Oregon LNG Bidirectional Project

Resource Report 1 — General Project Description

Docket Numbers CP13-___-000 and CP13-___-000

Prepared for
LNG Development Company, LLC (d/b/a Oregon LNG)
and
Oregon Pipeline Company, LLC

Prepared by CH2M HILL and CH-IV International

June 2013

Resource Report No. 1—General Project Description
Summary of Filing Information

Minimum Requirements	Location Addressed
1. Provide a detailed description and location map of the project facilities. (Section 380.12(c)(1)) • Include all pipeline and aboveground facilities. • Include support areas for construction or operation. • Identify facilities to be abandoned.	Sections 1.1, 1.3, 1.4, and 1.5; Figures 1.1-1, 1.1-2, 1.1-3, 1.3-1, 1.3-2, 1.3-4A–K, 1.3-5, 1.3-6, and 1.3-7; Appendices 1A through 1F
2. Describe any nonjurisdictional facilities that will be built in association with the project. (Section 380.12(c)(2)) • Include auxiliary facilities (see Section 2.55(a)). • Describe the relationship to the jurisdictional facilities. • Include ownership, land requirements, gas consumption, megawatt size, construction status, and an update of the latest status of federal, state, and local permits/approvals. • Include the length and diameter of any interconnecting pipeline. • Apply the four-factor test to each facility (see Section 380.12 (c)(2)(ii)).	Section 1.11 and Figure 1.11-1
3. Provide current original U.S. Geological Survey 7.5-minute series topographic maps with mileposts showing the project facilities. (Section 380.12(c)(3)) • Maps of equivalent detail are acceptable if legible (check with staff). • Show locations of all linear project elements, and label them. • Show locations of all significant aboveground facilities, and label them.	Appendix 1D
4. Provide aerial images or photographs or alignment sheets based on these sources with mileposts showing the project facilities. (Section 380.12(c)(3)) • No more than 1-year old. • Scale no smaller than 1:6,000.	Appendix 1E

Minimum Requirements	Location Addressed
5. Provide plot/site plans of compressor stations showing the location of the nearest noise-sensitive areas within 1 mile. (Section 380.12(c)(3,4)) • Scale no smaller than 1:3,600. • Show reference to topographic maps and aerial alignments provided above.	Figure 1.1-3; Appendices 1D and 1E
6. Describe construction and restoration methods. (Section 380.12(c)(6)) • Include this information by milepost. • Make sure this is provided for offshore construction as well. For the offshore this information is needed on a mile-by-mile basis and will require completion of geophysical and other surveys before filing.	Section 1.5
7. Identify the permits required for construction across surface waters. (Section 380.12(c)(9)) • Include the status of all permits. • For construction in the federal offshore area be sure to include consultation with the U.S. Minerals Management Service. File with the U.S. Minerals Management Service for rights-of-way grants at the same time or before you file with the Federal Energy Regulatory Commission.	Section 1.8; Table 1.8-1
8. Provide the names and addresses of all affected landowners and certify that all affected landowners will be notified as required in Section 157.6(d). (Section 380.12(c)(10)) • Affected landowners are defined in Section 157.6(d). • Provide an electronic copy directly to the environmental staff.	Section 1.9; Appendix 1L; electronic copy provided
Additional Information	
Describe all authorizations required to complete the proposed action and the status of applications for such authorizations.	Section 1.8; Table 1.8-1
Provide plot/site plans of all other aboveground facilities that are not completely within the right-of-way.	Appendix 1D; Figure 1.1-3
Provide detailed typical construction right-of-way cross-section diagrams showing information such as widths and relative locations of existing rights-of-way, new permanent right-of-way, and temporary construction right-of-way.	Appendix 1C
Summarize the total acreage of land affected by construction and operation of the project.	Section 1.4
If Resource Report 5, Socioeconomics, is not provided, provide the	Please refer to Resource

Minimum Requirements	Location Addressed
start and end dates of construction, the number of pipeline spreads that will be used, and the workforce per spread.	Report 5. Also see Figure 1.5-1 and Tables 1.5-1 and 1.5-2 in this Resource Report 1.
Send two additional copies of topographic maps and aerial images/ photographs directly to the environmental staff of the Office of Energy Projects.	Provided

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Appendices

Tables

Figures

[Please note: the figures referenced in the main text of this Resource Report 1, and listed below, are provided together in Appendix 1A.]

List of Acronyms and Abbreviations

AC	alternating current
APCI	Air Products & Chemicals, Inc.
ARO	abrasion-resistant overcoat
ATWS	additional temporary workspace
BMP	Best Management Practice
BPA	Bonneville Power Administration
BOG	boiloff gas
Bscf/d	billion standard cubic feet per day
Btu/hr/ft^2	British thermal units per hour per square foot
BTX	benzene, toluene, and xylene
BWRO	brackish water reverse osmosis systems
ºC	degrees Celsius
CDSM	cement deep soil mixing
CFR	*Code of Federal Regulations*
CO_2	carbon dioxide
CORES	Commission Registration System
CRPUD	Columbia River People's District
CWA	Clean Water Act
cy	cubic yards
d/b/a	doing business as
DEIS	Draft Environmental Impact Statement
DMMP	Dredge Material Management Plan
DSME	Daewoo Shipbuilding & Marine Engineering
DWS	Deep Water Site
EEZ	Exclusive Economic Zone
EIA	U.S. Energy Information Administration
EIS	Environmental Impact Statement
EPC	Engineering, Procurement, and Construction
EPSC	erosion prevention and sediment control
ER	Environmental Report
ESA	Endangered Species Act
ESD	Emergency Shutdown
ESP	East Bank Skipanon Peninsula
ESU	Evolutionarily Significant Unit
°F	degrees Fahrenheit
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
GAO	U.S. Government Accountability Office
gpm	gallons per minute
HDD	horizontal directional drill/drilling

HDMS	Hazard Detection and Mitigation System
HDPE	high-density polyethylene
hp	horsepower
kV	kilovolt(s)
LF	linear feet
LLC	Limited Liability Company
LNG	liquefied natural gas
LNGC	liquefied natural gas carrier
m^3	cubic meters
MCHE	main cryogenic heat exchanger
MCR	Mouth of Columbia River
MG	million gallons
mgd	million gallons per day
mg/L	milligrams per liter
MG/Y	million gallons per year
MLLW	mean lower low water
MLV	mainline valve
mm	millimeter
MMBtu	million metric British thermal units
MMcf/d	million cubic feet per day
MP	milepost
MR	mixed refrigerant
msl	mean sea level
MTPY	million metric tons per year
MW	megawatt
NA	not applicable
NAVD	North American Vertical Datum
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NGA	Natural Gas Act
NMFS	National Marine Fisheries Service
nmi	nautical miles
Northwest	Northwest Pipeline GP
NPDES	National Pollutant Discharge Elimination System
NPI	Northwest Pipeline Interconnect
NW Natural	Northwest Natural Gas Company
O&M	operations and maintenance
OD	outside diameter
ODEQ	Oregon Department of Environmental Quality
ODF	Oregon Department of Forestry
ODFW	Oregon Department of Fish and Wildlife
ODOT	Oregon Department of Transportation
OHP	Oregon Highway Plan
ORW	Outstanding Resource Water
OWRD	Oregon Water Resources Department
PCB	polychlorinated biphenyl

P&ID	process and instrumentation diagram
POTW	Publicly Owned Treatment Works
psf	pounds per square foot
PSHA	probabilistic seismic hazard analysis
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
RM	river mile
RO	reverse osmosis
ROW	right-of-way
SCADA	supervisory control and data acquisition
SEPA	State Environmental Policy Act
SJS	South Jetty Site
SPCC	Spill Prevention, Control, and Countermeasures
SWPPP	Stormwater Pollution Prevention Plan
SWS	Shallow Water Site
Tcf/y	trillion cubic feet per year
TDS	total dissolved solids
TIS	Traffic Impact Study
TSS	total suspended solids
TWS	temporary workspace
U.S.	United States
USACE	U.S. Army Corps of Engineers
USEPA	U.S. Environmental Protection Agency
USGS	U.S. Geological Survey
USFWS	U.S. Fish and Wildlife Service
v/c	volume-to-capacity
Williams	Williams Northwest Pipeline Company
WSA	Waterway Suitability Assessment
WSDOT	Washington State Department of Transportation
WSR	Waterway Suitability Report

1.0 Introduction

LNG Development Company, LLC (d/b/a Oregon LNG) proposes to own, construct, and operate a bidirectional liquefied natural gas (LNG) terminal (Terminal) consisting of marine facilities, LNG storage tanks, LNG vaporization facilities, natural gas liquefaction facilities, and associated support facilities, to be located in Warrenton, Oregon. The Terminal will have a base load liquefaction capacity of 9.6 million metric ton per year (MTPY), which requires approximately 1.25 billion standard cubic feet per day (Bscf/d) of pretreated natural gas; and a base load regasification capacity of 0.5 Bscf/d.

Natural gas will be transported to and from the Terminal via an approximately 86.8-mile-long, 36-inch-outside-diameter (OD) bidirectional pipeline (Pipeline) that is being developed by Oregon Pipeline Company, LLC (Oregon Pipeline; and together with LNG Development Company, LLC, Oregon LNG).[1] The Pipeline will interconnect with the interstate transmission system of Northwest Pipeline GP (Northwest), a subsidiary of the Williams Companies, at the Northwest Pipeline Interconnect (NPI) near Woodland, Washington.[2] The Pipeline will be routed through Clatsop, Tillamook, and Columbia counties in Oregon, and Cowlitz County in Washington. An electrically-driven gas compressor station (Compressor Station) will be constructed at milepost (MP) 80.8 of the Pipeline. The Terminal, Pipeline, and Compressor Station are collectively referred to as the Bidirectional Project or Project.

1.0.1 Resource Report Summary

This Resource Report provides an overview of the Project; discusses the purpose and need for the Project; describes the Project location and constituent facilities, aquatic area and land requirements, construction procedures and anticipated construction schedule, and operations and maintenance procedures; addresses future plans and abandonment; identifies permits that must be obtained and landowners potentially affected; outlines public outreach conducted to date; and describes nonjurisdictional facilities associated with the Project.

The resources encompassed by the Project, the potential impacts associated with the construction and operation of the Project, and measures to mitigate such impacts are described in Resource Report 2—Water Use and Quality, Resource Report 3—Fish, Wildlife, and Vegetation, Resource Report 4—Cultural Resources, Resource Report 5—Socioeconomics, Resource Report 6—Geologic Resources, Resource Report 7—Soils, Resource Report 8—Land Use, Recreation, and Aesthetics, and Resource Report 9—Air and Noise Quality.

Resource Report 10—Alternatives describes possible system and siting alternatives as well as a "No Action or Postponed" alternative. Resource Report 11—Reliability and Safety describes the design, construction, operation, and maintenance measures that will be implemented for the Project to minimize potential hazards to the public from failure of the proposed components as a result of accidents or natural catastrophes. Resource Report 12—PCB Contamination, pertaining to polychlorinated biphenyls (PCBs), is not applicable because the Project does not involve the removal, replacement, or abandonment of PCB-contaminated facilities. Resource Report 13—Engineering and Design Material provides detailed descriptions of the Project terminal facilities.

[1] The Terminal and Pipeline are proposed at the site, and along the route, of Oregon LNG's proposed LNG import terminal and proposed pipeline that currently are pending before the Federal Energy Regulatory Commission (FERC) in Docket Numbers CP09-6-000 and CP09-7-000, as amended in Docket Number PF12-18-000.

[2] A separate application will be filed by Northwest for the Washington Expansion Project to expand capacity of Northwest's existing natural gas transmission facilities along the Interstate 5 corridor in the state of Washington.

1.0.2 Regulatory Compliance

The Project will be constructed and operated in compliance with applicable federal, state, and local regulations. As required by 18 *Code of Federal Regulations* [CFR] 380.12, Oregon LNG has prepared this Environmental Report (ER) in support of its Application under Section 3 of the Natural Gas Act (NGA) for authorization to site, own, and construct the Terminal, and under Section 7 of the NGA for a Certificate of Public Convenience and Necessity for the Pipeline. The data for the Resource Reports have been compiled based on comprehensive field surveys, review of United States (U.S.) Geological Survey (USGS) topographic maps, National Wetlands Inventory maps, recent aerial photographs, consultation with appropriate federal, state, and local agencies, and other stakeholder outreach activities.

1.1 Project Overview

Described below are (1) the Import Project as originally proposed in Docket Numbers CP09-6-000 and CP09-7-000, (2) the Export Project as more recently proposed in Docket Number PF12-18-000, and (3) the associated modifications and additions to the Import Project that convert it into the Bidirectional Project.

1.1.1 Import Project

As initially proposed, the Import Project consisted of an onshore LNG receiving terminal in Warrenton, Oregon, and associated facilities and a 121-mile, 36-inch-OD mainline natural gas pipeline, referred to as the Oregon Pipeline, that would have interconnected at the Molalla Gate Station (near Molalla, Oregon) with other natural gas pipelines. As proposed in 2008, the Oregon Pipeline would have been routed through Clatsop, Tillamook, Columbia, Washington, Yamhill, Marion, and Clackamas counties in Oregon. The Import Project is described in *Environmental Report (Exhibit F/F-I), Oregon LNG Terminal and Oregon Pipeline Project, Warrenton, Oregon* (Oregon LNG, 2008) submitted with the October 10, 2008, application currently pending before FERC (Docket Numbers CP09-6-000 and CP09-7-000).

1.1.2 Export Project

The Export Project consists of the addition of liquefaction trains and associated support facilities at the LNG terminal in Warrenton, Oregon; approximately 39 miles of new pipeline (New Pipeline Segment) beginning at MP 47.5 of the Oregon Pipeline and terminating at the Northwest Pipeline Interconnect (NPI) near Woodland, Washington; and an electrically driven gas compressor station (Compressor Station) at approximately MP 81 of the New Pipeline Segment. As proposed, the New Pipeline Segment will be routed through Tillamook, Washington, and Columbia counties in Oregon, and Cowlitz County in Washington. The Export Project is described in the prefiling draft Resource Reports submitted to FERC in August 2012 (Docket Number PF12-18-000).

1.1.3 Modifications to Import Project

The Bidirectional Project modifies the Import Project through the reduction of vaporization capability, elimination of one of the LNG storage tanks, and modification of LNG spill containment and collection systems, fire protection gas detection and safety systems, stormwater treatment system, ground improvements and foundations, piping, pipe racks, electrical systems, control systems, utilities, telecommunications, structures, access road, and other supporting systems. The Bidirectional Project eliminates approximately 75 miles of the Oregon Pipeline from MP 47.5 to MP 121, the meter station in Molalla, and the 10-mile Northwest Natural Lateral.

1.1.4 Bidirectional Project

The Bidirectional Project consists of marine facilities, LNG storage tanks, LNG vaporization facilities, natural gas liquefaction facilities, and associated support facilities to be constructed at the Terminal site in Warrenton, Oregon; approximately 86.8 miles of pipeline from the Terminal to the NPI near Woodland, Washington; and a Compressor Station at MP 80.8. The Pipeline will be routed through Clatsop, Tillamook, and Columbia counties in Oregon, and Cowlitz County in Washington. The location of the Terminal is shown in Figure 1.1-1; the Pipeline route is shown in Figure 1.1-2; the Compressor Station plot plan is shown in Figure 1.1-3. (The figures referenced in the main text of this Resource Report 1 are provided together in Appendix 1A.)

The following major components of the Project will be subject to FERC's jurisdiction:

- A marine facility, including a turning basin and one berth for loading and unloading LNG carriers (LNGCs)
- Pretreatment facilities to remove sulfur compounds, water, and mercury from natural gas before liquefaction
- Liquefaction facilities
- Refrigerant storage
- Flare system
- Interconnecting facilities consisting of piping, electrical, and control systems
- An LNG spill containment and collection system
- Two full-containment LNG storage tanks, each with a nominal usable storage capacity of 160,000 cubic meters (m^3)
- A vapor handling, regasification, and sendout system
- Utilities, telecommunications, and other supporting systems
- Administrative offices, a control room, warehouse, security, and other buildings and enclosures
- Interconnecting roadways and civil works
- Water intake on the Columbia River (River Water Pump Station) and water delivery pipeline from the intake to the water treatment system
- Deluge firewater system that draws from the Skipanon River
- Water treatment system
- Pipeline
- Appurtenant, auxiliary facilities necessary for the Pipeline, including the Compressor Station at MP 80.8, existing and new access roads, metering and regulating facilities, corrosion protection systems, pigging facilities, and mainline valves

The following major components of the Project are nonjurisdictional:

- Electrical facilities for the Terminal
- Electrical facilities for the Compressor Station

- Water and wastewater pipelines from and to the City of Warrenton Publicly Owned Treatment Works (POTW)

1.1.5 LNG Safety and Security

LNG—primarily composed of methane—is odorless and nontoxic and is produced by supercooling natural gas to minus 260 degrees Fahrenheit (–260°F) at atmospheric pressure. When exposed to ambient heat sources such as water or soil, LNG vaporizes rapidly. LNG will generally produce 620 to 630 standard cubic feet of natural gas for each cubic foot of liquid when released from its containment vessel and/or transfer system. A large quantity of LNG spilled without ignition would form a vapor cloud that would travel with the prevailing wind until it either dispersed below the flammable limits or encountered an ignition source. If a large quantity of LNG is spilled in the presence of an ignition source, the resulting pool fire would produce high levels of radiant heat in the area surrounding the LNG pool.

LNG's principal hazards result from its cryogenic temperature (–260°F), flammability, and vapor dispersion characteristics. In a liquid state, LNG will neither burn nor explode. Although it can cause freeze burns and, depending on the length of exposure, more serious injury or death, its extremely cold state does not present a significant hazard to the public, which rarely, if ever, comes in contact with it as a liquid. As a cryogenic liquid, LNG will quickly cool materials it contacts, causing extreme thermal stress in materials not specifically designed for ultra-cold conditions. Such thermal stresses could subsequently subject the material to brittleness, fracture, or other loss of tensile strength. These hazards, however, are not substantially different from the hazards associated with the storage and transportation of liquid oxygen (–296°F) or several other cryogenic gases that have been routinely produced and transported in the United States.

The U.S. Government Accountability Office (GAO) released a report in February 2007, *Maritime Security*, that presents a survey of experts in areas related to LNG risks, hazards, and consequence modeling. As described in Appendix III of the GAO Report, the 19 LNG risk and hazard experts unanimously agreed that rapid phase transition "would be very unlikely to have a direct effect on the public." Methane vapors, the primary component of natural gas, are colorless, odorless and tasteless, and are classified as a simple asphyxiant. Methane vapors may cause extreme health hazards, including death, if inhaled in significant quantities within a limited time. Although very cold methane vapors may cause freeze burns, any cloud resulting from an LNG spill would continuously mix with the warmer air surrounding the spill site. Dispersion modeling indicates that the majority of the cloud would generally be within 25°F of the surrounding atmospheric temperature, with colder temperatures closest to the spill source. In addition, this modeling estimates that most of the cloud would be below concentrations resulting in oxygen deprivation effects, including asphyxiation, with the highest methane concentrations closest to the spill source. Therefore, asphyxiation and freezing normally represent a negligible risk to the public from LNG facilities. Also as presented in Appendix III of the GAO Report, the 19 LNG risk and hazard experts unanimously agreed that asphyxiation would represent a negligible risk to the public.

LNG thermal radiation and flammable vapor exclusion zone calculations are presented in Resource Reports 11 and 13. Resource Report 11 provides details on concentrations of methane in air at particular distances and also heat flux from a fire at particular distances. A vapor dispersion calculation was performed for LNG spills into the unloading line trough and the sendout line trough for the proposed Terminal (Appendix 11A in Resource Report 11). The calculations performed indicate that the ½ lower flammability limit concentration vapor cloud generated as a result of a design spill into either the unloading line trough or the sendout line trough would not extend beyond the Oregon LNG Terminal boundaries. The U.S. Coast Guard will establish a moving security zone around inbound LNGCs beginning as each vessel passes the Columbia River Buoy and continuing to the dock. The U.S. Coast Guard will require two or three security escort boats. The security zone will limit how close another vessel will be allowed to come in proximity to a inbound or outbound LNGC. During the busiest fishing seasons, inbound LNGCs will be limited to night transits (between approximately 6 p.m. and 5 a.m.).

1.2 Purpose and Need

1.2.1 Purpose

The Bidirectional Project will facilitate the reexport of Canadian-sourced natural gas (and to a lesser extent, the export of U.S.-sourced gas from the Rocky Mountain region) to foreign markets as well as facilitate the availability of such gas supplies for delivery to Pacific Northwest markets, including the Portland metropolitan area. The Project may serve as a peaking gas resource to help manage this regional demand, especially given the absence of significant regional natural gas storage. The Project will also enable the delivery of gas to isolated U.S. markets in need of supply, including Hawaii and coastal Alaskan communities. Moreover, the bidirectional nature of the Project will help ensure that should current market conditions of oversupply change in the future, there will be a means for importing and revaporizing foreign-sourced LNG for consumption in U.S. markets. For the foreseeable future, however, it is more likely that the liquefaction and export capabilities of the Project will be utilized. While the Project is proposed to export primarily Canadian-sourced natural gas, the Project will interconnect with the multi-legged Northwest system connecting Pacific Northwest demand centers with Rockies as well as British Columbian supplies. However, Oregon LNG does not expect that the gas feedstock for the Export Project will be derived to any significant degree from Rockies supply given the relative economics of Canadian supply at the present time and through the relevant forecasted period.

1.2.1.1 Domestic Benefits

The Project presents various benefits to the public, including the much-needed expansion of market scope and access for North American natural gas producers at times when neither U.S. nor Canadian gas prices support continued production. Analysts have expressed concern that the Canadian gas storage levels may reach capacity in 2013, potentially affecting U.S. natural gas prices as Canadian producers attempt to move surplus gas across the border to the United States.

The Project will create jobs and increase domestic economic activity and tax revenues, both directly and indirectly. Direct economic benefits to both the Pacific Northwest regional and local economies are quantified in the report Oregon LNG commissioned from ECONorthwest and included as Appendix 5A to Resource Report 5—Socioeconomics, entitled *An Economic Impact Analysis of the Oregon LNG Project in Northwest Oregon* (ECONorthwest Report) (ECONorthwest, 2012). During the construction phase, there will be an average of 10,438 direct, indirect, and induced jobs created through the Project. This translates into approximately $4,238 million (or $4.238 billion) in wages and benefits to U.S. workers over the 5 year construction period (ECONorthwest, 2012, page 16, Tables 8 and 9). Once operational, the Project will support an estimated 643 jobs in Clatsop County or a total of 1,591 jobs when indirect and induced, new jobs elsewhere in Oregon and Washington are included. This translates into total annual labor incomes of $46.5 million and $102.5 million, respectively (ECONorthwest, 2012, page 18, Tables 11 and 12).

Another direct benefit of the Project will be the expansion of existing pipeline infrastructure in the Pacific Northwest to transport Canadian natural gas across the State of Washington to the Oregon Pipeline interconnection in Woodland, Washington. Expansion of the Williams system is required to accommodate the additional transportation volumes to the Project and is estimated to add approximately $700 million in construction revenues and an estimated 1,854 additional direct, indirect, and induced construction jobs to the Washington state economy over a 4-year period.

1.2.1.2 Global Benefits

On a global scale, the Project is uniquely positioned to advance the security interests of the United States and its allies through a more proactive role in the international natural gas market. In serving markets in Asia, which is the targeted region for the Project, the Project will play an important role in furthering America's geopolitical interests by enhancing the diversity of global natural gas supply in Asia and advancing the principles of liberalized global natural gas markets. Moreover, the Project will serve to reinforce the U.S. trade relationship with Canada, which is among the closest and most extensive trade markets in the world as reflected in the staggering volume of bilateral trade (the equivalent of $1.6 billion a day in goods) (U.S. Department of State, 2012). Finally, because of the forecasted long-term LNG price differential between North American and Asian LNG markets, exports from the Project are projected to result in a net improvement to the balance of trade for the United States of up to $4.5 billion for a 25-year period, even after taking into account the cost of gas imports from Canada.

1.2.1.3 North American Natural Gas Supply

Western Canada

The vast majority of the natural gas feedstock for the Project would come from resources in Western Canada. The latest data concerning production and reserves from this region show that there will be an abundant supply of natural gas for the Project. As indicated in the *Oregon LNG Export Project Market Analysis Study* (Navigant Report), the Province of British Columbia has planned an increase in production from 1.2 trillion cubic feet per year (Tcf/y) to over 3.0 Tcf/y in 2020 to supply three new proposed LNG export facilities and to accommodate a diversification of its gas markets (Navigant, 2012, page 14). Short-term historical trends show an increase in production as well. Natural gas production in British Columbia for February 2012 was 122.6 billion standard cubic feet (Bscf) (4.23 Bscf/d), up from 111.5 Bscf (3.98 Bscf/d) in February 2011 (British Columbia Ministry of Energy, 2012).

Recoverable natural gas reserves in Western Canada can support the demand from the Project. The most recent data indicate that a minimum of 372 Tcf resides in Western Canada's largest natural gas reserve, the Horn River Basin (Navigant, 2012, page 15). Including the other two major resources on the Horn River, the Cordova Embayment and the Liard Basin, the total reserves are estimated at 448 Tcf (Navigant, 2012, page 15). Estimates of marketable gas from the Horn River range from 90 to 200 Tcf (Navigant, 2012, page 15). Recoverable gas estimates from the other major reserve in British Columbia, the Montney play, range from 65 to 221 Tcf (Navigant, 2012, page 15). In 2009, British Columbia consumed approximately 386 Bscf of natural gas (Navigant, 2012, page 15). Assuming a steady level of demand and the most conservative reserve estimates, the two major gas resources could support British Columbia's demand for over 400 years, even without tapping the tremendous reserves recently discovered in the Liard Basin. Given the intention of British Columbia to increase exports, this results in a more than adequate supply of gas for the Project.

United States

Domestic production and reserves collectively provide for an abundant domestic supply of natural gas. Domestic gas production has been on an upward trend in recent years, allowing the United States to transition from a net importer to a net exporter of natural gas (U.S. Energy Information Administration [EIA], 2012a). According to the EIA, shale gas production in the United States reached 4.87 Tcf in 2010, or 23 percent of U.S. dry gas production (EIA, 2011a). By 2035, the EIA estimates that shale gas will account for 46 percent of total domestic natural gas production (EIA, 2011a).

There have been a number of reports and studies that attempt to identify the total amount of technically recoverable shale gas resources (i.e., gas retrievable using current technology irrespective of cost) available in the United States. These estimates vary from 482 Tcf (EIA, 2012b, 9)[3] of shale gas to 842 Tcf (Navigant, 2012, page 3). To put these numbers in context, the United States is projected to consume nearly 25.20 Tcf of gas in 2012 (EIA, 2012a, Table 13),[4] suggesting that the estimates for the shale gas resource alone would be enough to satisfy between approximately 20 and 35 years of U.S. domestic demand.

Available data point to continued growth in domestic production in 2011.[5] EIA estimates U.S. dry gas production totaled 2.00 Tcf (64.6 Bscf/d) in March 2012, a 2.7 Bscf/d increase compared to March 2011 dry production of 1.92 Tcf (61.9 Bscf/d) (EIA, 2012d). Increased drilling productivity has enabled domestic production to continue expanding despite a reduction in upstream industry development.

1.2.1.4 National Natural Gas Demand

As evidenced by the plummeting U.S. natural gas price,[6] domestic natural gas demand continues to be outpaced by the available supply. Over the past decade, the United States has experienced essentially no growth in demand for natural gas. EIA predicts long-term annual gas demand growth of only 0.4 percent, with the domestic market expected to reach 26.63 Tcf (72.9 Bscf/d) in 2035 (EIA, 2012a, Table 13). EIA predicts U.S. natural gas consumption of 25.39 Tcf (69.6 Bscf/d) in 2015, or growth of only 14 percent from the 1998 benchmark (22.24 Tcf) (EIA, 2011c and 2012e). U.S. demand in 2012 of 25.20 Tcf represents a mere 8 percent increase from the 23.33 Tcf consumed in 2000, according to EIA data (EIA, 2011c and 2012e).

1.2.2 Need

From a regional perspective, the Navigant Report (2012) highlights not only the feasibility, but the need for the Project. First, with projections of Canada maintaining its status as a net exporter of natural gas to the United States, a regional analysis indicates that cross-border flows into the Pacific Northwest consist solely of imports from Canada, confirming the feasibility of obtaining Oregon LNG's exports from burgeoning Western Canadian supplies. In fact, historical data show that natural gas flows from Canada into the U.S. Pacific Northwest have averaged about 340 MMcf/d at Sumas and almost 750 MMcf/d from Kingsgate into Idaho over the last 15 years, on an annual average basis. Second, the situation in Eastern Canada is one where Canada is forecast to be a net importer of U.S. supplies, for the entire forecast term, as a result of burgeoning U.S. gas production from the Marcellus. The benefit to Oregon LNG of this regional supply shift is that Eastern Canadian market imports from the United States lessen competitive demand for Western Canadian supplies, ensuring Western Canadian supply availability for the Project. The benefit to the Western Canadian producing sector is that the Project provides an additional demand that is needed to support Western Canadian natural gas development and further enhancing price stability over the long term. Thus, the ample Canadian and U.S. supply resources are both important for the Project. Navigant forecasts that Western Canadian supplies will be, for the most part, the feedstock for Oregon LNG exports and that

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3 In the *Annual Energy Outlook 2012 Early Release Overview* (EIA, 2012b) and the *Annual Energy Outlook 2012 with Projections to 2035* (EIA, 2012a), the Reference Case estimate of unproven shale gas resources was lowered to 482 Tcf from the estimate of 827 Tcf in the *Annual Energy Outlook 2011 with Projections to 2035* (EIA, 2011b). This lowered estimate is a matter of considerable controversy and concern expressed by industry and other experts in the Marcellus shale.

4 Available at http://www.eia.gov/oiaf/aeo/tablebrowser/#release=AEO2012&subject=8-AEO2012&table=13-AEO2012&region=0-0&cases=ref2012-d020112c.

5 Lower 48 states wellhead natural gas production increased in the five consecutive months, from December 2009 to May 2010, according to EIA's Form 914 Survey of U.S. natural gas producers (EIA, 2012c).

6 Natural gas spot prices averaged $1.95 per million metric British thermal units (MMBtu) at the Henry Hub in April 2012, down $0.23 per MMBtu from the March 2012 average and the lowest average monthly price since March 1999, which also was the last time the Henry Hub price averaged less than $2 per MMBtu (EIA, 2012e).

the ramping up of U.S. resources, particularly from the Marcellus, will help enhance the availability of Western Canadian supplies that would otherwise have been delivered to Eastern Canadian and Northeastern U.S. markets (Navigant, 2012, pages 8–9).

1.3 Project Location and Description

The locations of the proposed Project facilities were chosen according to selection criteria that included, but were not limited to, the following factors (see Resource Report 10 for more discussion of site selection criteria and alternatives):

- Public safety
- Operational safety
- Environmental factors
- Marine access
- Proximity to existing gas pipeline systems and consumers
- Minimization of impacts on other land uses

1.3.1 Terminal

The Terminal will be located on the northern portion of the East Bank Skipanon Peninsula (ESP) near the confluence of the Skipanon and Columbia Rivers in Warrenton, Clatsop County, Oregon, at River Mile 11.5 of the Columbia River. The Terminal location is shown in Figure 1.1-1.

The Terminal's location was selected to minimize the Project's environmental impacts, particularly air emissions, water usage, and potential fisheries resources impacts. The Terminal is sited on land that is appropriately zoned for industrial use, is on an existing deepwater channel, and is relatively close to major natural gas pipeline networks and markets. As discussed below, the Terminal will be located on the shoreland areas of the ESP, which are zoned Water Dependent Industrial Shorelands I-2. The marine facilities are proposed in areas that are zoned Aquatic Development A-1.

Oregon LNG obtained its interest in the 96-acre Project site through an Upland Lease Agreement dated November 2004 (the Lease) between the State of Oregon, acting through the Oregon Department of State Lands, and the Port of Astoria. In a Sublease Agreement, also dated November 2004 (the Sublease), the Port of Astoria subleased the property to Skipanon Natural Gas, LLC, the predecessor-in-interest to Oregon LNG. The commercial terms of the payment obligations under the Sublease are predicated on the subject property consisting of a 96-acre site. Moreover, the site is generally referenced by Oregon LNG (including throughout this Application) as comprising 96 acres. As a point of clarification, a subsequent land survey has shown that the land portion of the Project site comprises 88.7 acres above the line of the mean high water line (4.1 feet National Geodetic Vertical Datum). The exact size of the ESP varies based on accretion or erosion of some of the low-lying wetlands, which are part of the Lease and Sublease but not impacted by planned construction activities.

On December 5, 2008, Oregon Department of State Lands filed in Docket Number PF07-10-000 documentation with the Commission establishing that the State of Oregon is the unequivocal and sole owner of the 96-acre site subleased by Oregon LNG from the Port of Astoria.

The Terminal will be designed with a nominal 9.0 million MTPY liquefaction rate at base conditions and assuming an average annual availability of 95 percent to allow for scheduled and unscheduled maintenance. Assuming a heating factor of 1,000 British thermal units, this is equivalent to the liquefaction of approximately 1.25 Bscf/d of pretreated natural gas. However, the facilities will be able to operate at a liquefaction rate of up to 9.6 MTPY at times when favorable operating conditions combine with higher operating availability as a result of lower scheduled and unscheduled maintenance losses. The Terminal will be designed with a natural gas sendout capacity of 0.5 Bscf/d.

Figure 1.3-1 illustrates the layout of the Terminal and its operational footprint. Figure 1.3-2 shows the Terminal construction area, including the LNGC berth and turning basin.

The Terminal facilities are described in the following subsections:

- 1.3.1.1 Liquefaction Facilities
- 1.3.1.2 LNG Storage Tanks
- 1.3.1.3 Regasification Facilities
- 1.3.1.4 Vapor Handling System
- 1.3.1.5 Piping
- 1.3.1.6 LNG Transfer Lines
- 1.3.1.7 Control Systems and Safety Systems
- 1.3.1.8 Utilities
- 1.3.1.9 Terminal Firewater System
- 1.3.1.10 Terminal Stormwater Treatment
- 1.3.1.11 Buildings
- 1.3.1.12 LNG Impoundments
- 1.3.1.13 Marine Facilities

1.3.1.1 Liquefaction Facilities

The liquefaction facilities will consist of two identical Air Products & Chemicals, Inc. (APCI) liquefaction trains of 4.5 MTPY each, for an overall nominal liquefaction rate of up to 9.0 MTPY, which assumes an average annual availability of 95 percent to allow for scheduled and unscheduled maintenance. Each liquefaction train will include a heavy hydrocarbons removal unit.

Each liquefaction train will contain the following equipment:

- Propane compressor
- Low-pressure mixed refrigerant (MR) compressor
- Medium-pressure/high-pressure MR compressor
- Propane compressor variable frequency drive
- Low-pressure MR compressor variable frequency drive
- Medium-pressure/high-pressure MR compressor variable frequency drive
- Propane compressor motor
- Low-pressure MR compressor motor
- Medium-pressure/high-pressure MR compressor motor
- Scrub column
- Scrub column overheads separator
- Main cryogenic heat exchanger (MCHE) start-up drum
- Propane accumulator
- Propane reclaimer
- Low-pressure propane drum
- Medium-pressure propane drum
- High-pressure propane drum
- High high-pressure propane drum
- Propane collection drum
- High-pressure MR separator

- Low-pressure MR drum
- Medium-pressure MR drum
- High-pressure MR drum
- High high-pressure propane feed gas cooler
- High-pressure propane feed gas cooler
- Medium-pressure propane feed gas cooler
- Low-pressure propane feed gas cooler
- Scrub column reboiler
- Scrub column condensate cooler
- MCHE
- Defrost gas heater
- Propane desuperheater
- Propane condenser
- Propane reclaimer condenser
- Propane subcooler
- High high-pressure propane MR cooler
- High-pressure propane MR cooler
- Medium-pressure propane MR cooler
- Low-pressure propane MR cooler
- Low-pressure MR compressor intercooler
- Medium-pressure MR compressor intercooler
- High-pressure MR compressor aftercooler
- LNG expander driven generator
- MR expander driven generator
- Scrub column overheads pump
- LNG expander
- Propane transfer pump
- MR expander

Process Description. The process systems installed at the Terminal will include the following equipment as illustrated in Figure 1.3-1:

- Feed gas pretreatment
- Natural gas liquids removal facilities including storage and handling
- Liquefaction facilities including refrigerant storage and handling
- Cooling facilities including convection cooling towers
- In-tank low-pressure LNG sendout pumps—to send LNG to LNGC

Natural gas that arrives at the Terminal will first be treated at a feed gas pretreatment facility at the Terminal to make it suitable for liquefaction.

The pretreated natural gas will then be liquefied at the Terminal via two identical liquefaction trains. Each liquefaction train will include a heavy hydrocarbons removal unit. Subcooled LNG produced in these trains will flow into two 160,000-cubic-meter (m^3) aboveground, full-containment LNG storage tanks.

The liquefaction technology will be APCI propane-precooled MR (C3-MR), which entails two refrigeration cycles to precool and liquefy the natural gas feed.

First, the natural gas feed will be precooled using propane refrigerant at descending pressure levels and corresponding lower vaporization temperatures. After being cooled by the propane refrigeration, the feed gas will enter the MCHE where subcooled LNG will be produced by cooling and liquefying of natural gas against the MR. Subcooled LNG leaving the MCHE will then be depressurized and further cooled through LNG liquid turbines. LNG at approximately 50 pounds per square inch gauge (psig) will flow to the LNG storage tanks.

Process cooling will be provided by cooling water, cooled in an evaporative cooling tower.

Electric motors will drive the propane and MR compressors.

Liquefaction Operating Modes. Natural gas will be continuously liquefied with or without ship loading operations.

When there are no LNGC loading operations occurring, a portion of the LNG from the liquefiers will circulate through a small-diameter circulation line to the marine facility and back through the LNG transfer pipeline to the LNG storage tanks in order to keep these piping systems cold.

Feed Gas Pretreatment. Natural gas will be treated at a feed gas pretreatment facility that will consist of the following components:

- An amine gas sweetening system to remove carbon dioxide (CO_2) and sulfur compounds from the natural gas
- A molecular sieve dehydration system to remove water down to very low levels acceptable for the design and operation of the cryogenic heat exchanger
- A mercury removal unit to protect downstream aluminum equipment from damaging corrosion mechanisms

The following features characterize the feed gas pretreatment process:

- The pretreated feed gas will be delivered to the liquefaction facilities via the natural gas pipeline at 815 pounds per square inch absolute (psia) and 100°F, where it will be liquefied via the two identical liquefaction trains.
- A scrubber column located upstream of the MCHE will be used to remove heavy components, mercaptans, and benzene, toluene, and xylene (BTX) from the feed gas before liquefaction.
- Liquid turbines will be used on the LNG letdown downstream of the MCHE outlet and heavy MR liquid letdown in the middle of the MCHE's shell.
- Backpressure of the liquid turbines' outlet for the LNG downstream of the MCHE will be 50 psig to allow sufficient head for the LNG to enter the LNG storage tanks.
- Subcooled LNG will be below the bubble point temperature at the tanks' pressure at the inlet of the LNG storage tanks.
- Backpressure of the liquid turbines' outlet for the heavy MR liquid letdown will be at the minimum two bars above the bubble point to ensure no vapor is formed in the liquid turbines. The remaining pressure drop will be taken across a control valve.
- Gas will enter the plant from the Oregon Pipeline at approximately 875 psig. This gas will be routed to two, 50 percent capacity amine gas sweetening trains. These parallel trains will treat the gas to meet carbon dioxide, hydrogen sulfide, water, and mercury content specifications for the liquefaction process.
- Each amine gas sweetening train will consist of a trayed amine contactor tower where carbon dioxide and sulfur components in the gas will be adsorbed in a circulating liquid amine solution.

Treated water saturated gas from the amine trains will flow through a particulate filter and then through multiple, parallel dehydrator vessels.

- The circulating amine mixture will be a closed loop system. Contacted amine will be regenerated in the trayed regenerative tower, where contaminants will be essentially boiled off and exit the tower as an overhead vapor. Regenerated amine will recirculate back to the contactor tower for reuse.
- Dehydration of the water-saturated, sweetened gas will be achieved through the use of molecular sieve dehydration beds. Treated gas will circulate through the packed sieve beds, which will absorb most of the water from the gas. The molecular sieve beds will continuously regenerate through a sequential online, regeneration, standby scheme that provides process assurance and controlled availability.
- Dry, sweetened gas will then pass through multiple, consumable parallel carbon beds for the removal of any mercury in the gas. The carbon beds cannot be regenerated, so it will be necessary to replace them after a design life of several years.
- Sweetened, dry, mercury-free gas will flow through two final particulate filters in series and a pressure control valve to the inlet of the Terminal LNG liquefaction process at approximately 815 psia and 100°F.

Described below are the byproducts of the feed gas pretreatment process and how they will be disposed of, recycled, or reused:

- Liquid Wastes
  - Slop liquids (regeneration gas separator) are mainly water and produced at 4,500 gallons per day, so they will be disposed of through a National Pollutant Discharge Elimination System (NPDES) permit.
  - Slop liquids (inlet separator/pig liquids and amine skim liquids) are expected to be contaminated with natural gas liquids, lube oil, triethylene glycol, and amine solvent and are minimal in amounts and infrequently generated. These wastes will be collected and disposed of as a liquid waste, after waste characterization.
- Solid Wastes
  - Mercury removal bed media consists of activated carbon contaminated with mercury. Depending on the mercury concentrations and what is acceptable to a regeneration facility, the carbon may be sent to a regeneration facility. If concentrations are too high, the mercury may not be acceptable to a regeneration facility, may fail the hazardous waste characteristic for mercury, and may need to be sent for mercury retorting as required by the hazardous waste land disposal restrictions.
  - Molecular sieve bed media is spent zeolite and may be regenerated, depending on the zeolite system design. Otherwise, the zeolite may need to be analyzed to determine if it is contaminated enough to fail the hazardous waste characteristic for mercury.
  - Amine particulate filter elements, amine carbon filter elements, and gas particulate filter elements will be analyzed to determine if they fail a hazardous waste characteristic or can be disposed of as a solid waste.
  - Hot oil filter elements may qualify for an exemption from being managed as a hazardous waste if they are crushed and hot drained and then sent for recycling as discussed in 40 CFR 261.4(b)(15) and Oregon Administrative Rule 340-111-020.

- Ion exchange (water treating) resin—the ion exchange resin required for producing demineralized makeup water to the amine is assumed to be regenerated offsite.

Mixed Refrigerant Compressors. The load between the MR compressors will be approximately equally split. The refrigeration compressors will be centrifugal type.

Flare System. The Terminal will be designed to minimize fugitive emissions with no flaring during all normal operations using a closed vent/drain system. All LNG and natural gas relief valves (excluding the LNG storage tank, fuel gas drum, and LNG vaporizer process relief valves) will be vented into a closed vent flare system that is common with the LNG storage tank vapor spaces.

Releases in the liquefaction trains during an operation upset or train start-up will be sent to a closed dry gas flare system. The following will be the basis of the liquefaction flare design:

- Initial dry-out and cool-down of a single train
- Maximum emergency release during operation of the LNG trains

The design drawings for the new ground flare system are provided in Appendix 1B.

Cooling Media. An average of 4.5 million gallons per day (mgd) of treated water will be required to provide cooling water makeup to the cooling tower and pretreatment facilities. Cooling water specifications will be as follows:

- Cooling process: evaporative cooling water tower
- Design supply temperature: 68°F
- Return temperature: 83°F
- Design wet-bulb/dry-bulb ambient temperature: 62°F/68°F
- Assumed cooling water concentration ratio: up to 20 cycles
- Approximate recirculation rate: 275,000 gallons per minute (gpm)

Other Design Considerations. A tank pressure maintenance system will be provided to prevent vacuum conditions from occurring during normal operation. A vacuum relief system will be installed on each tank and will be sized for the worst-case conditions.

The heat leak into the LNG storage tank will give a maximum boiloff of 0.05 percent per day at 68°F ambient temperature, based on pure methane and a full tank.

Instrumentation will be provided for continuous level, temperature and density measurements throughout the level of the tank inventory to monitor for stratification of the tank contents. Features will be provided in the design to rapidly circulate the stored LNG to thoroughly mix the contents, should stratification start to develop.

1.3.1.2 LNG Storage Tanks

Two aboveground LNG storage tanks will be installed at the Terminal. Each tank will have a nominal usable storage capacity of 160,000 m^3 and will be a full-containment design consisting of an inner 9 percent-nickel steel tank and an outer concrete tank. The outer concrete tank will be sized to contain 110 percent of the volume of the inner tank.

The LNG storage tanks will have a base elevation of 0 feet (North American Vertical Datum [NAVD] 88) and will be surrounded by the perimeter earthen berm. Mean sea level (msl) at the Terminal site is equal to 4.51 feet (NAVD 88); therefore, the base of the tanks will be 4.51 feet below msl. The crest of the earthen berm varies in elevation between 22 and 27 feet to prevent inundation of the site from a tsunami. A concrete wall has been added to the LNG storage tank bottom slab to separate groundwater from surface water. No permanent dewatering of groundwater is needed to maintain stability of the LNG storage tanks. The site grading inside the earthen berm slopes from just below the top of the LNG storage tank bottom slab wall at elevation 9.5 feet to the toe of the earthen berm at elevation 7.7 feet. A drainage layer will be added beneath the finished crushed rock layer and connected to the surface water collection system. The foundation piles will have sufficient additional capacity to accommodate the uplift forces at the bottom of the slab. Drawing 07902-DG-000-200 in Appendix 1B shows a cross-section of the earthen berm.

The height of each LNG storage tank will be approximately 190 feet. As described above, the ground elevation of the storage tanks will be 4.51 feet below msl; therefore, the elevation of the top of each tank will be approximately 185.5 feet above msl. The LNG storage tanks thus exceed obstruction standards set by the Federal Aviation Administration (FAA). To determine the potential effects of the tanks on the safe and efficient use of navigable airspace by aircraft and on the operation of air navigation facilities, the FAA is conducting an aeronautical study under the provisions of 49 *United States Code* Section 44718 and 14 CFR 77.

Each LNG storage tank will include:

- Two 100 percent duty in-tank LP LNG sendout pumps
- Pressure and vacuum relief systems
- Level, pressure, temperature, and density monitoring equipment
- Access platforms, stairways, cranes, and hoists.

There will be no penetrations through the tank inner container, outer container sidewall, or tank bottom. Piping into and out of the tank inner or outer containers will enter from the top of the tank.

When LNG is imported, it will be unloaded from LNGCs at a maximum rate of 14,000 m^3/hr into two aboveground LNG storage tanks.

1.3.1.3 Regasification Facilities

The Terminal will be capable of unloading LNG from LNGCs into the LNG storage tanks. The Terminal will be designed with a natural gas sendout capacity of 0.5 Bscf/d and will use a vaporization system consisting of shell and tube heat exchangers. The heat exchangers will employ an ethylene glycol water mixture as an intermediate heat transfer fluid that will be heated via natural gas -fired heaters. Natural gas will be sent to the proposed Pipeline at a temperature of 40°F at the proposed Terminal boundary.

1.3.1.4 Vapor Handling System

Vapor generated during LNGC loading operations will be returned to the proposed Terminal's vapor handling system via a vapor return pipeline and a vapor arm connected to the LNGC.

Vapor displaced from the LNG storage tanks during LNGC unloading operations will be returned to the LNGC via a vapor return pipeline and a vapor arm connected to the LNGC.

All boiloff gas (BOG), including the BOG generated from the heat leak into the LNG storage tanks, pumping systems, and piping systems, and vapor displaced by the incoming LNG to tanks and LNG ship, will be recycled to the liquefaction feed gas system upstream of the MCHE via BOG compressors.

The vapor handling system will include an atmospheric flare system that will be used during abnormal operations (i.e., in the event that the vapor handling system is not functioning correctly or during other emergency situations).

The system will include the following:

- In-tank low-pressure LNG sendout pumps—to send LNG to LNGC or to regasification system
- Regasification system including high-pressure LNG sendout pumps and a vaporization system that consists of shell and tube heat exchangers utilizing a glycol water intermediate heat transfer fluid heated in natural gas-fired heaters
- Vapor handling facilities including BOG compressors and a flare system

1.3.1.5 Piping

Piping will be installed at the Terminal for the following systems:

- LNG
- Natural gas and boiloff gas
- Nitrogen (liquid and gaseous)
- High-expansion foam (concentrate and solution), aboveground and underground
- Dry chemical
- Firewater, aboveground and underground
- Potable water and service water
- Instrument air and plant air
- Heat transfer fluid

Natural gas sendout will commence at the boundary of the Terminal. A metering and regulation station will be installed at the Terminal and will consist of dedicated fiscal-quality flow meters, analyzers, and flow computers. The metering computer and electronics will be located in the main control room. Additionally, a pipeline pig launching station will be located at the Terminal. There will be no natural gas odorization facilities at the Terminal.

Specifications have been prepared for each of the piping systems that will be installed at the Terminal and are described in Resource Report 13.

The use of flanges in cryogenic piping will be minimized. Welded connections will be used except where entry for inspections or maintenance after startup is anticipated or required.

Provisions will be made to allow for the de-inventorying of LNG transfer systems following startup of the Terminal.

LNG headers and dead-headed piping will be provided with a means for maintenance cooling. Piping that serves an intermittent operation will also be provided with a means for maintenance cooling.

Cryogenic pipeline systems will be insulated, and an insulation specification has been prepared and is described in Resource Report 13. The specification scope includes insulation for piping and equipment that contain the following fluids:

- Liquefied natural gas or boiloff gas at cryogenic temperatures as low as −270ºF (−168 degrees Celsius [ºC]). For these fluids, the insulation has been designed to minimize heat leakage into the process fluid and to minimize condensation or freezing of atmospheric moisture onto the insulation outside surface;
- Boiloff gas at temperatures as low as −150ºF (−101ºC). For this fluid, the insulation has been designed to minimize heat leakage into the process fluid and to minimize condensation or freezing of atmospheric moisture onto the insulation outside surface; and

- Fluids in general with temperatures as low as 32ºF (0ºC) that operate below ambient temperatures. For these fluids, the insulation has been designed to minimize condensation or freezing of atmospheric moisture onto the insulation outside surface.

Specifications have been prepared for each of the piping systems that will be installed at the Terminal and are described in Resource Report 13.

1.3.1.6 LNG Transfer Lines

LNG will be transferred to or from LNGCs to the onshore LNG storage tanks via three LNG loading arms and a single LNG transfer pipeline.

During LNGC loading or unloading operations, a single LNGC will moor at the loading berth and following cooldown of the LNG arms, LNG will be transferred either to the LNGC via the in-tank LNG sendout pumps at a rate of 10,000 m^3/hour, or to the LNG storage tanks via LNG cargo transfer pumps located on the LNGC at a rate that will maintain LNG storage tank pressure within design operating limits. In either operating mode, LNG will flow through a single, 32-inch-diameter LNG transfer pipeline that will connect the LNG arms to the LNG storage tank. When there are no LNGC loading activities during liquefaction operation, a portion of the LNG from liquefiers will circulate LNG through the LNG transfer pipeline via a 6-inch-diameter line to the LNG storage tank(s) in order to keep these piping systems cold. During the regasification mode of operation when the liquefaction facilities are out of service, LNG from the in-tank LNG sendout pumps will be circulated through the LNG transfer pipeline.

1.3.1.7 Control Systems and Safety Systems

A control and safety system will be installed at the Terminal that consists of:

- A plant control and monitoring system
- A hazard detection and mitigation system
- An independent instrumented safety system

The Plant Control and Monitoring System will consist of field instrumentation and a number of microprocessor-based subsystems located in strategically placed control centers throughout the Terminal. Primary operator interfaces will be provided at the main control room and at the platform control room. The control system equipment will be of proven design and operational reliability.

A Hazard Detection and Mitigation System (HDMS) will be installed to continuously monitor and alert the operator of hazardous conditions throughout the Terminal from fire, combustible gas leaks, and low-temperature LNG spills.

The Terminal will have a dedicated stand-alone system for fire, heat, combustible gas, smoke or combustion product, and low-temperature LNG spill monitoring.

Fire and gas detection and protection of offices and other buildings will be networked. These networks will provide common alarms and status information to the HDMS.

An independent Safety Instrumentation System will be installed. The Terminal will have an Emergency Shutdown (ESD) system with shutdown and control devices designed to maintain safe operating conditions. The ESD system will be used for major incidents and will result in either total plant shutdown, shutdown of carrier unloading, shutdown of the sendout system, and/or shutdown of individual pieces of equipment depending on the type of incident.

1.3.1.8 Utilities

Utility and auxiliary systems to support the operation of the Terminal will include the following items:

- Refrigerant component storage and transfer
- Refrigerant cooling systems using cooling water and evaporative cooling towers
- Heavy hydrocarbon disposal
- Mechanical handling systems including fixed cranes and lifting devices
- Sanitary sewer and wastewater treatment
- Storm sewer and disposal
- Waste/oily water collection and treatment system
- Diesel fuel oil storage and distribution
- Ammonia (for control of emissions from gas-fired heating equipment)
- Nitrogen, plant/utility air, and instrument air

1.3.1.9 Terminal Firewater System

A firewater system will be installed at the Terminal and will be a private, freshwater-distributed fire main loop fed via fire pumps from a firewater storage tank. The tank will be filled from the potable water system at a rate of 125 gpm, which will fill the tank in less than 48 hours. The distributed loop will provide firewater to various sprinkler systems, automatic water systems, hydrants, monitors, and other systems as needed. The firewater storage tank capacity will be sufficient to provide water to the largest system demand for 2 hours plus a 1,000-gpm hose stream allowance per the National Fire Protection Association (NFPA) 59A (2001 edition).

In addition, an LNG storage tank deluge system will be installed to protect tanks that would be exposed to heat from a fire involving an adjacent tank. The deluge system will be fed from dedicated pumps (with a maximum total capacity of 18,400 gpm) taking suction from the Skipanon River. The intake structure will be designed using Hydraulic Institute standards to keep salmonid fry from entering the structure. Design criteria include a maximum approach velocity of less than 0.4 feet per second and a maximum screen opening of 1.75 millimeters (mm) in the narrow direction. The screen will have a hydraulically-driven rotating brush system, which will be used periodically to clean the screen. See Figure 1.3-3 for additional information on the intake structure.

The main firewater pumps will consist of two 100 percent fire pumps, one motor-driven and the other diesel-driven, and two electric jockey pumps. The deluge system fire pumps will be diesel-driven with sufficient fuel for 8 hours of operation. Besides possible operation during a fire event, the firewater pumps will only be operated periodically for testing.

In accordance with the requirements of NFPA 25, each of the four diesel-engine deluge fire pumps will be tested weekly for at least 30 minutes, and once a year for approximately 2 hours. During the weekly testing, each pump will withdraw 6,750 gpm from the Skipanon River. Assuming that each pump operates at full flow for a full hour once per week (which conservatively bounds the required 30 minutes for the weekly testing and includes ramp-up and ramp-down), each pump will withdraw 6,750 gpm x 60 minutes = 405,000 gallons. The four pumps will be tested in series; therefore, after each 4-hour test period, the total water usage will be 4 x 405,000 gallons = 1,620,000 gallons. For the annual test, the runtime for each pump is bounded by 2 hours. Accordingly, each pump will withdraw 810,000 gallons (3,240,000 gallons total for four pumps). The pump discharge piping will include valving to direct the pump discharge back into the river. A riprap pad will be used to prevent erosion at the point where the water is discharged. By discharging test water back into the river, the net volume of water removed from the Skipanon River will be minimized.

Additional information about design, construction, operation, and maintenance of the deluge fire suppression system intake structure is provided in Appendix 1B.

1.3.1.10 Terminal Stormwater Management

Stormwater at the Terminal will be managed for use as makeup water for the cooling tower as needed. This includes stormwater from process areas and nonprocess areas within the Terminal berm.

Stormwater from Process Areas. Stormwater that falls onto impervious surfaces in the process areas at the Terminal will be conveyed to the stormwater treatment system, which will consist of a 4,000-gpm oily water separator). The capacity of the stormwater treatment system is based on a 25-year, 24-hour storm event, which produces a 24-hour rainfall total of 5.5 inches, and a runoff coefficient of 0.5. Total estimated stormwater volume produced at the Terminal during this storm event is 3.6 million gallons (MG).

Stormwater that falls within the LNG storage tank containment area will be collected in a sump and pumped to the stormwater treatment system. Stormwater that falls within the LNG process area will generally flow into the LNG impoundment tank, where it will flow into a sump and then be pumped to the stormwater treatment system.

When process area stormwater cannot be directed to the raw water storage tank because it exceeds what can be effectively used for cooling tower makeup water, it will be discharged to the POTW outfall after treatment by the oily water separator.

Stormwater from Nonprocess Areas. Stormwater from the nonprocess areas of the Terminal within the facility berm will not require treatment and will flow by gravity via ditches or will be collected in sumps and pumped to the raw water storage tank. When nonprocess area stormwater cannot be directed to the raw water storage tank, it will be collected in the wastewater sump and then pumped to the POTW outfall.

1.3.1.11 Buildings

The following buildings will be installed at the Terminal:

- Main Control Room
- Platform Control Room
- Administration Building
- Maintenance Workshop and Warehouse Building
- Utilities Building
- Boiloff Gas Compressor Building
- Security Building
- High-Pressure Pump Building
- Heater Building
- Emergency Diesel Building
- Fire Pump House
- Deluge Pump House

The main control room will be permanently manned and will be the center for operational activities. The building will contain the distributed control system, HDMS, and associated instrumentation and control systems. The building will also contain the electrical motor control center room and office space for the operating team.

The platform control room will be manned during LNGC unloading operations, will contain controls necessary for unloading operations, and will contain panels for monitoring the status of the ESD system. The platform control room will be linked via network connections to the main control room for monitoring Terminal operations.

The administration building will include offices for the site management and administrative teams and will also include facilities for training, storage space, and the technical library.

The maintenance workshop and warehouse building will include space for general and clean area workshops and offices for the engineering and maintenance teams. The warehouse will be the central location for consumable items and spare parts.

The utilities building will house instrument air and plant air systems for the Terminal.

The boiloff gas compressor building will house the boiloff gas compressors and vapor return blowers. The building will be a two-story design, with the compressors and vapor return blowers being elevated.

The security building will be located at the entrance to the Terminal and will be occupied by the site security team. The building will include a security control center where security monitoring devices will be located. Direct communications with the main control room and the administration building will be provided. The building will also include a training area where site visitors and contractors can receive safety training before entering the Terminal.

1.3.1.12 LNG Impoundments

The following equipment that will be installed at the Terminal is applicable to the siting requirements from 49 CFR 193 Subpart B and the *NFPA 59A, Standard for the Production, Storage, and Handling of Liquefied Natural Gas (LNG)* (NFPA, 2001 edition):

- Two 160,000 m^3 (net) aboveground full-containment LNG storage tanks
- A marine facility consisting of an unloading platform with a single LNG carrier berth, and a marine cargo transfer system consisting of three LNG unloading arms, a single vapor return arm, and a single LNG transfer pipeline connected to the on-shore facility via a piping trestle
- An onshore regasification process system consisting of in-tank low-pressure LNG sendout pumps, high-pressure LNG sendout pumps, and a vaporization system
- An onshore liquefaction process system consisting of two identical liquefaction trains, refrigerant receiving and handling systems (ethane and propane), and natural gas liquids removal systems

Each LNG storage tank will be a full-containment tank with a primary inner container and a secondary outer container. The tanks will be designed and constructed so that the self-supporting primary containers and the secondary containers will be capable of independently containing the LNG. The primary containers will contain the LNG under normal operating conditions. The secondary containers will be capable of containing the LNG (110 percent capacity of the inner tank) and of controlling the vapor resulting from product leakage from the inner containers.

Although the LNG marine transfer pipeline will be a fully welded design, an LNG spill containment basin will be constructed to contain the volume of an LNG spill resulting from the largest single accidental leakage source in the area flowing for a period of 10 minutes. If LNG spills occur, they will flow along insulated concrete troughs that will be located beneath the LNG transfer pipeline along the length of the trestle and to the LNG storage tanks. A separate LNG spill containment basin will be constructed within the regasification process area and will be sized to contain the largest, single accidental LNG leakage source serving that area flowing for a period of 10 minutes. An LNG spill containment basin will also be constructed within the liquefaction process area that will be sized to contain the largest single accidental leakage source within that area and will also contain any spills occurring in the mixed refrigerant system flowing for periods of 10 minutes each. A swale will be constructed to contain spills occurring within the propane refrigerant system.

1.3.1.13 Marine Facilities

The marine facilities associated with the Terminal are proposed to be located in an adjacent aquatic area of approximately 148 acres. The proposed Project's marine facilities will consist of a single LNGC berth designed to accommodate port-to or starboard-to berthing of LNGCs ranging in size from 70,000 m^3 to 266,000 m^3. The berth will consist of an unloading platform, breasting and mooring structures (i.e., dolphins), interconnecting walkways and access trestle to shore. Breasting dolphins and mooring dolphins will be provided with quick-release mooring hooks for the safe mooring of an LNGC alongside the berth. In addition, the breasting dolphins will be provided with a fendering system to safely absorb the impact energy of the LNGC during berthing. The mooring and breasting dolphins will be connected to the unloading platform by personnel walkways. The unloading platform will have three unloading arms and one vapor return arm, and will support LNG piping, fire fighting, and other safety equipment.

Refer to Drawings 0902-DG-100-800 and -801 in Appendix 1B for an overview of the marine facilities. The component structures are itemized below with reference to drawings provided in Appendix 1B:

- An approximately 2,128-foot-long marine trestle supporting LNG piping and a containment trench, supporting utilities, and an access roadway (see Drawings 07902-DG-100-802 and -803 in Appendix 1B)
- A 124-by-94-foot unloading platform supporting the LNG unloading arms, a platform control room, an LNGC access gangway, a fire tower and monitor, and other supporting piping and equipment (see Drawings 07902-DG-100-804 and -805 in Appendix 1B)
- Four 34-by-24-foot breasting dolphins equipped with marine fenders, quick release mooring hooks, and motorized capstans (see Drawing 07902-DG-100-806 in Appendix 1B)
- Four 18-by-18-foot and two 42-by-18-foot mooring dolphins equipped with quick release mooring hooks and motorized capstans (see Drawing 07902-DG-100-807 in Appendix 1B)
- Interconnecting walkways (see Drawing 07902-DG-100-808 in Appendix 1B)

The berth will be accompanied by an approximately 135-acre turning basin immediately adjacent to the Columbia River Navigation Channel, provided to allow adequate depth for safely navigating to the berth, performing docking and undocking maneuvers, and performing 180-degree turns. The berth and the turning basin are shown in Figure 1.3-2.

Location. The I-2 zone allows water-dependent industrial development, such as an LNG bidirectional terminal facility. One of the allowed uses with the I-2 zone is a "marine cargo transfer facility." The City of Warrenton found that the LNG Terminal's primary use is consistent with that of a marine cargo transfer facility; therefore, it is a permitted use in the I-2 zone. In addition, the regasification process is a permitted accessory use that accompanies the Terminal's primary use. This interpretation was upheld on appeal to the Oregon Land Use Board of Appeals in June 2006 and to the Oregon Court of Appeals in October 2006.

Appropriate industrial, commercial, and other uses are allowed to occur in the Aquatic Development Zone (A-1). Water in these locations may be used more intensively than those in a Conservation or Natural Zone. Marinas, port facilities, aquaculture, and other water-dependent development facilities are the primary uses that are permitted with standards or allowed as a conditional use. Piers, secured floats, dredging, and filling are acceptable when adequately justified.

As part of the early development of the proposed Project, a conceptual LNG berth arrangement study was performed by Moffatt & Nichol and dated December 3, 2004, entitled *Columbia River LNG Receiving Terminal – Marine Facilities Conceptual Arrangements*. As recommended in this study, the arrangement with the berthing parallel with the predominant currents was chosen for further development. However, subsequent to the conceptual study and during interaction with various regulatory agencies (principally the U.S. Coast Guard), additional concerns surfaced regarding waterway safety because the marine facilities will be sited near the Tansy Point Turn in the Columbia River Navigation Channel. As a result, the location of the berth has been moved closer to shore, ensuring that an LNGC at berth will remain a minimum of 500 yards from the edge of the Columbia River Navigation Channel.

Navigation. The Columbia Bar Pilots and the U.S. Coast Guard initially raised concerns related to the berth being sufficiently far off the main channel of the Columbia River such that a ship losing steering or power would not collide with the berth or an LNGC occupying the berth. To address these concerns, to evaluate the feasibility of LNGC navigation and berthing, and to assess the risk of vessel collision at the berth, a series of 40 full-mission-bridge, real-time simulations were performed at the Pacific Maritime Institute in Seattle, Washington on November 12 through 16, 2007. The results of the study included probable wind, wave, and current conditions under which an LNGC could safely navigate from the sea buoy to the berth, as well as perform docking and undocking maneuvers.

Several emergency condition simulations were also performed, including LNGCs and other vessel types losing power or steerage near the Terminal. In each condition, the distressed vessel was found to be sufficiently controlled, using tugs, to avoid collision with the dock or a vessel at berth. The *Oregon LNG Simulation Report* is included as Appendix 11H (CEII) in Resource Report 11.

The berth will have full-time dedicated tugboats immediately available to assist any approaching LNGC in distress, as well as to assist LNGCs in transit to docking at the berth. When not in service at the Terminal, the tugboats will be docked at the Port of Astoria, which is the first deep-draft port available upon entering the Columbia River, located at RM 13 from the Pacific Ocean. The Port maintains nearly 7,250 feet of total dock space on three piers. These piers and the adjacent property are dedicated to marine-dependent commercial and industrial activities. Fueling and servicing facilities are available at the Port. (Washington North Tongue Point, located at RM 18.4, is another marine industrial facility providing short- and long-term berthage for tugboats and barges. At the time of filing, this facility was for sale and not accommodating new leases.)

Based upon the navigation simulations performed, the size of the turning basin (shown in Figure 1.3-2) will be adequate to perform the required turning, docking, and undocking maneuvers. A smaller turning basin was considered but was rejected as inadequate for maneuvering, as discussed in Resource Report 10.

Dredging. The berth will be located where the natural water depth is currently approximately 20 to 30 feet MLLW. Oregon LNG expects that construction of the berth will require dredging to a depth of -48 feet MLLW, with 2 additional feet allowed for overdredging (−50). Construction of the turning basin will require dredging of approximately 109 acres to −43 feet MLLW, with 2 additional feet allowed for overdredging (−45). Approximately 1.2 million cubic yards of dredge material will require removal, depending on the amount of actual overdredging.

Description of Facilities. The marine structures will include a marine trestle, a loading platform, four breasting dolphins, six mooring dolphins, interconnecting walkways, and associated piping and equipment as described in the following subsections.

Construction of these facilities will include the following Best Management Practices (BMPs) that will be implemented to prevent spillage of concrete:

- Watertight forms (usually plastic liners) will be required.
- A watertight "walkway" will be placed around each pour, at least 3 feet wide, so that misplaced concrete is unlikely to go into the water.
- The contractor will be required to provide a Spill Response Plan.

Marine Trestle. The 2,128-foot-long marine trestle will consist of a 12-foot-wide access roadway and an 11-foot-wide pipeway. To facilitate two-way vehicle traffic, turnouts will be provided at the third points of the trestle for vehicle passing. Platforms to support piping expansion loops will be provided at 310-foot intervals. A concrete trough containment trench will be installed beneath the pipeway to contain any spills that may occur along the trestle.

The superstructure elements of the marine trestle will consist primarily of a precast concrete u-shaped girder for carrying piping and spill containment, two precast concrete girders supporting the roadway, and an open-grate-type roadway deck. The substructure elements will consist of precast or cast-in-place concrete pile caps supported by 60-inch-diameter driven steel cylinder piles. Concrete traffic barriers 3 feet 6 inches high will be provided along each side of the roadway.

Loading Platform. The 124-by-94-foot loading platform will support three loading arms and a vapor return arm, a vessel access gangway, a tower and fire monitor, a platform control room, and associated piping and equipment. An open area will be provided large enough for vehicle parking and turnaround. A 32-foot-wide mezzanine platform is included along the outboard side of the platform to facilitate access to loading arm controls and valving.

The superstructure elements of the loading platform will be of two types. Where the potential for LNG spills exists, such as at the loading arm and piping locations, the superstructure will consist of a cast-in-place concrete deck and girders, including perimeter curbing to contain spills. At locations where no spill potential exists, the superstructure will consist of steel open-grid deck supported by precast concrete girders. The mezzanine platform will be framed using steel open-grid deck with rolled steel beams and columns. Foundations will be a combination of 42- and 60-inch-diameter driven steel cylinder piles.

Breasting Dolphins. The four 34-by-24-foot breasting dolphins will include marine fenders designed to absorb the berthing energy of the vessel, and quick-release mooring hooks and motorized capstans for vessel spring line attachment. The breasting dolphins will also include a steel pipe personnel safety railing and rub rails to prevent chafing of the vessel mooring lines along the outboard dolphin edges.

The breasting dolphin structures will consist of a cast-in-place concrete pile cap supported by a combination of vertical and batter, 42-inch-diameter driven steel cylinder piles.

Mooring Dolphins. Mooring dolphins will be provided in two sizes: four will be 18 by 18 feet, and two will be 42 by 18 feet. The two sizes will be provided primarily because of the vessel mooring line arrangements. Like the breasting dolphins, the mooring dolphins will be provided with quick-release hooks, motorized capstans, a steel pipe personnel safety railing, and rub rails.

Each mooring dolphin structure will consist of a cast-in-place concrete pile cap supported by batter, 42-inch-diameter driven steel cylinder piles.

Walkways. 4-foot-wide walkways will be provided for personnel access to the breasting and mooring dolphins. The walkways will be supported directly on the platform and dolphin superstructures, and thus will not require foundations. They will consist of space-truss-type tubular structures with pipe safety rails.

Dockside Equipment

Marine Fenders. Fenders will protect the dock from LNGCs berthing by using a rubber energy-absorbing pad as a cushion between the vessel and the dock. The fenders' size, type, grade of rubber, and manufacturer were selected based on the berthing analysis, and are the industry standard for LNGCs. Bridgestone is the most prominent of fender manufacturers.

Computer-Controlled Docking and Mooring System. Marquip's MQMVAS system enables safe berthing from a personal computer workstation; is unaffected by weather conditions; uses two lasers mounted at the berthing area that measure in real time the range, velocity, and angle of an approaching vessel; and provides a clear visual representation of approaching vessels. An automatic drift-mode alarm alerts the operator of a drifting condition. Once the vessel is moored and the hooks are tightened, the system accurately monitors and maintains safe tension levels on mooring, breasting and spring lines. Any deviation beyond a selected bandwidth triggers an alarm at the workstation. In addition to the line tension and vessel approach package, other modules include meteorological and oceanographic monitoring. Interactive display, alarm settings, and data logging can be configured to user requirements, and automatic data logging (by job) allows operators to review the docking history of a vessel or vessel type.

The components of the system are:

- Software
- Load pins
- Lasers
- Docking display board
- Current censors
- Meteorological package and lightning detection
- Tide meter

Motorized Capstans. Capstans are machines that allow heavy mooring, breasting, or spring lines to be hauled in or loosened. The size, type, and manufacturer of the capstans for the Project were selected based on the berthing analysis, the Terminal location, industry leadership, and the sizes of the LNGCs to be berthed. The capstans will be integrated by being placed on top of release hooks for most effective use.

Quick-Release Mooring Hooks. Quick-release hooks provide a safe, effective, and labor-saving method of vessel mooring. The hooks can be single, triple, or quadruple models. Each hook is designed to swing completely free up to 180 degrees horizontally and 45 degrees vertically to maintain a straight pull on the lines at all times. All models can be released under full load, and have a safety latch that prevents the hooks from opening accidentally. The latch can be operated manually or from a remote station, with either a pneumatically- or electrically-controlled hydraulic release.

The size, type, and manufacturer of the hooks for the Project were selected based on the berthing analysis, the Terminal location, industry leadership, and the size of the LNGCs to be berthed.

Dockside Crane. Cranes are used for raising, shifting, and lowering heavy goods and equipment on board a vessel by means of a projecting swinging arm. A standard industry off-the-shelf type, a specially fabricated model, or a Hydraulic Gangway integrated crane could be used.

Hydraulic Tower Gangway. Hydraulic tower gangways are used for reaching vessel deck levels from a dock without limitation. Each gangway comprises a steel structure with a lift platform, going automatically up and down along one side of the tower. Once the gangway has been positioned on a vessel's deck, the lift platform will go automatically to a next platform level, when the maximum angle has been exceeded. Movements are entirely hydraulically operated by means of hydraulic cylinders. Pressure is supplied by an explosion-proof electrical power pack. As an option, the tower can be equipped with a store crane on top for handling of equipment up to 5 tons at 70 feet.

Corrosion Protection. Carbon steel components above the waterline will be protected with a high-performance protective coating that consists of:

- Surface preparation: Abrasive blast to Near White Metal, SSPC-SP-10
- Primer: One coat, anti-corrosive epoxy primer
- Intermediate: One coat, high-build epoxy
- Finish: One coat, aliphatic or acrylic polyurethane

As an alternative, carbon steel components can be hot-dipped, galvanized, and coated with the following:

- Surface preparation: Solvent clean and brush blast, SSPC SP-7
- Primer: One coat, high-build epoxy
- Finish: One coat, aliphatic or acrylic polyurethane

Steel components exposed to atmosphere, water, and mud below the deck will be provided with a high-performance protective coating that consists of:

- Surface preparation: Abrasive blast to Near White Metal, SSPC SP-10
- Shop coating: Two or three coats of two-component epoxy, 18 to 20 mils dry-film thickness. Extend the coating from inside the concrete pile cap to a minimum of 10 feet below the mudline. If significant mechanical damage is anticipated in the tidal zone (from floating debris), the epoxy coating should be provided with a reinforcing material.
- Repairs: Liquid epoxy for small, isolated areas of damage, heat shrink sleeves or mechanical covers for welded joints. Surface preparation and application of repair materials will be in accordance with the manufacturer's written directions.

A cathodic protection system will be provided to supplement the corrosion protection of the pilings at coating defects in the tidal and submerged zones. Galvanic anode or impressed current cathodic protection systems may be suitable, depending on the final configuration of the dock piling system, operational and maintenance issues, and economics.

- Galvanic anodes: To be economically and technically effective, it may be necessary to coat the full length of the piles in the mud zone, with an associated added cost. This system may therefore be more expensive to install than an impressed current cathodic protection system.
- Impressed current: This will not require piles to be completely coated, and will have a lower initial installation cost. However, this type of system requires continual power and maintenance. It may be less durable, and the system will need to be designed, installed, and operated to minimize potential stray current corrosion and possible effects on LNG transfer systems.

Piles will be bonded together, and cathodic test stations will be installed on deck level to allow for monitoring of the cathodic protection system.

General Design Features. The berth is designed to accommodate port-to or starboard-to berthing of LNGCs ranging in size from 70,000 m^3 to 266,000 m^3. To the extent practical, the marine facilities design has been performed in accordance with the Marine Oil Terminal Engineering and Maintenance

Standards (MOTEMS), as published by the California State Lands Commission (2006). The general design features are as follows:

- Equipment and piping area loads: MOTEMS Table 31F-3-2
- Uniform traffic load – areas available for vehicle access: 50 pounds per square foot (psf) (applied so as to achieve maximum stress in considered member)
- Truck loads: American Association of State Highway and Transportation Officials H15 Truck
- Walkways between dolphins: 50 psf or a single 300 pound concentrated load (applied so as to achieve maximum stress in the considered member)
- Unloading platform walkways and elevated platforms: 60 psf (applied so as to achieve maximum stress in the considered member)
- Seismic loading: two level criteria calculated using a site-specific probabilistic seismic hazard analysis (PSHA)
- Current loading: 5 knots maximum within 10 degrees of the berth alignment
- Mooring loading: Capacity exceeds the 100-year return period wind speed

LNG Carriers. LNGCs will arrive at the Terminal via the Columbia River Navigation Channel. The current LNGC fleet consists of vessels with capacities ranging from 75,000 m^3 to 266,000 m^3. Of these, approximately 80 percent have capacities less than 155,000 m^3; 94 percent of these smaller LNGCs are steam-powered and 6 percent are diesel-powered. The 20 percent of LNGCs with capacities more than 155,000 m^3 are diesel-powered. The average capacity of LNGCs is 154,000 m^3 and the average size of LNGCs constructed after 2000 is 164,000 m^3.

The Terminal will be designed to accommodate LNGCs ranging in size from 70,000 m^3 to 266,000 m^3. The typical speed of an LNGC in the ocean is 18 to 19.5 knots (20.7 to 22.4 miles per hour). After clearing the Columbia River Bar, LNGCs will travel between 10 to 12 knots (11.5 to 13.8 miles per hour) on the Lower Columbia River. At approximately RM 5 to 6, LNGCs will slow down to meet tugboats, which will guide LNGCs to the dock at 4 to 6 knots (4.6 to 6.9 miles per hour). The LNGC transit route from the Pacific Ocean to the Terminal is shown in Figure 1.3-4. The 10- to 12-knot speed will be necessary for the LNGCs to maintain steering control.

Based on these assumptions, Table 1.3-1 shows the number of export and import LNGCs that are anticipated to arrive at the Terminal after the Project begins operation. The actual mixture of LNGCs that will arrive at the Terminal will reflect the current LNGC fleet as described above. If import LNGCs are used, it is assumed that the number of export LNGCs will be reduced and the total number of annual trips for import and export LNGCs together will be 125 or less.

The number of export LNGCs will average a frequency of approximately two to four ships per week. For the purpose of calculating the number and frequency of LNGCs anticipated to arrive at the Terminal, it is assumed that LNG will be delivered by LNGCs with rated capacities of 148,000 m^3 to 173,000 m^3.

Import LNGC traffic will be infrequent, up to two a year, most likely in the wintertime, and only occurring in the event of a major natural gas supply emergency on the Pacific Northwest pipeline grid during periods of peak heating demand. After the Northwest Pipeline is upgraded as part of the Washington Expansion Project, there will be two parallel pipelines from Sumas to Woodland and one pipeline from Hermiston to Woodland. In the unlikely event that both parallel pipelines from Sumas to Woodland failed, and they failed in the winter, then there could be a shortfall in natural gas supplies to meet local heating requirements. This would be an occasion to activate the import capabilities at the Terminal. If both of the parallel pipelines failed in the summer, the Hermiston-Woodland pipeline could service the demand in combination with other pipelines such as the South Mist, and importation would be unnecessary.

TABLE 1.3-1
Number of LNG Carriers Anticipated to Arrive at the Terminal

Capacity (m^3)	Approximate Number of Trips Annually
Export Vessels	
148,000	50
173,000	75
Total Export	**125**
Import Vessels	
148,000	2
Total Import	**2**

Note: If import LNGCs are used, it is assumed that the number of export LNGCs will be reduced and the total number of annual trips for import and export LNGCs together will be 125 or less.

Vessel Traffic in the Project Area. This section provides information on ship traffic volumes along the North Pacific Great Circle Route in the Aleutian Islands, along the west coast of the United States, and in the Lower Columbia River between the river mouth and the Terminal.

The primary path for LNGCs is the North Pacific Great Circle Route, which is shown in Figure 1.3-4. This route is the most economic pathway for commerce, and the shortest transportation distance for vessels travelling between Pacific Northwest in North America and East Asia. As shown in Figure 1.3-4, the North Pacific Great Circle Route passes in an arc through the Aleutian Islands. Traveling westward, ships on the North Pacific Great Circle Route primarily sail through Unimak Pass in the Aleutian Islands, and then after crossing north of the islands, sail again through the islands west of Tanaga Island. Thus, following this standard route, the LNGCs will pass through the Oregon Exclusive Economic Zone (EEZ) and the Alaskan EEZ.

Based on a recent ship traffic study prepared for the National Fish and Wildlife Foundation, United States Coast Guard, and Alaska Department of Environmental Conservations (Det Norske Veritas and ERM-West, Inc., 2010), it is estimated that approximately 2,200 ships travel through the Aleutian Islands yearly.[7] In total, these ships track through the area approximately 16,000 times each year. Of these ships, approximately 1,700 are deep-draft categories of ships that travel the North Pacific Great Circle Route. These include container ships, bulk carriers, general cargo vessels, LNG and gas carriers, roll on/roll off and car carriers, crude oil carriers, product tankers, and chemical carriers. In total, these categories of deep-draft ships track through the area approximately 4,400 times each year.

Assuming that the Project will add 250 tracks (125 trips to and from the Terminal) to the ship traffic in the Aleutian Islands, it is estimated that the Project will increase current ship traffic on the North Pacific Great Circle Route by roughly 6 percent. Ship traffic forecasts developed for the Aleutian Islands based on analysis of market trends (Det Norske Veritas and ERM-West, Inc., 2010) estimate

[7] Estimates are based on analysis of Marine Exchange of Alaska Automated Information System ship traffic data from August 1, 2008, to July 31, 2009.

approximately 6,500 westbound and approximately 3,200 eastbound deep-draft ship tracks per year by 2035. The estimated number of LNGC tracks for 2035 will remain constant at 250. Therefore, in the future, the Project LNGCs will contribute to westbound traffic by approximately 2 percent and eastbound traffic by approximately 4 percent,

Vessel traffic on the Columbia River was evaluated on the basis of number of ships crossing the bar at the mouth of the river and the number of vessel transits between the mouth and the Terminal. The average number of ships crossing the Columbia River bar each month has been declining since the late 1990s, from 321 a month during 1998-2002 to approximately 276 from 2003 through 2011 (Columbia River Bar Pilots, 2012, personal communication). Although cargo tonnages have increased during this period, ship traffic has declined because of increasing vessel size. The Project will add an average of ten vessels per month crossing the bar (inbound and outbound), an increase of 3 to 4 percent over the average levels between 2003 and 2011.

The Port of Astoria also receives calls from a number of ocean-going and river-based cruise ships. In 2011, there were 19 sea-based cruise ship calls at the port during the period from April to September (Port of Astoria, 2011). These ships will pass by the Terminal during arrival and departure. The smaller river cruise ships (200 to 250 passengers) operate upriver year-round, but mostly in the spring through fall; only a small number travel as far downriver as the Terminal. In the last 8 years, the number of combined cruise ship and river cruise calls at the port has decreased but the number of passengers has increased, from approximately 134 vessel calls and 20,000 passengers in 2000 to approximately 97 vessel calls and 29,548 passengers in 2011 (Halcrow, Inc., 2008).

Considerable ship traffic occurs along the west coast within the EEZ. Table 1.3-2 lists coastal transits between Cape Flattery, Washington, and San Diego, California, from July 1998 through June 1999. As shown, there were 19,161 arrivals to west coast ports during this period, including all types of cargo and passenger ships, fishing vessels, and barges. The data in the table also indicate that traffic density was heavier between the Strait of Juan de Fuca and Los Angeles/Long Beach than either north or south of this area.[8]

TABLE 1.3-2
Vessel Transit within the Exclusive Economic Zone Offshore from the West Coast, July 1998 through June 1999

Coastal Section		Section Length (nmi)[a]	Annual Coastal Ship Transits[b]	Nautical Miles (nmi)
From	To			
San Diego, CA	Los Angeles	95	2,615	248,425
Los Angeles	San Francisco	371	4,604	1,708,084
San Francisco	Humboldt Bay (Eureka)	232	3,668	850,976
Humboldt Bay (Eureka)	Crescent City	64	3,658	234,112
Crescent City	Coos Bay	125	3,658	457,250
Coos Bay	Columbia River (Astoria)	201	3,694	742,494
Columbia River (Astoria)	Grays Harbor (Aberdeen)	75	4,188	314,100
Grays Harbor (Aberdeen)	Strait of Juan de Fuca (Cape Flattery)	117	4,221	493,857
Total from Crescent City to Cape Flattery (OR-WA EEZ)				2,007,701
Total from San Diego to Cape Flattery (CA-OR-WA EEZ)				5,049,298

[a] Distances in nautical miles (nmi), as listed in Coast Pilot 7, Appendix B.
http://chartmaker.ncd.noaa.gov/nsd/coastpilot7.htm.

[8] Pacific States – British Columbia Oil Spill Task Force, 2002. http://www.oilspilltaskforce.org/wcovtrm_report.htm

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