects, the LNG carrier systems are correctly aligned, operators are stationed in the loading area and in the LNG carrier control room, LNG carrier discharge valves and vapor valves are aligned, a responsible crewmember is stationed at the manifold, and a person-in-charge is located in the LNG carrier control center. After cargo transfer is complete, liquid lines and arms must be drained and purged with nitrogen prior to disconnecting.

Prior to departure, the Mooring Master will make a security announcement to warn any and all vessels in the area that the LNG carrier will soon depart. As the LNG carrier prepares to exit the deepwater port, the Mooring Master will evaluate weather conditions and instruct the LNG carrier on the safest procedures and route for exiting the deepwater port.

After the LNG carrier confirms its readiness to exit, the Mooring Master will instruct support vessels of the exit plan and deploy them to specific positions for unberthing the LNG carrier. Support vessels will hold the LNG carrier at the Soft Berth™ System as bow and stern lines are slackened then released. Then all spring lines and breast lines will be slackened and retrieved. The LNG carrier will slowly exit the deepwater port as the Mooring Master employs LNG carrier main engine power and rudder control to increase speed and course control as the LNG carrier exits. Support vessels will passively escort the LNG carrier to the sea-lanes. All support vessels will release themselves before the LNG carrier achieves an ahead speed of 5 knots. A support vessel may continue its security patrol if requested by the Mooring Master.

Vessel Characteristics

The deepwater port is designed to handle vessels in the size range from 60,000 to 160,000 m^3 and the characteristics of typical vessels are shown in Table 17-1.

Table 17-1
Typical LNG Carrier Characteristics

LNG Carrier Type	Spherical Tanks			Membrane Tanks	
LNG carrier designation (m^3)	125,000	137,000	145,000	138,000	160,000
LNG capacity (m^3)	128,277	137,000	145,000	138,000	160,000
Length overall (m)	293.7	288	290	278.8	290
Molded beam (m)	41.6	48.2	49	44	46
Location of LNG Manifold: Forward from amidships (m) Vertical above water line At Design draft (m) Inboard from ship side (m)	 18.0 18.5 4.5 – 6.0	 -11.44 19.47 20.97 	TBD	 1.5 19.5 21.2 	TBD
Draft fully loaded (m)	11.5	11.25	11.4	11.3	11.6
Maximum displacement (mT)	96,235	114,499	104,000	98,000	116,000
Minimum water depth at Berth (m)		15.0	15.1	15.0	15.3
Design Discharge Rate (m^3/hr)	10,800	12,000	12,000	11,000	12,000

Key:
m = meter.
m^3 = cubic meter.
m^3/hr = cubic meters per hour.
mT = metric tons.

Weather Forecasting

The deepwater port will be located in a semitropical zone in the GOM. Storms can develop quickly in summer and winter and contain short-term wind bursts up to Beaufort Force 9/10. Hurricanes can occur between the months of June and November. On an annual average, wave heights are below 6 feet (1.8 meters) for 70% of the year and can exceed 10 feet (3 meters) for 5% of the year. Poor visibility (less than 2 miles [3.2 km]), although infrequent, most often occurs in January/early February. Sea currents are generally from the west with an average speed of about 0.75 knots. However, on some occasions currents can reach 2 knots.

The deepwater port will have a weather monitoring system to enable continuous information to be regularly communicated to the Terminal Manager. In addition, continuous weather information, forecasts, and weather warnings broadcast by the National Oceanic and Atmospheric Administration (NOAA) will be monitored.

Particular environmental conditions and their consequential impact on the LNG carrier while berthed at the deepwater port will depend on various factors, including size of the LNG carrier, the amount and distribution of LNG onboard, LNG carrier draft, wind direction and strength, wave height and direction, current speed and direction, and the near-term weather forecast.

The Terminal Manager and Mooring Master will watch for changes in environmental conditions at or near the location (wind speed and direction, wave height and direction, and current speed and direction). A combination of environmental forces could amplify sea conditions that challenge the LNG carrier and support vessels to successfully counter these conditions. In some cases, the LNG carrier may have to exit the deepwater port before environmental conditions exceed weather-induced limitations. When evaluating whether the LNG carrier can safely remain at the berth, the Terminal Manager and Mooring Master should also consider NOAA weather forecasts for the following 12- to 24-hour period.

18 *§148.105(q)* Floating Components

The floating components that will include part of the deepwater port are the semisubmersible berthing dolphins and associated berthing buoys. This section provides a description of these components. Drawings and additional information on the Soft Berth™ System design are contained in Volume III, Attachment 10 {*confidential*}.

18.1 *§148.105(q)(1)* Floating Components Descriptions and Drawings

The berthing of the LNG carriers to the terminal will be achieved by a patent-pending system designated Soft Berth™ System. The Soft Berth™ System will consist of two floating dolphins, one on either side of the deepwater port Platform No. 1. The platform will be oriented east-west with the LNG unloading arms located on the western face. The dolphins will be located adjacent to Platform No. 1 so that a berthed LNG carrier can be secured in an appropriate condition for cargo transfer. Two berthing buoys located to the south and north of the dolphins will provide improved berthing capability.

The Soft Berth™ System is illustrated in the following drawings provided in Volume III, Attachment 10, {*confidential*}.

Table 18-1
Floating Components

Drawing No.	Title
407-001-A	General Arrangement
407-002-A	Structural Arrangement
407-003-A	Bilge and Ballast System Isometric
407-004-A	Bilge and Ballast System
V-407-SK-3_Alt 3	Beam Direction Operating Envelope

Dolphins

The dolphins will be triangular-shaped semisubmersible structures with three cylindrical columns, diagonal braces, and a heave plate at the keel supported by buoyant box girders. The dolphins will be oriented with the apex pointed to the east and each will be about 50 feet (15.2 meters) clear of the platform edge in the north-south direction. The dolphin's two westernmost columns will incorporate a flat face, against which energy-absorbing fenders will rest. It is intended that two fenders will rest against the column closest to the platform and one fender on the other west column. This west face of the dolphins is the side to which the LNG carrier will be berthed. The west face of the dolphins will be positioned 20 feet (6.1 meters) from the western edge of the deepwater port platform. Each pneumatic fender (three for each dolphin) will be 15 feet (4.6 meters) in diameter and 40 feet (12.2 meters) long. This will place the side of the LNG carrier approximately 35 feet (10.7 meters) from the platform with the ship manifold at the center of the unloading arm location on the platform.

Each dolphin will be anchored to the seabed by a spread pattern of mooring lines. Three mooring lines will emanate from each west column and the east column will accommodate four mooring lines. All lines will attach to fixed piles installed by driving or by suction into the soil and will be pre-tensioned by mooring equipment on the dolphins. Once the lines are all pre-tensioned and the dolphins are correctly located, the load of the mooring lines will be transferred to chain stoppers and the dolphins will then be in a passive mode.

Berthing System

Each dolphin will support a berthing system designed to hold an LNG carrier in position adjacent to Platform No. 1 for LNG unloading. The system may include tension equipment for the berthing lines to prevent more than a predetermined limit of tension to occur in the lines. When that value is reached, the maximum line tension will not increase. This will prevent line breakage or damage to the mooring equipment aboard the LNG carrier. Each line also will be provided with a quick-release mechanism to allow for rapid emergency unberthing.

Fire, Bilge, and Ballast System

Each column will be equipped with an external submersible pump and caisson. The external pumps on the aft columns will feed water into a ring main at the main deck level. The ring main will supply water for the ballast tanks, firefighting, and deck wash-down. The bottom of each column will also be equipped with an internal submersible ballast pump and caisson. The internal submersible pumps will fill the ballast tanks, as well as evacuate water from the ballast tanks to the ring main and overboard discharge. The external pump and caisson on the forward column will be used as an oily water sump pump.

Cranes

Each dolphin will be equipped with a single crane of approximately 15-ton capacity and a boom length of 120 feet (36.6 meters). These cranes are positioned on the aft end to assist with handling of breasting and spring lines and fenders.

Auxiliary Generator

Each dolphin will be supplied power from Platform No. 1. In the event of loss of power, each dolphin will be equipped with a diesel driven auxiliary generator. This generator will be sized to provide for lighting and operation of a fire/bilge/ballast pump and provided with a day tank.

Access Bridges

An access bridge to and from Platform No. 1 will be provided for each dolphin. The bridge will land on a 50-foot by 60-foot (15.2-meter by 18.3-meter) platform, 20 feet (6.1 meters) above the main deck of the dolphin. The dolphin-end of the bridge will be fitted with rollers to allow it to move on the platform as the dolphin moves. The bridge will support foot traffic, as well as jumpers for electrical power and fresh water.

18.2 *§148.105(q)(2)* Floating Components Design Criteria

Structural

The Soft Berth™ System dolphins are expected to be minimally sized semisubmersibles that incorporate mooring equipment, fairleaders, fenders, hawser attachments, ballast system, bridge support, and other miscellaneous items. The designs will be based on American Bureau of Shipping (ABS) "Guide For Building and Classing Floating Production Installations," "Rule for Building and Classing Mobile Offshore Drilling Units," the American Institute of Steel Construction (AISC) Manual, and other documents as listed below.

Mooring

The mooring of the Soft Berth™ System structures to the seabed will be based on the requirements of ABS "Guide For Building And Classing Floating Production Installations" and American Petroleum Institute (API) 2RP-2SK "Recommended Practice For Design And Analysis of Stationkeeping Systems For Floating Structures."

Operating Environment

The environment for which the LNG carrier is designed to remain berthed is listed in "Basis of Design" in Volume III, Attachment 11 {*confidential*}. MPEH™ will be capable of accommodating LNG carriers from 60,000 m^3 up to 160,000 m^3. Different sizes of carrier will have different operability characteristics. In each of these, the wind, wave, and current are concurrent from the same direction, and the environment can approach from any direction.

18.3 *§148.105(q)(3)* Floating Components Design Standards and Codes

Code of Federal Regulations (CFR)

- 30 CFR Part 250, OG&S Operation in the OCS
- 49 CFR Part 193, Liquefied Natural Gas Facilities: Federal Safety Standards
- 49 CFR Part 192, Natural Gas Pipeline Facilities: Federal Safety Standards
- 46 CFR Parts 166 to 199, Shipping
- 33 CFR Subchapter N, OCS Activities
- 33 CFR Subchapter NN, Deepwater Ports
- 33 CFR Subchapter O, Pollution
- 33 CFR Subchapter P, Ports and Waterways Safety
- 46 CFR Part 154 Safety Standard for Vessel Carrying Bulk Liquefied Gases
- 40 CFR Protection of Environment

National Fire Protection Association (NFPA)

- NFPA 70, National Electric Code (NEC)
- NFPA 72, National Fire Alarm Code
- NFPA 10, Portable Fire Extinguishers
- NFPA 11A, Medium and High Expansion (hi-ex) Foam Systems
- NFPA 14, Installations of Stand Pipe and Hose Systems
- NFPA 15, Water Spray Systems for Fire Protection
- NFPA 16, Installation of Deluge Foam-Water Sprinkler and Foam-Water Spray Systems
- NFPA 24, Private Fire Service Mains and Their Appurtenances
- NFPA 231, Standard for General Storage
- NFPA 231C, Standard for Rack Storage of Materials
- NFPA 321, Standard on Basic Classification of Flammable and Combustible Liquid
- NFPA 2001, Clean Agent Extinguishing Systems

American Bureau of Shipping (ABS)

- Guide for Building and Classing Floating Production Installations 2000
- Rules for Building and Classing Single Point Moorings 1996
- Rules for Building and Classing Mobile Offshore Drilling Units

American Petroleum Institute (API)

- API RP 2C, Specifications for Offshore Cranes
- API RP 2SK, Recommended Practice for the Design and Analysis of Stationkeeping Systems for Floating Installations 1997
- API RP 14F, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities
- API RP 14G, Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms
- API RP 14, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities
- API RP 75, Recommended Practice for Design and Operation of a Safety and Environmental Management Program for OCS Operations and Facilities
- API RP 2003, Protection Against Ignitions Out of Static, Lighting, and Stray Currents
- API RP 2095, Recommended Practices for Operation and Maintenance of Offshore Cranes
- API STD 2000-98, Venting Atmospheric and Low Pressure Tanks
- API PUB 2030, Application of Fixed Water Spray Systems for Fire Protection in the petroleum Industry

American Welding Society (AWS)

- AWS D1.1, Structural Welding Code: Steel

Oil Companies International Marine Forum (OCIMF)

- OCIMF 4, Design and Construction Specifications for Marine Loading Arms
- OCIMF 20, Mooring Equipment Guidelines
- OCIMF, Guidelines and Recommendations for the Safe Mooring of Large Ships at Piers and Sea Islands
- OCIMF, Prediction of Wind Loads on Large Liquefied Gas carriers, 1997

Society of International Gas Tanker and Terminal Operators (SIGTTO)

- SIGTTO, Prediction of Wind Loads on Large Liquefied Gas Carriers
- SIGTTO, Liquefied Gas Handling Principles on Ships and in Terminals

18.4 *§148.105(q)(4)* Floating Components Engineering Practices

The Soft Berth™ System design will adhere to the applicable codes and standards listed in Section 18.3. In addition, sound and proven marine practice will be followed in all instances. If any circumstance should arise that is not covered specifically by the listed codes and standards, all effort will be made to identify and adhere to any relevant or applicable code or standard not currently listed. If no existing code is found to be applicable, analysis will proceed based upon sound engineering principles.

18.5 *§148.105(q)(5)* Floating Components Safety, Firefighting, and Pollution Prevention Equipment

Safety Equipment

Lifesaving equipment to be used on the Soft Berth™ System will be in accordance with 33 CFR Part 150 Subpart F--Operations (Emergency Equipment) and the section below; personal protective equipment will be provided in accordance with 33 CFR Part 150 Subpart G--Workplace Safety and Health."

Lifesaving Appliances

Each dolphin will be equipped with a variety of lifesaving appliances and devices appropriate to the anticipated staffing and operation of each unit in compliance with 33 CFR Part 149 Subpart C.

Firefighting

The external ballast pumps will provide water to the seawater ring main on the main deck. Both ballast pumps may be used as fire pumps. This ring main will distribute firefighting water for the dolphin. Three fire monitors, fire hydrants, and hose reel stations equipped with spanner wrenches will be provided at sufficient intervals along the deck and in the columns such that any space may be reached by at least two hose teams, at least one of which will use only a single length of hose. Portable fire extinguishers will also be provided, matched to the requirements of the particular space in which they may be located. A foam tank will be located on the main deck to provide foam where and when appropriate. Each dolphin will be provided with sufficient turnout suits, self-contained breathing apparatus (SCBAs), and other equipment, as necessary, at designated muster stations. The equipment and system will comply with 33 CFR Part 149 Subpart D.

Pollution Prevention

In compliance with 33 CFR Part 149 Subpart B, each dolphin will be provided with pollution control equipment in the event of a discharge from the dolphin, or to assist, if possible, in the event of discharge from another part of the facility or a vessel. All dolphin personnel will receive any necessary instruction in the use of this equipment. This equipment will be maintained and used in accordance with the facility emergency procedures to be detailed in the Operations Manual.

18.6 *§148.105(q)(6)* Lighting on Floating Hoses

Although no floating hoses will be used, each dolphin will be provided with sufficient lighting to meet applicable codes and guidelines.

19 *§148.105(r)* Fixed Offshore Components

19.1 *§148.105(r)(1)* Fixed Offshore Components Descriptions and Drawings

The fixed offshore structures that will constitute the deepwater port consist of a number of existing and new fixed platforms along with interconnecting bridges and associated support structures. The fixed structures are described in this section in two groups covering existing structures and new structures. The Basis of Design is contained in Volume III, Attachment 11 {*confidential*}, and the Equipment List is contained is Volume III, Attachment 12 {*confidential*}.

Existing Structures

A number of existing fixed platforms with interconnecting bridges and associated support structures currently exist on MP 299. These were part of the now discontinued sulphur mining operation on the block. Some of these existing structures will be modified to suit their new intended service as components of the deepwater port.

Platform No. 1 includes an eight-legged jacket, piles, and a two-level deck. The eight-legged jacket is fixed to the seabed by eight main piles installed through the jacket legs. During the construction of the deepwater port, Platform No. 1 will undergo extensive modifications both in-place and onshore. The anticipated modifications to the deck consist of removing the mothballed drilling rig presently on deck, removing the existing well conductors, removing the deck from the jacket, and transporting the deck to shore. Following the removal of the Platform No. 1 deck, the jacket main piles will be augmented by installing insert piles, seawater lift pump casings will be installed and the jacket made ready for re-installation of the modified deck. Once transported to shore, all existing sulphur operations equipment will be removed from the deck. A third deck level will be added, along with the installation of the new topsides modules.

The new topsides on Platform No. 1 will primarily consist of the LNG vaporization equipment (e.g., seawater lift pumps, LNG pumps, and vaporizers) and the Motor Control Center (MCC)/Switchgear Building, one of the turbine generators, and a new pedestal crane. The modified deck, complete with new topsides equipment, will be transported offshore and re-installed on the jacket. Following the installation of the modified deck, modularized topsides consisting of the LNG unloading arms, gas conditioning plant, two turbine generators, and a flare boom will be installed.

Platform No. 2 includes an eight-legged jacket, piles, and a two-level deck. The eight-legged jacket is fixed to the seabed by eight main piles installed through the jacket legs. During the construction of the deepwater port, Platform No. 2 will undergo extensive modifications in-place. The anticipated modifications to the deck consist of removing the mothballed drilling rig presently on the deck, removing most of the existing sulphur operations equipment, installing the new cavern leaching equipment, gas filter/separators, gas compression, gas dehydration, gas check meters, and a flare boom.

BS-Y7 includes a four-legged jacket, piles and a two-level deck. The four-legged jacket is fixed to the seabed by four main piles (installed through the jacket legs). During the construction of the deepwater port, BS-Y7 will undergo modifications in place. The anticipated modifications to the deck consist of removing all existing sulphur operations equipment and installing a new living quarters with integrated warehouse and shop.

BS-8 and BS-9 each include a four-legged jacket, piles and a two-level deck. BS-9 has a two-pad helideck. The four-legged jacket is fixed to the seabed by four main piles installed through the jacket legs. During the construction of the deepwater port, BS-8 and BS-9 will undergo modifications in place. The anticipated modifications to these two platform decks primarily consist of installing a new firewater pump and an electrical building on each platform.

Bridge No. 10 is a two-level, trussed bridge. Bridge No. 10 will be removed and brought to shore prior to the removal of the Platform No. 1 deck. The unused sulphur operations piping and cable tray will be removed and new piping, cable tray, supports, and cable will be installed onshore. Bridge No. 10 will be re-installed following the installation of the modified Platform No. 1 deck.

Bridges Nos. 11, 12, and 13 are two-level, trussed bridges that will be modified in place. The modifications will consist of removing unnecessary piping and cable tray remaining from the sulphur operations and installing new piping, cable tray, supports, and cable.

Platform No. 3 includes an eight-legged jacket, piles, a two-level deck, and a helideck. The eight-legged jacket is fixed to the seabed by eight main piles installed through the jacket legs. The deck areas of Platform No. 3 will be used for storage of containers, equipment, spares, and other materials for the facility's operations and maintenance activities. This platform requires no modifications for its intended use.

Platform No. 4 includes an eight-legged jacket, piles, and a two-level deck. The eight-legged jacket is fixed to the seabed by eight main piles installed through the jacket legs and eight skirt piles grouted into sleeves at the bottom of the jacket. The platform houses the two 12,000-long ton liquid storage tanks that were previously used for the sulphur mining operation. These existing tanks will be used for storage of tri-ethylene glycol (TEG) for the cavern gas dehydration system and other operating chemicals. The upper deck of the platform also has considerable area available for materials storage. The lower deck is a small deck that is available for storage of lighter materials and provides access to below deck piping. Although some of the residual sulphur may be removed from the tanks, the platform requires no modifications for its intended use as a supply/storage facility.

New Structures

Storage Platforms Nos. 1 and 2 are duplicate platforms, each include an eight-legged jacket and a two-level deck. The eight-legged jacket is fixed to the seabed by eight main piles (installed through the jacket legs) and 12 corner skirt piles. Both storage platforms will be fabricated onshore, transported offshore, and installed. Following platform installation, three LNG storage tanks (with in-tank pumps) will be installed on each platform and interconnecting piping, cable, and bridges installed.

Bridge No. 14 will include a two-level, trussed bridge similar to the other bridges. Bridge No. 14 will be fabricated, transported offshore, and installed offshore after installing Storage Platforms Nos. 1 and 2. This bridge will contain piping, cable tray, supports, and cable.

The MP 164 Junction Platform will include a four-legged jacket, piles, and a two-level deck. The platform will be located in approximately 130 feet (39.6 meters) of water and fixed to the seabed by four main piles (installed in the jacket legs). The platform will be fabricated onshore, transported offshore, and installed. The platform topsides will primarily consist of pig receivers, pig launchers, custody transfer, and check meters.

The fixed components of the deepwater port are shown in the overall site plans in Appendix A, the general arrangement drawings in Volume III, Attachment 2 {*confidential*} and the structural drawings in Volume III, Attachment 3 {*confidential*}.

19.2 *§148.105(r)(2)* Fixed Offshore Components Design Criteria

The design criteria for the fixed components are included in the Basis of Design provided in Volume III, Attachment 3 {*confidential*}.

19.3 *§148.105(r)(3)* Fixed Offshore Components Design Standards

This list of codes and standards used for the design and construction of the deepwater port will be expanded and revised as the deepwater port design progresses:

U.S. Code of Federal Regulations (CFR)

- 30 CFR Part 250, OG&S Operation in the OCS
- 30 CFR Part 250.900, Offshore Platforms
- 33 CFR Part 127, Liquefied Natural Gas Waterfront Facilities
- 33 CFR Parts 148, 149, 150, Deepwater Ports
- 33 CFR Subchapter N, OCS Activities
- 33 CFR Subchapter NN, Deepwater Ports
- 33 CFR Subchapter O, Pollution
- 33 CFR Subchapter P, Ports and Waterways Safety
- 40 CFR, Protection of Environment
- 46 CFR Part 154, Safety Standard for Vessels Carrying Bulk Liquefied Gases
- 46 CFR Parts 166 to 199, Shipping
- 49 CFR Part 193, LNG Facilities: Federal Safety Standards
- 49 CFR Part 192, Natural Gas Pipeline Facilities: Federal Safety Standards

National Fire Protection Association (NFPA)

- NFPA 59A, Standard for the Production, Storage and Handling of LNG (**Comment:** This land based code will be used as general good industry practice guidelines, but strict compliance for this offshore application is not considered mandatory.)
- NFPA 10, Portable Fire Extinguishers
- NFPA 11A, Medium and High Expansion (hi ex) Foam systems
- NFPA 11, Low Expansion Foam Systems (helideck)
- NFPA 12, Carbon Dioxide (CO_2)Systems
- NFPA 13, Installation of Sprinkler Systems
- NFPA 14, Installations of Stand Pipe and Hose Systems
- NFPA 15, Water Spray Systems for Fire Protection
- NFPA 16, Installation of Deluge Foam-Water Sprinkler and Foam-Water Spray Systems
- NFPA 20, Installation of Stationary Pumps for Fire Protection
- NFPA 24, Private Fire Service Mains and Their Appurtenances
- NFPA 58, Storage and Handling of Liquefied Petroleum Gases

- NFPA 70, NEC
- NFPA 72, National Fire Alarm Code
- NFPA 80A, Protection of Buildings from Exterior Fire Exposures
- NFPA 231, Standard for General Storage
- NFPA 231C, Standard for Rack Storage of Materials
- NFPA 321, Standard on Basic Classification of Flammable and Combustible Liquid
- NFPA 2001, Clean Agent Extinguishing Systems

American Bureau of Shipping (ABS)

- Guidance Notes on Building and Classing Offshore LNG Terminals
- Rules for Building and Classing Steel Vessels (used for SPB LNG Tanks)

American Petroleum Institute (API)

- API RP 500, Recommended Practice for Classification of Areas for Electrical Locations at Petroleum Facilities
- API RP 520, Recommended Practice for Design (Part 1), Selection (Part 2), and Installation (Part 3) of Pressure Relieving Systems in Refineries
- API RP 521, Guide for Pressure Relieving and Depressuring Systems
- API RP 526, Flanged Safety Relief Valves
- API RP 527, Commercial Seat Tightness of Safety Relief Valves with Metal-to-Metal Seats
- API RP 550, Manual on Installation of Refinery Instruments and Process Control
- API RP 551, Process Measurement Instrumentation
- API RP 552, Transmission Systems
- API RP 554, Process Instrumentation and Control
- API RP 2A–Working Stress Design, Recommended Practice for Planning, Designing and Constructing Fixed Offshore Platforms – Working Stress Design
- API RP 2C, Specifications for Offshore Cranes
- API RP 2G, Recommended Practices for Production Facilities on Offshore Structures
- API RP 2L, Recommended Practice for Planning, Designing and Constructing Heliports for Fixed offshore Platforms
- API RP 2SK, Recommended Practice for the Design and Analysis of Stationkeeping Systems for Floating Installations 1997
- API RP 6D, Specifications for Pipeline Valves
- API RP14C, Recommended Practice for Analysis, Design, Installation and Testing of Basic Surface Safety Systems for Offshore Petroleum Platforms
- API RP 14E, Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems
- API RP 14F, Recommended Practice for Design and Installation of Electrical Systems for Fixed and Floating Offshore Petroleum Facilities
- API RP 14G, Recommended Practice for Fire Prevention and Control on Open Type Offshore Production Platforms
- API RP 14J, Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities
- API RP 75, Recommended Practice for Design and Operation of a Safety and Environmental Management Program for OCS Operations and Facilities
- API RP 617, Centrifugal Compressors for General Refinery Services
- API RP 750, Management of Process Hazards
- API RP 752, Management of hazards Associated with Location of Process Plant Buildings

- API RP 1111, Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines
- API RP 2001, Fire Protection in Refineries
- API RP 2003, Protection Against Ignitions Out of Static, Lighting, and Stray Currents
- API RP 2095, Recommended Practices for Operation and Maintenance of Offshore Cranes
- API 607, Fire Test for soft Seated Quarter Turn Valves
- API 616, Type H Combustion Gas Turbines
- API 670, Vibration, Axial-Position and bearing-Temperature Monitoring Systems
- API 678, Accelerometer Base Vibration Monitor Systems
- API STD 601, Metallic Gaskets for Refinery Piping
- API STD 610, Centrifugal Pumps for General Refinery Services
- API STD 672, Packaged Integrally Geared Centrifugal Plant and Instrument Air Compressors
- API STD 2000-98, Venting Atmospheric and Low Pressure Tanks
- API STD 2534, Measurement of Liquid Hydrocarbon by Turbine Meter System
- API 5L, Manufacture and Transport of Line Pipe
- API PUB 2030, Application of Fixed Water Spray Systems for Fire Protection in the Petroleum Industry
- API PUB 2218, Fireproofing Practices in Petroleum and Petrochemical Processing Plants

American Society of Mechanical Engineers (ASME)

- ASME/ANSI B31.3, Process Piping
- ASME/ANSI B31.4, Pipeline Transmission Systems for Liquid Hydrocarbons and Other Liquids
- ASME/ANSI B31.5, Standards for Refrigeration Piping
- ASME/ANSI B31.8, Gas Transmission and Distribution Systems
- ASME BPVC, Section VIII-Pressure Vessels
- ASME B36.19, Stainless Steel Pipe
- ASME B46.1, Surface Texture
- ANSI, Flow Control Industries (FCI) 70-2 - Control Valve Seat Leakage
- ANSI B1.1, Unified Inch Screw Threads
- ANSI B.21, Pipe Threads
- ANSI B16.5, Steel Pipe Flange Fittings

American Welding Society (AWS)

- AWS D1.1-2000, Structural Welding Code: Steel

Oil Companies International Marine Forum (OCIMF)

- OCIMF 4, Design and Construction Specifications for Marine Loading Arms

Society of International Gas Tanker and Terminal Operators (SIGTTO)

- IP No. 14, Site Selection and Design for LNG Ports and Jetties
- IP No. 15, A Listing of Design Guidelines of Liquefied Gas Terminals
- SIGTTO, Liquefied Gas Handling Principles on Ships and in Terminals
- SIGTTO, Recommendations and Guidelines for Linked Ship/Shore Emergency Shutdown (ESD) of Liquefied Gas Cargo Transfer

Det Norske Veritas

- DNV RP 205, Impact Loads from Boats, technical notes
- DNV TNA 202, Impact Loads from Boats
- DNV TNA 101, Design against Accidental Loads
- DNV RP E305, On-Bottom Stability of Submarine Pipelines

The Instrumentation, Systems and Automation Society (ISA)

- ANSI/ISA-84.01, Application of Safety Instrumented Systems for the Process Industries
- ISA, Instrument Standards

National Electrical Manufacturers Association (NEMA)

- NEMA Electrical Standards

American Institute of Steel Construction (AISC)

- Manual of Steel Construction - Allowable Stress Design, Ninth Edition, 1989

American Concrete Institute (ACI)

- ACI 318, Design of Concrete Structures

19.4 *§148.105(r)(4)* Fixed Offshore Components Engineering Practices

The title of each engineering practice to be used is included in Section 19.3.

19.5 *§148.105(r)(5)* Lighting, Safety, Lifesaving, Firefighting, Pollution Prevention, and Waste Treatment Equipment

19.5.1 §148.105(r)(5)(i) Navigational Lighting

The navigation lighting for the deepwater port is shown on drawing AK-D-0004 Navigation Aids Location Plan provided in Appendix A. Thirty-three structure navigation lights will be present on the complex. Seventeen of these fixtures currently exist and 16 new fixtures will be added during the facility modifications. The fixtures will generally be mounted approximately 93 to 130 feet (28.3 to 39.6 meters) above mean sea level (MSL) depending on the height of the protected structure. Tall structures such as flares, quarters, LNG tanks, and drilling rigs will include aviation warning lights in accordance with all FAA and FCC requirements.

The navigation lighting for Platforms Nos. 3 and 4 is shown on Drawing No. 02290019 provided in Appendix A. Four structure navigation lights are installed, one at each corner on each platform. The fixtures are mounted approximately 96 feet (29.2 meters) above MSL.

The navigation lighting for platform MP 164 is shown on Drawing 022900017 provided in Appendix A. Four structure navigation lights will be installed one to each corner on MP 164. The fixtures will be mounted approximately 90 feet (27.4 meters) above MSL.

The navigational aids system will be complete with all required lighted fixtures and sound signals. The number and range of lighted fixtures and sound signals will be in full compliance with applicable codes and standards. A separate, independent battery charger and battery system will be provided for the navigational aids. The helicopter decks will be provided with all required approach lights and markings required.

19.5.2 §148.105(r)(5)(ii) Safety Equipment

The fixed personal safety equipment as currently proposed for the deepwater port will include fully provisioned safety cabinets and eyewash stations. In addition to the fixed equipment, each person within the deepwater port will be required to use the following personal protection equipment in designated areas: hard hat, eye protection, hearing protection, safety shoes, and fire retardant clothing.

19.5.3 §148.105(r)(5)(iii) Lifesaving Equipment

The deepwater port will provide escape, rescue, and flotation devices based on double the number of anticipated personnel. The normal crew, plus anticipated temporary work crews, will number up to a maximum of 94 people. The lifeboat or escape craft requirements will be sized accordingly. Two 60-man escape craft will be located at the living quarters. These craft will be of a fully enclosed design with air supply and water curtain for safe escape during an emergency. All escape, rescue, and flotation equipment will be USCG "type" approved.

19.5.4 §148.105(r)(5)(iv) Firefighting Equipment

Firewater Pumps and Distribution

The firewater demand is based on cooling three deluge zones on the LNG storage tanks while supplying two firewater monitors. One 10,000-gallon per minute (gpm) diesel-driven submersible pump will be located on BS-8 and an identical pump will be located on BS-9. A jockey pump will be included at each main firewater pump location to maintain the header pressure at all times.

Each platform (including living quarters) will contain a ring main. A single pipe will be provided along the bridges between platforms.

Deluge Systems

The following areas will have deluge systems.

Platform No. 1 (LNG Unloading, Vaporization, Gas Conditioning, Power Generation, MCC/Switchgear). In the event of a fire, deluge will be utilized to cool equipment within the fire area, as well as adjacent equipment. The firewater pumps will be sized to enable the facility to deluge four zones at a minimum.

Storage Platforms No. 1 and No. 2 (LNG Storage). Each of the two storage platforms will contain three individual LNG storage tanks. Each tank will be divided into three separate deluge zones. This will enable the simultaneous deluge of an affected area and two adjacent areas for cooling and protection.

Berthing Dolphins and Dolphin Access Bridges. Each berthing dolphin will have its own fire protection system and is described in Section 18.1. A water curtain will be installed on each dolphin access bridge to effect the safe egress to Platform No. 1. The bridge water curtain will feed from the firewater network on Platform No. 1.

Platform No. 2 (Gas Compression, Dehydration, and Gas Storage Wellheads). Deluge systems will be provided for each cavern wellhead and surrounding areas to cool and provide gas mitigation. Deluge systems will be provided for diesel tanks and other hazards. Gas compressors and generators will not have dedicated deluge systems, but will be covered by firewater monitors.

Foam Systems

High Expansion (hi-ex) Foam for LNG Spills on Platform No. 1. In the event of an LNG spill, the facility will be designed to move the LNG in a liquid state through insulated troughs and piping downcomers to a safe location. These troughs will be covered with high-expansion (hi-ex) foam. This foam system will cover the equipment area in the location that the spill has occurred and insulate it to minimize boil-off in the process area. The hi-ex foam systems will be supplemented with dry chemical.

Foam Systems for Helideck. The helideck foam system will be through an independent 150-gallon bladder tank mounted directly below the helicopter landing area and on top of the living quarters. This system will utilize 3% film-forming fluoroprotein (FFFP) foam, two oscillating monitors, and dry chemical, wheeled, extinguisher units.

Foam System for Loading Arms. In this area, medium-hi-ex devices will be utilized. The heavier blanket will provide insulation around the platform and between the LNG carrier and the platform jacket. This system can use the same foam skid and foam storage tank as the topsides.

Portable and Wheeled Extinguishers

The deepwater port will utilize a variety of portable extinguishers. These extinguishers will be placed in specific locations around the facility appropriate to the risk associated with the area being protected.

CO_2 extinguishers will be provided for electrical fires; foam extinguishers will be provided for lube oil fires; dry chemical extinguishers will be provided for general fires. These devices will be properly sized for the area of risk in which they will be placed. Where large quantities of extinguishing agent are required, mobile or wheeled units will be supplied.

Clean Agent Gaseous Systems

A clean agent fire suppression system will be used in areas where firewater damage could create additional problems in an emergency. This applies to the control room cabinet areas and the control room itself. The system will use either FM200 or Argonite suppression systems. All equipment will meet the minimum specification set by the NFPA and the USCG. The gas compression turbines will be provided with FM200 gaseous systems. CO_2 will be provided for vent snuffing where applicable.

Fire and Gas (F&G) Detection System

The deepwater port will have a fire and gas (F&G) detection system of the triple modular redundant (TMR) type. Devices will trigger both audible and visual alarms, and in the case of rate-of-rise heat detection or ultraviolet/infrared (UV/IR) detection will automatically activate deluge systems.

Living Quarters Sprinkler Systems

The deepwater port crew quarters will be protected by a pressurized pipe sprinkler system with fusible sprinkler heads. This system is standard practice worldwide, and will follow the recommended NFPA, Safety of Life at Sea (SOLAS), and ABS guidelines.

Hydrants, Monitors, and Hose Reels

To supplement the active fire protection systems, the deepwater port will have firewater monitors, hydrants, and hose lines placed in strategic positions on all platforms. Detail design will place such items in accordance with the hazard requirements of each structure.

Fireproofing

Generally, all equipment in the fire hazard area should be protected by fireproofing, water spray, or excluded from the fire hazard area. API-recommended practices or the results of a radiated heat study define the frame of reference for a fire protective zone (FPZ) or fire hazard envelope. The full extent of fireproofing for this project will be determined during detailed engineering.

19.5.5 §148.105(r)(5)(v) Pollution Prevention Equipment

Oil Spill Response

The deepwater port will be operated in accordance with an approved Oil Spill Response Plan. As part of this plan, the deepwater port will obtain access to a full range of pollution prevention and oil spill recovery equipment.

Oily Water

Equipment that has the potential to release liquid hydrocarbons that cause a sheen and that is not in a curbed area will contain drain pans. The drain pans will be designed to collect any potential hydrocarbons and rainwater. Open drain systems will collect any rainwater, wash water, or other fluids that might collect in the equipment skids or platform curbed areas. The collected open drain fluids will flow to a corrugated plate interceptor corrugated plate interceptor- (CPI-) type separator located on each platform or bridge support. The capacity of the open drain system will be designed to handle the expected maximum rainfall rate of 3.5 inches (8.9 cm) per hour.

Inside the CPI separator, the hydrocarbons and water will be separated to meet the overboard discharge standards for the facility. Water from the separator will be continuously monitored for oil and grease content. Clean water will be discharged overboard. Oil will be removed and stored in a used oil holding tank for eventual transport to an onshore reclaiming station.

Facility maintenance procedures will address hydraulic and lube oil spill cleanup from vehicles and other mobile equipment. Used engine oil, hydraulic fluid, and engine coolant, will be collected and transferred to one of two portable tanks. One tank will be used for used oil and hydraulic fluid. Another tank will be used for used engine coolant. When the tanks are full, they will be loaded on a supply or work boat and transported to shore for reclaiming or disposal.

Waste Treatment Equipment

A sanitary waste system consisting of a collection system and redundant sewage treatment units will be provided. Domestic waste from the living quarters building and various control rooms will be treated by the sewage treatment unit prior to discharge overboard in accordance with the NPDES permit requirements. Sewage will be treated chemically or biologically. Paper, plastic, and other solid wastes from the kitchen, shops, and other operations will be collected and transported to shore for proper disposal.

Emergency Flares

An emergency flare on the gas conditioning facility located on Platform No. 1 will provide 98% destruction/removal efficiency (DRE) of hydrocarbons that will otherwise be vented as volatile organic compound (VOC) emissions in an emergency. Flares located on Platform No. 1 and Platform No. 2 will safely dispose of vaporized gas with a 98% DRE.

Nitrogen Oxide (NO_X) Control Selective Catalytic Reduction (SCR) Units

All the gas turbines will be equipped with dry low-NO_X (DLN) combustors. The NO_X emissions will be reduced to 7 ppm on the three power-generating gas turbines using SCR units for NO_X control. These units will become part of the waste heat recovery systems on the three power-generating gas turbines. The pollution control equipment will include SCR catalyst, static gas mixing equipment, ammonia injectors, ammonia feed pumps, and 19.5% aqueous ammonia feed tanks.

The SCR units will vaporize the ammonia ahead of the NO_X catalyst, which will convert the NO_X to elemental nitrogen as it reacts with the ammonia. Excess ammonia will then be converted to elemental nitrogen and water in the catalyst when the NO_X reaches a level too low to react.

The power gas turbines will be equipped with waste heat recovery units designed to eliminate the need for gas fired hot oil heaters thus reducing the pollutants generated from the facility. The waste heat recovery units will cool the turbine exhaust to levels acceptable for the operation of the SCR catalyst. The hot oil recovery system will include seawater heaters that are used to cool the hot oil when it is not required to provide heat for the gas conditioning reboiler service.

19.5.6 §148.105(r)(5)(vi) Waste Treatment Equipment

This equipment is described in Section 19.5.5.

19.6 *§148.105(r)(6)* Descriptions and Design Drawings of Pumping Equipment, Piping, Control/Instrumentation Systems, and Other Associated Equipment

19.6.1 §148.105(r)(6)(i) Cargo Pumping Equipment

All the services directly in contact with LNG unloading from LNG carriers are considered part of the process facility. The deepwater port process facility is designed for unloading LNG from a LNG carrier, vaporization of LNG, and delivery of natural gas to pipelines such that the gas meets the pipeline specifications. The LNG from the carrier will be unloaded into the storage tanks in approximately 12 hours. LNG from the storage tanks will be pumped for vaporization and gas conditioning. The gas will be further routed to either the gas storage caverns or pipeline. Gas storage caverns will act as buffer storage to accommodate any fluctuations between vaporization rate and pipeline demand. The cavern pressure will vary as gas is stored or withdrawn from storage. Depending on the cavern pressure at any point of time, a gas compression system will boost the pressure of the gas from the cavern pressure to the pipeline pressure. In case the pipeline demand is less than the vaporization rate and the cavern pressure is less than the vaporized gas pressure, the same compression system will increase the excess vaporized natural gas pressure for injecting into the cavern. Prior to delivery into the pipeline, natural gas from the caverns will pass through a gas dehydration system. The purpose of the dehydration system is to lower the water content of the gas withdrawn from the caverns to meet pipeline specifications. The process facility is shown in the block flow diagrams in Appendix B and the more detailed process flow diagrams in Volume III, Attachment 4 {*confidential*}.

LNG Unloading

The LNG unloading facilities will be designed to accommodate LNG carriers ranging in capacity from 60,000 to 160,000 m^3. LNG will be unloaded from the ship to the storage tank through LNG unloading arms. The LNG unloading rate will be 10,500 to 12,000 m^3/hr. The unloading package consists of four 16-inch (40.6-cm) diameter unloading arms. The unloading arms will be similar to those used at existing onshore LNG terminals; however, the specific configuration will be designed to accommodate LNG carrier movements at berth. Out of four arms, two will be dedicated to liquid LNG service, one for gas return service, and one will normally be used for liquid, but can be used for vapor service if the vapor arm is not in service. The storage tank will operate at slightly higher pressure than the LNG carrier. To maintain the carrier pressure during the unloading, most of the displaced vapor from the LNG storage tanks will be desuperheated by injection of small amounts of LNG and returned to the LNG carrier through the vapor arm. During the absence of LNG carriers, LNG from the storage tanks will be re-circulated in the unloading piping network to maintain temperatures for the next ship cycle, and to minimize the need for cool-down. The complete LNG carrier berthing cycle will be approximately 18 hours including berthing, hookup, unloading, disconnect, and unberthing.

LNG Storage

The deepwater port will contain six USCG-approved LNG storage tanks, each with an approximate gross capacity of 24,660 m^3 per tank, for a total gross capacity of approximately 145,000 m^3. Prismatic (SPB) tanks are the base selection, but other LNG storage concepts may be considered during the detailed design phase. Three tanks each will be located on two new platforms and will be bridge-connected to BS-8 and then to Platform No. 1. The tanks will be designed to limit LNG boil-off to less than 0.1% during steady-state conditions. Each tank will have two submerged retractable LNG in-tank pumps. The pumps can be retracted from the tank externally. The capacity of each pump is 12.5% of the peak LNG flow required. The in-tank pump will transfer LNG from storage tanks to LP LNG supply pumps mounted on Platform No. 1. Each in-tank pump will be designed for a flow rate of 1,750 gpm with a differential head of 70 psi.

Details on the LNG Tank Design

The selected tank size was based on meeting the overall facility requirement to store 145,000 m^3 of LNG, having tanks of a size that can be completely prefabricated and tested at onshore fabrication facilities, keeping tank dry weights and dimensions within the safe limitations of marine lift equipment currently operating in the GOM, and fitting the normal footprint requirements of eight-legged jacket-supported platform decks.

The base selection is six identical tanks, located three to a platform, with each tank roughly the dimensions of 75.5 feet (23 meters) long, by 116.5 feet (35.5 meters) wide, by 103.3 feet (31.5 meters) in height. Each tank will have a working capacity of approximately 24,250 m^3 of LNG and a dry lift weight including insulation of approximately 2,000 short tons. This makes each tank somewhat smaller than the typical tanks found in the current larger LNG carriers.

The SPB type tanks can be constructed out of aluminium, stainless steel, or nickel steel. Advanced analytical tools and analysis are needed to determine stress level, fatigue life, and crack propagation characteristics. This enables the tank to be categorized as a Type B under the carrier codes and permits the use of a partial secondary barrier by which the tank insulation system contains any leakage of LNG and directs it to drip trays located around the support chocks. In this application, this concept has been expanded to make the entire area below the tanks capable of capturing leaks.

Type B prismatic tanks will be supported by a system of chocks. This configuration provides a space between the bottom of the insulated tank and the floor of the sealed nitrogen-purged enclosure, keeping the tank separated from the platform structure and providing access for inspection or repair of the insulation. The support chocks will be located at the positions of the stiffening members of the tanks.

The tank will be designed to contain LNG at any level up to a maximum corresponding to the maximum filling level of the tank. Each tank will have a dome at the top, and all penetrations into the tank such as piping, pump wells, and other tank fittings will be located in the dome. Tank top plates, side walls, and bottom plates will be stiffened by longitudinal beams that will be supported by transverse web frames and cross ties, and end walls will be stiffened by vertical stiffeners that will be supported by horizontal girders. A manway will be installed on the dome, which will provide access to an internal ladder down to the bottom of the tank. Tanks will be fitted with pressure relief valves to protect the tank from excessive pressure.

A sump will be constructed in the bottom of each tank to allow the in-tank pumps adequate head with a minimum LNG level in the main tank.

Connections to each tank, which will all be located in the dome at the top of the tank, will include: two in-tank pump well discharge columns, nozzles for the manway, bottom fill line, top fill line, vapor line, LNG spray line, vent, gas sample, pressure instruments, temperature instruments, level instruments, and relief valves.

The tanks will be insulated with polyurethane foam (or polystyrene foam) panels with the thickness based on the minimum acceptable BOG rate. The insulation will incorporate a splash barrier against LNG leak and guide any LNG leak down to the spill pan. A rupture barrier will be provided in the splash barrier on the lowest section of the insulation just above the spill pan. It will maintain the tightness of the insulation surface in normal condition, while it will open and lead leaked liquid to the spill pan.

The insulation system will consist of independent rigid polyurethane foam (or polystyrene foam) panels that will be secured at the center, directly to the tank by a rod threaded to a stud welded directly to the tank. Cushion joints will be provided between the insulation panels to absorb the relative movement between the insulation and the cargo tank due to thermal contraction and expansion. Pressure balancing holes will be provided at the top of the insulation for balancing the pressure of the insulation space and the surrounding purged enclosure space.

The tank will be completely surrounded by an enclosure. The exception is the tank dome, which protrudes through the top of the enclosure to provide connections and access to the tank. The enclosure will be self-supporting and nitrogen-purged. The enclosure will provide weather protection to the insulation and a location for instrumentation to provide alarm in case of gas leak. In addition it will be an integral part of the spill control system (see additional detail of the spill control system below).

The space between the enclosure outer wall and the tank insulation will be the minimum required for personnel access to inspect or repair the tank insulation. Instrumentation within the enclosure will include purge pressure sensors, purge space temperature sensors, purge space gas detectors, and purge space pressure relief valves. Additional information on the LNG tank design is provided in Volume III, Attachment 13 "LNG Storage Tanks" {*confidential*}.

Boil-Off Gas (BOG) Compression and Condensation

Some LNG will be vaporized in the tank by heat ingress from various sources, as well as flashed vapor during the tank filling operations. These sources will generally include the following:

- Heat ingress to the tank and piping from the surroundings;
- Changes in fluid composition when LNG is unloaded to the tank from an LNG carrier;
- Heat input due to thermodynamic inefficiencies of the in-tank pump and the ship unloading pumps; and/or
- Cooling of the tank walls when liquid level increases due to the higher temperature of the vapor section as compared to the liquid section.

The vapor produced from the above-mentioned sources is referred to as BOG. During steady-state conditions, the average BOG rate is estimated at 7 mmscfd. The BOG rate will rise to approximately 24 mmscfd during LNG carrier unloading. Two 50% BOG compressors will be provided. The BOG compressor(s) will compress this gas to approximately 100 psig. The gas will then be routed to the BOG condenser where it will be condensed by being mixed with a portion of the sub-cooled LNG pumped out of LNG storage tanks. LNG leaving the bottom of the condenser will be combined with the main flow from the in-tank LNG pumps, and then flow to the suction of the LP LNG supply pumps. Normally, only one BOG compressor will be in operation, except during unloading when both the BOG compressors may be required to meet the duty.

Low-Pressure (LP) LNG Supply

LNG from the BOG condenser will be pumped to an intermediate pressure of 590 psig by the LP LNG supply pump. Only part of this LNG will be routed via the gas conditioning plant to remove ethane, propane, and butanes so that it meets the final gas to pipeline GHV specification. Six LP LNG supply pumps will be provided, five for regular operations and one as an installed spare. Each of these canned motor submerged pumps has a design capacity of 2,800 gpm with a differential head of 520 psi.

Gas Conditioning

The pipeline specification requires the send-out natural gas to have a maximum GHV of 1,075 British thermal units per standard cubic foot (Btu/scf). Incoming LNG (design case) GHV may be above pipeline specifications; therefore, a gas conditioning plant is required to be a part of this facility to condition the LNG by extracting part of the ethane, propane, and butanes in the LNG. Only part of the LNG stream will be processed in the gas conditioning plant and the rest will be bypassed. The gas conditioning plant technology is proprietary, but in general, a portion of the rich LNG is pumped through cross exchangers and enters a demethanizer. The demethanizer fractionates the ethane, propane, and butanes from the methane, ultimately becoming part of the vaporized LNG entering the gas storage caverns or pipeline. The NGL from the demethanizer are pumped to the NGL pipeline. The design capacity of the gas conditioning plant is equivalent to 1.0 bscfd of natural gas.

High-Pressure (HP) LNG Delivery

The pressure of the combined stream downstream of the gas conditioning plant will be boosted up to the pipeline send-out pressure of 1,750 psig. To achieve a design flow rate of vaporized LNG of 1.6 bscfd, 11 HP LNG send-out pumps will be provided, 10 for working operations and one as an installed spare. Each pump has a design capacity of 1,500 gpm and a differential head of 1,200 psi. The pressurized LNG will then routed to the vaporizers for regasification.

LNG Vaporization

The design capacity of the vaporizers is 1.6 bscfd, with the vaporized natural gas heated to 40° F (4.4° C. At peak vaporization rate, all the ORVs will be in operation. Nine operating ORVs are required to meet the 1.6-bscfd design vaporization capacity with the gas conditioning plant in operation. ORVs utilize seawater as the heating medium for vaporization of LNG. The heat transfer surface will be vertical, panel-shaped tubes of aluminum-zinc alloy for seawater resistance, and an aluminum base/tube assembly. LNG will flow upward inside finned heat transfer tubes, with seawater flowing downward along the outside of the tubes.

Six seawater lift pumps will be provided, each with a design capacity of 23,200 gpm and a differential head of 120 psi. Normally, five pumps will be in operation and one will be an installed spare. During winter operations when seawater temperatures are lower, the sixth seawater lift pump may be operated to obtain adequate heat transfer. Seawater will be pumped to the top of the ORVs where it will be distributed in overhead troughs to create a water film falling as a sheet in contact with the vertical tube surface. The seawater temperature will be reduced by approximately 22 °F through the ORV and will be collected in a basin for discharge back to the sea.

Seawater lift pumps have intake screens to eliminate debris and minimize impacts on marine life. These screens are passive, cylindrical wedge wire-type screens. They have no moving parts and are easy to maintain. The screens are designed so that the intake flow is at a uniform low velocity across the entire screen surface and limited to 0.5 feet (0.2 meters) per second (ft/s). The protective screen has a slot width of 0.25 inches (0.6 cm). This will minimize impingement and entrainment of marine organisms. Concentrations of marine organisms are greater near the water surface and decrease with depth. To minimize entrainment of marine organisms such as ichthyoplankton (fish eggs and larvae), the top of the intake screens will be located deeper than 65 feet (19.8 meters) below the MSL. This location of seawater intake has the advantage of being well below the near-surface concentrations of marine organisms and shallow enough for routine diver maintenance access. An automated air backwash system will periodically remove impinged debris from the screen surface. The backwash system will be automated based on a timed sequence or measurement of pressure drop through the screens.

Waters used in the vaporization of the LNG will be discharged through three outfall pipes at least 120 feet (37 meters) below MSL. Each outfall pipe will have two 45-degree deflectors at the terminus in order to promote mixing with the surrounding waters.

Sodium hypochlorite will be injected continuously into the suction of the operating seawater lift pumps for bio-fouling control at a rate to attain a residual chlorine level of 0.5 to 1.0 ppm. The system will be designed to inject up to 2.0 ppm continuously and up to 5.0 ppm on a “shock” basis into each of the operating pumps and operating ORV inlet branch headers for 20 minutes every 24 hours; these latter shock injections will be staggered so that no more than one point is shock-dosed at any one time. Operations will monitor the residual chlorine levels and adjust the dosing rate as needed.

At peak capacity, the seawater lift pumps will circulate 139,200 gpm of water through the ORVs. ORV maintenance will consist of occasional cleaning, the frequency of which will depend on the cleanliness of the seawater. Daily observation will ensure that ice does not build up on the panels.

Gas Storage

Undersea salt caverns provide a storage buffer for natural gas. Natural gas, which is vaporized in excess of the pipeline demand, will be stored in the caverns. Likewise, whenever the vaporization rate falls short of the pipeline demand, gas from the caverns will be supplied to the pipelines. Additional information on salt cavern storage can be found in Volume III, Attachment 14, {*confidential*}.

Gas Compression

The gas compression system will perform dual functions and operate under the following events. First, in the event the LNG vaporization rate is higher than the pipeline demand and the cavern pressure is higher than the pipeline send-out pressure, the compression system will increase the excess vaporized natural gas pressure to inject into the caverns. Second, in the event the LNG vaporization rate is lower than the pipeline demand and cavern pressure is lower than the pipeline send-out pressure, the compression system will boost the pressure of cavern gas to make up the shortfall in gas demand. Two 50% gas compression trains will be provided. The trains are generally operated in parallel to achieve the desired pressure and flow rate in each case, except for HP injection when the compressors operate in series.

Gas Dehydration

The natural gas directly from the LNG vaporization plant is “dry” gas and does not need dehydrating. However, natural gas from the caverns may be water-saturated and will require dehydration in order to meet the pipeline specification of 7 pounds of water per mmscf of gas. TEG will be the selected dehydration medium. The dehydration unit will accept wet gas either directly from the caverns or from the gas compression system. The wet gas will be directed into the gas contactor where the gas and TEG, will be contacted over structured packing. When the TEG comes in contact with the wet gas, water is absorbed from the gas into the TEG, resulting in “dry” gas exiting the vessel. The dry gas will be sent to a natural gas scrubber to allow the knockout of any TEG carried over from the gas contactor operation. The gas will then be sent to gas metering and pipeline transmission.

The TEG system is a recirculation loop. Water-saturated, rich TEG will flow from the gas contactor through a set of exchangers, designed to pre-heat the rich TEG prior to the regeneration step. The heated TEG will be flashed in a LP vessel to allow any hydrocarbon gas to exit the system. The rich TEG will then be sent through a set of TEG filters to clean any contaminants in the TEG system. The rich TEG will be heated in the TEG regenerator to vaporize the water out of the TEG. The TEG regenerator will form a lean, mostly water-free glycol that will be sent to the lean TEG surge tank. From this tank, the TEG will be sent through the pre-heat exchangers to cool the TEG from the regeneration temperature down to the contactor temperature. The lean TEG will be pumped to pipeline pressure and routed to a cross exchanger where it will be further cooled against dry natural gas from the contactor. Finally, the cooled, lean TEG will be sent to the top of the contactor to dry the gas.

Gas Metering

The gas will pass through a check meter system before entering the pipeline. The LNG pumps or gas compressors will produce a gas pressure of slightly greater than the expected gas pipeline operating pressure of 1,000 to 1,750 psi at the check meters delivering gas from the deepwater port to the pipelines.

Utilities

The utility systems are described in detail in the following sections.

Power Generation. All electrical systems are designed to be suitable for offshore use. Normal electrical power for the deepwater port will be generated by three 50% load natural gas powered turbine generators. Of the three units, two will be for working operations and one will be an installed spare. However, normal operations are based on running all three natural gas-powered turbine generators concurrently to prevent interruption of operations when a generator shuts down. Each power-generation turbine will have capacity to generate approximately 19.5 MW of power (site rated). Gas to run the turbines will be supplied by the fuel gas system from product gas. Three GE LM-2500 or equivalent turbines will be installed.

All three power-turbine generators' exhausts will be treated for NO_X reduction in SCR units. Each power turbine exhaust will be equipped with an SCR unit to reduce the NO_X level to 7 ppm before discharging to the atmosphere. The facility will be equipped with an ammonia storage and injection system to deliver 19.5% ammonia to the SCRs.

Emergency backup power service will be supplied by one emergency generator driven by diesel engine. The capacity of this generator will be 2.0 MW.The generator will be fueled from a 31-barrel (1,300-gallon) diesel day tank. The emergency backup power generator will have two functions: first, to provide power for operation of essential services during the absence of natural gas for black start; and second, to provide emergency power to essential services during other emergency situations involving loss of power from the gas power generation turbines.

A small diesel-driven emergency generator (500 kilowatts [kw]) will be provided separately for the living quarters. The purpose of this generator will be to provide lighting and other essential services independent from the rest of the facility.

Power distribution will be at 4,160 volts alternating current (VAC), 480 volts, and 208/120 VAC, and will be distributed to electrical loads through switchgear and MCCs located in the MCC MCC/Switchgear Building.

An uninterruptible power supply (UPS) system will provide power to safety and navigational systems, process control instrumentation, programmable logic controllers (PLCs), and computers and communication equipment for up to 3.5 hours if generating power is not available.

The deepwater port electrical systems are shown in the electrical drawings included in Volume III, Attachment 5 {*confidential*}.

Hot Oil System. A closed-loop hot oil system will be provided on the facility. The hot oil system will serve the following purposes:

- Provides heat for the demethanizer column reboiler duty;
- Uses the waste heat from the power generation turbine exhausts;
- Reduces the exhaust temperature on the power-generator turbines below 800° F (427° C) for effective operation of the SCR system; and

- Preheats the seawater supplied to the ORVs.

The hot oil system will consist of three 50% hot oil supply pumps, each with a capacity of 3,300 gpm. Two pumps will operate to provide design capacity and the third will be an installed spare. Hot oil coolers will be provided for cooling the oil when the demethanizer column reboilers are out of service or do not meet the oil cooling demand. The hot oil coolers will utilize seawater from the previously described ORV seawater system.

The water supplied for the hot oil cooling will be discharged with a maximum capacity of 23,200 gpm utilizing the ORV seawater discharge system. These volumes represent a portion of the flow from intake water for the ORVs. No additional intake or outflow will be generated by this function.

Instrument and Utility Air. Two 100% screw-type air compressors operating on lead-lag demand will provide compressed air for instrument and utility air. The common discharge of the compressors will supply a wet utility air to a dual set of air dryers. Compressed dry air will be stored in an instrument air receiver and distributed throughout the deepwater port. The capacity of the instrument air receiver will allow instrument air to be provided to users for 10 minutes after loss of the compressor.

Open Drains and Oily Water Treatment. Open drain systems will collect spills and rainwater from all equipment drain pans and other appropriate areas. The drain fluids will flow to corrugated plate interceptor-type oil water separator units for separation; clean water will flow overboard. Oil will be removed and stored in a used oil holding tank for transport to an onshore reclaiming facility. Clean water from the separator discharge overboard will meet NPDES permit requirements.

Stormwater drainage from open areas of the facility not subject to petroleum, oil, lubricant, or hazardous substance spills will flow overboard. Should a spill in these areas occur from mobile equipment fuel, oil, or hydraulic hoses, the spill will be cleaned up.

Used engine fluids, such as lube oil, hydraulic fluid, and engine coolant will be collected and transferred to one of two portable tanks. An approximately 1,000-gallon tank will be used to collect used oil, and an approximately 200-gallon tank will be used to collect aqueous engine coolant. When filled, the tanks will be loaded on a supply or work boat and transported to shore for reclaiming or disposal.

LNG Spill Control. LNG piping and LNG equipment will be located on all levels of Platform No. 1. Piping or equipment flanges will have shields to prevent any spraying. The area below the flanges will be designed to capture the spill and divert it through open troughs to the LNG spill downcomers.

The proposed LNG spill control system at the LNG storage tanks is similar to that found in LNG carriers, but enhanced in key aspects. The tanks will be single-containment and will be enclosed in a nitrogen-purged cover.

Potential LNG spill areas will include both thermal and gas-type detection devices to alert personnel of the spill condition and to shut down associated systems. LNG spills will be defined based on the flow rate and length of time for a spill. Flange leaks are considered the most likely source. Spill control flooring, troughs, and downcomers will be sized to handle the spill. Main structural members, such as columns and support beams, will be shielded or insulated from contact with LNG. Solid flooring designed for the cryogenic temperatures will prevent the spill from contacting the structure.

Each LNG downcomer will terminate at an elevation just above the normal high sea level. The downcomers from the LNG storage tanks will be equipped with a rupture disk that will hold the nitrogen purge pressures, but will burst when subjected to the head pressure of spilled LNG in the downcomer. All LNG spill downcomers will be equipped with a deflection/dispersion plate at the exit point, which serves two purposes: 1) to direct the spilled LNG away form the platform jacket structure; and 2) to spray the spilled LNG over the surface of the sea to minimize any effect from rapid phase transition (RPT).

Long runs of LNG piping across bridges will be vacuum-jacketed pipe, which will provide secondary containment should the inner pipe fail. Thermal instrumentation will indicate if and where a failure of the inner pipe has occurred.

Fuel Gas. A fuel gas system will provide fuel gas to power generation turbines and gas compressors. Fuel gas will be sourced from downstream of the ORVs. The natural gas will be heated by hot oil in a shell and tube exchanger or by electric heaters to meet the turbine dew point requirement. The fuel gas system will be sized to provide fuel gas to all turbines simultaneously at the manufacturer's supply rate and will be metered to each user.

Potable Water. The potable water system will also meet the utility water requirement. The system will consist of a proven reverse osmosis (RO) purifying method. Two 50% RO water purifiers will produce approximately 8,000 gallons per day (gpd) of freshwater from seawater. Seawater will be supplied from the seawater supply header for ORVs. The potable water from the RO unit will be chlorinated, collected in one of two 200-bbl storage tanks, and distributed on demand from a potable water pressure set. The potable water produced will meet minimum United States Food and Drug Administration and World Health Organization (WHO) potable water quality standards.

Nitrogen Generation and Storage. Nitrogen gas is used for inerting purposes. A nitrogen blanket will surround the space between the LNG tanks and LNG tank enclosure, and the vapor space will be continuously monitored for the presence of leaking methane. Nitrogen will be made using a proven membrane-based nitrogen generator that will remove oxygen from air. The skid-mounted nitrogen generator will consist of two 100% air compressors and one 100% nitrogen generation membrane unit. The nitrogen generator design capacity will be 15,000 standard cubic feet per hour (scf/hr) at 98% nitrogen purity. Nitrogen will be stored in a 5,000-gallon pressurized storage tank where it can be sent to users on demand. The supply of nitrogen to users will be controlled according to priority (critical versus normal users). In the event of failure of the nitrogen generator, a bank of compressed nitrogen cylinders will serve as backup.

Emergency Flare System. To meet applicable safety standards, an emergency gas flare system will be installed on boom support structures at both ends of the facility. The flare system will not have interconnecting piping between Platform No. 1 and Platform No. 2; therefore, two independent, HP flare boom structures will be installed. Platform No. 1 will include a LP flare as well as a HP flare. The LP flare system will collect and safely dispose of LP emergency relief from the LNG storage tanks. The flare booms will be oriented so that the prevailing winds will direct plumes predominantly away from the facility. Crew quarters will be located on BS-Y7, midway between the two processing platforms and a safe distance from the flare structures. A flare header system will collect hydrocarbon flows from relief valves, blowdowns, tank blankets (air spaces around the tank with nitrogen and natural gas sensors), and miscellaneous sources and send them to a flare drum and then to the flare. The flare will be equipped with multiple pilots and electronic igniters. The flare system will be continuously purged with sweep gas to prevent air infiltration through the flare tip. Liquid discharge from an ESD event will be returned to the storage tanks and not flared.

Waste and Waste Water Treatment. A sanitary waste system consisting of a collection system and redundant sewage treatment units will be provided. Domestic waste from the living quarters building and various control rooms will be treated by the sewage treatment unit prior to discharge overboard in accordance with the NPDES permit requirements. Sewage will be treated chemically or biologically. Paper, plastic, and other solid wastes from the kitchen, shops, and other operations will be collected and transported to shore for proper disposal.

Diesel Fuel. The facility will receive bulk diesel from supply vessels. Since there will be no interconnecting piping from Platform No. 1 to Platform No. 2, two separate fill locations on either side of the complex will be needed. The supply vessels will pump the diesel into a storage tank, located in a crane pedestal through an approved cargo transfer system. Diesel from this pedestal tank will be transferred to additional storage pedestals around Platform No. 1 and Platform No. 2. Diesel will be transferred to day tanks provided to users through the motor-driven diesel transfer pumps located adjacent to the pedestal storage. Diesel pump discharge will include high-quality filtering (for removal of water) and a totalizing meter. Design configuration of the hub will not include ship-refueling capability or supplies for provisioning vessels.

Firewater System. The firewater demand for the facilities is based on cooling three zones on the LNG storage tanks while supplying two firewater monitors. The firewater pumps will be two each 10,000-gpm diesel-driven submersible pumps. One pump will be located at BS-8 and the other will be located at BS-9. Isolation valves will be placed at the ends of each bridge to minimize the potential of losing all fire water. Each pump will have a caisson around a fiberglass riser and seawater strainer.

Other Infrastructure (Buildings)

Living Quarters. Living quarters will be located on the existing BS-Y7 platform positioned between Platform No. 1 and Platform No. 2. The building will routinely accommodate 50 personnel, but can accommodate up to 94 personnel for brief periods, and includes offices, recreation, communications, and a galley. A jib crane will be provided for loading and unloading stores. In addition to the living areas, the building will include the control room, offices, shop, warehouse, and laboratory spaces. Building exterior walls or floors facing the storage tanks or LNG processing equipment, or adjacent to gas piping systems will be rated H-60 and the remaining walls and floors will be rated A-60.

Helideck. An existing helideck is located on BS-9 and can accommodate two helicopters. There will be a helideck located above the living quarters building and a further helideck is located nearby on Platform No. 3. There will also be a helideck at the pipeline junction platform at MP 164. All helidecks will meet the latest FAA and USCG rules and regulations for lighting and firefighting requirements.

Control Room, Shop, and Warehouse. A control room will be located on the top floor of the quarters building on BS-Y7. The quarters building will also contain a warehouse and shop located at the lowest level (traffic level) of the living quarters. The warehouse (25 feet by 80 feet [7.6 meters by 24.4 meters] at traffic level) will store spare parts and operations and maintenance supplies and will be the collection point for all materials and equipment used for routine maintenance. The shop (25 feet by 80 feet [7.6 meters by 24.4 meters]) will contain welding, electrical, and instrument shops, and a 2-ton overhead crane. Items originating from the bridge decks will be received into this building and maintained, repaired, or transferred onto a workboat for transport to shore. A safe burn/welding area will be designated within the shop. The control room (50 feet by 50 feet [15.2 meters by 15.2 meters], located at the highest level of the building) will contain all plant monitoring, safety, and control equipment consoles. The control room will include windows providing views in all directions.

MCC/Switchgear Building. A single story MCC/Switchgear Building will house switchgear, MCCs, panel boards, UPS, batteries and battery chargers, lighting transformers, PLC panels for switchgear, generator control panels, and other equipment for all process and utility users. Power distribution transformers will be located adjacent to the MCC/Switchgear building.

Additional studies on the facility design are provided in Volume III, Attachment 15 {*confidential*}.

19.6.2 §148.105(r)(6)(ii) Cargo Piping System

The piping systems, as described in Section 19.6.1, will be fabricated using the piping classifications and materials listed in Table 19-1.

Table 19-1
Piping Classifications and Materials

Services	ANSI Rating	Material
Process Services		
Low Pressure (LP) LNG	150 lb	316/316L SS
Boil–Off Gas	150 lb	316/316L SS
High Pressure (HP) LNG	900 lb	316/316L SS
Natural Gas Liquids	300 lb	CS
HP Natural Gas Liquids	600 lb	CS
Natural Gas	900 lb	LTCS
HP Natural Gas	2,500 lb	LTCS
Utility Services (Liquid)		
Seawater Supply and Return	150 lb	FRP
Hot Oil Supply and Return	300 lb	CS
Sodium Hypochlorite	150 lb	Titanium / FRP
Potable Water	150 lb	CS Galv
Fire Water (Seawater)	150 lb	SS(Dup) / FRP
Diesel (Fuel)	150 lb	CS
Glycol Supply/ Return (HP)	1500 lb	LTCS
Glycol Return (LP)	150 lb	CS
Methanol	1,500 lb	316/316L SS
Ammonia Solution	150 lb	316/316L SS
Turbine Wash Water (DM Water)	150 lb	316/316L SS
Lube Oil	150 lb	SS
Service Water	150 lb	CS Galv
Sanitary Sewers	150 lb	PVC
Storm Water	150 lb	PVC
Oily Water Sewer	150 lb	CS
Used Oil	150 lb	CS
Utility Services (Gas)		
HP Fuel Gas	300 lb	316/316L SS
LP Fuel Gas	150 lb	316/316L SS
LP Nitrogen	150 lb	CS Galv
HP Nitrogen	1500	LTCS

Table 19-1
Piping Classifications and Materials

Services	ANSI Rating	Material
Plant Air	150 lb	CS Galv
Instrument Air	150 lb	CS Galv
Cold Vent	150 lb	316/316L SS
Warm Flare	150 lb	CS
Cold Flare	150 lb	316/316L SS

19.6.3 §148.105(r)(6)(iii) Control and Instrumentation System

The control system will allow for a continuous supply of natural gas at specified flow rates. The control system will automatically adjust controls to correct for disturbances caused by changing weather, process or utility conditions. The control system will be capable of controlling the changes during start-up, normal shutdown, ESD, and F&G detection. Manual control operations will be limited to special cases such as: start-up of major equipment, LNG unloading, and repairs of field control equipment.

All operations will generally be controlled and managed from the control room located on the top floor of the quarters building on platform BS-Y7. The control room operators will manage operators in charge of the various tasks in the field. The control room operators will be able to monitor all critical variables in the plant, be alerted to abnormal conditions by an alarm system, and take corrective action in a timely manner.

As a general rule, all control equipment (controllers, input/output [I/O] cards, etc.) will be housed in racks/cabinets to be installed in the I/O Rack Rooms. Main control and monitoring operations will be performed with video display units (VDUs) and control/alarm panels mounted in consoles in the main control room. Local monitors will be installed at various locations on the platforms for field operator access to process and alarm data.

The integrated control, safety, and instrumentation system will incorporate the following sub-systems:

- Distributed control system (DCS);
- Emergency shutdown (ESD) system;
- Fire and gas (F&G) system;
- Supervisory control automated data acquisition (SCADA) system;
- Field instrumentation; and
- Packaged equipment control systems.

Integration of the various sub-systems into the DCS will be performed to the fullest possible extent.

Distributed Control System (DCS)

The distributed control system (DCS) will include a remote supervisory console in FME's offices in New Orleans, Louisiana, with a capability of monitoring the deepwater port operations. Additionally, the remote supervisory console in New Orleans will have a capability to control the predefined deepwater port operations, allowing uninterrupted cavern gas deliveries during unmanned periods.

The microprocessor-based DCS will be located in the control room for the operator workstations and in the I/O Rack Rooms for the controller processors and I/O cards. The I/O Rack Rooms will be located in the MCC/Switchgear Building on Platform No. 1 and electrical buildings on BS-8, BS-9, and and Platform No. 2. All process controls will be included in the DCS controllers. The DCS will be the main process control system, the data concentrator for all the deepwater port data, and the main operator window from which authorized personnel can access information.

Emergency Shutdown (ESD) System

The safety requirements and layers of protection system will be evaluated for the deepwater port. The ESD system will provide an effective sequence of operations that will lead the plant to a safe condition upon the occurrence of hazardous events. The ESD system will be a fault-tolerant, fail-safe, and self-testing TMR PLC, composed of multiple processors with suitable components and functions. The ESD system will consist of an ESD workstation located in the control room, relevant controller cabinets and marshalling cabinets located in the rack room, and a dedicated, hardwired ESD control and alarm panel mounted on the console in the control room.

Three levels of shutdown will be considered:

- Level 1: Total deepwater port shutdown;
- Level 2: Process area shutdown; and
- Level 3: Local or individual packaged equipment shutdown.

Shutdown Levels 1 and 2 will be performed through the ESD System and activated through emergency push buttons located in the control room or locally in the field. Level 3 will be activated by process abnormal conditions or cascaded from Level 2 Shutdown, and will be performed through the DCS, package unit control systems, or the ESD System.

The ESD system will be in accordance with the following redundancy philosophy:

- All I/O and processors will be TMR;
- Data communications will be redundant with hot back-up configuration; and
- Power feeders and power supply units will be redundant. The power supply will be in hot back-up configuration with at least one feeder connected to a UPS.

Fire and Gas (F&G) System

The F&G system will be autonomous, with dedicated interfaces, F&G workstation, printer and power supply system. Monitoring and printing functions will also be available on the DCS, including diagnostic messages. The F&G system will provide zoned and specific-point detection for the presence of flammable gas, fire, smoke or LNG spills in buildings and on the platforms. The F&G system will also include line-monitored manual stations in the field and buildings.

The F&G system will utilize one out of three TMR PLCs to take pre-programmed actions when fire and/or gas is detected. The TMR will be of the same type used for the ESD system with the same redundancy requirements.

F&G System inputs will include:

- Combustible gas detectors for open process areas that will incorporate sensors utilizing infrared absorption technology;
- Combustible gas detectors for enclosed buildings that will incorporate sensors utilizing catalytic bead-type sensors;
- Low temperature resistance thermal device (RTD)-type detectors for cryogenic spills;
- Thermal detectors for monitoring fires in buildings (rate-of-rise) and open process areas (fusible plug or RTD);
- UV/IR-type flame detectors for equipment handling combustible gas;
- Smoke detectors for buildings; and
- Break-glass-type manual alarm stations in the buildings and in the plant.

Supervisory Control Automated Data Acquisition (SCADA) System

The SCADA system will be dedicated to gathering data from the meters, pipeline pressure regulation stations, pig launchers and receivers, and shutdown valves installed offshore and onshore at export pipeline tie-ins. The SCADA system will allow the monitoring of pipeline, custody transfer, and the pigging operations from the deepwater port control room.

Like any other equipment or package, monitoring and control of the associated pipeline equipment will be integrated as far as possible into the DCS; therefore, all the standard functions such as graphic displays, alarm management, data logging and archiving, reports, etc., will be directly handled by the DCS.

The SCADA system will consist of one redundant Main Terminal Unit (MTU) in the control room on BS-Y7 platform and will communicate with various remote terminal units (RTUs). The MTU configured in a hot backup mode will be used as a data concentrator. The RTUs at each location will transmit metering pipeline shutdown valves status and control data to the MTU.

One redundant remote thermal unit (RTU) in a hot backup configuration will be installed at the following delivery pipeline tie-in locations:

- NGL pipeline tie-in near Venice, Louisiana;
- SP 55 Platform;
- MP 298 Platform;

- MP 164 Platform; and
- Natural gas pipeline tie-ins near Coden, Alabama.

Data communications between the MTU and the various RTUs will be achieved through telecommunication signal transmission. The MTU will be connected to the DCS via a redundant serial link.

Independent Systems

Independent systems are systems that are not directly used for the process operation. Independent systems are meant to be fully autonomous and have their own workstations/panels in the control room.

Personnel Access Control System. The deepwater port will be equipped with an access control and personnel accounting system that will have the capability of providing reports of personnel located within the various platforms at any given time.

Meteorology Monitoring and Simulation System. The meteorological monitoring and simulation system will be provided to collect meteorological data and provide simulations for impending weather conditions.

Closed Circuit Television (CCTV) System. The deepwater port will be provided with a CCTV system. The video cameras located at strategic locations will be tied to the video surveillance monitor in the control room. The camera controls will be able to tilt, pan, and zoom these cameras from the control room.

Public Address and Alarm (PA&A) System. The deepwater port will be provided with a PA&A system for all alarms and capable of generating automatic message announcement for emergency, process and abandon platform alarms.

LNG Carrier Approach Monitoring. The deepwater port operator and Mooring Master will be equipped with hand-held, low speed, Doppler radar systems. The devices will provide the Mooring Master with an accurate readout of final docking approach speeds. Both Doppler units will be configured identically for the deepwater port operator and the Mooring Master in order to facilitate communication.

Berthing and Mooring Monitoring System. The berthing and mooring monitoring system will be provided for real-time monitoring of all mooring lines, to provide warnings of excessive or dangerous loads, and to enable the deepwater port operator and Mooring Master to maintain safe and effective mooring line tension, and to provide vessel drift-warnings. The berthing and mooring system will be located in the LNG operator room.

The deepwater port instrumentation and control systems are shown in the instrumentation drawings included in Volume III, Attachment 5 {*confidential*}.

19.6.4 §148.105(r)(6)(iv) Associated Equipment

This equipment is described in Section 19.6.3.

19.7 *§148.105(r)(7)* Personnel Capacity of Platform Complex

The deepwater port is considered a single unit for personnel purposes as all structures are bridge-connected and serviced by a single living quarters. The normal operations, maintenance, and management staffing requirement is 50 people; however, the living quarters and safety equipment requirements are based on 94 people.

20 *§148.105(s)* Offshore Pipelines

20.1 *§148.105(s)(1)* Marine Pipelines Descriptions and Drawings

Four new transmission, pipelines include seven individual pipeline segments, totaling approximately 192 miles (309 km), will be constructed to connect the deepwater port to existing offshore and onshore pipeline infrastructure. The pipelines will have a combined delivery capacity of 3.0 bscfd, with capability to operate at approximately 2,000 psig. The pipelines will be located in water depths varying from the shoreline, 0.0 feet to 750 feet (0.0 meters to 229 meters) and will be buried to meet the regulatory standards with an equivalent 3 feet (0.9 meters) of cover, except that pipelines crossing shipping fairways in 80 feet (24.4 meters) water depth or less will be buried with 10 feet (3.05 meters) of cover. The pipelines will be installed using a variety of lay vessel types depending on water depth, pipe size, and length of line. Pipeline lowering will be accomplished either during or after the completion of pipe laying. All required permits and clearances will be obtained before construction begins.

Descriptions of each pipeline segment are listed below. The maximum capacities are given for each segment, with the corresponding upstream pressures needed to achieve these flow rates, based on typical operating pressures at the downstream delivery points. There will be flexibility to operate individual segments at varying volumes and pressures as needed, within the overall maximum capacity of the pipeline network.

- **MP 299 to SP 55.** Pipeline will be 20 inches (51 cm) in diameter, and 51.5 miles (82.9 km) in length. The capacity will be 500 mmscfd of natural gas at 1,750 psig.

- **MP 299 to MP 298.** Pipeline will be 16 inches (40.6 cm) in diameter, and 2.5 miles (4 km) in length. The capacity will be 460 mmscfd of natural gas at 1,275 psig.

- **MP 299 to MP 164.** Pipeline will connect the LNG terminal to a new platform to be located near two major transmission pipelines. It will be 36 inches (91.4 cm) in diameter, and 30.8 miles (49.6 km) in length. The capacity will be 2,050 mmscfd of natural gas at 1,730 psig.

- **MP 164 to subsea tie-in.** Pipeline will be 16 inches (40.6 cm) in diameter, and about 300 feet (91.4 meters) in length. The capacity will be 550 mmscfd of natural gas at 1,150 psig.

- **MP 164 to subsea tie-in.** A second, future subsea tie-in is planned that will be 16 inches (40.6 cm) in diameter, and about 300 feet (91.4 meters) in length. Planned capacity is 500 mmscfd of natural gas, at a maximum operating pressure of 1,440 psig.

- **MP 164 to Coden, Alabama interconnects.** Pipeline will be 36 inches (91.4 cm) in diameter, and 62 miles (99.8 km) in length, with approximately 5 miles (8 km) of this segment to be installed onshore Alabama. The capacity will be 1,500 mmscfd of natural gas at 1,430 psig.

- **MP 299 to Venice Dynegy Plant.** Pipeline will be 12 inches (30.5 cm) in diameter, and 45.7 miles (73.5 km) in length. The capacity will be 85,000 bbls/d of NGL at 1,400 psig.

Drawing No. PC-PL-0001 in Appendix F shows the proposed pipeline routes.

All pipelines will undergo a hydrostatic test to prove the strength after construction and before being placed in operation. Hydrostatic tests will be performed in accordance with 49 CFR Part 192, ASME B31.8 (“Gas Transmission and Distribution Piping Systems – 1992,” re-issued in 1995 and 1999) and B31.4 (“Liquid Petroleum Transportation Piping Systems”), as well as API RP 1110. As defined within the codes, test factors depend upon class location of the pipeline. Class definitions are provided in 49 CFR 192.5 and ASME B31.8 Clause 840.22.

For pipeline risers, both codes (49 CFR 192.5 and ASME B31.8 Clause 840.22) define the design requirements to be the same as for a Class 3 location. The test factors differ slightly between the two codes. ASME B31.8 states a factor of 1.4, whereas 49 CFR 192.619 requires a factor of 1.5, which is thus governing. For the pipeline section both codes define this area as a Class 1 location. The CFR requires a factor of 1.1 and the ASME code requires a factor of 1.25; therefore, the ASME code governs.

Specification breaks will be defined at tie-in locations where the pipelines have different maximum allowable operating pressures (MAOPs). Overpressure protection will be provided at the specification break locations, to prevent accidental over-pressuring of the pipeline with the lower MAOP. For each tie-in point, LP protection will be provided, as may be required by applicable regulations.

20.2 *§148.105(s)(2)* Marine Pipelines Design Criteria

With the exception of the two 16-inch (40.6-cm) diameter pipelines departing the MP 164 Junction Platform, which will be designed for a MAOP of 1,440 psig, all gas pipelines will be designed for MAOP of 2,220 psig. The NGL pipeline will be designed for a MAOP of 1,440 psig. The pipelines will be located in water depths ranging from 0 to 750 feet (0 to 229 meters). The pipelines will be constructed of API 5L line pipe. The pipelines will be constructed in accordance with 49 CFR Section 192.327(g) and Section 192.612(b)(3) requiring natural gas pipelines in the GOM to have a minimum of 36 inches (91.4 cm) of cover for normal excavation and 18 inches (45.7 cm) of cover for rock excavation in water depths less than 200 feet (61 meters), except that pipelines crossing shipping fairways in water depths less than 80 feet (24.4 meters) will be lowered to provide 10 feet (3.05 meters) of cover. For undersea stability, the pipeline will have an appropriate concrete weight coating. The corrosion protection system will include a thin film external coating and sacrificial anodes. The design life of the pipelines is at least 40 years.

20.3 *§148.105(s)(3)* Marine Pipelines Design Standards and Codes

The new pipelines will be designed to withstand stresses during installation, testing, and operations. The pipelines will be designed, constructed, tested, operated, and maintained in accordance with 49 CFR Part 192 and the standards incorporated by reference therein. The specification break between the topsides and downstream piping will occur at pig launchers and receivers. Excluding launchers and receivers themselves, all piping downstream of a pig receiver or upstream of a pig launcher will be designed in accordance with ASME/ANSI B31.3. On gas lines, all piping upstream of a pig receiver or downstream of a pig launcher, including the launchers and receivers, will be designed in accordance with ASME/ANSI B31.8. On the NGL pipeline, all piping upstream of the pig receiver or downstream of the pig launcher will be designed in accordance with ASME/ANSI B31.4. The pipelines will be designed according to API RP 1111.

20.4 *§148.105(s)(4)* Marine Pipelines Engineering Practices

Specific design standards, codes, and recommended engineering practices to be followed include:

American Petroleum Institute (API)

- API RP 1111 – Design, Construction, Operation, and Maintenance of Offshore Hydrocarbon Pipelines
- API RP 1110 – Pressure Testing of Liquid Petroleum Pipelines
- API RP 1104 – Welding of Pipelines and Related Facilities
- API 5L – Line Pipe
- API 6D – Pipeline Valves (Gate, Plug, Ball, and Check Valves)

American Society of Mechanical Engineers (ASME)

- ANSI B31.3 – Process Piping
- ANSI B31.4 – Piping Transportation Systems for Liquid Hydrocarbons and Other Liquids
- ANSI B31.8 – Gas Transmission and Distribution Piping Systems

20.5 *§148.105(s)(5)* Marine Pipelines Metering System

The natural gas will be metered and regulated by equipment designed specifically for each of the delivery pipelines. Each of the metering stations will utilize multiple metering tubes, appropriately sized to accurately measure expected flow rates. Each meter station will have a redundant metering tube, to allow for continuous flow when one tube is taken out of service for maintenance or other purposes.

20.6 *§148.105(s)(6)* Submerged or Buried Pipelines Crossed by Marine Pipelines

Although, the proposed pipeline routes were selected to minimize the length of the pipeline segments, consideration was given to limiting the number of existing pipeline crossings and to avoid existing platforms. A pipeline route survey has been performed to identify any underwater hazards along the pipeline routes and to locate the exact location of subsea cables and existing pipeline crossings. Summary materials from the survey reports are provided in Volume III, Attachment 9 "Archeological, Engineering, and Hazards Surveys" {*confidential*}. Three copies of the confidential survey reports have been filled with the USCG under separate cover as part of this application.

The proposed pipelines will cross 90 existing pipelines and eight known cables, including 17 multiple crossings of the same pipelines. Divers and/or remotely operated vehicles (ROVs) will be used to locate and prepare the crossings, monitor the crossings during the pipeline construction, and finalize the crossings after the pipeline has been installed, all in accordance with pre-approved and agreed procedures.

The pipelines will be constructed in accordance with the requirements of 49 CFR 192.325, which ". . . mandates 12 inches (0.30 meters) of clearance from all other underground structures." The pipeline will be installed over the tops of existing pipelines/cables. In some cases, it may be necessary to lower the existing pipeline or cable in order to achieve the required clearance between the new and existing pipelines. Sandbags and/or concrete mats will be used to ensure 18 inches (0.46 meters; 45.7 cm) of separation between the proposed pipeline and the existing line(s). In the event that the installation results in less than 36 inches (0.91 meters; 91.4 cm) of cover over the new pipelines, concrete mats will be used to provide an equivalent degree of protection. All crossings will be coordinated with the relevant pipeline owners/operators and the MMS, federal waters only. Crossings in state waters of Alabama and Louisiana will be coordinated with applicable regulatory agencies.

21 *§148.105(t)* Onshore Components

21.1 *§148.105(t)(1)* Detailed Data on Onshore Components

Natural gas will be delivered to various markets throughout the United States through interconnection with several main gas transmission pipelines. Pipelines associated with the project interconnect with existing offshore and onshore infrastructure. The interconnects are shown in Volume III, Attachment 6.1 {*confidential*}. A diagram illustrating the natural gas transmission pipeline interconnections, capacities, and expected delivery rates is provided in Volume III, Attachment 6.2 {*confidential*}.

The proposed MP 299 to Coden, Alabama transmission line will be 36-inch (91.4-cm) diameter and a portion of this pipeline will be onshore in Mobile County, Alabama. The onshore portion of the proposed pipeline will begin at the onshore landing and proceed generally northeast 5.0 miles (8.0 km) to proposed interconnections with existing gas transmission pipelines. The interconnections will include pigging and metering equipment. The interconnections will be to existing Gulf South, Gulfstream, and Transco pipelines near Coden, Alabama. These pipelines form part of the national distribution grid delivering natural gas to commercial and residential consumers throughout the United States.

A junction platform installed along this pipeline route at MP 164 will provide metering and pigging equipment that will afford additional tie-ins. Two proposed 16-inch (40.6-cm) lateral lines will extend from this platform to connect via subsea tie-ins to the existing DIGP and TETCO pipelines. DIGP comes onshore in Alabama also near Coden and delivers gas through several existing interconnections to various markets throughout the United States. The TETCO pipeline comes onshore near Venice, Louisiana, and through existing transmission lines and interconnections also delivers gas to various markets in the United States.

The proposed MP 299 to MP 298 transmission line will interconnect with an existing pipeline owned by Southern Natural at MP 298. This pipeline comes onshore near Venice, Louisiana, and delivers gas to various existing transmission lines. The proposed MP 299 to SP 55 transmission line will interconnect with existing pipelines owned by Tennessee Gas Pipeline and Columbia Gulf Transmission. These transmission lines come onshore in south Louisiana and also interconnect with the national pipeline grid delivering gas through out the United States.

For NGL service, applicant's pipeline will connect to the Venice Energy Services Company (VESCO) gas plant that is located 1.25 miles (2.01 km) south of Venice, Plaquemines Parish, Louisiana. The facility has the capacity to process 1.3 bcfd of onshore and offshore production and serves three interstate natural gas pipelines: Columbia Gulf, TETCO, and Gulf South. The facility also has the capacity to further fractionate 30,000 bbls/d of "Y-Grade" derived from the processing facility into the purity streams of ethane, propane, isobutane, normal butane, and natural gasoline. The processed liquids and ethane stream are transported by two NGL pipelines to markets and fractionation facilities along the Mississippi River industrial corridor while the ethane, propane, and butanes are barged from the VESCO dock facility to various intra and interstate locations. The 8-inch (20.3-cm) Faustina NGL pipeline has 45,000 bbls/d of Y-Grade capacity while the newly reactivated ChevronTexaco 8-inch (20.3-cm) Venice, Louisiana to Paradis, Louisiana NGL pipeline has 50,000 bbls/d of Y-Grade capacity. The VESCO facility has 12,000,000 bbls of salt cavern storage for various NGL products, including 1,000,000 bbls segregated for Y-Grade. The facility is currently operated by Dynegy Midstream Services, L.P. of Houston, Texas. A diagram of the interconnections at the VESCO plant in Venice, Louisiana, is provided in Volume III, Attachment 6.3 {*confidential*}.

21.2 *§148.105(t)(2)* Chart of Planned and Existing Facilities to be served by Port

A chart showing the proposed pipeline interconnections along with diagrams of the proposed interconnections of the NGL line at Venice, Louisiana, and natural gas lines at various locations are provided in Volume III, Attachment 6 {*confidential*}. From the deepwater port pipeline interconnections to existing infrastructure, natural gas is delivered to various commercial and residential consumers throughout the United States via the national pipeline transmission grid. NGL from the proposed deepwater port NGL pipeline to the VESCO plant in Venice, Louisiana, are transported by two NGL pipelines to various markets and fractionation facilities along the Mississippi River industrial corridor while the ethane, propane, and butanes are barged from the VESCO dock facility to various intrastate and interstate locations.

21.3 *§148.105(t)(3)* Proposals and Agreements

Once the deepwater port becomes operational, daily throughput is expected to average approximately 1.0 bscfd. No formal proposals have been received or agreements made governing the throughput from the deepwater port. When these are received, copies will be made available to the USCG. Additional information on market analysis is contained in Volume IV of this application {*confidential*}.

22 *§148.105(u)* Miscellaneous Components

22.1 *§148.105(u)(1)* Radio Station and Communications Systems

The deepwater port will have communication systems providing voice, alarm, and data communications. These systems will provide the means of communicating with other offshore installations, onshore systems, the public telephone network, vessels and aircraft, and supporting personnel evacuation and lifesaving activities in the event of an emergency situation.

The following communications systems will be installed:

- Microwave radio communication system;
- Satellite communications system used as microwave backup;
- PA&A System;
- Telephones;
- Local area network (LAN);
- DCS/ESD data connections;
- Marine and aeronautical radio systems;
- Emergency and rescue radio systems;
- Two-way company radio system; and
- Anti-collision radar.

Additional communications systems that may be installed at the facility include the following:

- Fiber Web. Fiber optic communications system with state-of-the-art network operations center located in New Orleans, Louisiana. (This system is not yet installed in this section of the GOM); and/or
- FAA approved Automated Weather Observing System (AWOS).

The two-way land transportation radio system will operate in the 811 megahertz (MHz) to 860 MHz band. The radio will be a five-channel Motorola Smart Net system with telephone capability. The antenna system will consist of one transmit antenna, one receive antenna, one receiver multicoupler, and one transmit duplexer along with associated cables.

Computer-based data communication facilities will be required in various locations. Data jacks will be installed where required and connected to equipment located in the equipment rooms via LAN, which in turn will be connected to the host equipment in the living quarters. The LAN standard will be Ethernet.

Each crane will be provided with:

- Ultra high frequency (UHF) radio;
- Very high frequency (VHF) marine radio; and
- PA&A speakers.

The UHF radio and VHF (marine) radio will be supplied stand-alone. The PA&A speakers will be wired to the central equipment in the living quarters.

The following will be supplied with the escape craft:

- Emergency position-indicating rescue beacon (EPIRB);
- Search and rescue transponder (SART); and
- Marine portable radio.

22.2 *§148.105(u)(2)* Radar Navigation System

A continuous security watch will be maintained inside the control room of the deepwater port. Two radar sets will be installed in the control room for use with support vessels. The first set will operate on the 3-cm band while the other operates on the 10-cm band for best performance with long- and short-distance searching, respectively. Both units will be equipped with automated radar plotting aid (ARPA) devices. The Terminal Manager and Mooring Master will be supplied with low-speed, Doppler radar to accurately measure LNG carrier speed as an LNG approaches the berth.

22.3 *§148.105(u)(3)* Vessel Bunkering Methods

No facilities for bunkering vessels using the deepwater port will be provided.

22.4 *§148.105(u)(4)* Vessels for Bunkering, Mooring, and Servicing Vessels Using the Deepwater

No vessels will be used for bunkering at the deepwater port. The LNG carriers used for servicing the vessels using the deepwater port are the support vessels used for berthing and un-berthing the LNG carriers. The support vessels are expected to be approximately 110 feet (33.5 meters) to 120 feet (36.6 meters) in length over all with approximately 8,000 to 10,000 horsepower (installed). Each support vessel will be equipped with the towing winch forward and a towing winch aft with associated gear necessary to tow an LNG carrier away from the deepwater port. The support vessels assigned to service the deepwater port will be suitable for the intended requirements including the following:

- Escorting LNG carrier vessels from the traffic lanes to the deepwater port;
- Towing an LNG carrier;
- Docking and un-docking an LNG carrier;
- Security patrol around the deepwater port;
- Firefighting; and
- Oil spill response.

The support vessels will also be equipped with firefighting monitors. The support vessels will be equipped to support cleanup of oil spills.

22.5 *§148.105(u)(5)* Shore-Based Support Facilities

A wide variety of services and supplies are required for every offshore operation. Existing onshore support bases will provide everything needed for the construction and operation of the MPEH™. The onshore support bases listed are predominantly located in southern Louisiana, although some support may come from Texas as well. Some specialized equipment that deals with LNG is not constructed in the United States and will need to be fabricated overseas and transported to the offshore receiving terminal.

Due to the proposed reuse of existing facilities at the MP 299 facility, onshore construction of components to be used will be reduced from what would have otherwise been required. Onshore fabrication yards will be able to accommodate the construction of the three platforms to be built for the project without an increase in the size of their facilities, or the requirement to hire new personnel. No major expansions of any onshore facility is anticipated as a result of the proposed project.

The existing shore-based support facilities and the various services they may provide are listed in Table 22-1.

Table 22-1
Shore-Based Support Facilities

Construction Yards		
J. Ray McDermott	2317 Highway 662, Morgan City, LA	(985) 631-2561
Gulf Island Fabrication	583 Thompson Rd Houma, LA	(985) 872-2100
Kiewit Offshore Services	2440 Kiewit Rd, Ingleside, TX	(361) 775-4300
Gulf Marine	1942 FM 2725, Ingleside, TX	(361) 776-7245
Delta Engineering Corp.	16415 ½ Jacintoport Blvd, Channelview, TX	(713) 461-6200
Helicopter Services		
Petroleum Helicopters	38963 Hwy 23, Buras, LA	(985) 534-7131
Air Logistics	42011 Hwy 23, Venice, LA	(985) 534-7481
ChevronTexaco	Tidewater Rd, Venice, LA	(985) 534-6600

Table 22-1
Shore-Based Support Facilities

Rotorcraft	43097 Hwy 23, Venice, LA	(985) 534-9352
ERA	42336 Hwy 23, Venice, LA	(985) 534-7610
TexAir	41854 Hwy 23, Venice, LA	(985) 534-4191
Drilling Support Docks		
M I	172 McDermott Rd, Slip 2, Venice, LA	(985) 534-7422
Baroid	365 Halliburton Rd, Tiger Pass, Venice, LA	(985) 534-2021
Newpark	223 Coast Guard Rd, Slip 2, Venice, LA	(985) 534-9496
Halliburton	376 Halliburton Rd, Slip 1, Venice, LA	(985) 534-2386
Dowell	432 McDermott Rd, Tiger Pass, Venice, LA	(985) 534-2321
Fuel and Water Supply Docks		
John W. Stone	Coast Guard Rd, Tiger Pass, Venice, LA	(985) 534-2613
Asco	485 Jump Basin Rd, Venice Jump, Venice, LA	(985) 534-7401
Material and Crane Support Docks		
M I Dock	172 McDermott Rd, Slip 2, Venice, LA	(985) 534-7422
Premier Dock	308 Halliburton Rd, Slip 1, Venice, LA	(985) 534-2874
Newpark Dock	223 Coast Guard Rd, Slip 2, Venice, LA	(985) 534-9496
Energy Logistics Dock	310 McDermott Rd, Slip 1, Venice, LA	(985) 534-2375
PMI Dock	290 McDermott Rd, Slip 2, Venice, LA	(985) 534-9118
Baroid Dock	365 Halliburton Rd, Tiger Pass, Venice, LA	(985) 534-2021
Newman's Dock	McDermott Rd, Slip 1, Venice, LA	(985) 534-7507

22.6 *§148.105(u)(6)* Radio Station License

A copy of the radio station license for the existing facility is attached in Appendix I.

23 *§148.105(v)* Construction Procedures

Construction Schedule

Construction is estimated to take approximately 34 months from start of activities in the first quarter of 2005 to terminal completion late in the fourth quarter of 2007 (Table 23-1). The storage caverns are estimated to be complete in the second quarter of 2009. Table 23-1 shows an outline schedule for the main construction activities. Additional information on the construction schedule is contained in Volume IV {*confidential*}.

Table 23-1
Construction Schedule

Description	2005	2006	2007	2008	2009
Cavern Creation					
Drilling	X	X			
Leaching/Dewatering		X	X	X	X
Demolition					
Remove Existing Drill Rigs	X				
P&A Existing Wells on Platform No. 1		X			
Pipelines					

Table 23-1
Construction Schedule

Description	2005	2006	2007	2008	2009
36-inch MP 299 to Coden			X		
36-inch Coden to Delivery Points (onshore)			X		
20-inch MP 299 to SP 55			X		
16-inch MP 299 to MP 298	X				
12-inch MP 299 to Venice			X		
Fixed Offshore Structures					
Platform No. 1 Deck and Bridge Removal		X			
Platform No. 1 Deck and Bridge Installation			X		
Living Quarters Installation			X		
MP 164 Junction Platform		X			
Storage Plat. No. 1/2 Installation			X		
Hook-up and Commissioning					
Platform No. 2 Hook-Up			X		
Platform No. 1 Hook-Up			X		
Commissioning and Startup			X		
Soft Berthä System					
Pile Installation			X		
Dolphins and Berthing Buoys Installation			X		

All terminal construction activities are anticipated to occur at existing United States Gulf Coast facilities or at the terminal site, except for the construction of the Soft Berth™ System dolphins, which are anticipated to be fabricated in the Far East. The following sections describe the construction activities for each component of the deepwater port construction.

Cavern Creation

The three gas storage caverns will be similar and constructed sequentially over a period of four years. Cavern creation includes installing the surface conductor pipe, drilling and completing the wells, preparing the wells for leaching operations, leaching the caverns by circulating seawater, dewatering the caverns with gas and preparing the wells for gas storage operations.

Demolition

1. Removal of Existing Drill Rigs on Platform No. 1 and Platform No. 2

The drill rigs on Platform No. 1 and Platform No. 2 originally used in the sulphur mining operation will be removed. A heavy lift vessel (HLV) will mob to site to remove the drill rigs and their associated packages from each platform. The drill rig packages will be placed on material barges and barged to an onshore site.

2. Plug and Abandon (P&A) Existing Wells

Existing wells on Platform No. 1 formerly used in the sulphur mining operation will be plugged and abandoned. This operation is assumed to require 24 days using one support vessel, one workover rig, and one generator.

Pipelines

The pipeline construction will utilize several different pipe installation methods and techniques depending on the time of year, size of pipe, length of line, water depth range, bottom conditions and obstacles.

MP 299 to Offshore Coden – 36-inch (91.4-cm) Gas Pipeline

A 3rd Generation Lay Vessel (3GLV) will be used to install the 36-inch (91.4-cm) diameter pipeline. This pipeline originates at Platform No. 2, in MP 299 in over 200 feet (61 meters) of water and proceeds northerly approximately 30 miles (48 km) to a platform, in about 130 feet (40 meters) of water. The 3GLV is limited to a minimum of 50 to 60 feet (15 to 18 meters) water depth. Consequently a 2nd Generation Lay Barge (2GLB) will continue laying the pipeline from the 3GLV drop-off crossing the Alabama State 3-mile (4.8-km) line until about 15 feet (4.6 meters) of water west of Dauphin Island, at which point the shallow-water lay barge (SWLB) will pickup and continue laying the pipe to the shore approach. The shore approach near Coden, Alabama, will be made by a horizontal directional drill (HDD).

Since this pipeline is predominately in water depths less than 200 feet (61 meters), most of the line will require lowering. From 200 feet (61 meters) to about 20 feet (6.1 meters) water depths, a pipeline jet barge and/or a pipeline plow can be used. From 20 feet (6.1 meters) to shore, a shallow-water jetting system or a pre-lay dredged trench will develop the desired depth of burial. Existing pipeline or communication cables will have to be properly spaced prior to the 36-inch (91.4-cm) pipeline crossing. A diver support vessel (DSV) may be used to lower the existing line and/or to place the spacing material (cement/sand bags or concrete mattresses) for crossing over the existing lines. After the pipeline is installed, other construction activities required are the installation of the risers and platform piping tie-ins at the MP 299 and MP 164 platforms. These installations may be performed with the lay vessel, a derrick vessel, or a large DSV.

Horizontal Directionally Drilled (HDD) Hole Offshore Coden to Onshore Coden – 36-inch (91.4-cm) Gas Pipeline

The marine-to-shore crossing will be by means of a HDD hole from onshore to a pre-determined exit hole offshore Coden, Alabama. This type of marine-to-shore crossing will be used to construct landfalls without disturbing the shoreline. The HDD exit hole and the pipe transition ditch will require dredging and side-casting the spoil to insure egress for the pipe pulled into the HDD and flotation for the lay barge to assemble the HDD pipe string, make the tie-in after the pull, and lay the pipe away from the HDD site. A dipper/backhoe or clamshell dredge barge may be used to excavate the pipe trench. Or, if the water is deep enough for flotation for the lay barge, the pipe may be buried by jetting or hydraulic lifting the spoil from under the pipe. A land-based HDD rig will bore the pilot hole, ream the hole with successive larger reamers, and finally pull the pre-laid pipe string through the HDD hole to shore.

MP 299 to SP 55 – 20-inch (50.8-cm) Gas Pipeline

This particular pipeline leg is entirely in water depths greater than 200 feet (61 meters) and is between two existing platforms. Consequently, no burial or lowering of the pipeline will be required.

A 2GLB or a 3GLV may be used to install the 20-inch (50.8-cm) diameter pipeline. A 2GLB normally assembles the pipeline using 40-foot (12.2-meter) joints of pipe. If a 3GLV is used, this type of vessel can fabricate pipe sections in ‘double jointed’ (80-foot [24.4-meter]) lengths. The higher production rate as a result of the longer sections of pipe minimizes the construction time and, subsequently, the risks of damage. A DSV will be used to lower the existing line and/or to place the spacing material (cement/sand bags or concrete mattresses). Other construction activities will be the installation of the risers and platform piping tie-ins at the Platform No. 2, MP 299, and SP 55 platforms. These installations may be performed with the lay vessel, a derrick vessel, or a large DSV. A number of pipe haul barges and support vessels or pipe transporter vessels will be used to move the pipe from the concrete weight coating plant to the lay vessel.

MP 299 to MP 298 – 16-inch (40.6-cm) Gas Pipeline

This particular pipeline leg is entirely in water depths greater than 200 feet (61 meters) and is between two existing platforms. Consequently, no burial or lowering of the pipeline will be required.

A 2GLB or a 3GLV may be used to install the 16-inch (40.6-cm) diameter pipeline. As previously described, a 2GLB normally assembles the pipeline using 40-foot (12.2-meter) joints of pipe. If a 3GLV is used, this type of vessel can fabricate pipe sections in 'double jointed' (80-foot [24.4-meter]) lengths. The higher production rate as a result of the longer sections of pipe minimizes the construction time and, subsequently, the risks of damage. A DSV will be used to lower the existing line and/or to place the spacing material – cement/sand bags or concrete mattresses. Other construction activities are the installation of the risers and platform piping tie-ins at the Platform No. 2, MP 299 and MP 298 platforms. These installations may be performed with the lay vessel, a derrick vessel or a large DSV. A number of pipe haul barges and support vessels or pipe transporter vessels will be used to move the pipe from the concrete weight coating plant to the lay vessel.

MP 299 to Venice – 12-inch (30.5-cm) NGL Pipeline

A 2GLB will be used to install the 12-inch (30.5-cm) diameter pipeline from platform BS-8 at MP 299 in over 200 feet (61 meters) of water proceeding to near Venice, Louisiana. From 200 feet (61 meters) to about 15 feet (4.6 meters) water depths, a pipeline jet barge or plow can be used to lower the pipeline after it has been installed. From 15 feet (4.6 meters) to shore, a post-lay shallow water jetting system or a pre-lay dredged trench can be used to lower the pipeline below the existing bottom. For the offshore and inshore crossings, a DSV may be used to lower the existing line and/or to place the spacing material (cement/sand bags or concrete mattresses). Other construction activities relating to the 12-inch (30.5-cm) NGL pipeline are the installation of the riser and platform piping tie-in at the BS-8 platform in MP 299. These installations may be performed with the lay vessel, a derrick vessel, and/or a shallow water construction barge

Fixed Offshore Structures

Platform No. 1

The retrofit of Platform No. 1 will occur in three phases:

- Phase I – Removal of deck;
- Phase II – Onshore retrofitting of the deck; and
- Phase III – Reinstallation of the deck.

Phase I (removal of deck) and Phase III (reinstallation of deck) will occur offshore.

Phase I will involve the removal of the Platform No. 1 deck and Bridge No. 10. A pre-cut crew will mobilize offshore prior to the arrival of a HLV. This crew will pre-cut the bridge and deck. The Platform No. 1 deck and bridge will then be lifted and loaded on to a barge for transport to the retrofit fabrication yard.

Phase II will involve the onshore retrofitting of the deck, including modification of the existing deck structure and the installation of the new equipment, piping, electrical, and control systems. Systems will be tested and pre-commissioned to the extent possible onshore prior to the load-out for transportation to the site and the Phase III installation activities.

Phase III will include the installation of insert piles, seawater lift pump casings and intake screens, and reinstallation of the Platform No. 1 deck and bridge on to the existing platform jacket. This will include transportation of the deck and bridge from the retrofit yard to MP 299. The reinstallation of the Platform No. 1 retrofitted deck will require a dual HLV lift. The second HLV will demob after the deck is lifted in place. The equipment modules (i.e., loading arms, ORV, gas turbines, and demethanizer) will be installed prior to the installation of Bridge No. 10.

Platform No. 1 - Soft Berth™ System Bridges

Two new bridges will be built to span the distance from Platform No. 1 deck to the mooring dolphins for the Soft Berth™ System. These bridges will be fabricated onshore and transported to the MP 299 site. Installation will occur after the installation of the Platform No. 1 deck and the Soft Berth™ System dolphins.

Living Quarters Located at BS-Y7

A new quarters building will be installed on BS-Y7. Installation of the living quarters will occur in conjunction with the other installation activities.

Platform No. 2 - Bridge Support Platforms and Bridge Retrofitting

Platform No. 2, BS-8, BS-9 and the interconnecting bridges (Nos. 11, 12 and 13) will have extensive modifications performed. This work to complete the retrofit of both the platform deck and the bridges will be performed on-site.

Storage Platforms Nos. 1 and 2

Two new storage platforms and six new LNG tanks will be installed. The platforms will be eight-legged/12-skirt pile structures and will be installed by the following procedure for both platforms:

- Launch and upend jacket;
- Set jacket at final location;
- Drive main piles and skirt piles;
- Weld jacket shims and make final deck cuts;
- Lift and set deck;
- Lift and set LNG storage tanks nos. 1, 2, and 3 on each platform; and
- Install interconnecting bridges, piping, and cables.

Junction Platform Located at MP 164

A new platform will be installed at MP 164 to serve as a junction platform for pipeline tie-ins. This platform will be a four-pile structure with a small, unmanned deck structure to house pig launchers and meter skids. The components will be transported on a single material barge. The platform will be installed by the following procedure:

- Lift and upend jacket;
- Set jacket at final location;
- Drive piles;
- Weld jacket shims and make final deck cuts;
- Lift and set deck; and
- Install risers.

Hook-Up And Commissioning

Platform No. 1 Hook-Up

The Platform No. 1 deck is being removed, modified onshore, and reinstalled. The hook-up activities begin after the deck is reinstalled and include inter-module connections, as well as connections to the bridges to the other platforms. A work barge including a crane and generator will be required along with support vessels, platform-mounted generator, and the use of the existing platform cranes.

Platform No. 2 Hook-Up

As stated previously, Platform No. 2 will be modified offshore. However, modularized equipment will be transported offshore, lifted onto Platform No. 2, and system interconnects will have to be made. A work barge, including a crane and generator, will be required for the hook-up work along with support vessels, platform mounted generator, and the use of the existing platform cranes.

Commissioning and Start-up

The commissioning and start-up activities are estimated to require 120 days. A work barge, including a crane and generator, will be required along with support vessels, platform-mounted generator, and the use of the existing platform cranes.

Soft Berth™ System

Construction

The Soft Berth™ System dolphins will most probably be constructed in the Far East and dry-towed to a protected United States Gulf Coast location to await installation. The Soft Berth™ System dolphin mooring system and berthing buoys will be assembled in the United States Gulf Coast.

Installation

A jack-up, barge, or other type of vessel will be used to install the piles to be used for seabed mooring of both the Soft Berth™ System dolphins and berthing buoys. The pile installation vessel will be positioned over the site for the particular pile, and the pile will be lowered by an onboard crane to the seabed and allowed to penetrate under its own weight. The pile can be installed either with a pile driver or by using suction piles, the preferred method being pile driving. For pile driving, a pile follower will be used to avoid the use of underwater hammer. The hammer will be placed on the follower allowing the pile to sink even farther into the seabed. The pile will then be driven to grade using a hammer (steam or diesel). After the first pile is installed, the vessel will move to the next location and repeat the procedure until all piles are installed. This will be done and completed before the dolphins are brought to the site for installation.

The mooring lines will be attached to the piles in sequence while a tug maintains the dolphin onsite. When all mooring lines have been attached, all lines will be pre-tensioned to a predetermined value, the dolphin location will be verified, and the dolphin/mooring system installation will be complete. The installation of the berthing buoys will be performed in a similar manner.

24 *§148.105(w)* Operations Manual

A draft copy of the deepwater port Operations Manual is contained in Volume III, Attachment 16 {*confidential*}. In addition, a Security Plan for the deepwater port is provided in Volume III, Attachment 17 {*confidential*}.

25 *§148.105(x)* Environmental Evaluation

The applicant has prepared an extensive Environmental Evaluation (EE) of the proposed MPEH™ deepwater port. The EE is structured in the same fashion as an Environmental Impact Statement (EIS) developed to comply with the National Environmental Policy Act (NEPA), and the provisions of the Temporary Interim Rule, 33 CFR 148.105(x) ("Environmental Evaluation") and 33 CFR 148 Subpart G ("Environmental Review Criteria for Deepwater Ports"). The EE for the MPEH™ deepwater port is provided as Volume II to this deepwater port license application.

The EE describes a number of short-term and long-term environmental impacts resulting from the construction and operation of the MPEH™ deepwater port. The project is not expected to result in significant long-term adverse impacts to the environment.

In addition to the EE, the applicant has prepared an evaluation of the expected environmental impacts resulting from construction of a 5-mile (8-km) long natural gas pipeline segment extending onshore near Coden, Alabama. This pipeline segment has been termed the Coden Onshore Pipeline for purposes of this application. This short, onshore segment of the 36-inch (91.4-cm) diameter natural gas pipeline falls within the jurisdiction of the Federal Energy Regulatory Commission (FERC). Accordingly, the EE for this segment of the project has been developed to mirror FERC's environmental requirements described in 18 CFR Part 380 Appendix A ("Minimum Filing Requirements for Environmental Reports Under the Natural Gas Act."). The EE of the FERC-regulated component of the project is included as Appendix A to the EE that includes Volume II of this application.

The applicant will make a separate application to FERC for authorization to build and operate the 5-mile (8-km) onshore segment of the MPEH™ project.

26 *§148.105(y)* Aids to Navigation

All fixed platforms and connection bridges that are part of the deepwater port complex at MP 299 will be marked with the obstruction lights required by 33 CFR Part 67. In addition, the high-intensity rotating beacon specified in 33 CFR 149.535 will be installed to distinguish the deepwater port from other surrounding offshore structures. Sound signals (fog horns) that meet the requirements of 33 CFR Part 67 also will be provided as required by 33 CFR 149.585.

At least one RACON that meets the requirements of 33 CFR 149.580 is proposed for installation on the main deepwater port platform complex. This RACON will be capable of receiving signals from vessel radars and transmitting responding signals that appear as a brighter than normal target on the receiver's radar in Morse code. A complementary AIS is also proposed for installation at the deepwater port. The AIS will transmit the name of the deepwater port and its position. This data will identify the deepwater port as a fixed marine facility to vessels in the area.

The applicant does not propose to install any navigation buoys or other aids to navigation to mark the location of the recommended route for LNG carriers. The water in the vicinity of the deepwater port is between 140 and 230 feet (43 and 70 meters) deep. This depth of water makes it unnecessary to install aids to navigation to formally define a navigation fairway or channel. Two berthing buoys will be installed as part of the Soft Berth™ System. These buoys, however, are not considered aids to navigation.

Many of these aids to navigation are currently operating on the existing facilities at MP 299 and others will be added as a result of the additions and modifications proposed in this application. Existing and proposed aids to navigation are generally mounted approximately 93 to 130 feet (28 to 40 meters) above MSL depending on the height of the protected structure. Tall structures such as flares, quarters, LNG tanks, and drilling rigs will include aviation warning lights in accordance with all FAA and FCC requirements. The helicopter decks will be provided with all required approach lights and markings.

The aids to navigation for the main deepwater port platform complex are shown on Drawing AK-D-0004, Navigation Aids Location Plan, provided in Appendix A. The aids to navigation on Platform No. 3 and Platform No. 4 currently exist and have been previously permitted by the USCG as part of past mineral extraction activities at MP 299. These are shown in Drawing No. 02290019, Appendix A. Platform No. 3 and Platform No. 4 each have four obstruction lights and one sound signal as required by 33 CFR Part 67. No changes to the existing permitted aids to navigation on Platform No. 3 and Platform No. 4 are proposed as part of this application.

The obstruction lights and sound signals required by 33 CFR Part 67 also will be installed on the proposed pipeline junction platform at MP 164. A total of four obstruction lights (one on each corner of the 85-by-85-foot [26-by-26-meter] upper deck) and one sound signal (fog horn) are planned for this fixed platform. The aids to navigation for the proposed platform at MP 164 are shown on Drawing 02290015 provided in Appendix A. The fixtures will be mounted approximately 95 feet (29 meters) above MSL.

26.1 *§148.105(y)(1)* Proposed Positions of Navigational Aids

The latitude and longitude of existing and proposed aids to navigation are shown on the following drawings located in Appendix A:

- AK-D-0004 Navigation Aids Location Plan;
- 02290019 (MP 299 Platform No. 3 and Platform No. 4 Location Plan); and
- 02290015 (MP 164 Structure Location and Navigation Aid Diagram).

26.2 *§148.105(y)(2)* Descriptions of Proposed Obstruction Lights and Rotating Lighted Beacons

The obstruction lights on the existing facilities that are proposed as part of the deepwater port meet the requirements of 33 CFR Part 67 for Class A structures. The additional obstruction lights proposed as part of the deepwater port will likewise meet USCG specifications for obstruction lights on Class A structures. The obstruction lights are white in color with a visibility of at least 5 miles (8 km) and the flashing characteristics specified in 33 CFR Part 67. All the obstruction lights will be mounted more than 20 feet (6.1 meters) above the water as required by the regulations.

The proposed rotating beacon will be located on existing platform BS-Y7. Following modifications, this platform will be the tallest enclosed structure within the deepwater port complex. The rotating beacon will meet the color, characteristics, intensity, and height requirements specified in 33 CFR 149.535. Specifically, the rotating beacon will be white, have an intensity of at least 15,000 candela, and flash at least once every 20 seconds. The rotating beacon will be mounted in a location that meets the requirements of 33 CFR 149.535(f).

26.3 *§148.105(y)(3)* Descriptions of Proposed Fog Signals

The sound signals proposed for the deepwater port facilities will meet the requirements of 33 CFR Part 67. The sound signals will have a 2-mile (3.2-km) or greater range and be mounted between 10 and 150 feet (3.05 and 45.7 meters) above mean high water as required by 33 CFR 149.585. The sound signal for the proposed deepwater port will be an Automatic Power, Inc., Model DA-8 or equivalent device with a 2-mile (3.2-km) range.

26.4 *§148.105(y)(4)* Descriptions of Proposed Berthing Buoys

No navigation buoys are proposed as part of the deepwater port. Two berthing buoys will be installed as part of the Soft Berth™ System. These buoys, however, are not considered aids to navigation. Each berthing buoy will be lighted with an obstruction light as shown on Drawing AK-D-0004 in Appendix A.

26.5 *§148.105(y)(5)* Descriptions of Proposed Radar Beacon

The proposed RACON will be located on existing platform BS-Y7. Following modifications, this platform will be the tallest enclosed structure within the MPEH™ deepwater port complex. The RACON will be an FCC-type accepted device capable of transmitting in both the 2900-3100 MHz and 9300-9500 MHz frequency bands. The RACON will be mounted more than 15 feet (4.6 meters) above the highest deck of the platform so that the signal is not obstructed in any direction as required by 33 CFR 149.580.

27 *§148.105(z)* National Pollutant Discharge Elimination System

Section 402 of the Clean Water Act (CWA) establishes the National Pollutant Discharge Elimination System (NPDES) to authorize the issuance of permits for discharges into United States waters (33 USC 1342). Section 402 has been further extended to the waters of the United States OCS by Section 403, which provides guidelines for EPA to issue permits for discharges into the territorial sea, contiguous zone, and ocean waters (see 33 USC 1393). Section 403 of the CWA also requires that EPA NPDES permits for discharges into the territorial sea, contiguous zone, and the oceans be issued in compliance with the agency's guidelines for determining the degradation of marine waters.

FME intends to submit a separate request to the EPA for a NPDES permit authorizing discharge of process wastewater, rainwater, hydrostatic test water, and other miscellaneous outfalls associated with the MPEH™ project. Copies of EPA permit application form 3510-2D (Form 2D), and EPA form 3510-1 (Form 1) are included in Appendix E. The EPA application has been structured to comply with the regulations applicable to the NPDES program. On several occasions, FME has consulted with EPA Region 6 NPDES program officials to ensure that the application is responsive to agency needs and concerns. FME expects to submit a NPDES permit application directly to EPA Region 6 on or near the date of this deepwater port license application.

An analysis of the potential effects of discharges associated with the MPEH™ deepwater port is included in Volume II of this application. In addition, a detailed modeling study of the major effluent discharges is included as an appendix to Volume II. An evaluation of the LNG warming water, brine discharges from salt cavern creation, and critical dilution factors for the sodium hypochlorite biocide is included in this modeling study.

28 *§148.105(aa)* USACE Dredge and Fill Permit

Construction of the deepwater port will include installation of three new fixed platforms and 24 anchor piles. Of the three new fixed platforms, two new LNG storage platforms are proposed for installation at MP 299. The third new fixed structure will be the proposed gas pipeline junction platform at MP 164. All 24 proposed anchor piles are part of the proposed Soft Berth™ System for ship berthing at MP 299. Of these anchor piles, 20 are proposed as attachment points for the mooring lines to the two berthing dolphin semisubmersible units (10 each). The remaining four anchor piles are proposed as mooring points for the two berthing buoys that include part of the Soft Berth™ System.

The MPEH™ deepwater port also includes installation of approximately 192 miles (309 km) of offshore and onshore pipelines. The offshore and onshore pipelines are described in greater detail in Sections 20 and 21, respectively. The proposed construction techniques for installation of the project's pipelines include jetting, trenching, HDD, and other pipeline construction techniques.

The USACE has permitting authority under Section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. 403) over any obstruction or alteration occurring in the navigable waters of the United States. Subsequently, the USACE's authority under Section 10 was extended to the construction of artificial islands, installations, and other devices on the seabed, to the seaward limit of the OCS, by Section 4(f) of the Outer Continental Shelf Lands Act (OCSLA; 33 U.S.C. 1331 et. seq.). In addition to the Rivers and Harbors Act, Section 404 of the Clean Water Act (33 U.S.C. 1344) establishes requirements for the discharge of dredged and fill material into waters of the United States, including wetlands.

Normally, a single permit application can be made to the USACE to request Section 10 and Section 404 authorization for the construction activities associated with a proposed project. In this case, however, the deepwater port crosses the boundary between the Mobile, Alabama, and New Orleans, Louisiana, district offices of the USACE. For this reason, separate applications will be made to the Mobile and New Orleans USACE district offices to authorize activities associated with the deepwater port project. The Section 10/Section 404 permit application for the 5-mile (8-km) segment of the 36-inch (91.4-cm) natural gas pipeline that extends onshore in Alabama will be included in the permit application submitted to the Mobile District USACE office.

The Section 10 (Rivers and Harbors Act) and Section 404 (Clean Water Act) permit applications ("ENG FORM 4345") to the Mobile and New Orleans USACE district offices will include the necessary drawings, diagrams, and environmental information. FME will submit these permit applications directly to the appropriate USACE offices on the same day that this deepwater port application is filed with the Commandant [G-M] USCG in Washington D.C. Copies of the USACE permit applications are contained in Appendix D.

FME does not anticipate that construction of the deepwater port structures and modules will require expansion of existing United States fabrication facilities. In addition, the project will be supported from one of several existing onshore support bases in the Venice, Louisiana area. Thus, construction and operational support of the deepwater port is not expected to result in secondary impacts to navigable waters or adjacent wetlands.

29 *§148.105(bb)* Additional Federal Authorizations

As the lead agencies for administration of the DWPA, the USCG and the Maritime Administration (MARAD) are responsible for license application processing and issuance, NEPA compliance, and compliance with the provisions of several environmental laws that require consultation with other agencies concerning specific environmental resources. Examples of these include Section 7 of the Endangered Species Act (ESA), the Magnuson-Stevens Fishery Conservation and Management Act (MSFCMA), Section 106 of the National Historic Preservation Act (NHPA), and Section 307 of the Coastal Zone Management Act (CZMA). A description of these regulations and subsequent consultation obligations are presented below and, where applicable, in Sections 3, 4, and 5 of the EE, Volume II. In addition, any enforceable conditions imposed as part of an approved license must be consistent with the appropriate and applicable regulatory requirements.

Volume 68, *Federal Register*, No. 66, Monday, April 7, 2003, pp 16808-09.

Volume 68, *Federal Register*, No. 72, Tuesday, April 15, 2003, p 18252.

Volume 68, *Federal Register*, No. 104, Monday, May 30, 2003, p 32486.

Volume 68, *Federal Register*, No. 104, Monday, May 30, 2003, pp 32538-39.

Volume 68, *Federal Register*, No. 109, Monday, June 6, 2003, p 33934.

For its part, the applicant is required to obtain and comply with all applicable and appropriate permits, guidelines, and approvals as provided for in the CZMA, the Clean Water Act, and the Clean Air Act for any impacts on coastal resources, wastewater discharges, and/or regulated air emissions to the environment. It is the applicant's responsibility to provide the licensing agency with the information necessary to evaluate potential compliance with the applicable regulations and guidelines. The Title V air permit application is included in Appendix G.

Table 29-1 lists major federal and state permits, approvals, and consultations that will be required to construct and operate a natural gas deepwater port, some of which prescribe standards for compliance. Others require that specific planning and management actions be designed to protect environmental resources that might be affected by issuance of a deepwater port license. The authorities shown in Table 29-1 are addressed in various sections of the EE when relevant to particular environmental resources and conditions. Full text of the laws may be accessed at http://uscode.house.gov/uscode.htm. Executive Orders may be accessed at http://www.archives.gov/federal_register/executive_orders/disposition_tables.html.

Table 29-1
Major Permits, Approvals, and Consultations for Natural Gas Deepwater Ports

Agency	Permit/Approval/Consultation
U.S. Department of Homeland Security, United States Coast Guard (USCG)	▪ License application processing
U.S. Department of Transportation, Maritime Administration (MARAD)	▪ License application processing and approval
U.S. Department of Transportation, Research and Special Programs Administration	▪ Establish and enforce deepwater port pipeline safety regulations ▪ Consultation on LNG facility design
U.S. Department of Interior, Minerals Management Service (MMS)	▪ Pipeline right-of-way guidance and coordination ▪ Hazard surveys guidance and coordination ▪ Archeological coordination
U.S. Department of Interior, United States Fish and Wildlife Service (USFWS)	▪ Section 7 (Endangered Species Act [ESA]) coordination Migratory Bird Treaty Act coordination ▪ Coastal Barrier Resources Act coordination

Table 29-1
Major Permits, Approvals, and Consultations for Natural Gas Deepwater Ports

Agency	Permit/Approval/Consultation
U.S. Environmental Protection Agency (EPA)	▪ Clean Water Act ▪ National Pollutant Discharge Elimination System (NPDES) permit ▪ Title V (Clean Air Act) permit ▪ Marine Protection, Research and Sanctuaries Act (MPRSA) consistency
U.S. Department of Commerce, National Oceanic and Atmospheric Administration National Marine Fisheries Service (NOAA Fisheries)	▪ Section 7 (ESA) coordination ▪ Essential fish habitat (EFH; Magnuson-Stevens Fishery Conservation and Management Act [MSFCMA]) coordination ▪ Marine Mammal Protection Act coordination
U.S. Department of Energy, Office of Fossil Energy	▪ Import certificate under Section 3, Natural Gas Act
U.S. Army Corps of Engineers (USACE)	▪ Rivers and Harbors Act Section 10 Permit
U.S. Department of Defense	▪ Consultation (review of license application adequacy and views on effects on departmental programs)
U.S. Department of State, Bureau of Oceans and International Environment and Scientific Affairs	▪ Consultation (review of license application adequacy and views on effects on departmental programs)
Advisory Council on Historic Preservation (ACHP)	▪ Section 106 (National Historic Preservation Act [NHPA]) coordination
Federal Energy Regulatory Commission (FERC)	▪ Certificates of public convenience and necessity for natural gas pipelines in interstate commerce
Governor of Alabama	▪ Consent to issue license
Alabama Department of Environmental Management (ADEM) - Field Operations Division–Coastal Section	▪ USACE/ADEM Joint Application and Notification ▪ Coastal Consistency certification
ADEM Water Quality Section	▪ State Water Quality Certification ▪ Notice of Registration for hydrostatic test water discharges
Alabama Department of Conservation and Natural Resources (ADCNR) Division of Wildlife and Freshwater Fisheries	▪ State protected species consultation
Governor of Louisiana	▪ Consent to issue license
Louisiana Department of Natural Resources (LDNR), Coastal Management Division	▪ Coastal Zone Management Act (CZMA) Consistency Determination
Louisiana Department of Wildlife and Fisheries	▪ Louisiana Endangered Species Act (ESA) coordination
Louisiana State Historic Preservation Office, Department of Culture, Recreation, and Tourism	▪ NHPA coordination
Governor of Mississippi	▪ Consent to issue license
Mississippi Department of Environmental Quality	▪ CZMA Consistency Determination

Section 7 of the ESA states that any project authorized, funded, or conducted by any federal agency should not "… jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of habitat of such species which is determined … to be critical." USCG and MARAD, or an applicant if designated as a non-federal representative, is required to consult with the United States Fish and Wildlife Service (USFWS) and the National Oceanic and Atmospheric Administration National Marine Fisheries Service (NOAA Fisheries) to determine whether any federally listed or proposed endangered or threatened species or their designated critical habitats occur near the proposed project. If, upon review of existing data or data provided by the applicant, USCG and MARAD determine that these species or habitats might be affected by the project, USCG and MARAD must prepare a biological assessment (BA) to identify the nature and extent of adverse impacts, and recommend measures that will avoid the habitat or species or reduce potential impact on acceptable levels. The BA will be used in the interagency consultation as a basis for determining whether the adverse effects are likely to result in jeopardy to any listed species.

After consultation, NOAA Fisheries or the USFWS will issue a biological opinion (BO) on the potential for jeopardy. If their opinion is that the project is not likely to jeopardize any listed species, they may also issue an incidental take statement as an exception to the prohibitions in Section 9 of the ESA. If, however, USCG and MARAD determine that no federally listed or proposed endangered species or their designated critical habitat will be affected by the project, no further action is necessary under the ESA.

The MSFCMA, amended by the Sustainable Fisheries Act of 1996, establishes procedures designed to identify, conserve, and enhance essential fish habitat (EFH) for those species regulated under a Federal Fisheries Management Plan. The MSFCMA requires federal agencies to consult with NOAA Fisheries on all actions or proposed actions authorized, funded, or undertaken by the agency that may adversely affect EFH. NOAA Fisheries recommends consolidated EFH consultations with interagency coordination procedures required by other statutes such as NEPA or the ESA (50 CFR 600.920(e)(1)) to reduce duplication and improve efficiency. The mandatory contents of an EFH assessment are detailed in 50 CFR 600.920(e)(3). Sections 2, 4.2.4, and 5.1.2 of the Environmental Review are intended to address those portions of the EIS that serve as the EFH assessment for the project.

Section 106 of the NHPA requires USCG and MARAD to consider the effects of the project on properties listed on or eligible for listing on the National Register of Historic Places (NRHP), including prehistoric or historic sites, districts, buildings, structures, objects, or properties of traditional religious or cultural importance, and to allow the Advisory Council on Historic Preservation (ACHP) to comment on the undertaking. It is anticipated that USCG and MARAD will request that FME, as a non-federal party, assist in meeting USCG's and MARAD's obligations under Section 106 by preparing the necessary information and analysis as required by ACHP procedures (36 CFR 800).

The CZMA calls for the "effective management, beneficial use, protection, and development" of the nation's coastal zone and promotes active state involvement in achieving those goals. To reach those goals, the CZMA requires participating states to develop management programs that demonstrate how these states will meet their obligations and responsibilities in managing their coastal areas. The Alabama Department of Environmental Management (ADEM) administers Alabama's CZMP, whereas the Louisiana Department of Natural Resources (LDNR) and the Mississippi Department of Environmental Quality (MDEQ) are the responsible agencies in their respective states. As required, FME has prepared a consistency certification finding that its proposed activities will be fully consistent with the enforceable policies of Alabama's, Mississippi's and Louisiana's CZMPs. FME will submit copies of this deepwater port application to the appropriate state agencies for consistency review at an appropriate time after a determination by the USCG that this application is complete.

Under Section 101 of the Marine Protection, Research, and Sanctuaries Act (MPRSA), 33 U.S.C. 1401, no person may transport material from the United States for the purpose of dumping it in ocean waters in the absence of a permit issued by the EPA pursuant to Section 102 of the MPRSA. "Dumping" does not, however, include "construction of any fixed structure or artificial island nor the intentional placement of any device in ocean waters, or on or in the submerged land beneath such waters, for a purpose other than disposal, when such construction or such placement is otherwise regulated by federal or state law…." The construction of the proposed deepwater port falls within the scope of this statutory exclusion.

In 1953, Congress enacted the OCSLA and the Submerged Lands Act as a response to public concern about the ownership and development of offshore resources. These laws authorize the Secretary of the Interior, and by extension the MMS, to grant mineral leases and to prescribe regulations governing oil and gas activities on OCS lands. The OCSLA also recognizes the need for conducting operations safely and using technology to minimize the likelihood of fires, spills, and interference with other uses of the ocean.

The OCSLA was amended six times between 1978 and 1998. These amendments include, for example, the establishment of an oil-spill liability fund and the distribution of a portion of the receipts from the leasing of mineral resources of the OCS to coastal states. The OCSLA is one of the primary laws regulating the offshore development of oil and gas in the federal exclusive economic zone (EEZ).

On February 27, 2004, pursuant to Section 7(c) of the Natural Gas Act (NGA), FME filed with the FERC a request for a certificate of public convenience and necessity to construct and operate a 5.0 mile single-use natural gas pipeline to be known as "the Coden Onshore Pipeline" as part of the proposed MPEH™ deepwater port. Specifically, the Coden Onshore Pipeline, which is the northernmost end of the MPEH™ pipeline system, will be located landward of the high water mark in Mobile County, Alabama, and will terminate at interconnection(s) with existing interstate natural gas pipeline(s) in the vicinity of Coden, Alabama.

The scope of the DWPA does not extend onshore (i.e., to areas above the high water mark); therefore, from the point where the MPEH™ pipeline crosses the high water mark along the Alabama coast to its interconnection(s) with existing interstate natural gas pipeline(s), it is within FERC jurisdiction pursuant to the NGA. The FERC-jurisdictional section of the MPEH™ natural gas pipeline is only a small fraction of FME's overall proprietary deepwater port development. No other facilities of the MPEH™ deepwater port are FERC-jurisdictional.

Like the MPEH™ deepwater port, which will be a proprietary natural gas facility, the Coden Onshore Pipeline will be a single-use pipeline dedicated solely to transporting natural gas from FME's MPEH™ deepwater port facilities. FME will utilize the entire capacity of the Coden Onshore Pipeline to transport natural gas that it owns, so there will be no capacity available to serve other parties.

The applicant has conducted an extensive consultation process with federal, state, and local agencies. Table 29-2 provides a record of these consultations.

Table 29-2
Agency Correspondence Between January 2003 and February 2004

No.	Date	Agency	Agency Representative(s)	Location of Meeting	Topic(s) of Discussion
1	January 15, 2003	U.S. Coast Guard (USCG)	CDR Mark Prescott	Washington D.C.	USCG DWP Requirement
2	January 15, 2003	Federal Energy Regulatory Commission (FERC)	Robert Cupina	Washington D.C.	FERC Jurisdiction
3	January 29, 2003	Minerals Management Service (MMS)	Chuck Schoennagel, Cathy Moser	New Orleans, LA	MMS Issues and Jurisdiction
4	March 20, 2003	USCG	LCDR John Cushing, Guy Tetreau	New Orleans, LA	USCG District Eight Issues
5	March 25, 2003	USCG	CDR Mark Prescott, Bob Corbin	Washington D.C.	USCG Technical Issues
6	March 25, 2003	MMS	David Moore, Elmer "Bud" Danenberger	Washington D.C.	MMS Concerns and Issues
7	June 10, 2003	LA Dept. of Natural Resources Coastal Management Division	Jeffrey Harris and LA agency representatives from: • LA Dept. of Nat Resources/ Coastal Management Division, • USCG, • LA Dept. Wildlife & Fisheries, • LA Geological Survey, • Dept. of Transportation, • MMS, • LA Oil Spill Coordinator's Office/Office of the Governor, • NOAA Fisheries, and • USACE.	Baton Rouge, LA	Review of MPEH™ Project State and Federal Regulatory Agencies
8	June 25, 2003	Environmental Protection Agency (EPA) Region 6	Larry Giglio, Rob Lawrence, Mike Boydston, Pat Rankin, Scott Wilson, Mary Stanton	Dallas, TX	Air and Water Permitting
9	June 27, 2003	White House Task Force on Energy Project Streamlining	David LaRoche	Washington D.C.	Interagency Jurisdictional Issues
10	July 16, 2003	White House Task Force on Energy Project Streamlining	B. Middleton, Helen Golde, David LaRoche	Washington D.C.	Interagency Jurisdictional Issues

Table 29-2
Agency Correspondence Between January 2003 and February 2004

No.	Date	Agency	Agency Representative(s)	Location of Meeting	Topic(s) of Discussion
11	September 25, 2003	National Oceanic and Atmospheric Administration (NOAA)	Richard Rubsamen	Telephone Call	Essential Fish Habitat (EFH)
12	October 2, 2003	Representatives of the Governor's Office	Don Hutchinson (Secretary of the LA Dept. of Economic Development) Mike Taylor (Director, Petrochemical/Environmental Technology Cluster Development)	New Orleans, LA	Coordination with Louisiana Governor's Office
13	October 3, 2003	USCG	CDR Mark Prescott, Bob Corbin, David Reese	New Orleans, LA	Meeting on Pipeline Survey Requirements
14	October 10, 2003	USCG	CDR Mark Prescott	Telephone Call	Shallow Hazard and Archaeological Surveys for DWP License Applications and Definition of Natural Gas
15	October 15, 2003	NOAA Fisheries	Eric Hawk	Telephone Call	NOAA Managed Threatened and Endangered Species Near MP 299
16	October 27, 2003	White House Task Force on Energy Project Streamlining	B. Middleton, Helen Golde, David LaRoche	Washington D.C.	Discussion of NGL, Permit Timing, and Jurisdictional Issue of Gas Storage in Caverns.
17	October 28, 2003	USCG and Maritime Administration (MARAD)	USCG: CDR Mark Prescott, Joan Lang, Bob Corbin, LCDR Smith (Safety), John Dickinson, LCDR Kevin Tone, Crystal Smith, Lt. Derrick Dostie, Kevin Frank Esposito (Env. Law) MARAD: Dan Yuske, Sugi Foj	Washington D.C.	Project Update and Discussion of DWP Application Process
18	October 28, 2003	MMS	Jonnie Burton (Director of MMS), Barry Crowell (Interior Solicitor's Office), Edward Shaw (Special Assistant to Director), Darryl Francois (Deputy Chief of Staff), Tom Readinger (Associate Director)	Washington D.C.	Project Overview and Discussion of Cross Jurisdictional Issues
19	October 28, 2003	MMS	David Moore, Anne Wiggin, Tim Reading, Dirk Hertoff, Bud Dannenberger, Radford Schantz, Melanie Stright	Washington D.C.	Discussion of MMS Concerns and Issues

Table 29-2
Agency Correspondence Between January 2003 and February 2004

No.	Date	Agency	Agency Representative(s)	Location of Meeting	Topic(s) of Discussion
20	October 29, 2003	MARAD	Francis Mandula, Mike Ferris, Lennis Fludd	Washington D.C.	MARAD Role and Expectations in DWP Process
21	October 29, 2003	NOAA Fisheries	Carla Sullivan, Jennifer Koss, Mike Aslaksen	Washington D.C.	Project Overview and Involvement of NOAA in MPEH™ Project
22	October 31, 2003	NOAA Fisheries and U.S. Fish & Wildlife Service (USFWS)	NOAA Fisheries: Richard D. Harman, Kelly Shotts USFWS: Brigitte Firmin	Lafayette, LA	Project Overview and Request for Feedback on Project
23	November 13. 2003	MMS	Nancy Parmelee	New Orleans, LA	
24	November 17, 2003	U.S. Army Corps of Engineers (USACE), USFWS, Alabama Public Service Commission (PSC)	USACE: David Schwartz USFWS: Darren Leblanc PSC: Tommy Lancaster, Judy Ramsey	Mobile, AL	Project Overview and Discussion of DWP License Application

Table 29-2
Agency Correspondence Between January 2003 and February 2004

No.	Date	Agency	Agency Representative(s)	Location of Meeting	Topic(s) of Discussion
25	November 21, 2003	LA State and Federal Regulators Meeting	LA Dept. of Nat. Res./Coastal Mngt. Division: Brian Marcks, Jeff Thibodeux, Rocky Hinds MMS: Angie Gobert, Michael Tolbert, Ed Richardson, Clay Pilie USFWS: Brigitte Fermin, LA Dept. of Wildlife & Fisheries: Fred Dunham LA Geological Survey: John Johnson III EPA: Jeanene Peckham NOAA Fisheries: Kelly Shotts	Baton Rouge, LA	Interagency Meeting on Environmental Permit Process and Wetland Issues Associated with Pipeline Routes
26	December 1, 2003	Alabama Oil and Gas Board	Delores Burrows	Telephone Call	Alabama Oil and Gas Board Onshore Pipeline Requirements
27	December 1, 2003	Alabama Dept. of Environmental Management	Allen Phelps	Letter Correspondence	Project Overview and DWP Application Submittal
28	December 1, 2003	EPA	Darryl Williams, Kacy Campbell	Letter Correspondence	Project Overview and Notice of DWP Application Submittal
29	December 1, 2003	Alabama Marine Resources Division	Mark Van Hoose, Steven Heath	Letter Correspondence	Project Overview and Notice of DWP Application Submittal
30	December 2, 2003	FERC	John Leiss	Telephone Call	Onshore Pipeline Permitting Issues
31	December 3, 2003	Alabama Division of Marine Resources	Jim Duffy, Ralph Harvard, Mark Van Hoose	Dauphin Island, AL	Project Status Update
32	December 10, 2003	U.S. Army Corps of Engineers	Pete Serio, Joaquin Mujica	New Orleans, LA	Project Overview and Plans for NGL Pipeline

Table 29-2
Agency Correspondence Between January 2003 and February 2004

No.	Date	Agency	Agency Representative(s)	Location of Meeting	Topic(s) of Discussion
33	December 16, 2003	FERC	FERC: Richard Hoffman, Mark Robinson, Bob Christin, Robert Cupina, John Leiss USCG: CDR Mark Prescott White House Task Force on Energy Project Streamlining: Helen Golde	Washington D.C.	FERC Jurisdictional Issues
34	December 17, 2003	USCG	Bob Corbin	Washington D.C.	USCG Meeting on LNG Vapor Dispersion & Thermal Modeling
35	December 17, 2003	Dept. of Transportation Office of Pipeline Safety	Joy O. Kadnar, Paul Sanchez, and L.E. Herrick	Washington D.C.	DOT Office of Pipeline Safety Jurisdiction and Issues
36	January 6, 2004	EPA	Rob Lawrence, Stephanie Kordzi, Mike Boydson, Shannon Snyder, Barbara Keeler, Pat Rankin, Erik Snyder, David Neleigh, Scott Wilson, Isaac Chen	Dallas, TX	EPA Expectation on Air and Water Permitting
37	January 12, 2004	Alabama State Archaeologist	Tom Maher	Montgomery, AL	Portion of MPEH™ Pipeline Route by Coden, AL
38	January, 14, 2004	Alabama Historical Commission	NA	Telephone Call	Requested List of Tribal Historic Preservation Officers
39	January 14, 2204	Louisiana Division of Archaeology	Section 106 Review and Compliance Officer: Rachel Watson Archaeology Manager Duke Rivet	Telephone Call	Proposed Survey Methodology and Request for List of Tribal Historic Preservation Officers
40	January 14, 2004	Louisiana Division of Archaeology	Duke Rivet	Letter Correspondence	Letter Outlining Proposed Survey Methodology
41	January 22, 2004	MARAD	Michael Ferris, Francis Mardula, Carol Powers	Washington D.C.	Financial Responsibility, Corporate Structure, and Jurisdiction over NGL
42	January 22 and 26, 2204	Louisiana Division of Archaeology	Duke Rivet	Electronic Correspondence	Proposed Survey Methodology and Request for Additional Information

Table 29-2
Agency Correspondence Between January 2003 and February 2004

No.	Date	Agency	Agency Representative(s)	Location of Meeting	Topic(s) of Discussion
43	January 26, 2004	State of Alabama Tribal Historic Preservation Officers	All Consulting Tribal Historic Preservation Officers	Letter Correspondence	Letter Outlining Proposed Project with Accompanying Maps
44	January 29, 2004	FERC	Bob Christin, Anna Cochran, Berne Mosley, Mike McGehee, John Leiss, Bill Zoller, Richard Foley, Jim Martin	Washington D.C.	Application by a Single Entity for a Part 157 Certificate
45	February 5, 2004	US Army Corps of Engineers, New Orleans District	Pete Serio, Jerry Colletti	New Orleans,LA	US Army COE Permitting of Mississippi River Crossing
46	February 11, 2004	Louisiana Division of Historic Preservation, and Louisiana Office of Cultural Development	Executive Secretary of Pam Breaux	Telephone Call	Requested List of Consulting Tribal Historical Preservation Officers for LA
47	February 11, 2004	State of Louisiana Tribal Historic Preservation Officers	All Consulting Tribal Historic Preservation Officers	Letter Correspondence	Letter Outlining Proposed Project with Accompanying Maps
48	February 11, 2004	Louisiana State and Federal Regulators Meeting	LA Dept. of Env. Quality: Tessa Roy Larry Wiesepape LA Dept. of Wildlife and Fisheries: Fred Durham LA Dept. of Nat. Res./Coastal Mngt. Division: Brian Marcks Rocky Hinds Chris Davis USFWS: Brigitte Firmin	Baton Rouge, LA	Proposed Construction of 12-inch NGL Pipeline
49	February 11, 2004	NOAA Fisheries	Kelly Shotts	Electronic Correspondence	Pipeline Right-of-Way in Louisiana
50	February 17, 2004	Air National Guard	Jason Peterson	Telephone Call	New MMS Notice to Lessees pertaining to Military Warning and Water Test Areas

30 *§148.105(cc)* Statement Certifying Application

STATE OF LOUISIANA

PARISH OF ORLEANS

Pursuant to the United States Coast Guard's Temporary Interim Rule with Request for Comments of January 6, 2004 (69 FR 724), 33 CFR 148.104(cc), the undersigned, David C. Landry, having been first duly sworn, deposes and says that he is Vice President of Freeport-McMoRan Energy LLC, that he is familiar with the content of this Application, that to the best of his knowledge, information and belief, the information in said Application is true, and that he possesses full power and authority to sign this statement.

David C. Landry

David C. Landry

Sworn to and subscribed before me this 25th day of February 2004.

John J. Seip, III

John J. Seip, III, Bar No. 11922
Notary Public
Orleans Parish, Louisiana
My Commission is for life.

[seal]