3.0 ALTERNATIVES

In considering Jordan Cove's and Pacific Connector's applications, the FERC will review both the environmental and non-environmental record in deciding whether it is in the public convenience and necessity to issue any authorization for the Project. The EIS addresses alternatives to the proposed actions before the FERC, COE, Coast Guard, BLM, USFS, and BOR. The FERC must consider whether or not to approve the facilities proposed by Jordan Cove and Pacific Connector.

The COE will review permit applications submitted by the applicants in September 2007 under section 10 of the RHA and section 404 of the CWA. The Coast Guard will consider issuing an LOR under its regulations at 33 CFR 127.009 regarding the suitability of the waterway for LNG marine traffic. The BLM must decide whether or not to issue a Right-of-Way Grant for the Pacific Connector pipeline across BLM-administered lands, across BOR lands, and across USFS lands with agreement from the USFS and BOR.

3.1 FERC ALTERNATIVES

In accordance with the NEPA and Commission policy, we have evaluated a number of alternatives to the JCE & PCGP Project to determine if any are reasonable and environmentally preferable to Jordan Cove's and Pacific Connector's proposed action. Alternatives considered by the FERC, described in more detail below, include no action or postponed action, system alternatives, LNG terminal site alternatives, LNG terminal layout alternatives, dredging and dredge material disposal alternatives, and pipeline route alternatives.

Alternatives were evaluated against the objectives of the JCE & PCGP Project, as described in section 1.1 of this EIS. The primary objective of the Project is to provide a new access point for LNG imports and a new source of natural gas to Pacific Northwest, northern California, and northern Nevada markets to meet growing demands. To achieve this objective, Jordan Cove would construct and operate an LNG import terminal with docking/unloading facilities capable of berthing one LNG carrier, an LNG storage capacity of 320,000 m^3, and vaporization facilities capable of sending out about 1.0 Bscfd of natural gas to the Pacific Connector pipeline. The 230-mile long, 36-inch-diameter pipeline would serve the target markets by:

- delivering natural gas to the existing interstate facilities of Williams Northwest Grants Pass lateral through an interconnect near Myrtle Creek, Oregon (MP 69.70);
- delivering natural gas to the LCD facilities of Avista through an interconnect near Shady Cove, Oregon (MP 122.1); and
- delivering natural gas to the existing facilities of GTN, Tuscarora, and PG&E through interconnects at the terminus of the pipeline at the Oregon/California border near Malin, Oregon (MP 230.90).

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

- are technically and economically feasible, reasonable, and practical;
- offer significant environmental advantage over the proposed Project; and
- meet the objectives of the Project, as described above.

With respect to the first criterion, it is important to recognize that not all conceivable alternatives are technically and economically feasible and practical. Some alternatives may be impracticable because they are unavailable and/or incapable of being implemented after taking into consideration costs, existing technologies, and logistics in light of the overall Project purpose. In conducting a reasonable analysis, it is also important to consider the environmental advantages and disadvantages of the proposed action and to focus the analysis on those alternatives that may reduce impacts and/or offer a significant environmental advantage.

The Commission has three possible courses of action in processing the applicant's proposals. The Commission may: 1) deny the proposals, 2) postpone action pending further study, or 3) authorize the proposals with or without conditions. In arriving at a course of action, the Commission considers a range of alternatives in light of the Project's objectives, evaluation criteria, and environmental comparisons. Each alternative is considered until it is clear that the alternative is not reasonable or would result in greater environmental impacts that could not be readily mitigated. Those alternatives that appear to be the most reasonable with less than or similar levels of environmental impact are reviewed in the greatest detail.

3.1.1 NO ACTION OR POSTPONED PROJECT

If the Commission denies Jordan Cove's and Pacific Connector's proposals or postpones action on the proposals, the short- and long-term environmental impacts identified in this EIS would not occur. If the Commission selects the no action or postponed action alternative, the objectives of the proposed Project would not be met and the applicants would not be able to import LNG to provide natural gas to markets in the Pacific Northwest, northern California, and northern Nevada. It is purely speculative to predict the resulting effects and actions that could be taken by other suppliers or users of natural gas in the region as well as any associated direct and indirect environmental impacts.

Various studies indicate that under certain scenarios existing natural gas supplies and infrastructure could fall short of meeting regional peak demand by 2012 (NWGA 2007; ICF 2007). Without the additional natural gas volumes to be provided through the LNG import terminal proposed by Jordan Cove and the associated sendout pipeline proposed by Pacific Connector, customers in the Pacific Northwest, northern Nevada, and northern California would have fewer and potentially more expensive options for obtaining natural gas supplies in the future.

In the state of Washington, the price of natural gas increased by as much 300 percent over the last several years, due to a number of factors, such as lack of investment in new infrastructure, growth in regional demand, including an increase in the use of natural gas for power generation, deregulation of state controls on electric generation, and limitations on natural gas supplies, especially reduction of imports from Canada (Washington Utilities and Transportation Commission 2008). In California, natural gas prices doubled between 2002 and 2006 (CEC 2007). Higher natural gas prices could adversely influence the regional economy by reducing realized household incomes and business profits (Greenspan 2003). A 2005 report by the U.S. Department of Commerce (Impacts of Rising Natural Gas Prices on the U.S. Economy and Industries) estimated that higher gas prices reduced growth of the Gross Domestic Product by about 0.2 percent between 2000 and 2001, and between 2000 and 2004 about 489,000 civilian jobs were lost to the national economy, including 79,000 in manufacturing industries, because of increases in the price of natural gas. Another U.S. Department of Commerce report released in

2006 (Macroeconomic and Industrial Effects of Higher Natural Gas Prices) indicated that higher natural gas prices in the future would push up consumer prices and reduce real disposal income. A study sponsored by the INGAA Foundation in 2005 found that a delay of 3 years for installing new natural gas infrastructure, including LNG import terminals, in the Pacific Northwest would cost the Oregon economy an estimated $11.1 billion and the Washington state economy about $9.7 billion. According to the CEC (2007), if new sources of imported LNG were added to the energy mix in the future, it may be less expensive than domestic production, and is expected to stabilize natural gas supplies and prices.

Higher natural gas prices (or the threat of higher gas prices) could also lead to alternative proposals to develop natural gas delivery infrastructure, increased efficiency and conservation or reduced use of natural gas, and/or the use of other sources of energy. Alternative fuel sources, such as coal or oil, could provide an equivalent amount of energy as the proposed Project, but may have greater environmental impacts (see section 3.1.1.3 below).

The EIA Annual Energy Outlook for 2008 projected an increase in total coal consumption in the United States between 2006 and 2030 as coal is used more in the future for electric generation, in part because of constraints on supplies of natural gas and higher natural gas prices. Higher natural gas prices were also cited as a reason for the projected increased demand for total renewable fuels. However, as discussed in more detail in section 3.1.1.3, renewable energy sources such as solar, wind, and geothermal resources would not be able to produce the amount of energy equal to the proposed Project.

3.1.1.1 Alternative Natural Gas Infrastructure Proposals

The adoption of the no action alternative could result in the expansion of other existing interstate natural gas pipeline systems or LNG facilities to meet the increasing demand for natural gas in the Pacific Northwest, northern California, and northern Nevada. This might include constructing or expanding regional pipelines as well as LNG import and storage systems. In section 3.1.2 we examine the most reasonably foreseeable natural gas and LNG system alternatives. Any expansion of existing systems or construction of new facilities would result in specific environmental impacts that could be less than, similar to, or greater than those associated with the proposed Project.

3.1.1.2 Increased Efficiency and Conservation of Natural Gas

Denying or postponing a decision on Jordan Cove's and Pacific Connector's applications could limit access to new supplies of natural gas for the Pacific Northwest, northern Nevada, and northern California in the future. One possible result of limiting new supplies of natural gas in the region could be consumer conservation and programs to stifle demand and increase energy efficiency. There is no doubt that both conservation and increased efficiency have an important role to play in the future energy needs of the Pacific Northwest. Between 1990 and 2002, utilities in the Pacific Northwest invested $2.4 billion in conservation, resulting in savings of 2,600 average MW per year (ODE 2005a). In its Fifth Power Plan, the Northwest Power and Conservation Council (NWPCC 2005) recommended conservation targets of 700 average MW between 2005 and 2009 and 2,500 average MW during the 20-year planning period.

State regulators have already begun to require gas and electric companies to implement conservation programs and have promoted public programs encouraging energy conservation.

The state of Oregon offers both Business and Residential Energy Tax Credits and an Energy Loan Program designed to help businesses and residential consumers invest in energy efficiency through such actions as the purchase of more efficient appliances, heating and air conditioning systems, and building renovations. These programs have seen dramatic results in the last 5 years. According to the 2005-2007 Oregon Biennial Energy Plan (ODE 2005a), in 2000 the combined residential and business energy tax credit programs stimulated savings of 58.9 kilowatt-hours (kWh). By 2003, savings had reached 860.3 million kWh. In 2005, the Business Energy Tax Credit resulted in savings of 2.2 billion kWh in electricity and 107.9 million therms in natural gas, while the Residential Energy Tax Credit saved 104.1 million kWh in electricity and 2.8 million therms in natural gas total in Oregon (ODE 2008a). California implemented one of the most aggressive energy efficiency programs in the United States, with the lowest per capita consumption rate of electricity in the nation.

Although conservation may slow the growth of natural gas use, energy efficiency programs alone are not expected to reverse the demand for additional natural gas or reduce the price of natural gas for customers in the face of growing populations in the Pacific Northwest, northern California, and northern Nevada, and increased use of natural gas for industrial purposes including electrical generation. Even though energy efficiency has helped to flatten demand, the CEC (2007) estimates that electricity use in California will continue to rise at a rate of 1.25 percent annually.

3.1.1.3 Other Sources of Energy

It is also conceivable that adoption of the no action alternative could promote the development of other (non-LNG/natural gas) sources of energy. State agencies are promoting renewable energy programs to help reduce the demand for fossil fuels. These include hydropower, solar, wind, geothermal, nuclear power, and biofuels. While renewable fuels can contribute to meeting the energy needs of the area, they take years to develop and are not predicted to totally replace the future demand for natural gas in the region partly because natural gas has other end-uses beyond electric power production. Absent new additional sources of natural gas, other fossil fuels, including coal and oil, may be used to make up the projected energy gap. The use of other fossil fuels, in place of natural gas, could have more adverse environmental impacts than the proposed Project by generating more greenhouse gases and contributing to global warming (see discussion below). For comparison purposes where applicable, we assume that all of the LNG would be converted to electric power, through typical high-efficiency combined cycle gas-fired turbine generating stations. However, as alluded to above, this might not be a reasonable assumption.

Renewable Energy

Renewable energy resources represent a possible alternative to the use of natural gas. For example, hydro and wind resources represent alternatives for electricity generation, whereas biomass, solar, and geothermal resources can be used to generate heat as well as electricity. However, there are also environmental impacts associated with the use of renewable resources. For example, hydropower dams may affect fish, and wind turbines may affect birds and bats.

The Pacific Northwest and California have been at the forefront nationally in terms of the use of renewable energy resources, in large part due to the historical prevalence of hydropower resources in the region. The state of Washington passed the Energy Independence Act and Renewable Portfolio Standard (RCW 19.285) in 2006, requiring electric utilities with more than

25,000 customers to establish conservation targets beginning in 2010, with the goal of having 15 percent of their load generated from renewable resources by 2020. In 2007, the Oregon legislature created a Renewable Portfolio Standard requiring electric utilities in that state to include power generated from renewable sources in their energy mix, with the goal of having 25 percent come from renewable sources by 2025 (ODE 2008). California also has a Renewables Portfolio Standard, with of goal of generating one-third of the state's energy from renewable resources by 2020. Currently, about 11 percent of the electricity generated in California comes from renewable resources other than hydropower, including solar, wind, and biomass sources (CEC 2007).

Hydropower and Wave Energy

Hydropower, or generating electricity from water stored behind dams and then run through turbines, plays a significant role in the current energy mix of the Pacific Northwest, accounting for 64 percent of the region's energy capacity in 2006 (NWPCC 2008). In 2007, hydropower generated 66,700 thousand megawatt hours (MWhr) in Washington State (EIA 2007). In Oregon, in 2005, hydropower produced 42 percent of the electricity in the state (ODE 2008a). Hydropower provided about 7 percent of the power capacity for the state of Nevada in 1997 (Nevada 2008). In California, hydropower accounts for about 21 percent of the state's energy (California 2008). Combined, instate hydropower projects in California generated 48,876 gigawatt-hours (GWh) of electricity in 2006 (California 2006).

However, the ODE recognizes that climate change may alter the runoff regime feeding water to the hydroelectric dams along the upper Columbia River, resulting in less summer power in the future. Legal issues concerning the operation of the dams with regards to fisheries could also diminish hydropower generation (ODE 2008b). According to the NWPCC (2007), most feasible hydroelectric facilities have already been developed. It is unlikely that new dams would be constructed in the future because of high development costs and environmental impacts. In fact, efforts are underway to remove some existing dams to restore habitat. Further, environmental scrutiny during the relicensing process for existing dams has, in some instances, resulted in increased release of water for fisheries, which has reduced their electric generation capacity. It has been estimated that the percentage contribution of hydrogeneration is going to decline from supplying about 10 percent of the nation's electricity in 2005 to about 6 percent in 2020 (U.S. Department of Energy 2005). Thus, the development of additional hydropower resources is not considered to be a reasonable or environmentally preferable alternative to the proposed Project.

A new potential source of electric power for the future is hydrokinetic energy, or electricity generated from ocean currents, swells, waves, or tidal action. These facilities could only be developed offshore. Currently, the United Kingdom has an ocean energy program supported by the government. The FERC recently initiated a licensing process for hydrokinetic test projects in the United States. The goal of the FERC pilot process is to allow developers to test new technologies, to determine the best location for hydrokinetic facilities, and to discover the environmental effects associated with the siting and operation of such facilities. It has been estimated that if hydrokinetic technologies could be successfully developed, it could potentially double the amount of hydrogenerated electricity available in the United States (FERC 2008). The ODE (2008a) estimated that ocean wave energy could provide over 500 MW in electricity from Oregon projects developed over the next 10 years.

Although numerous preliminary permits have been issued on the east coast, only two wave power projects have been licensed under the FERC pilot program. Both are proposals from Finavera Renewables Ocean Energy, Ltd. (Finavera). One proposal calls for the installation of four 250 kW wave energy conversion buoys in Makah Bay off the coast of Washington State. The other Finavera project would be located off the coast of Humboldt County, California (Irish Independent 2008). Additional wave power projects are in the early development stage for facilities near Grays Harbor, Washington and Reedsport and Coos Bay, Oregon (International Water Power and Dam Construction 2008; Coos Bay World 2008; KCBY 2008). A report by the Electric Power Research Institute identified seven sites along the Oregon Coast as being potentially suitable for wave energy projects. In July 2006, Ocean Power Technologies proposed a 50 MW wave-power project in Oregon. The ODE counted eight applications for wave energy projects to the FERC proposed by developers or Oregon coastal counties (ODE 2008a). In March 2008, the FERC signed a memorandum of understanding with the State of Oregon to coordinate procedures and schedules for the review of wave energy projects in state waters off the coast of Oregon (Electric Light & Power Utility 2008; Dam Engineering 2008).

While there are many proposals being pursued, there are currently no commercial hydrokinetic facilities operating in the United States. There are two experimental test projects in operation: one in the East River of New York, and one off the Washington coast (1 MW).

The development of wave energy resources in the future is speculative, because of challenges related to the use of new technologies, financial barriers, and an unclear regulatory process. Nor do we know about the potential environmental impacts resulting from the construction and operation of a hydrokinetic facility, although it appears that such a facility would likely have some affects on aquatic resources. Therefore, we do not consider hydrokinetic facilities to be a reasonable, feasible, or foreseeable alternative to the proposed Project.

Geothermal

Geothermal resources are naturally occurring sources of heat, such as hot springs, geysers, or volcanoes that could be tapped to generate energy. Geothermal resources include high-temperature (above 100 °C) sources for electric generation, intermediate temperature (50 to 100 °C) sources for industrial, agricultural, and municipal uses, and low temperature sources for residential heat pump uses.

In 2003, wind and geothermal resources combined supplied 1 percent of the electric generation in Oregon, averaging 53 MW of power (ODE 2008). Geothermal resources in Oregon are used to supply heat for buildings, swimming pools, and industrial uses. As of 2005, there were about 2,200 ground-source heat pumps providing space and water heating to homes in Oregon. The City of Klamath Falls uses geothermal energy for a district heating system. There have been explorations on the flanks of Newberry Volcano to evaluate its potential future use for high-temperature geothermal electricity production (ODE 2005). The Warm Springs Tribes are considering a geothermal project at Mount Jefferson.

The 13-megawatt Raft River Project in southern Idaho is the only commercial geothermal power plant operating in the Pacific Northwest (NWPCC 2007). California produced near 13 million MWh of electricity from geothermal sources in 2003.

The main barriers to the further development of geothermal resources are the identification of potential naturally occurring sources, and above-market costs. In California, most available geothermal sites appear to have already been exploited, with a decline in geothermal energy production from its peak of 14.5 MWh in 1990. Given the physical limits of geothermal sites that have a potential for future exploitation, the lack of interest from investors in developing new potential resources, and the minimal energy geothermal resources produce, we do see this type of renewable resource as a feasible, reasonable, or predictable alternative to the proposed Project.

Biomass and Biogas

Biomass resources can produce electricity and heat or steam from wood, wood waste, plant and animal waste, or other organic matter. As of 2007, biomass generation represented about 2 percent of the total electric power capacity of the Pacific Northwest (NWPCC 2007). That year, the Washington Public Utilities Commission (PUC) estimated that biomass projects in the state were capable of generating almost 200 MW in total. In 2004, biomass produced 79 trillion Btu of energy in Oregon, or about 6 percent of that state's total energy supply (ODE 2008a).

More than 90 percent of Oregon's biomass energy comes from forest or wood waste and paper mill pulping liquor. About 40 percent of Oregon's biomass energy comes from wood waste burned at 49 industrial sites. Ten of these sites produced 866,000 MWh of electricity. About 46 percent of the total biomass energy in Oregon is produced from combustion of pulping liquids at six mills. Two mills produced about 310,000 MWh of electricity in 2004 (ODE 2008a). A new 10-MW wood waste cogeneration plant recently went on line at the end of 2007 in Lyons, Oregon (NWPCC 2008).

There are three landfills in Oregon that tap waste methane gas to generate 37,000 MWh of electricity annually for industrial use, with a fourth under construction in southern Oregon. In addition, 29 wastewater treatment plants in Oregon use methane to generate 26,000 MWh of electricity annually to provide heat for sewage treatment. Two facilities produced about 500 MWh of electricity annually from cow manure (ODE 2008a).

In California, about 19 percent of the state's renewable energy comes from biomass resources. California would like to see about 2,000 MW generated from biomass resources by 2020, mainly the product of biogas from dairies and landfills (CEC 2007).

Barriers to the further development of biomass resources include uncertainty in biomass outputs, the high costs associated with the transporting of forest products to an energy conversion facility, and lack of private capital investment in the development of additional biomass facilities. The CEC has invested $94 million over the last 5 years attempting to develop biomass resources, and overcome economic obstacles and environmental impacts. In Oregon, virtually every paper mill has already installed equipment to allow the utilization of biomass waste, leaving little potential to develop new resources. Because of the relatively high costs of development, only about 15 MW in new biomass generation were brought on line between 2004 and 2007 in the Pacific Northwest (NWPCC 2007). Because of the difficulties of developing biomass resources, and the small amount of additional energy they could produce, we do not believe that this represents a feasible, reasonable, and foreseeable alternative to the proposed Project.

Solar

There are three primary ways to harvest solar energy: 1) direct sunlight into buildings can be used for light and heat; 2) roof-mounted collectors can use sunlight to heat water; and 3) sunlight can be converted into electricity using photovoltaics or solar panels. There are about 300 solar electric systems in the State of Oregon, and residents have installed more than 17,600 solar water heating systems in the last 25 years (ODE 2008a). In California, solar power accounted for 616 GWh of electricity in 2006, representing only about 0.2 percent of the gross system power for the state (CEC 2006).

Solar power has never made a significant contribution to the energy mix in the Pacific Northwest because of the weather conditions in its major metropolitan population centers. There is not enough sunlight to generate much solar energy during the cloudy winter months when there is peak demand in Portland and Seattle. National Weather Service data collected at the Seattle-Tacoma International Airport, which has a similar climate to much of western Oregon, showed the average annual possible sunshine for the area is about 47 percent. Data presented by the Renewable Energy Power Project indicated that the daily average is 2.9 kWh per square meter (m^2) for Seattle. At this rate, thousands of acres of solar collectors would be needed. Solar power does not appear capable of producing enough energy in this region to be considered a reasonable or feasible alternative to the proposed Project.

Wind

In the Pacific Northwest in 2007, wind power accounted for about 3 percent of the regional electric capacity (NWPCC 2007). As of 2007, wind projects in operation in Oregon could generate a total of 450 MW (ODE 2008a). The Washington PUC estimated that in 2007 wind farms in that state could generate a total of about 915 MW (with two projects overlapping into Oregon). In California, wind power generated about 4,927 GWh of electricity in 2006, representing about 1.8 percent of the gross system power in the state (CEC 2006).

Due to the variable nature of wind, on average, wind turbines only generate about one-third of their maximum output capacity. Another barrier to the further development of wind farms in eastern Oregon is lack of transmission capacity. Clustering effects at wind farms result in spikes and troughs in production that have no relation to demand, and contribute to transmission congestion. However, a stakeholder group evaluating this situation in 2006 believes that about 6,000 MW of electricity from eastern Oregon wind projects could find its way into the region's grid by 2024 (ODE 2008a). In addition, the cost of developing new wind projects has gone up since 2004 because of rising prices for equipment (NWPCC 2007). In California, wind power generation has grown at a rate of only about 1.5 percent per year since 1990. Environmental consequences from wind farms include visual effects and impacts on birds and bat populations.

Lastly, there are limitations to wind power in comparison to energy production from the proposed Project. We estimate that 1 Bscf/d throughput of natural gas when supplied to a combined cycle combustion turbine would generate about 5,200 MW on a continuous basis. Based on conversations with staff at the ODE, it is estimated that the total capacity of all currently operating, approved, and proposed wind farms in Oregon would be 3,700 MW. This represents about 23 percent of the energy sendout capacity of the JCE & PCGP Project. Using the largest wind turbine made by General Electric (capable of generating 3.6 MW in high wind areas offshore), it would take 4,337 wind turbines to produce an equivalent amount of electricity

that could be generated using the total capacity of the natural gas from the JCE & PCGP Project. Therefore, we do not believe that wind power represents a reasonable, feasible, foreseeable alternative to the proposed Project.

Nuclear Energy

Nuclear power has the potential to generate enough energy to substitute for the proposed Project. However, due to economic, environmental, and regulatory factors, the future of nuclear power as an energy alternative is in doubt. There are currently 103 nuclear reactors operating at 65 sites in 31 states, generating about 19 percent of the nation's electricity. There is only one nuclear power plant currently operating in the Pacific Northwest; the Columbia Generating Station in Washington with an electrical output of 1,107 MW. There are four nuclear power plants currently operating in California; two at Diablo Canyon and two at San Onofre, with a combined electrical generation capacity of 4,324 MW (NRC 2008). Nuclear power represented about 5 percent of the energy mix in California in 2006, and imported nuclear power represented about 3.4 percent of the energy mix in Oregon in 2003 (ODE 2008a; CEC 2007).

The only nuclear power facility in Oregon, the Trojan plant on the Columbia River in Columbia County, operated between 1976 and 1992. It was closed in 1993, years before its scheduled operational life-span, in part because of environmental and safety issues. The Hanford nuclear weapons plant in southeast Washington halted production in 1988, but is the site of radioactive contamination that will take years and billions of dollars to remediate (ODE 2008a).

Until recently, no new nuclear power plants have been planned since the mid-1980s due to concerns raised after the Three Mile Island incident in Pennsylvania in 1979. As a result of incentives offered in the EPAct, the Nuclear Regulatory Commission expects that it may receive up to 21 new applications for nuclear power plants between 2007 and 2009. Two of these proposed plants would be located in Idaho; one at Bruneau and one near Boise. The NWPCC believes that the earliest a new nuclear power plant could come online in the Pacific Northwest would be 2015. The CEC indicated that it does not expect to see the development of new nuclear power plants in California in the near future because of problems related to the disposition of spent fuel, long regulatory review time, and costs. The ODE (2008a) has stated that "nuclear plants are not likely to be approved in Oregon in the near term." An Oregon law requires voter approval to allow a new nuclear power plant to be built in the state, and only if a permanent repository can be found for the disposal of plant waste.

We do not consider nuclear power to be a feasible foreseeable alternative to the proposed Project. Barriers to the nuclear industry include problems related to the disposition of spent fuel, long regulatory review time, and costs. The Watts Bar nuclear power plant in Tennessee that began operation in 1996 took 23 years to complete, at a cost of $6.9 billion. The proposed nuclear power plant at Bruneau, Idaho is estimated to cost $4.5 billion to build (Idaho Statesman 2008).

Other Fossil Fuels

Compared to other fossil fuels, such as oil and coal, natural gas is relatively clean and efficient. Burning natural gas results in less emission of regulated pollutants (nitrogen dioxide [NO_2], sulfur dioxide [SO_2], and particulate matter with an aerodynamic diameter of 10 microns or less [PM_{10}]), or unregulated green house gasses such as CO_2. It is likely that other fossil fuels would

be used in place of natural gas if it were not available. Table 3.1.1.3-1 shows a comparison of air emissions from burning different types of fossil fuel. The emissions shown in the table demonstrate the advantage of using natural gas in terns of air quality. In order to reduce emissions from new coal- or oil-burning power facilities, emission control equipment could be required. This may reduce the economic viability of these facilities.

In addition to the increased emissions associated with the burning of coal or fuel oil, each of these fuels would also have to be imported into the Project area and stored, similar to the proposed LNG. The distribution of these fuels to market would require more truck, barge, and train trips than the distribution of an equivalent amount of energy derived from natural gas, which would increase emissions and traffic congestion.

TABLE 3.1.1.3-1

Comparison of Air Emissions from Burning Fossil Fuels

	Emission Rate (tons per year) a/		
	Natural Gas	**Fuel Oil**	**Coal**
Sulfur dioxide (SO_2)	110	86,643	231,785
Nitrogen oxide (NO_2)	16,555	33,113	115,893
Particulate matter with a diameter of 10 microns or less (PM_{10})	1,325	1,878	5,133
Carbon monoxide (CO)	16,445	17,440	3,618
Carbon dioxide (CO_2)	18.333,333	26,583,333	34,833,333
Carbon (C)	5,000,000	7,250,000	9,500,000

a/ The emissions generated by coal, fuel oil, and natural gas were estimated using information from the EPA Web site. They were calculated for boilers with heat input ranges of between 100 and 250 million BTUs per hour. The emissions for each fuel type were estimated based on a total annual fuel use of 146,000,000 million BTUs per year.

The ODE conducted an independent review of lifecycle GHG emissions resulting from an LNG project, making assumptions about fuel burned from the point of origin to its use for electric generation in Oregon. The ODE concluded that carbon emissions from vaporized LNG when combusted in a conventional electric power plant would fall somewhere between domestically produced natural gas transported by interstate pipeline and coal. According to the ODE review, when combusted in a conventional electric power plant, lifecycle GHG emissions from LNG were forecast to be 6 to 12 percent greater than domestically produced natural gas transported by interstate pipelines, but 39 to 48 percent less than coal (ODE 2008b).

The ODE admits that natural gas would produce less GHG than using coal for electric generation. The report states: "Over 40 percent of the electricity consumed in Oregon comes from coal-fired generation. As climate change legislation is enacted, it is likely that financial considerations will encourage the switch from coal to natural gas since natural gas has much lower life-cycle GHG emissions. It is unlikely that Oregon will be able to replace all of the coal-fired power it uses with renewables in the short-term, so natural gas consumption is likely to rise."

Another LNG developer in Oregon has questioned the validity of the ODE LNG review and GHG conclusions (NorthernStar 2008). That developer claims that the ODE GHG calculations were flawed because they were based on disputed research conducted by Carnegie Mellon University that made assumptions regarding not-yet-developed carbon capture technologies.

3.1.2 System Alternatives

System alternatives would make use of other existing or proposed LNG or natural gas pipeline facilities to meet all or most of the natural gas demand of the proposed Project. A system alternative would make it unnecessary to construct all or part of the proposed Project, although some modifications or additions to the existing facilities may be necessary. These modifications or additions would result in environmental effects that may be less than, similar to, or greater than those associated with this Project.

3.1.2.1 Existing Pipeline Systems

Two existing interstate natural gas pipelines, the Williams Northwest system and TransCanada's GTN pipeline system, currently serve the Pacific Northwest. Williams Northwest is a 3,900-mile-long bi-directional transmission system crossing the states of Washington, Oregon, Idaho, Wyoming, Utah, and Colorado. This system provides access to British Columbia, Alberta, Rocky Mountain, and San Juan Basin natural gas supplies. It has a peak design capacity of 3.4 Bscfd (Williams Northwest Pipeline 2008).

The GTN pipeline system includes 612 miles of pipeline beginning at Kingsgate, British Columbia, traversing through northern Idaho, southeastern Washington and central Oregon, and terminating near Malin, Oregon, where it interconnects with Tuscarora and PG&E. Natural gas for the GTN pipeline originates primarily from WCSB supplies; although it can receive Rocky Mountain gas through an interconnection with Williams Northwest near Spokane and Palouse, Washington and Stanfield, Oregon. The GTN system can handle about 2.9 Bscfd (GTN 2008). In 2006, GTN transported about 2190 Mscfd to the northern California border (CEC 2007).

Natural gas is transported into northern Nevada via two jurisdictional interstate pipeline systems operated by Paiute Pipeline Company (Paiute) and Tuscarora. Paiute, a subsidiary of Southwest Gas Corporation, receives gas from Williams Northwest via its Owyhee Lateral at the Idaho border, and has an interconnection with Tuscarora at Wadsworth Junction, Nevada. Natural gas in the Paiute system could originate from the San Juan Basin, the Rockies, or the WCSB. Paiute's existing pipeline system serves the communities of Elko, Lovelock, Fallon, Dayton, Yerington, Reno, Carson City, and Lake Tahoe. Paiute provides firm transportation and contract LNG storage (through a peak shaving plant) for three LDC customers: Sierra Pacific Power Company, Southwest-Northern Nevada, and Southwest-Northern California.

Tuscarora, a subsidiary of TransCanada, receives gas from GTN near Malin, Oregon, and extends over northern California to an interconnection with Paiute near Wadsworth, Nevada. Tuscarora consists of about 240 miles of 20-inch-diameter pipeline, with a subscribed capacity of 180,000 Mscfd (Tuscarora Gas Transmission 2008). It mainly supplies natural gas to the Reno metropolitan area.

The existing PG&E system serves northern California. PG&E receives natural gas originating from the Rocky Mountains and the Southwestern United States via its Line 300, with a receipt capacity of about 1,140 Mscfd. It receives natural gas originating from Canada and the Rocky Mountains via an interconnection with GTN at the Oregon/California border with PG&E Lines 400/401, which has a receipt capacity of about 2,021 Mscfd. PG&E also accepts natural gas produced in California into its system (CEC 2007). PG&E's existing system extends from Eureka to Bakersfield. It includes 6.136 miles of transportation pipelines and 40,123 miles of

distribution lines (PG&E 2008). The local distribution system operated by PG&E is regulated by the California Public Utilities Commission.

There is an existing non-jurisdictional 12-inch-diameter pipeline that extends some 60 miles, over the Coast Range, from the Williams Northwest Grants Pass lateral near Roseburg to Coos Bay. This pipeline was constructed by Coos County and is operated by Northwest Natural as a LDC. The Coos County pipeline has a MAOP of 1,000 psig and was designed to bring gas from the Williams Northwest interstate system to the communities around Coos Bay, flowing in the opposite direction of the proposed Pacific Connector pipeline. The terminus of the Coos County pipeline is approximately 7.7 miles south of the proposed Jordan Cove LNG terminal. Northwest Natural built a line from the terminus of the Coos County pipeline across Coos Bay to the North Spit, as part of its local distribution system.

It is possible that the Coos County pipeline could be converted into a jurisdictional facility, and used as a system alternative to the proposed Pacific Connector pipeline. In that situation, modifications would need to be made to the Coos County pipeline, to connect to the proposed Jordan Cove LNG terminal, and reverse the direction of flow to make deliveries into the Grants Pass lateral. However, the estimated maximum capacity of the Coos Bay pipeline is about 45,000 Dth/d, which is less than 5 percent of the proposed Jordan Cove LNG terminal send-out capacity. Also, the Coos County pipeline ends at the Grants Pass lateral, and one of the main objections of the Pacific Connector pipeline is to provide gas from imported LNG to markets in northern Nevada and northern California through an interconnection with the existing Tuscarora and PG&E pipeline systems near Malin, Oregon, about 170 miles east of Roseburg. Because it does not extend to the California border, and has restricted capacity and operating pressure, we do not believe the conversion of the Coos County pipeline to interstate service would be a reasonable or practical system alternative to the Pacific Connector pipeline. However, the route of the Coos County pipeline was considered as a partial alternative route for Pacific Connector pipeline below in section 3.1.4.1.

As system alternatives to the proposed JCE & PCGP Project, we considered the possibilities of expanding or modifying the existing interstate natural gas systems of either Williams Northwest, GTN, Tuscarora, Paiute, or PG&E to handle the additional volumes proposed by the JCE & PCGP Project and meet the Project objectives of bringing new sources of gas to southern Oregon, northern Nevada, and northern California. It is unknown exactly what additional facilities would have to be built to accommodate the proposed volumes of the JCE & PCGP Project on existing systems. The expansion or modifications to those existing systems would result in environmental impacts equal to or greater than the new facilities proposed by Jordan Cove and Pacific Connector. Both Williams Northwest and GTN are currently pursuing expansions of their systems, as discussed below in section 3.1.2.2.

One of the obstacles associated with the expansion of existing interstate pipeline systems as alternatives to the JCE & PCGP Project, would be the procurement of new sources of natural gas that those systems could transport, in addition to the volumes they currently carry, as opposed to the importation of LNG. It is unlikely that substantial additional volumes of natural gas could be produced in the Southwest (Anadarko Basin of Oklahoma and Permian Basin of Texas) in the future and transported to the West Coast. The CEC estimated that natural gas supplies coming into southern California at Topock and Blythe from Southwest sources (via the existing El Paso pipeline system) would decline by about 17 percent between 2007 and 2017. Net natural gas

imports from Canada are projected to decrease from 3.3 Tcf in 2005 to 1.2 Tcf in 2030 (EIA 2007). The only North American gas region, outside of the Gulf of Mexico and Alaska, that may have increased production in the future would be the Rocky Mountains. However, the ODE (2008a) believes that a pipeline bringing natural gas from Alaska to the lower 48 states would not be constructed until 2018 or later.

The Rocky Mountain region is expected to increase its production of natural gas over the next 20 years, primarily from unconventional sources such as tight sands, shale, and coalbed methane. The portion of natural gas contributed by the Rocky Mountain region to the total of the lower 48 states onshore natural gas production is expected to increase from 27 percent (in 2003) to 38 percent in 2025 (EIA 2005). Part of this predicted gain in share of total onshore production is because some other domestic regions are expected to experience declining production rates.

Much of the additional new production in the Rocky Mountain region is targeted for markets in the Midwest and Eastern United States. For example, the western phase of the REX, a joint venture by Kinder Morgan Energy Partners L.P. and Sempra Pipelines and Storage, authorized in FERC Docket No. CP06-354-000, consists of about 718 miles of 42-inch-diameter pipeline from Colorado to Missouri that went into service early in 2008. At the end of May 2008, the Commission issued a Certificate to REX authorizing the eastern phase of its project, in Docket No. CP07-208-000, that would extend the pipeline an additional 639 miles from Missouri to Ohio. Alliance Pipeline, Inc., in partnership with Questar Overthrust Pipeline, recently announced plans to develop the proposed Rockies Alliance Pipeline Project, which would extend an 800-mile-long 42-inch-diameter pipeline from Wamsutter, Wyoming to Emerson, Minnesota (Natural Gas Intelligence 2008c). In response, TransCanada announced plans for a 500-mile-long, 42-inch-diameter pipeline from Wamsutter, Wyoming to interconnect to the existing Northern Border system (Natural Gas Intelligence 2008d).

There are also plans for new pipelines to bring Rocky Mountain gas to southern Oregon, northern Nevada, and northern California. Both the Bronco and Ruby Projects propose to construct pipelines between the hub at Opal, Wyoming to interconnections with the existing GTN, Tuscarora, and PG&E systems just east of Malin, Oregon. The Ruby and Bronco Projects are discussed below in section 3.1.2.2.

In addition, Sempra LNG, a subsidiary of Sempra Energy (Sempra), recently put its Energia Costa Azul LNG terminal (Costa Azul), located near Ensenada, Mexico, into service. This facility, which can supply natural gas to northern Mexico and southern California using LNG imported from the Pacific Basin, is discussed more fully below.

3.1.2.2 Newly Proposed Pipelines

We considered three newly proposed jurisdictional interstate pipelines as system alternatives to the JCE & PCGP Project. One of these pipelines (Palomar) could to bring Canadian and Rocky Mountain gas to the Portland metropolitan area. The Ruby Project and Bronco Pipeline Projects, which are in different stages of review, would both transport Rocky Mountain gas to the Oregon/California border.

Palomar

On August 30, 2007, the FERC accepted a request from Palomar Gas Transmission, LLC (Palomar), to initiate the Pre-filing environmental review process for its proposed new pipeline

project in Oregon, in Docket No. PF07-13-000. Palomar is a partnership between TransCanada's GTN and Northwest Natural. The main purpose of the Palomar pipeline is to bring Canadian and Rocky Mountain gas to the Portland, Oregon metropolitan area and the Willamette Valley, and compete with the Williams Northwest system, which currently is the only interstate pipeline with direct interconnections with Northwest Natural, the LDC for northwestern Oregon and southwestern Washington. In addition, a segment of the Palomar pipeline would interconnect with the proposed Bradwood Landing LNG terminal near Wauna, Oregon, and provide a second sendout pipeline that could bring new supplies of natural gas from imported LNG to the Portland metropolitan area and to the GTN mainline.

The Palomar Project would include about 215 miles of 36-inch-diameter pipeline, with a bi-directional flow capable of handling up to 1.4 Bscfd of natural gas. The pipeline would begin at an interconnection with GTN northwest of Madras, and extend over portions of Wasco, Clackamas, Marion, Yamhill, Washington, Columbia, and Clatsop Counties, Oregon. Palomar envisions the construction of the pipeline in two segments. The first segment would be about 109 miles long from the point of origin with GTN to an interconnection with Williams Northwest near Molalla, Oregon. A short lateral would provide an interconnection with Northwest Natural also near Molalla. The second segment would be about 103 miles long between Molalla and Wauna, Oregon. If the Bradwood Landing LNG Project is not authorized, or not built, Palomar would terminate its pipeline somewhere west of Molalla, at an as yet undetermined point of interconnection with Northwest Natural. Northwest Natural could then construct an expansion of its non-jurisdictional local distribution system to connect Palomar to its Mist storage field in Columbia County, Oregon.

The Palomar pipeline would be co-located adjacent to existing powerlines or roads rights-of-way for about 26 percent of its route. For a total of about 49 miles, the pipeline would cross federal lands, including parcels administered by the Prineville and Salem Districts of the BLM, and the Mount Hood National Forest. The route would cross two federally designated Wild and Scenic Rivers: the Deschutes and the Clackamas. Other special management areas crossed include the Tillamook and Clatsop State Forests, and the White River State Game Management Area.

The FERC intends to do a separate environmental review of the Palomar Pipeline Project. Palomar filed its initial draft environmental Resource Report 1 (Project Description) on September 28, 2007, but indicated it would not be providing the remainder of its first drafts of environmental resource reports until the summer of 2008, or later. Therefore, at this time we have no specific information about the potential environmental impacts that would result from the Palomar pipeline.

We expect that the Palomar pipeline may have environment impacts similar to the Pacific Connector pipeline, because Palomar is about the same length, would also cross the Cascade and Coast ranges, would go through forest that may provide habitat for the marbled murrelet and northern spotted owl (NSO), and pass over parcels of federal lands managed by the USFS and BLM. Therefore, the Palomar pipeline has no clear environmental advantages over the Pacific Connector pipeline.

We do not consider Palomar to be a preferable alternative to the JCE & PCGP Project because it could not meet some of its main objectives, to provide new sources of natural gas through imported LNG to markets in southern Oregon, northern Nevada, and northern California. While

Palomar would bring new sources of natural gas to the Pacific Northwest, its target market is the Portland metropolitan area and Willamette Valley, where it could compete with Williams Northwest, which is currently the only interstate natural gas pipeline system serving that market. Palomar would transport most of its gas from Canada, obtained from GTN. It could also transport natural gas produced in the Rockies, obtained through GTN's interconnections with Williams Northwest. A number of studies have predicted that Canadian exports into the Western United States are not likely to increase in the future, and may even decline as production in the WCSB levels off over time and additional customers in Canada are served. Palomar may supplement deliveries to Northwest Natural and Williams Northwest with imported LNG obtained from the proposed Bradwood Landing LNG terminal (discussed below). However, the Bradwood Landing LNG Project has not yet been authorized by the FERC. If the Bradwood Landing LNG Project is authorized and built, natural gas from that facility flowing through the Palomar pipeline would have to be transported long distance through the existing GTN system to reach markets in northern Nevada and northern California.

Ruby

The Ruby Project was originally planned to be a joint venture between El Paso Corporation, Bear Stearns, and PG&E. Bear Stearns has recently undergone financial problems, and in early May 2008 PG&E announced it was pulling out of an agreement to acquire a 25.5 percent equity interest in the project, citing rising steel prices contributing to higher-than-expected pipeline costs. However, PG&E will remain as the anchor shipper for the Ruby pipeline, contracted for 375,000 Dt/d for 15 years (Energy Daily 2008; Inside FERC 2008c).

The 42-inch-diameter Ruby pipeline would extend for about 655 miles from the Opal Hub in southwestern Wyoming to the Oregon/California border near Malin, Oregon, where it could interconnect with the northern terminus of PG&E's 400/401 lines, the northern terminus of Tuscarora, and the southern terminus of GTN. The Ruby pipeline would be designed to eventually transport up to 2.0 Bscfd (Inside FERC 2008b). The purpose of the Ruby Project is to deliver Rocky Mountain gas to markets in northern California and northern Nevada.

Ruby has filed an application with the BLM for a Right-of-Way Grant over federal lands. The FERC recently initiated the Pre-filing review process for the Ruby Project. We intend to produce a separate, stand alone environmental document for the Ruby Project to comply with the NEPA. Ruby filed its initial draft environmental Resource Report 1 in April 2008. We do not know when Ruby would file its other draft Resource Reports to provide specific data about specific potential environmental impacts resulting from the pipeline.

After PG&E pulled out as a project sponsor, James Yardley, chairman of El Paso's Pipeline Group, told industry analysts that his firm has "not yet committed to go forward with Ruby." Yardley further indicated that El Paso would only move ahead with the Ruby, "if we see a return on the project" (Energy Daily 2008). Although El Paso completed an open season in April 2008, Bruce Connelly, vice president of investor and media relations, indicated the company would be going back to committed and potential shippers with new cost estimates (Inside FERC 2008c).

The Ruby Project could satisfy some of the main of objectives of the JCE & PCGP Project. It would bring additional volumes of natural gas from the Rocky Mountain region to markets in northern Nevada and northern California. Studies have indicated that the Rocky Mountain region is one of the few areas where domestic natural gas production is predicted to increase in

the near future. The Project objectives that would not be met would be the diversification of West Coast gas supplies through the importation of LNG, and direct interconnections with LDCs like Avista to serve markets in southern Oregon.

The Ruby pipeline would be significantly longer (almost 655 miles) than the proposed Pacific Connector pipeline (230 miles). It stands to reason that a longer pipeline would not have any clear environmental advantages. For example, construction of the Pacific Connector pipeline would affect about 6,260 acres, while construction of the Ruby pipeline would affect about 12,000 acres. Ruby has not yet filed a formal application with the FERC, and has not yet provided draft environmental Resource Reports under its Pre-filing docket review. We have no information about specific resources that may be impacted by construction or operation of the Ruby pipeline, including potential effects on waterbodies, wetlands, soils, vegetation, wildlife, and cultural resources. Given that not all of the Project objectives would be achieved, and uncertainties about it environmental impacts and schedules for review or approval, we cannot consider the Ruby Project to be a preferable alternative to the JCE & PCGP Project.

Bronco

The Bronco Pipeline Project is being proposed by Spectra Energy (Spectra). While Spectra has not identified a specific route for the pipeline, it would extend almost 700 miles from Opal, Wyoming to Malin, Oregon. The purpose of the Bronco Project would be transport Rocky Mountain gas to the Pacific Northwest and California markets. The pipeline would have a capacity of about 1 Bscfd.

While the BLM indicated that Spectra has filed a Right-of-Way Grant application to cross federal lands, it has not yet requested the initiation of Pre-filing review at the FERC. Spectra has not yet announced the results of its open season for the Bronco Pipeline Project, which ended in February 2008. A Spectra representative stated that the project "may not work out as we originally saw it." Other industry analysts have indicated that the Bronco Project may be canceled because of competition from the Ruby Project and Williams' Sunstone Project, which would serve the same markets, purpose, and need (Inside FERC 2008a).

The Bronco Project could achieve objectives similar to the JCE & PCGP Project, in providing additional volumes of natural gas to northern Nevada and northern California. However, the gas from Bronco would come from domestic wells in the Rocky Mountains, while Jordan Cove wants to import LNG to diversify West Coast supplies. The Bronco pipeline would have no clear environmental advantages over the Pacific Connector pipeline, as it would be substantially greater in length. We have no environmental information about the potential impacts the Bronco pipeline may have on specific resources. At this time, even its exact route is uncertain. We consider the Bronco Project to be speculative, given its lack of customer support.

Sunstone and Blue Bridge Projects

In January 2008, Williams, in partnership with TransCanada, sent out a letter to prospective customers to determine interest in expanding its existing Williams Northwest pipeline system between Wyoming and Oregon (Williams 2008). The potential expansion would consist of a new pipeline, to be known as the Sunstone Project, designed to transport about 1.2 Bscfd of natural gas. In June 2008, Sempra announced it would acquire a 25 percent stake in the Sunstone Project, together with an undisclosed amount of capacity on the pipeline (Coos Bay World 2008; Gas Daily 2008).

The Sunstone Project would consist of a new 618-mile-long, 42-inch-diameter pipeline parallel to the existing Williams Northwest mainline from Opal, Wyoming to an interconnection with the GTN system near Stanfield, Oregon. The purpose of the Sunstone Project would be to transport natural gas produced in the Rocky Mountain region and the WCSB to markets in the Pacific Northwest, northern Nevada, and northern California (Natural Gas Intelligence 2008e).

In March 2008, Williams and PSE announced their joint plans to develop the so-called Blue Bridge Project. This would consist of up to about 170 miles of 30- and 36-inch-diameter pipeline extending from the terminus of the Sunstone Project at Williams Northwest's existing interconnection with GTN at Stanfield, Oregon to Seattle, Washington. The Blue Bridge Project would also require the addition of compression at Williams Northwest's existing Plymouth, Washougal, and Chehalis compressor stations in Washington. The Blue Bridge Project would make available up to 500,000 Dth/d of natural gas from Rocky Mountain and WCSB producers (Steis 2008). PSE, an LDC serving customers in western Washington, indicated it would be the anchor shipper on the pipeline, and may become an equity investor in the project.

The Sunstone and Blue Bridge Projects could achieve many of the main objects of the JCE & PCGP Project. They would provide additional volumes of Canadian and Rockies produced natural gas to markets in the Pacific Northwest, northern Nevada, and northern California. However, these projects would not meet the objective that Jordan Cove has of diversifying regional sources of natural gas through the importation of LNG.

We consider the Sunstone and Blue Bridge Projects to be in the speculation stage. Williams and its partners are still weighting customer interest in these projects. The open season for the Blue Bridge Project was scheduled to conclude by June 2008. Williams and its partners have not yet come to the FERC to discuss their plans. However, a TransCanada spokesman indicated that eight shippers had committed to the Sunstone Project, and that they may request that the FERC begin the Pre-filing environmental review process in August 2008 (Seay 2008).

However, at this time we have no data about the potential environmental impacts of either the Sunstone or Blue Bridge Projects. Because the Sunstone pipeline would be longer than the Pacific Connector pipeline, it does not appear to be clearly environmentally superior.

3.1.2.3 Existing LNG Facilities

Existing LNG Import Terminals in the United States and Mexico

There are seven existing onshore LNG import terminals in operation in the United States that are regulated by the FERC. They are located in Everett, Massachusetts; Cove Point, Maryland; Elba, Georgia; Lake Charles and Sabine, Louisiana; Freeport, Texas; and Peneulas, Puerto Rico. There are two operating offshore LNG import facilities in the waters off the United States: one in the Gulf of Mexico and the other in Massachusetts Bay; both buoy-based receiving facilities owned by Excelerate Energy, that come under the jurisdiction of the Coast Guard and U.S. Department of Transportation, Maritime Administration (MARAD) according to the Deepwater Port Act. There are three other FERC-authorized onshore LNG import terminals currently under construction along the Gulf of Mexico (at Hackberry, Louisiana; Pascagoula, Mississippi; and Sabine, Texas). In addition, the FERC has authorized ten other LNG import terminals along the Gulf and East Coasts of the United States (at Falls River, Massachusetts; Long Island Sound, New York; Logan Township, New Jersey; Cameron, Louisiana; Pascagoula, Mississippi; Port

Lavaca, Texas; Port Arthur, Texas; and three in Corpus Christi, Texas) that have not yet been built. None of the operating, under-construction, or authorized but un-built LNG import terminals on the Gulf or East Coasts would be a reasonable or feasible system alternative to the proposed project because of their distance from the proposed market area for the JCE & PCGP Project.

As previously mentioned, there is an LNG terminal that was recently completed by Sempra on the Pacific Coast in Baja, Mexico. The Costa Azul terminal is sited within a 400-acre parcel, about 15 miles north of Ensendada, with two full containment LNG storage tanks with a total capacity of 320,000 m^3, open rack vaporizers (ORV), and a 42-mile-long, 36-inch-diameter pipeline with an average sendout capacity of 1.0 Bscfd. Half of the processing capacity is leased to Shell. In April, 2008, Costa Azul received its first shipment of LNG from Qatar to test the LNG terminal. Sempra signed a 20 year agreement to receive future shipments from Indonesia.

In October 2007, in Docket No. CP06-61-000, the FERC authorized the expansion of the North Baja Pipeline between an interconnection with the El Paso pipeline system at Ehrenberg, Arizona and the Mexican border near Yuma, Arizona where it interconnects with the Gasoducto Bajanorte pipeline. The Gasoducto Bajanorte pipeline terminates at Costa Azul, while the El Paso pipeline system extends to southern California near Blythe where it interconnects with the Southern California Gas Company (SoCal Gas) intrastate pipeline network. The purpose of the North Baja pipeline expansion is to bring new supplies of natural gas, from LNG imported to Costa Azul, to markets in southern California. In addition, the proposed Transportadora De Gas Natural De Baja California pipeline would transport natural gas from Costa Azul to southern California via an interconnection with the existing intrastate pipeline system of the San Diego Gas and Electric Company (SDG&E) (CEC 2007).

The CEC estimates that up to 50 percent of the capacity of the Costa Azul LNG terminal would be contracted for use in Mexico, with the remainder available for southern California markets. Natural gas from Costa Azul would be conveyed into southern California via the existing intrastate pipeline systems of SoCal Gas and SDG&E, both subsidiaries of Sempra, the owner of Costa Azul. The California Public Utilities Commission has divided the state so that SoCal Gas and SDG&E are LDCs that serve southern California, while PG&E serves northern California. It is unlikely that substantial volumes of gas intended for SoCal Gas and SDGC would find its way to the northern California distribution system of PG&E.

Existing LNG Storage Facilities in the Pacific Northwest and Nevada

Five LNG storage facilities currently exist in the Pacific Northwest. These are peak shaving plants that liquefy natural gas, store it as LNG, and then vaporize the LNG back into natural gas for use during periods of peak demand. These facilities do not add new supplies of natural gas to the region, but rather act as storage facilities, using existing supplies, to even out the discrepancies created by varying seasonal demands. Pauite operates a peak shaving plant in Lovelock, Nevada.

There are no LNG peak shaving plants in California. PG&E operates a 10,000-gallon per day methane liquefaction plant in Sacramento, and as of 2004 there were eight other liquefaction plants in California (California Electricity Oversight Board 2004). These small-scale plants are used mostly for commercial applications, including producing LNG as fuel to power vehicles.

In Oregon, Northwest Natural owns and operates two peak shaving LNG storage plants. One is located in Portland, and has a 28,000 m^3 tank with a storage capacity of 600 Mscfd. The other is located in Newport and has a 48,000 m^3 tank and a storage capacity of 1.0 Bscfd. In Washington, Williams Northwest owns and operates a peak shaving LNG storage plant in Plymouth with a liquefaction capacity of 19.7 Mscfd, a storage capacity of 60,000 m^3, and a vaporization capacity of 300 Mscfd. In Gig Harbor, Washington, PSE operates a small LNG peak shaving plant with a capacity of 31 million Dth, and a maximum withdrawal rate of 3 million Dth a day. In Nampa, Idaho, Intermountain Gas operates an LNG peak shaving plant with a capacity of 588 million Dth and a maximum withdrawal of 60 million Dth/d (NWGA 2007).

We considered the possibility of converting one of the existing peak shaving LNG storage plants into an LNG import terminal as a system alternative to the proposed Project. Such a conversion would not make sense at land-locked peak shaving plants, such as at Nampa, Idaho, and Lovelock, Nevada, which cannot receive LNG carriers. While several other existing peak shaving plants are located along waterbodies, they could not presently handle deep draft LNG carriers. Plymouth is located on the Columbia River, but is upriver of several dams, and so it would not be accessible to LNG carriers. Although Gig Harbor is located on Puget Sound, the PSE peakshaving facility is located about 1 mile from the harbor and would not be accessible to LNG carriers. While it may be feasible to construct a pipeline to transmit LNG from the harbor to the PSE peak shaving facility, such a pipeline would have additional associated environmental impacts. The Portland facility is located on the Willamette River and would potentially be accessible to LNG carriers. However, the waterway for LNG marine transit would be over 100 miles long and the navigation channel is obstructed by a bridge at Ross Island that only has clearances of 120 feet high and 100 feet wide. Newport is on the Oregon coast; however, the port of Newport is relatively small, with channel depths ranging from 20 to 30 feet. The port at Newport could not accommodate LNG carriers without extensive dredging. Therefore, we conclude that converting existing peak shaving LNG storage plants in the region into LNG import terminals is not a reasonable or feasible system alternative to the proposed Project.

3.1.3 Proposed West Coast Alternative LNG Import Terminals

We assessed existing proposals for offshore and onshore LNG import terminals on the Pacific Coast of North America, including facilities proposed on the west coast of Mexico, Canada, and the United States.

3.1.3.1 Proposed LNG Import Terminals on the West Coast of Mexico

The proposed LNG import terminals on the West Coast of Mexico include two offshore facilities (Terminal GNL Mar Adentro de Baja California and Moss-Maritime LNG Project) and one onshore facilities (Terminal GNL de Sonora). The Terminal GNL Mar Adentro de Baja California, proposed by Chevron Corporation (Chevron), would have been a gravity-based structure (GBS) (see section 3.1.4.1) located near the Coronado Islands off the coast of Tijuana with a projected average sendout capacity of 700 Mscfd. In March 2007, Chevron announced it was dropping its plans to develop its proposed Baja, Mexico LNG import terminal (East Bay Business Times 2007). The Moss-Maritime LNG Project, proposed by a partnership between Moss-Maritime and Terminales y Almacenes Maritimos de Mexico, would be a floating storage and regasification unit (FSRU) (see section 3.1.4.1). The terminal would be located about 5 miles from Rosarito Beach off the coast of Baja, Mexico and have an average sendout capacity

of 297 Mscfd. This facility was granted a permit from the Mexican government, but its current status is unknown (Lindquist 2007).

The Terminal GNL de Sonora would be an LNG import terminal located near Puerto Libertad, Sonora, on the eastern shore of the Gulf of California (Sea of Cortez), with a sendout capacity of 1.3 Bscfd, proposed by El Paso and DKRW Energy LLC. The partners have received some environmental permits from the Mexican Federal Ministry of the Environment and Natural Resources. Gas supply for this facility still needs to be secured, and in May 2006 El Paso announced it was halting plans for a 59-mile-long sendout pipeline that would link the proposed terminal to markets in Tucson (CEC 2007).

The target markets for the LNG import terminals on the west coast of Mexico would be northern Mexico, southern California, and other states in the southwestern United States (Arizona and Texas). The proposed LNG import terminals in northern Mexico would be far from the market areas of northern California, northern Nevada, and the Pacific Northwest proposed to be served by the JCE & PCGP Project. These terminals could not meet the Project objectives without substantially increasing their proposed capacity and constructing over 1,000 miles of new pipeline with compressor stations. Therefore, we do not consider the Mexican LNG terminals to be reasonable or feasible alternatives to the proposed Project and did not evaluate them further.

3.1.3.2 Proposed LNG Import Terminals on the West Coast of Canada

One proposed onshore LNG import facility (WestPac) in British Columbia, Canada, has not yet begun the environmental review process for its revised project, while another LNG import terminal (Kitimat) has received regulatory approval and is planning to begin construction in the near future.

WestPac LNG Terminal, British Columbia

WestPac LNG Corporation proposes to construct and operate an LNG import terminal near Kiddie Point on Texada Island, about 75 miles northwest of Vancouver in the Straights of Georgia, British Columbia, Canada. Originally, WestPac started the environmental review process with the Prince Rupert Port Authority in 2006 for an LNG terminal site on Ridley Island (CEC 2008). The proposed location of the LNG terminal was moved to Texada Island in July 2007. The terminal would include a marine jetty capable of handling about 36 LNG carriers a year, with capacities up to 165,000 m^3. Onshore, there would be two full-containment LNG storage tanks, re-gasification facilities, and an electric generation plant. While WestPac indicated it would have access to the Vancouver Island gas pipeline, it did not reveal any details about its sendout pipeline. Instead, WestPac indicated that it would provide a detailed project description with the application it intends to file with the British Columbia and Canadian Environmental Assessment Offices (EAO) early in 2009 (WestPac 2008). In January 2008, the sponsors put the project on hold pending review of initiatives that may be taken by the provincial government of British Columbia related to emission or climate change regulations (Gas Daily 2008).

The WestPac LNG facility may be an alternative to the proposed JCE & PCGP Project, if the project were to include pipeline connections to the existing grid enabling the transportation of natural gas to markets in the Western United States. However, at the present time it is unclear what the target markets may be for this project, and how gas would be transported from the LNG terminal to end users. In addition, environmental review of the proposal would not resume until

2009, and there is uncertainty over whether or not the appropriate Canadian government authorities would approve the project. Therefore, we do not consider the WestPac LNG terminal to be a feasible alternative to replace the JCE & PCGP Project.

Kitimat LNG Terminal, British Columbia

The Kitimat LNG terminal, proposed by a subsidiary of Galveston LNG, Inc., would be located at Bish Cove, about 8 miles southwest of the Port of Kitimat, British Columbia. The facility would receive four or five LNG shipments per month. The LNG terminal design includes marine offloading, two 160,000 m^3 LNG storage tanks, natural gas liquids recovery, and regasification facilities, with terminal capacity being 1 Bscfd. The terminal would deliver gas via a 9-mile-long lateral pipeline into the Pacific Trail Pipeline, to be operated by a partnership between Galveston LNG Inc. and Pacific Northern Gas Ltd. This would be a new 292-mile-long pipeline extending from Kitimat to Summit Lake, British Columbia, where it would interconnect with the existing Spectra Energy Transmission (formerly Duke Energy) pipeline system (Kitimat LNG Inc. 2008). An environmental assessment was completed for the Kitimat LNG terminal, and the project was approved by the Canadian Environmental Ministry in August 2006. Pacific Trails Pipeline filed a formal environmental application with the British Columbia EAO in August 2007 (CEC 2008). The Kitimit developers expect to have their LNG terminal in operation by the end of 2010.

The Kitimat LNG terminal appears to be a reasonable alternative for importing new additional volumes of natural gas to the Pacific Northwest. However, one of the main goals of the Kitimat LNG Project is to provide natural gas to the oil sands production area of Alberta, Canada, one of the fasting growing natural gas markets in North America. Further, interconnections with the Spectra and TransCanada pipeline systems would allow natural gas to be transported to Midwest and Eastern United States markets through the existing Northern Border, Alliance, and Iroquois pipeline systems. Thus, only a portion of the natural gas from Kitimat would probably be available for delivery to markets along the West Coast of the United States. In order to reach northern Nevada and northern California, through the existing GTN interconnection with TransCanada, gas from Kitimat would have to be transported a longer distance than from the Jordan Cove LNG terminal through the Pacific Connector pipeline to interconnections with Tuscarora and PG&E. Therefore, the Kitimat LNG terminal could not satisfy all of the objectives of the JCE & PCGP Project.

3.1.3.3 Proposed LNG Import Terminals in California

There is one proposed onshore LNG import terminal, at Long Beach, and multiple proposals for terminals off the Pacific Coast in California. While the onshore terminal is under the jurisdiction of the FERC, the offshore proposals are being reviewed by the Coast Guard and MARAD under the authority of the Deepwater Port Act.

Long Beach LNG Import Terminal Project

The Long Beach LNG Import Terminal Project was proposed by Sound Energy Solutions (SES), a joint venture between Mitsubishi Corporation and ConocoPhillips, in FERC Docket Nos. CP04-58-000 et al., to be located within the Port of Long Beach, California. Features of the terminal include an LNG carrier berth capable of handling an LNG carrier up to about 200,000 m^3 capacity in size, two LNG storage tanks with a combined capacity of 320,000 m^3, four shell and tube vaporizers (STV), and a typical sendout capacity of 700 Mscfd of natural gas. A 2.3-

mile-long 36-inch-diameter pipeline would be constructed to transport natural gas from the LNG terminal to existing SoCal Gas facilities. In addition, a 4.6-mile-long 10-inch-diameter pipeline would be constructed to transport vaporized ethane from the LNG terminal to an existing Conoco Phillips plant. In October 2005, the FERC and Port of Long Beach produced a joint draft EIS for this project. In January 2007, the Long Beach Board of Harbor Commissioners, who would be responsible for leasing the property for the LNG terminal, decided to end its environmental review (Polakovic 2007). In March 2008, the FERC issued a letter to SES stating that staff would no longer work on its application for an LNG import terminal at Long Beach, because the company could not document that it had access to or control over its proposed terminal site. SES appealed the City of Long Beach's decision through the local judicial system, but a Superior Court judge ruled, in March 2008, against SES, finding that Long Beach had acted in an appropriate manner in halting its environment review process. In June 2008, SES withdrew its proposal (CEC 2008).

Cabrillo Deepwater Port LNG Facility

The Cabrillo Deepwater Port LNG facility, proposed by BHP Billiton, would be located in the Santa Barbara Channel about 14 miles from Point Mugu. The import facility would consist of an FSRU permanently moored to the ocean floor, with three independent Moss spherical storage tanks mounted within the hull together with eight vaporizers. An underwater 30-inch-diameter pipeline would extend about 21 miles, coming ashore in the vicinity of Ormond Beach in Ventura County, California, and interconnecting with the existing SoCal Gas system. The facility would have the ability to send out an average of about 800 Mscfd of natural gas.

BHP Billiton filed an application with MARAD on September 3, 2003, that was deemed complete on January 27, 2004. The Coast Guard and California State Lands Commission (CLC) issued a final EIS for this project in March 2007. In April 2007, the CLC and the California Coastal Commission voted against authorizing the Cabrillo Deepwater Port LNG facility. The governor of California rejected BHP Billiton's proposal in May 2007. Consequently, on June 5, 2007, the MARAD issued a Record of Decision denying the application for the Cabrillo Port (MARAD 2007).

Clearwater Port LNG Project

The Clearwater Port LNG Project was proposed by NorthernStar Natural Gas, Inc., the same developers promoting the Bradwood Landing Project. The Clearwater Port Project would use existing offshore Platform Grace, located in the Santa Barbara Channel about 13 miles from Oxnard. A new floating dock would need to be installed adjacent to the existing platform to moor LNG carriers during transfer. No storage facilities are proposed. The platform would be reconfigured to accommodate vaporizers. The natural gas would be delivered from the platform to the shore via a new 32-inch-diameter, 13-mile-long subsea pipeline. An additional 12-mile-long underground pipeline would convey the gas onshore from Oxnard to an interconnection with the existing SoCal system near Camarillo. The average sendout capacity of the facility would be about 1.2 Bscfd.

Clearwater Port filed an application with MARAD on January 28, 2004. On August 23, 2007, the application was deemed complete, and on September 18, 2007, MARAD issued a notice of intent to produce a draft EIS for the project. On October 23, 2007, the Coast Guard issued a "stop the clock" letter to the applicant with a list of 396 questions.

Ocean Way LNG Terminal

The Ocean Way LNG terminal, to be located in the Pacific Ocean about 22 miles south of Los Angeles, California, is proposed by Woodside Energy, Inc. (Woodside). The project would include a mooring facility and an underwater pipeline that would come onshore near Los Angeles International Airport and interconnect with the existing SoCal Gas intrastate local distribution system. The LNG would be regasified while still on board the ship, and the facility would have a first phase nominal sendout capacity of about 400 Mscfd.

Woodside filed its application with MARAD on August 18, 2006. In September 2007 the application was deemed complete, and a notice of intent to prepare a draft EIS was issued. The Coast Guard stopped the clock on this project on November 23, 2007, issuing a letter to Woodside with a list of 61 questions (CEC 2008).

Pacific Gateway LNG Facility

The Pacific Gateway LNG facility is proposed by Excelerate Energy, LLC (Excelerate) to be located off the shore of northern California. Excelerate, which currently operates an offshore LNG import terminal in the Gulf of Mexico, would use specially designed LNG tankers for the transportation of LNG and vaporization into natural gas. The northern California proposal would deliver up to 1.0 Bscfd of natural gas. This project is currently in the conceptual design phase, with Excelerate conducting "fatal flaw" analyses of offshore terminal locations and pipeline routes (Excelerate 2007). An application under the Deepwater Port Act has not yet been submitted for this project.

Esperanza LNG Terminal

In March 2007, Esperanza Energy, LLC (Esperanza), a subsidiary of Tidelands Oil and Gas Corporation, announced plans for an offshore LNG import terminal to be located in the Pacific Ocean about 15 miles from Long Beach, California. This facility would use the proprietary HiLoad system developed by TORP Technology to vaporize LNG as it is offloaded from ships. The natural gas would be transported to shore by an undersea pipeline, with a sendout capacity of about 1.2 Bscfd. One unique feature of this proposal would be the use of warm water discharged from an onshore host to regasify the LNG (Esperanza 2007; Nemec 2007). Esperanza has not yet filed its application under the Deepwater Port Act.

Conclusions About the Proposed California LNG Import Terminals

None of the proposed LNG import terminals in California is viewed as reasonable or feasible alternatives to the JCE & PCGP Project. None of these proposals have been authorized at this time. The Long Beach onshore LNG terminal proposal has been withdrawn by its sponsor. One of the offshore terminal applications (Cabrillo Port) has been denied. Others (Pacific Gateway and Esperanza) are in the speculation stage, with no applications yet submitted. In addition, the target markets for most of these projects are in southern California. If any of these projects were authorized and constructed, a multiple hundred mile long pipeline would be necessary to reach markets in northern California, northern Nevada, and southern Oregon. The California LNG import terminal proposals, therefore, could not easily meet some the main objectives of the JCE & PCGP Project, and may have environmental impacts greater than the JCE & PCGP Project.

3.1.3.4 Other Proposed LNG Import Terminals in Oregon

In addition to the JCE & PCGP Project, there are two other LNG import terminals that have been proposed in Oregon. As discussed below, both the Bradwood Landing LNG Project and the Oregon LNG Project are considered feasible alternatives to the JCE & PCGP Project. It appears that these alternatives could meet most, but not all, of the stated objectives of the JCE & PCGP Project. If the FERC finds that these projects are environmentally acceptable, the Commission could approve none, all, or some of them, and allow the market to decide which LNG terminals and associated pipelines ultimately get built.

Bradwood Landing LNG Project

In June 2006, Bradwood Landing LLC and NorthernStar Energy LLC (together referred to as NorthernStar) filed their applications with the FERC, in Dockets CP06-365-000 and CP06-366-000, for a proposed LNG import terminal in Clatsop County, Oregon, and an associated sendout pipeline located in Clatsop and Columbia Counties, Oregon and Cowlitz County, Washington. The Bradwood Landing LNG import terminal would be located at Columbia River Mile 38 and its operational footprint would cover about 40 acres onshore. Dredging would be necessary within a 58-acre area in the Columbia River to create a ship maneuvering basin. NorthernStar anticipates about 125 LNG carriers coming to call at the terminal each year. The LNG terminal facilities would include a single ship berth, two 160,000 m^3 LNG storage tanks, and SCV vaporizers.

The project also includes a 36.3-mile sendout pipeline that would connect the LNG terminal to the existing Williams Northwest system north of Kelso, Washington. The pipeline would follow an existing right-of-way for about 22 percent of its route. There are three residences identified within 50 feet of the construction right-of-way along the proposed pipeline route.

The closest residences to the proposed Bradwood Landing LNG terminal are about 0.6 mile away, on Puget Island. However, LNG marine traffic in the Columbia River waterway to the terminal would pass by the communities of Warrenton and Astoria, Oregon, and Skamokawa and Cathlamet, Washington. The Coast Guard issued a WSR, on February 28, 2007, indicating that the waterway may be suitable for LNG marine traffic if certain conditions are met. Those conditions include the enforcement of safety and security zones around LNG carriers, and the restriction of meeting places for other commercial river traffic.

The proposed Bradwood Landing LNG Project would be located in a high seismic hazard area, and the facilities may be susceptible to soil liquefaction and landslides. Approximately 700,000 cubic yards (cy) of sediment would be dredged to create the proposed ship maneuvering area in the Columbia River. The project would temporarily affect about 113 acres of wetland during construction, and have permanent impacts on about 19 acres of wetlands during operation. The pipeline would cross 94 waterbodies, of which 19 are proposed to be crossed using HDDs, including the Columbia River and Cowlitz River. About 211 acres of forest would need to be cleared for construction of the Bradwood Landing LNG Project.

The Bradwood Landing LNG Project may affect EFH for 90 species of groundfish, 5 coastal pelagic species, and 13 migratory species. The project may also affect federally listed threatened or endangered species. There are 14 ecologically significant units (ESUs) of salmonid species (5 Chinook salmon ESUs, 1 chum salmon ESU, 1 coho salmon ESU, 1 sockeye salmon ESU 5

steelhead ESUs, and 1 char ESU [bull trout]); 4 species of sea turtles; 8 marine mammal species; 1 deer species; 5 bird species; 1 butterfly; and 3 plant species. Although the FERC submitted a BA in March 2007, that document is currently being revised to address comments received from the FWS and the NMFS.

The FERC issued a final EIS for the Bradwood Landing LNG Project in June 2008. The main environmental advantages of the Bradwood Landing LNG Project in comparison to the JCE & PCGP Project would be the shorter distance of its sendout pipeline. Some disadvantages would be the longer LNG carrier voyage up the Columbia River waterway past several communities, and potential impacts on federally listed threatened and endangered species, including 13 salmonid ESUs.

The purpose of the Bradwood Landing LNG Project is to provide up to 1.3 Bscfd of natural gas to markets in the Pacific Northwest through new sources of imported LNG. Therefore, the Bradwood Landing LNG Project could be an alternative to the proposed JCE & PCGP Project. However, it is unclear if the Bradwood Landing LNG Project could meet all of the objectives of the JCE & PCGP Project, because it would not directly connect to the Avista LDC system serving southern Oregon. Also, if natural gas were to be provided by the Bradwood LNG import terminal to markets in northern Nevada or northern California, it would have to be transported longer distances through the existing GTN system than the Pacific Connector pipeline.

Oregon LNG Project

On June 10, 2007, the FERC agreed to the request from LNG Development Company LLC and the Oregon Pipeline Company (hereafter referred to together as Oregon LNG) to initiate the Pre-filing environmental review of their proposed Oregon LNG Project, in Docket No. PF07-10-000, with an LNG import terminal in Warrenton, Clatsop County, Oregon, and an associated 121-mile-long sendout pipeline crossing Clatsop, Tillamook, Washington, Yamhill, Marion, and Clackamas Counties, Oregon. The development of an LNG import terminal at Warrenton was originally proposed by Calpine Corporation (Calpine). However, after Calpine declared bankruptcy, rights to the project were transferred to Oregon LNG, a subsidiary of the Leucadia National Corporation. The FERC intends to produce a separate, stand-alone, independent EIS for the Oregon LNG Project.

Oregon LNG proposes to construct and operate and LNG import terminal within a 96-acre tract on the East Skipanon Peninsula, near the confluence of the Skipanon and Columbia Rivers, at about Columbia River Mile 11.5. The portion of the East Skipanon Peninsula containing the site for Oregon LNG terminal is owned by the State of Oregon, and leased by the ODSL to the Port of Astoria. Oregon LNG holds a 65-year sublease with the Port of Astoria for the parcel. The Skipanon Peninsula was created by placement of sandy sediments dredged from adjacent waterways beginning in the 1920s. The surrounding land use is industrial and recreational. An 18-hole golf course was planned for this area (Port of Astoria 2006). The City of Warrenton recently rezoned the area for water-dependent industrial use in order to allow for an LNG terminal at this location (Ramsayer 2005). The onshore portions of the parcel are zoned Water Dependent Industrial Shorelands 1-2, while the marine facilities are zoned Aquatic Development A-1.

The proposed Oregon LNG import terminal would be located downstream of the Astoria-Megler Bridge. It would have a single berth designed to handle about 100 LNG carriers per year, sized

from 138,000m3 to 266,000m3 in capacity. The berth would be located offshore in Young's Bay, adjacent to the Columbia River navigation channel, on submerged lands owned in fee by the ODSL, with current depths between 20 and 30 feet below mean lower low water. Oregon LNG expects that construction of its berth and turning basin would require dredging of about 1,275,000 cy of material within an 83-acre area to reach depths of about 45 to 50 feet required for the safe docking of LNG carriers. Oregon LNG indicated that its preferred alternatives for disposal of dredge materials would be in-water placement, including a combination of flow lane/scour hole placement and shallow open water placement. However, it has not specified the exact locations for dredge disposal.

Oregon LNG believes that its dock would qualify for the "wharf exception" under ORS 780.040(1), which would not require a lease from ODSL. The unloading platform at the berth would include three unloading arms and one vapor return arm. Construction of the dock and turning basin would affect about 138 acres.

Onshore facilities would include three 160,000 m^3 full containment LNG storage tanks, vaporizers, and a sendout system with a peak capacity of 1.5 Bscfd of natural gas. Oregon LNG currently plans on using a combination of direct ambient air vaporizes and natural gas-fired heaters to re-gasify the LNG. Construction of land based portion of the LNG import terminal would affect a total of about 70 acres.

Oregon LNG would install a new 36-inch-diameter 121-mile-long natural gas sendout pipeline to connect the LNG import terminal with the existing Williams Northwest system near Molalla, Oregon. About 30 percent of this pipeline route would follow existing rights-of-way, for roads, railroads, and powerlines. Construction of the sendout pipeline would affect about 1,634 acres. In addition, Oregon LNG would install a 9.4-mile-long 24-inch-diameter lateral, in Washington County, Oregon, that would connect to existing Northwest Natural LDC system facilities. The lateral's maximum capacity would be 0.8 Bscfd. Aboveground facilities associated with the sendout pipeline would include a single electric-drive gas compressor station, located about MP 51, where the Northwest Natural lateral would split off from the mainline. Oregon LNG indicated that it would be willing to transport its gas on the proposed Palomar pipeline, instead of building its own sendout pipeline, if the parties could reach a mutual agreement.

National Wetlands Inventory (NWI) data indicate approximately 70 acres of wetlands are present within the 96-acre site proposed for the LNG terminal. Oregon LNG estimates that construction of its import terminal would affect about 21 acres of wetlands in total, including about 2.2 acres of mudflats, 18 acres of high marsh, and 1 acre of low marsh.

Calpine conducted a preliminary habitat category determination according to ODFW standards for its proposed Warrenton LNG terminal site (Ellis Ecological Services and CH2M Hill 2005). Most of the parcel was proposed as Category 4 or 5 habitat, because it is degraded and does not provide important habitat for fish and wildlife. The shallow subtidal and mudflat habitats, where the trestle and unloading pipeline from the berth would be located, was proposed as Category 2 because these areas are important for salmonids. No Category 1 habitat was identified within the property.

The lower portion of the Skipanon Waterway, like the lower Columbia River, is designated critical habitat for salmon. The area that would require dredging for the Oregon LNG turning basin and berth was identified as deep subtidal habitat, proposed as Category 4. Listed adult and

juvenile salmonids use deep subtidal habitat for migration. Juvenile salmonids may also seasonally feed on zooplankton in such habitat. The deep subtidal habitat likely supports Dungeness crab (*Cancer magister*). It may also provide foraging opportunities for bald eagles (*Haliaeetus leucocephalus*). Steller sea lions (*Eumetopias jubatus*) are known to congregate along the South Jetty at the mouth of the Columbia River in the fall and winter months, and may forage in the estuary during this period (Lower Columbia Fish Recovery Board [LCFRB] 2004).

Within the vicinity of the proposed LNG terminal, ship route, and pipeline facilities there are 34 federally listed threatened and endangered species. No federally listed threatened or endangered species were found during surveys of the upland portion of the proposed Oregon LNG terminal. The waterway for LNG marine traffic and the terminal berth would be located within the Lower Columbia River estuary. The estuary provides habitat for federally listed threatened and endangered fish species, including eight units of Pacific salmon and five segments of steelhead trout. In total, there are 15 federally listed threatened and endangered fish species in the project area. The waterway for LNG marine traffic is also a potential habitat for four species of federally listed threatened and endangered turtles, eight marine mammals, one invertebrate, and two plants. Four federally listed threatened and endangered bird species (brown pelican, NSO, marbled murrelet, and short-tailed albatross) were identified in the Project area.

The closest residences are about 0.5 mile from the southern boundary of the Oregon LNG terminal site. The facility would be visible from the hillside of the western portion of the City of Astoria and from the City of Warrenton. Oregon LNG indicated that there may be 39 structures located in close proximity to its proposed sendout pipeline.

The proposed pipeline would cross about 699 acres of non-wetland forest, including portions of the Clatsop and Tillamook State Forests. About 549 acres of non-wetland agricultural land would be crossed by the pipeline, including some vineyards in the Willamette Valley.

The proposed pipeline would result in 192 waterbody crossings, which include 61 currently known perennial flow waterbodies, 39 currently known ephemeral flow waterbodies, and 27 currently known intermittent waterbodies. Oregon LNG indicated that it proposes to use HDDs at 20 waterbodies, including Adams Slough, Lewis and Clark River, Nehalem River, Tualatin River, Yamhill River, Willamette River, and Pudding River.

No archaeological sites were identified at the proposed Oregon LNG terminal, mainly because the terrestrial portion of this facility would be located on fill. Nine archaeological sites were found along surveyed portions of the pipeline route; of which eight require additional investigations to assess their NRHP eligibility.

In summary, the main environmental advantage of the Oregon LNG Project would be the shorter distance of the sendout pipe in comparison to the Pacific Connector pipeline. Disadvantages of the Oregon LNG Project include potential effects on salmon in the Columbia River, lack of identification of dredge disposal areas, and the potential impacts of the sendout pipeline on agricultural land (including vineyards) in the Willamette Valley. The Oregon LNG Project may not meet all of the objectives of the JCE & PCGP Project. It does not propose a connection with Avista to serve LDC markets in southern Oregon. Natural gas would have to transported a longer distance from the Oregon LNG terminal to reach markets in northern Nevada and California in comparison to the Pacific Connector pipeline from the Jordan Cove terminal.

3.1.3.5 Regional Review of Alternative Onshore LNG Import Terminal Ports

The project proponent selects the location of its facilities. The FERC then conducts an environmental review of that location, and compares the proposed facilities against other identified feasible and reasonable alternatives to determine if any alternative may be environmentally preferable. Below is a discussion of how Jordan Cove selected its proposed location for an LNG import terminal at Coos Bay. After reviewing these data, the FERC was unable to identify any other alternative locations for an LNG terminal in the region that could serve the same target markets, and would be environmentally superior.

A number of factors were used by Jordan Cove to screen potential ports for its proposed LNG import terminal within a regional context. Jordan Cove based its regional site selection process on the growing demand for natural gas in the Pacific Northwest, northern Nevada, and northern California (see section 1.1 of this EIS), and the fact that this area is currently underserved in terms of existing LNG import terminals and access to additional North American natural gas supply. Potential sites along the West Coast of Canada, Mexico, and southern California were not considered by Jordan Cove because of their distance away from the selected target markets, and constraints on existing pipeline infrastructure.

Jordan Cove and Pacific Connector set the boundaries of their target markets around the main metropolitan areas that they seek to serve: Boise, Idaho; Spokane, Washington; Seattle, Washington; Portland, Oregon; Reno, Nevada; and Sacramento, California. Sacramento, rather than San Francisco, was identified as the southernmost market center because it has a higher projected growth rate in the future.

Jordan Cove then identified ports within its study area that could handle LNG carriers. It examined 7 ports in California, 12 in Oregon, and 22 in Washington, with Stockton, California being the southern most port and Bellingham, Washington the northernmost port (figure 3.1-1). Those ports that have a channel depth of 36 feet MLLW are listed on table 3.1.3.5-1.

TABLE 3.1.3.5-1

Ports Potentially Suitable for LNG Carrier Traffic Within Jordan Cove's Project Study Area Based on Channel Depth of 36 Feet MLLW a/

Washington Ports	Oregon Ports	California Ports
Port Angeles	Portland	Humboldt
Port Townsend	St. Helens	
Gray's Harbor/Aberdeen	Port Westward	
Skamokawa	Wauna/Bradwood Landing	
Longview	Astoria/Warrenton	
Kalama	Coos Bay	
Vancouver		

a/ Depth of maintained federal navigation channel.

Using the list of potentially suitable ports that met minimum channel depth requirements, Jordan Cove then applied other suitability criteria to further narrow the list of potential ports:

- transit navigation restrictions;
- population density near site;

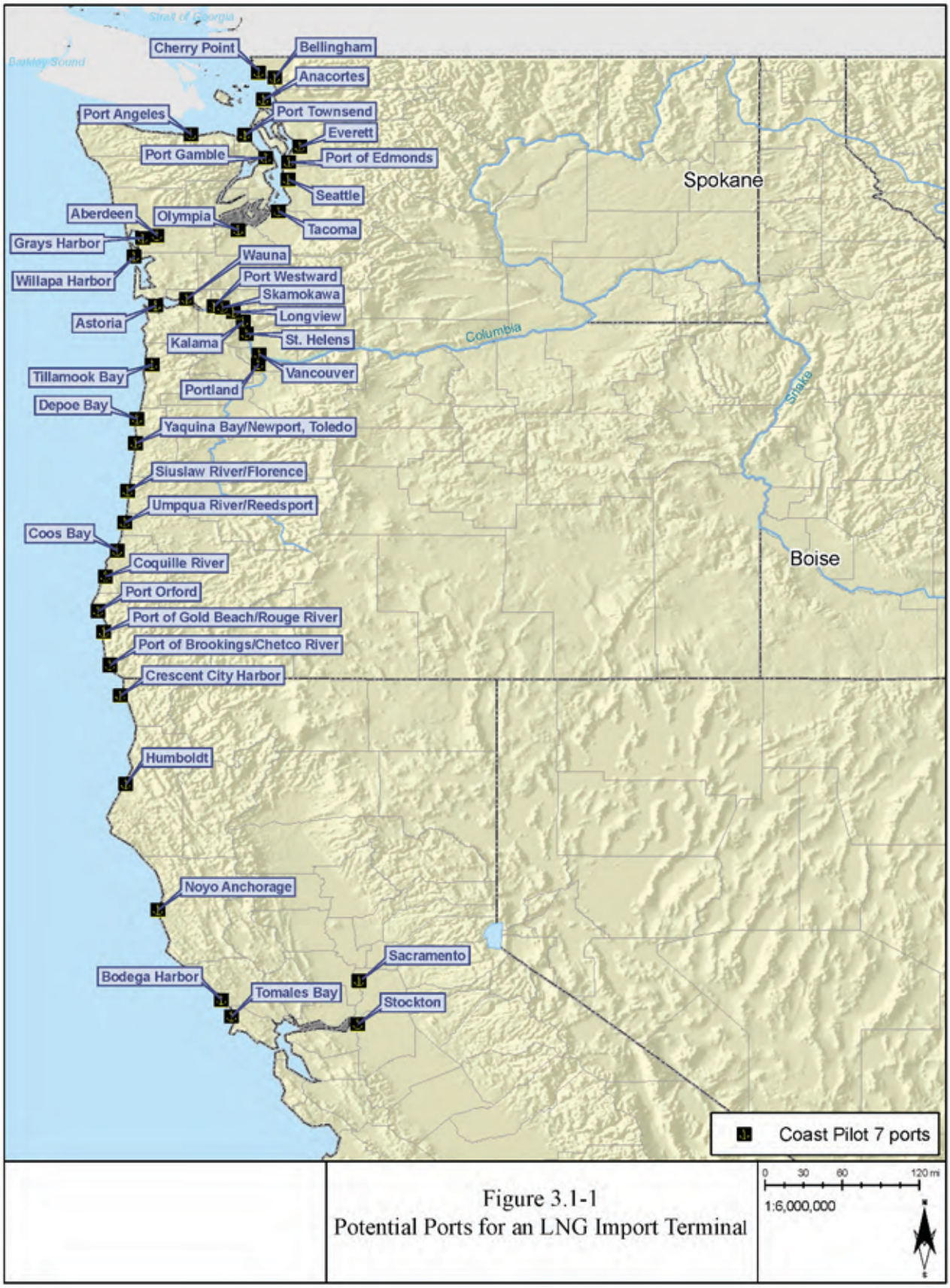


Figure 3.1-1
Potential Ports for an LNG Import Terminal

- population density along waterway to terminal, and transit distance;
- compatibility with existing port users;
- impacts on other waterway users, including commercial fishing and recreational boating;
- land use zoning;
- land availability and ownership; and
- environmentally sensitive areas.

Even if the navigation channel is deep enough to handle LNG carriers, there may be other obstructions along the channel that may prohibit LNG carrier transit. A typical LNG carrier requires a vertical air draft of 135 feet high, and horizontal clearance of at least 185 feet wide. There may be bridges or powerlines across the channel that would be less than those clearances. In addition, Jordan Cove considered other navigational obstacles, such as shoaling and swift currents, and existing restrictions that may prohibit transit by LNG carriers. Jordan Cove was also concerned about high levels of vessel traffic in the navigation channel, conflicts with other existing berths, and other users of the waterway, including commercial fishing and recreational boating. Lastly, Jordan Cove preferred that its LNG import terminal not be located in proximity to densely populated, urban areas.

Jordan Cove ruled out potential ports in northern California because they either did not have deep enough navigation channels, had obstructions to LNG carrier transit, or had high population densities. The San Francisco Bay area is heavily populated. The navigation channel from San Francisco to either Stockton or Sacramento is about 75 nautical miles long. The channel to Stockton is 35 feet deep at MLLW. The channel to Sacramento is only 30 feet deep. At least a 36 foot deep channel would be necessary to handle LNG carriers. Bodega Bay, Tomales Bay, and Crescent City Harbor are also not deep enough to accommodate LNG carriers. Humboldt Bay is deep enough, but the navigation channel is obstructed by a fixed highway bridge.
The ports at Cherry Point, Port Angeles, Port Townsend, Gray's Harbor, Skamokawa, Longview, Kalama, and Vancouver, Washington all have navigation channels deep enough to handle LNG carriers. However, these ports have the disadvantage of greater distance away from target markets in northern Nevada and northern California. In addition, there are injunctive exclusions to LNG tankers at Cherry Point and Port Townsend. At Gray's Harbor, there is an obstruction of a highway bridge that has a clearance of only 35 feet.

Except for Coos Bay, ports along the Oregon Coast, such as Tillamook Bay, Depoe Bay, Yaquina Bay, Florence, Reedsport, Bandon, Port Ordford, Gold Beach, and Brookings have channels that are not deep enough for LNG carriers. There are some suitable deepwater ports along the Columbia River. On the lower Columbia River, potential sites for LNG terminals have been identified at Warrenton/Astoria and Bradwood Landing/Wauna. At Warrenton and Bradwood Landing there are potential sites for an LNG import terminal that have been previously taken up by other LNG developers (Oregon LNG and NorthernStar), which are discussed above in section 3.1.3.4 as proposed LNG terminal alternatives. The Port of Astoria itself was not considered for an LNG terminal because of population density and lack of industrial zoned waterfront land that could be developed for this purpose. However, a potential site for an alternative LNG terminal was identified at Tansy Point in Warrenton, at the location presently occupied by Warrenton Fiber. This parcel is surrounded by residences, and no developer has stepped forward yet to propose the conversion of this existing wood chipping yard into an LNG import terminal.

Other potential ports in Oregon further up the Columbia River, including Port Westward, St. Helens, and Portland, were found undesirable by Jordan Cove because of longer transit distance along the waterway and populations densities. LNG carriers would have to transit about 58 miles up the Columbia River waterway to reach Port Westward, and about 104 miles to reach Portland. In the case of Port Westward, problems related to the lease of waterfront property caused another LNG developer to not to go forward with a proposal at that location.

At Coos Bay, Jordon Cove found a navigation channel deep enough to handle LNG carriers. The transit along the waterway is relatively short, at 7.5 miles to the proposed terminal location. There are no obstructions along the waterway. LNG marine traffic in the waterway would pass by the communities of Charleston, Empire, North Bend, and Coos Bay, with population densities ranging between 2,500 and 5,000 people per square mile in portions of North Bend and Coos Bay. In comparison, LNG carriers heading up the lower Columbia River to the proposed Bradwood Landing LNG import terminal would have to travel about 38 miles and pass by the communities of Warrenton and Astoria, with population densities at Astoria being about 1,600 people per square mile. There are no residences within one mile of the proposed Jordan Cove LNG terminal. The Jordan Cove terminal property is currently zoned for industrial development, and is large enough to accommodate all proposed facilities and the surrounding vapor hazard zone. There has been declining commercial shipping at the Port of Coos Bay over the last 20 years, and the Port is taking an active role in encouraging the location of an LNG terminal by providing the land, access channel, and slip.

3.1.3.6 Coos Bay Terminal Site Alternatives

Within Coos Bay, Jordan Cove looked at four tracts of industrial land as potential LNG terminal locations below the railroad bridge at CM 9 that would prevent LNG carriers from transiting further up the bay (figure 3.1-2). These sites are discussed below.

- Parcel A - Port Industrial Park – This parcel, comprising less than 100 acres, was eliminated by Jordan Cove because of limited size. The Port sold this tract to Southport Lumber who constructed a small dimension lumber mill on the site in 2005. Concurrent with this development, the Port installed a new railroad spur that runs parallel to the Trans-Pacific Parkway on the North Spit to serve the mill. Southport also has a berth at CM 6.4 along the Coos Bay navigation channel. Jordan Cove proposes to store sand dredged from the access channel and slip for its LNG terminal on Port owned land adjacent to the Southport parcel (see section 2.1.1.2).
- Parcel B – Former Weyerhaeuser Linerboard Mill – The Weyerhaeuser mill has been removed from this property, and the tract is available for future industrial development. However, Jordan Cove believes it is too close to the railroad bridge to allow for the creation of an access channel and berth to handle LNG carriers. Instead, Jordan Cove proposes to use the former Weyerhaeuser Linerboard Mill property to store material that would be excavated and dredged by the Port for the slip at the proposed Jordan Cove LNG terminal located at the Henderson Ranch tract (see below).
- Parcel C - Roseburg Forest Products – Jordan Cove originally proposed to use the Roseburg tract for its smaller terminal, conceived for intrastate gas supply, under the Oregon Energy Facilities Siting Council (EFSC) review process. That proposal would have only included one LNG storage tank, and is discussed in more detail below as an alternative design scenario (see section 3.1.3.7). The Roseburg tract would not be large

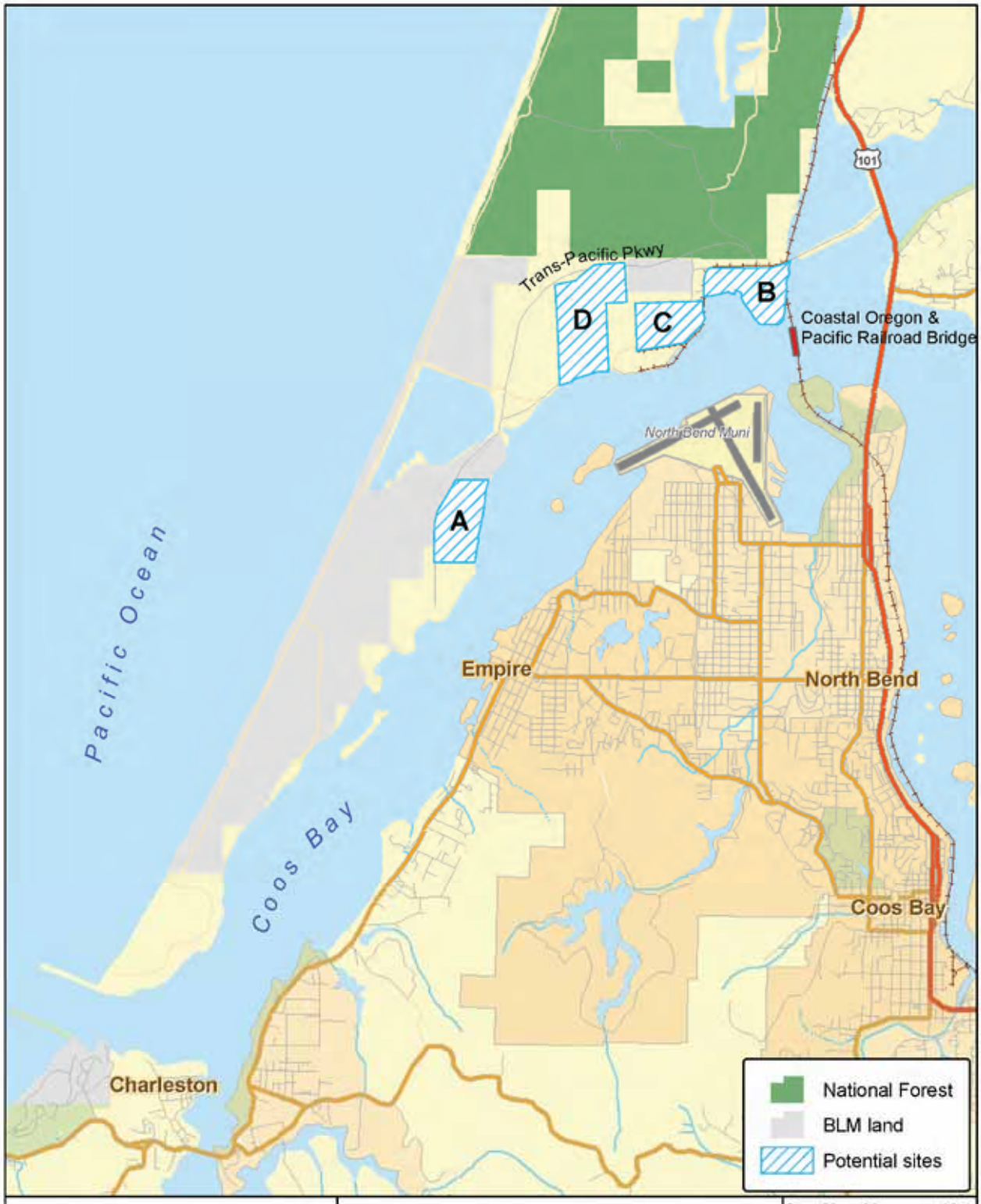


Figure 3.1-2
Potential LNG Terminal Sites in the Coos Bay Area

enough for an LNG import terminal with a slip, two LNG storage tanks, and the necessary vapor exclusion zones. However, Jordan Cove would use portions of the Roseburg property for some of its buildings, including the entry office, construction staging areas, access roads, and the NGL extraction export facilities.

- Parcel D - Henderson Ranch – The Henderson Ranch site, located immediately to the west of the Roseburg property was identified as the preferred location for the Jordan Cove LNG terminal. The Port obtained this property through an agreement with Weyerhaeuser. The tract is zoned for industrial use, and is currently vacant land that was formerly used by the COE to deposit materials dredged from the Coos Bay navigation channel.

3.1.3.7 Alternative Terminal Configurations

We considered whether or not there are alternative designs for the LNG terminal that may lessen environmental impacts and still achieve the Project objectives. This included an examination of a smaller facility with only one storage tank; various other storage tank designs; different berth configurations; and other vaporizer technologies. Based on Jordan Cove's responses to our data request questions about these issues, we believe that the currently proposed LNG facility terminal design makes sense from both an engineering and environmental standpoint in order to meet the Project objectives. We could not identify another alternative design that was environmentally superior, and still could meet the engineering criteria necessary to achieve Jordan Cove's expectations and the Project objectives. Those criteria included the ability to dock LNG carriers up to 217,000 m^3 in capacity, store up to 320,000 m^3 of LNG, send out up to 1.0 Bscfd of natural gas at peak deliverability, and include thermal exclusion zones that could be owned or controlled by Jordan Cove within its terminal tract.

Smaller LNG Terminal at Roseburg Property Alternative

In November 2004, Jordan Cove provided the EFSC with a Notice of Intent to build an LNG import terminal at Coos Bay with a smaller footprint at a different site than the proposal filed with the FERC in September 2007. The earlier design included a single berth for LNG carriers, a 3,000-foot-long, 20-inch-diameter cryogenic transfer pipeline from the dock to the LNG storage tank, a single duel-containment LNG storage tank with a capacity of 120,000 m^3, vaporization system with the capacity to deliver about 8,500 thousand standard feet of natural gas per hour, and a 25 MW power plant. These facilities would have been located on about 93 acres within the Roseburg property. The single full containment LNG storage tank was to be located east of the existing Roseburg mill buildings. The berth would have been adjacent to the existing Roseburg dock. Jordan Cove originally envisioned this smaller LNG terminal as serving a "niche" market entirely within the state of Oregon.

Jordan Cove eventually became convinced that the smaller LNG terminal with a single storage tank was not economically viable. Two LNG storage tanks, with a combined volume of 320,000 m^3, would be necessary to serve future demands. The project objectives changed to providing gas to markets in the Pacific Northwest, northern Nevada, northern California, as well as LDCs in southern Oregon. The increased volume of LNG storage capacity would be necessary to ensure a constant rate of natural gas sendout with minimal risk of stock outages, and to avoid demurrage of inbound LNG cargoes.

Jordan Cove considered the possibility of constructing one large LNG storage tank on the Roseburg property, with a 200,000 m^3 capacity. However, no existing LNG terminal in the United States has a storage tank that large, and so Jordan Cove settled on a design using two full containment tanks with a capacity of 160,000 m^3 each, which are the size of LNG storage tanks installed at the Costa Azul terminal near Ensenada, Mexico. While two tanks could be located within the Roseburg track, modeling indicated that the vapor dispersion zone for storage of 320,000 m^3 of LNG would extend beyond the parcel that Jordan Cove originally sought to acquire.

Besides the fact that the one LNG storage tank design could not meet the objectives of the newly redefined project, and the Roseburg parcel was too small to contain all the facilities for the new design and its associated vapor hazard zones, there were no significant environmental differences between the original concept and the current LNG terminal proposal on the adjacent Henderson Ranch property. Both parcels are zoned for marine industrial development. While there is existing industrial land use at Roseburg, the Henderson Ranch property is currently vacant, and was formerly used by the COE to deposit materials dredged during maintenance of the Coos Bay navigation channel. Total land required for operation of the LNG terminal at Henderson Ranch, 149 acres, is slightly larger than the 93 acres required for a smaller terminal at the Roseburg parcel. Construction of the storage and processing facilities at both Roseburg and Henderson Ranch would require removal and grading of existing sand dunes. While no upland wetlands would be disturbed during construction of the proposed LNG terminal at Henderson Ranch, it is possible that wetlands would be affected at the Roseburg site. Terminals at either location would require dredging in Coos Bay for the creation of an access channel and slip for LNG carriers. Jordan Cove believes that the portion of the bay at Roseburg contains habitat for oysters and other mollusks. The cryogenic transfer pipeline from a berth at Roseburg would be longer, at 3,000 feet, than the current design at Henderson Ranch, which would have a transfer pipeline 2,600 feet long. The single LNG storage tank at the Roseburg location would be outside of, but close to, the glide path for non-instrument runway 13/31 at the North Bend Airport. The two LNG storage tanks on the Henderson Ranch property would be farther away from the airport runways.

Other LNG Storage Tank Design Alternatives

Jordan Cove examined ways to design the LNG terminal to minimize the visibility of the LNG storage tanks. This design concept could best be accomplished by reducing overall tank height and increasing the diameter to height ratio, while still being constrained by the requirement that the maximum individual LNG tank would have a volume of 160,000 m^3. The possibility also existed that rather than employing two tanks to contain the necessary volumes, the 320,000 m^3 of storage could be spread between three or more tanks. This would have the potential to lower the overall height of each of the tanks, but would require an additional tank(s) and additional land area, with the trade-offs in this instance being both economic and aesthetic. The most economically efficient liquids storage methodology is established by basic solid geometric principles. The larger the tank, the smaller the tank materials required per volume contained (larger tanks use less materials per unit of volume than smaller tanks). Additionally, given the NFPA 59A thermal radiation and vapor dispersion exclusion zone distances, the use of fewer tanks would result in the smallest land area impact.

Shorter tank heights, which require larger tank diameters, were evaluated to reduce visual impact. Jordan Cove deemed the use of shorter tanks infeasible, since larger tank diameters than those proposed began to strain the limits of proven construction techniques, while at the same time creating thermal exclusion and vapor dispersion exclusion zones that extended beyond the site property boundaries.

An alternative of burying the LNG storage tanks was also considered. However, this approach was limited by local soils and geologic conditions. Geotechnical investigations at the proposed Jordan Cove terminal found the water table to be approximately 10 feet below the surface. In order to support a buried tank, the foundations would have to be below the water table, which would present difficult engineering and environmental problems. The groundwater would need to be continually pumped from the subsurface area in the vicinity of the LNG tanks to avoid the potential for contact with the underground tank heat coils, resulting in potential disruptions to groundwater flow, as well as, an additional water discharge. The high heat transfer coefficient of water would result in an excessive amount of power being used to energize the heat coils. The mobility of the water would exacerbate this problem because as the water was warmed it would flow away from the coils due to the natural groundwater migration pattern in this area. The warmed water would then be replaced by cold water resulting in still greater power consumption requirements.

Jordan Cove also considered different ways of orienting the LNG storage tanks within the Henderson Ranch parcel. Relocation of the tanks to the east or west is constrained by property boundaries. The location of the Henderson Marsh along the entire western side of the site and the wetlands in the north eastern corner of the site property, the existing Roseburg facilities, and the Port's concept for a slip dictated the primary north south axis on which the facility components could be oriented. Movement of the tanks to the south was limited by the required NFPA 59A distances from the slip. Although the tanks could be located slightly more northerly than presently planned, doing so would extend the length of the cryogenic transfer pipeline that connect the berth to the LNG storage tanks, and create a situation where the thermal exclusion and vapor dispersion exclusion zones would overlap the Trans-Pacific Parkway and the adjacent railroad line.

Alternative Berth Configurations

Jordan Cove compared placing a single berth for LNG carriers on the west side of the existing chip ship dock at Roseburg, to the current proposal for a slip at Henderson Ranch. An LNG carrier docking at Roseburg would be closer to the glide path for the 13/31 runway at the North Bend Airport than a ship at berth at the Henderson Ranch site. A berth at Roseburg would place an LNG carrier at dock within 600 feet of the Coos Bay navigation channel at the Jarvis Turn. In the event that another inbound vessel failed to properly negotiate the Jarvis Turn, there could be the possibility of a collision with an LNG carrier at the Roseburg berth location. The Coos Bay pilots and the Port, as well as engineering and safety consultants engaged by Jordan Cove, recommended that the Roseburg berth design be abandoned in favor of a berth at Henderson Ranch.

Vaporization Alternatives

We considered if possible vaporization alternatives may reduce potential Project-related impacts on water and air quality. Vaporizers are used to warm the LNG and turn it back into natural gas.

There are various technologies that could be used in the design of the re-gasification units. This includes ambient air vaporizers, open rack vaporizers, shell and tube vaporizers, and submerged combustion vaporizers. Vaporizers that burn natural gas to heat enclosed water baths to warm the LNG can produce air pollutants, including NO_x, CO, CO_2, and PM_{10}. Estimated air emissions associated with SCVs, water baths, and STVs are presented in table 3.1.3.7-1.

TABLE 3.1.3.7-1

Estimated Air Emissions Associated with Vaporizer Combustion

Vaporizer Design	Air Emissions (tpy) a/		
	NO_x	CO	PM_{10}
SCV b/	121.9	199.3	13.4
Water Bath c/	310	261	24
STV c/	310	261	24

a/ Tones per year. Based on a sendout rate of 1.0 Bscfd and 12-month operation of vaporizers.
b/ Based on an SCV firing rate of 17 Mscfd, 120 MMBTU/he heat rate.
c/ Based on large wall-fired boiler with flue gas recirculation and low NO_x burners, assuming 17 Mscfd firing rate. Estimated from EPA AP-42 guidelines for external combustion engines – boilers.

In the cases where water is used to warm the LNG, there are various heat sources that could be used to heat the water. These include electric power, wood chips, natural gas, and waste heat from cogeneration. Technologies relying on electric power for heating were eliminated because acceptable price. Burning of wood chips for a heating source was eliminated because of the large variability in wood chip costs over time, air emissions, lack of storage areas on site for the wood chips, and because of potential impacts associated with transporting large volumes of wood chips to the site.

Ambient Air Vaporizers

At some locations with warm climates, it is possible to use ambient warm air or ambient warm water as a source of the heat needed to vaporize the LNG. The advantage of vaporizers that utilize ambient air or water vaporization systems is that air emissions tend to be lower than for a system that involves combustion of a hydrocarbon fuel. Although air or water vaporizers can result in very small quantities of air emissions associated with electrical generation required to power fans or pumps, the power is generally produced off-site and the amount needed for the vaporizers is relatively minor (Coast Guard and MARAD 2003).

Ambient air-heated vaporizers use air warming structures to warm and vaporize the LNG. Because the surface area of the heat exchangers needs to be large for efficient heat transfer, the structures would be large and require significant space for construction and operation. Ambient air-heated vaporizers utilize air warming structures as heat exchangers to re-circulate the cooled water from the water bath and warm it through exposure to the air. Because the surface area of the water–air interface needs to be large for efficient heat transfer, the structures are generally large and require significant space for construction and operation. Because water would condense on the warming structures, ambient air vaporizers would produce about 1.3 mgd of water during operation compared to approximately 0.4 mgd for operation of SCV units.

Ambient air vaporizers are proposed for the Sabine expansion in Cameron Parish, Louisiana and at the proposed Oregon LNG terminal in Warrenton, Oregon. NorthernStar did a study of the

technical feasibility of using ambient air vaporizers at its proposed Bradwood Landing LNG terminal in Clatsop County, Oregon, and concluded that they would not be practical because of limitations associated with periods of cool weather along the Columbia River. Average monthly temperatures in Coos Bay and in the lower Columbia are similar.

Water-Based Vaporization

A water-based vaporization system would require withdrawing (and discharging) large volumes of water from an available source. In the case of the proposed Jordan Cove LNG terminal, that source would be Coos Bay. If the bay water temperature is above approximately 63°F, the water can typically serve as the sole heat source for LNG vaporization. When water temperatures drop to between 50°F and 63°F, supplemental heat is typically required. The water temperature in Coos Bay ranges from 46 to 58°F. This is too cold year-round to use for vaporization without supplementation from other sources. Also, the use of water-based vaporization, without another heat source, was not found viable because of concerns over potential impacts water withdrawals or discharges may have on aquatic resources. Water withdrawals for vaporizers may entrain fish. Additional concerns have been raised about the thermal plume associated with discharging cold water back into the affected waterbody. In the case of the bay, there may be concerns about the temperature of the discharge water.

Water Bath

Water baths use an open bath containing combustion tubes and LNG tubes. The fired gases transfer heat through the combustion tubes to the water bath and the water bath transfers heat to the LNG piping. The combustion gases and the water bath are not in direct contact with each other (unlike in SCVs). The combustion gases are discharged to the atmosphere. Approximately 2 percent of the natural gas produced by the terminal would be used in this process resulting in more air emissions than SCVs. This system is less efficient than SCVs.

Open Rack Vaporizer

ORVs are commonly used at LNG terminals in Asia and Europe. The Sempra Costa Azul LNG terminal in Baja Mexico uses ORVs. Typically, ORVs use seawater as their sole source of heat. Seawater is supplied by intake pumps to an overhead distribution header and flows over the outer surface of long finned tube panels. LNG flows inside the tubes and is vaporized by the warm seawater. The seawater is cooled by the LNG exchange, and would be returned to the ocean by an outfall at temperatures lower than when it was withdrawn. Electric power is required to run the seawater intake pumps. As noted above, water withdrawals for vaporizers may entrain fish and concerns have been raised about the thermal plume associated with discharging cold water back into the bay.

Shell and Tube Vaporizer

STV systems involve a heat exchanger in which tubes containing LNG pass through a shell containing an external fluid counter-current of heat exchange media such as a water/glycol mixture. On the opposite end of the heat exchanger loop, the water/glycol mixture is typically heated by using direct-fired combustors burning natural gas. However, the source of heat may vary depending on the particular design. About 100,000 gallons of fresh water would be necessary to operate a closed-loop system. An advantage of the STV is that selective catalytic reduction systems and oxidation catalysts can be used on the heaters to reduce NO_x and CO

emissions. In an open loop system the external fluid could consist of sea water in a single-pass seawater system. Sea water would enter through the side of the exchanger at an upper and lower inlet where it would be circulated over the tubes with the LNG flowing inside and warming it to a gaseous state where it would exit at the top of the shell. STV technology using a single-pass seawater system requires an abundant supply of sea water. The primary disadvantages of this technology are fouling and maintenance of the shell and tube exchangers, frequent periods of downtime for maintenance, potential freezing of the shell and tubes, and impingement and entrainment of marine organisms. We do not recommend use of this alternative for these reasons.

Submerged Combustion Vaporizer

Based on its analysis of the various technologies and heat sources, Jordan Cove chose the SCV system with natural gas for vaporization, supplemented with heat exchanged from the proposed on-site power plant. SCVs are generally based around a concrete structure containing a water bath with submerged stainless steel pipe coils. LNG enters the coils and, as it is warmed by the water bath, the vaporized LNG (natural gas) exits the coils. The water bath is warmed by burning natural gas delivered through the BOG recovery system. SCVs typically consume about 1.5 percent of the sendout natural gas from the terminal. Blowers provide combustion air at a pressure sufficient to force the combustion emissions up through the water bath where they heat the water. Electric power is required to run the combination of air blowers and water circulation pumps. The SCVs produce excess condensate water, on the order of several million gallons per day. Disposal of the excess water requires treatment with alkaline chemicals to neutralize the acidity caused by absorbed CO_2. SCVs tend to have higher air emissions, particularly NO_x, than other combustion units because the use of selective catalytic methods to control emissions has not proven reliable.

3.1.3.8 Dredging and Dredged Material Placement Alternatives

In order to create the access channel and slip for the proposed Jordan Cove import terminal, a total of about 5.6 mcy would need to be dredged and excavated by the Port. Jordan Cove and the Port determined that this was the minimum volume needed to construct the access channel and slip so that the terminal could safely accommodate LNG carriers. Therefore, we did not consider it feasible to reduce the volume or extent of dredging and still satisfy the objectives of the Project, and we did not evaluate alternatives for dredging and storing lesser amounts of material.

The proposed Project would store excavated and dredged materials at three different locations (discussed in more detail in section 2.1.1.2): Jordan Cove site; Weyerhaeuser Linerboard site; and Port Sand Stockpile site. In addition, materials dredged during maintenance activities would be deposited at sea at Site F. In choosing these dredged material storage locations, Jordan Cove and the Port examined a number of alternative sites for dredge material disposal; as discussed below. In addition, Jordan Cove and the Port considered which dredging methods were likely to have the least environmental impacts. Therefore, alternative dredging methods are discussed below.

Dredging and placement of structures within waters of the United States requires authorization from the COE under section 404 of the CWA and section 10 of the RHA. In addition, permission must be acquired to construct the access channel in Coos Bay on lands owned by the ODSL. As an element of its review, the COE is required to consider whether a proposed project

represents the least environmentally damaging practicable alternative pursuant to the CWA section 404(b)(1) guidelines (40 CFR 230). The term practicable means available and capable of being done after taking into consideration cost, existing technology, and logistics in light of overall project purposes. As a cooperating agency, the COE has recommended that the alternatives analysis in this EIS consider project design, configuration, and construction alternatives that avoid or minimize effects on the aquatic environment. In this way, this EIS could be used to identify the COE's least environmentally damaging practicable alternative.

Ultimately, activities associated with dredging, as well as construction of the LNG carrier berth and unloading facility, would be conducted in accordance with COE permit stipulations as well as the requirements of state permits (see section 1.3). To avoid or minimize impacts on water quality or biological resources associated with these activities (see sections 4.3.2.2 and 4.5.2.1), alternative dredging methods and dredged material placement areas were considered.

Alternative Dredging Methods

There are two general types of dredging methods: mechanical dredging and hydraulic dredging. The methods vary by the process by which material is loosened and transported from the seafloor to the water surface. The type of dredging equipment that is used affects the characteristics of the dredged material.

Mechanical Dredging

Mechanical dredging excavates sediments with a grab or bucket. The most common type of mechanical dredge is the clamshell dredge, which is named for the type of bucket used in the operation. The dredging process consists of lowering the bucket to the seafloor, closing the bucket and raising it back to the water surface, and depositing the dredged material into a scow or, if appropriate, directly into an adjoining placement site. The efficiency and capacity of this type of dredging is determined by the capacity of the bucket, which varies between 1.5 and 25 cy, scow capacity, which typically varies from 3,000 to 7,200 cy, the number of available scows, and sediment characteristics.

Mechanical dredges are often used in tightly confined areas, such as harbors, around docks and piers, and in relatively protected channels. By using numerous scows with one dredge, mechanical dredging can proceed continuously. As one scow is being filled, another can be towed to the placement site.

Hydraulic Dredging

In hydraulic dredging, material is loosened and lifted in suspension through a pipe system connected to a centrifugal pump. Hydraulic dredging is most efficient when working with fine materials and sands since they are easily held in suspension. Coarser materials, including gravel, may be hydraulically dredged; however, these materials require a greater demand of pump power and can cause excessive wear on pumps and pipes. The two main types of hydraulic dredges are cutter suction (pipeline) and hopper dredges.

Cutter Suction (Pipeline) Dredge

A cutter suction dredge is a hydraulic dredge that uses a rotating cutting apparatus around the intake of a suction pipe, called a cutterhead, to break up or loosen bottom material. A large

centrifugal pump removes the material from the bottom of the channel and pumps the sediment-water slurry through a discharge pipeline. Cutter suction dredges are generally rated based on the size of the discharge pipe, which ranges from 6 to 30 inches. A typical 30-inch dredge has a production rate of up to 20,000 to 30,000 cy per day, depending on sediment characteristics and placement method. Pipeline dredges are often operated on a 24-hour, 7-day per week basis, but downtime due to maintenance and other factors are often 25 percent or more.

Material dredged by a cutter suction dredge is directly placed into the placement area by the discharge pipeline or, less frequently, can be pumped into scows, which are then transported to the placement site and emptied via mechanical or hydraulic means. Discharge pipelines are usually floated on the water surface, but may be placed on land, submerged on the seabed, or buried. In a typical application, dredged material is pumped up to 25,000 feet. The addition of booster pumps, located on land, jack-up type rigs, or on moored barges, increases the distance to 50,000 feet or greater.

Cutter suction dredges operate continuously, and are cost effective if the placement site is in relative close proximity to the dredge area. However, booster pumps increase pumping cost and can decrease productivity. Cutter suction dredges are not recommended for areas with heavy debris that can clog pumps and impair efficiency.

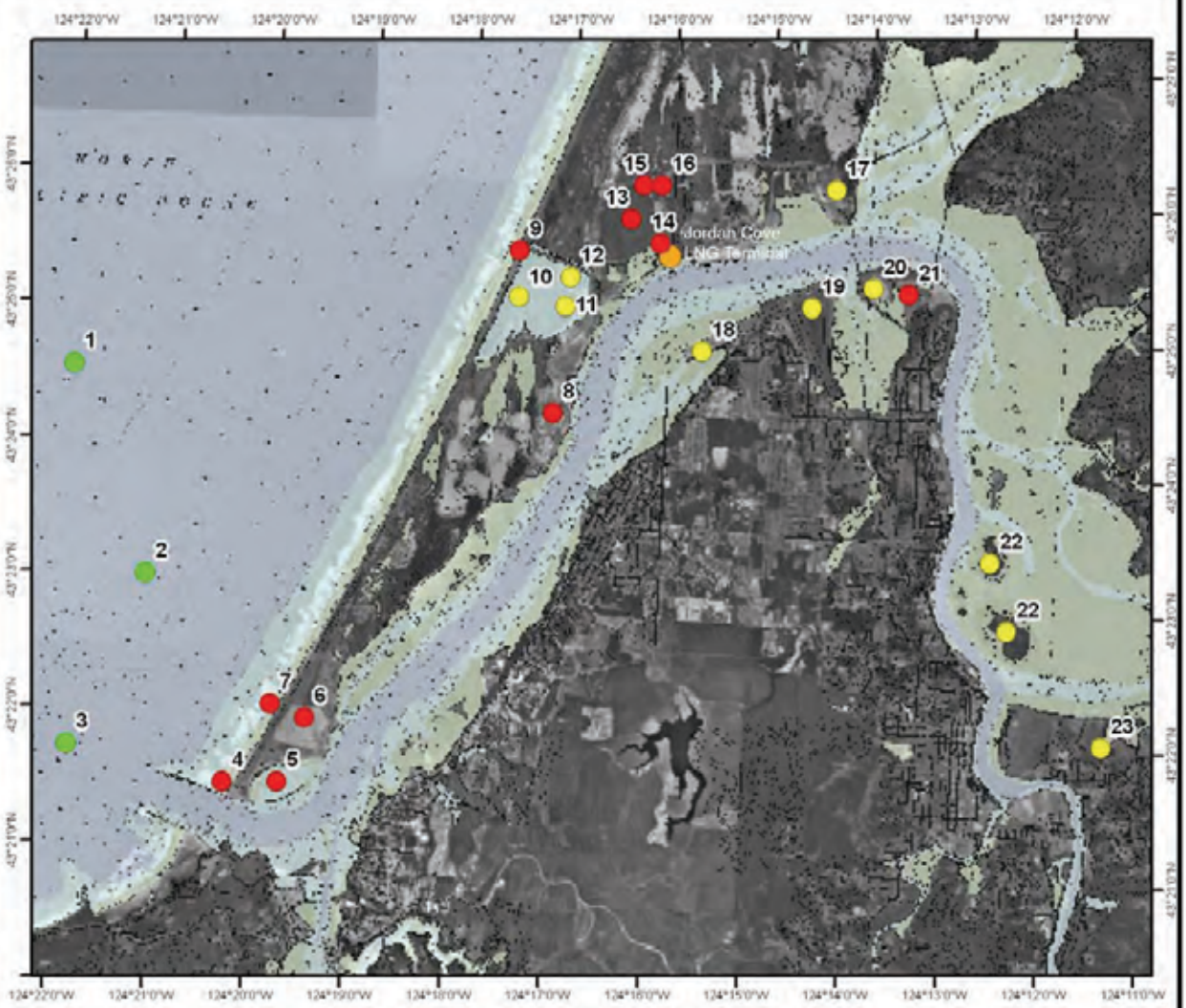
Hopper Dredge

Hopper dredges have the shape of a conventional ship hull and are equipped with either single or twin trailing suction pipes. A hopper dredge operates much like a floating vacuum cleaner in that material is lifted through the trailing suction pipes by one or more pumps and then the mixture of water and solids is stored in a hopper contained within the hull of the dredger. This type of dredge is often used for rougher, open waters where mechanical and hydraulic/pipeline dredges cannot operate effectively. A hopper dredge operates best by skimming layers of material in long, narrow runs and is primarily used in open water, such as rivers, canals, and open sea. This type of dredge is unable to get into corners, difficult to maneuver in confined spaces, unsuitable for use in shallow water, and is not effective on hard materials such as stiff clays. A hopper dredge can move quickly to a placement area under its own power, but the operation loses efficiency as the transport distance increases.

Once the hopper is full, material may be discharged onto an open-water placement site by opening the hopper doors located in the bottom of the ship's hull or fluidized by jets and hydraulically pumped from the hopper. For bottom dumping, the entire contents of the hopper can be emptied in a matter of minutes. Upon discharge from the hopper dredge, the dredged material falls through the water column as a well-defined jet of high-density fluid. The descent and deposition of the slurry mixture is dependent on the material's physical characteristics. Hydraulic pump out can take up to 30 to 60 minutes and discharge slurry is similar in density to cutter-head slurry.

Dredged Material Placement Alternatives

Initially, the Port evaluated 23 dredged material management alternatives, including conventional open water disposal, confined placement, and beneficial use. Disposal sites evaluated in the Excavated and Dredged Material Management Plan are shown on figure 3.1-3. In addition to the four sites chosen for the proposed Project, the Port seriously considered other options, including the Industrial Waste Pond, the North Spit beach nourishment site, and the



ID #	Alternative
1	Coos Bay Entrance Site H
2	Coos Bay Entrance Site F
3	Coos Bay Entrance Site E
4	North Jetty Breach
5	Crescent Bay Shoreline Stabilization
6	Western Snowy Plover Habitat
7	North Spit Beach Nourishment
8	Port Commercial Sand Stockpile Site
9	North Spit Tsunami Protection Levee
10	Industrial Waste Pond Site A (4CS)
11	Industrial Waste Pond Site B (3WD)
12	Black Liquor Lagoon
13	Henderson Marsh (DMD-4X)
14	Grassland Industrial Development
15	Excavated Material Stockpile Site
16	JCE Placement Site
17	Weyerhauser Linerboard Site
18	North Bend Municipal Airport Nearshore Disposal Facility (DMD-9X)
19	North Bend Municipal Airport Upland Disposal Facility (DMD-9Y)
20	North Point Island Disposal Facility
21	North Point Tsunami Zone Remediation
22	Island Disposal Facility (DMD-18A/B)
23	White Point Upland Disposal Facility (DMD-19B)

Legend

- Open Water Placement
- Confined Placement
- Beneficial Use
- Jordan Cove LNG Terminal

N

0 0.25 0.5 1 1.5 2 Miles

Figure 3.1-3
Potential Dredged Material Disposal Sites Evaluated by the Port

North Spit Tsunami Protection Levee. These are discussed below, with an explanation about why they were not selected. Table 3.1.3.8-1 lists the 23 sites evaluated by the Port, and the explanation of which sites are considered by the Port to be suitable.

TABLE 3.1.3.8-1

Excavated and Dredged Material Placement Sites Evaluated by the Port for the Proposed Jordan Cove Energy Project a/

ID No. (see Fig 3.1-3)	Potential Site	Available	Capacity	Feasibility		
				Technical	Logistical	Environmental
12	Black Liquor Lagoon	No - withdrawn by the owner				
3	Coos Bay Entrance Site E	No	No - site is closed and not accepting new material			
2	Coos Bay Entrance Site F	Yes	Yes – Jordan Cove proposes to deposit 3.5 mcy of maintenance dredged material over 20 years	Yes	Yes	Yes
1	Coos Bay Entrance Site H			No - restricted to finer-grained sands and silt materials from above RM 12		
5	Crescent Bay Shoreline Stabilization		No - capacity limited to between 200,000 and 500,000 cy			
15	Excavated Material Stockpile Site					No - wetlands are located on site.
14	Grassland Industrial Development	No - Site is not available for dredge storage because of overlap with Jordan Cove terminal facilities				
13	Henderson Marsh (DMD-4X)					No - wetlands are located on site.
10	Industrial Waste Pond – Area A (4CS)	No - withdrawn by the owner due to wetland mitigation issues				No – wetlands and birds could be affected
11	Industrial Waste Pond – Area B (3WD)	No - withdrawn by the owner due to wetland mitigation issues	Yes – capacity for 5.4 mcy of dredged materials			No – wetlands and birds could be affected
22	Island Disposal Facility (DMD-16A/B)	No	No – already at capacity and not accepting new material.			
16	Jordan Cove Energy Placement Site	Yes	Yes – capacity for 0.5 mcy of dry materials	Yes	Yes	Yes
18	North Bend Municipal Airport Nearshore Disposal Facility (DMD-9X)			No - pier has been constructed that provides lighting for runway.		No – wetlands are located at site.

TABLE 3.1.3.8-1

Excavated and Dredged Material Placement Sites Evaluated by the Port for the Proposed Jordan Cove Energy Project a/

ID No. (see Fig 3.1-3)	Potential Site	Available	Capacity	Feasibility		
				Technical	Logistical	Environmental
19	North Bend Municipal Airport Upland Disposal Facility (DMD-9Y)			No – airport has extended runway on one end of site and an access road on the opposite side	No - due to airport additions, access to open area of site is not available	
4	North Jetty Breach	No	No - site has not required additional material since the original repair to the breach in 2002			
20	North Point Island Disposal Facility	No – property is owned by the Al Pierce Lumber Company and is currently for sale. Property is zoned for water dependent industrial developments	No – dredged material was placed on the site in the 1980's creating wetland habitat, adding to the difficulties in trying to sell the property			
21	North Point Tsunami Zone Remediation	No – property is owned by the Al Pierce Lumber Company and is currently for sale	No – dredged material has been placed on site previously, but zoning changes preclude the placement of additional material			
7	North Spit Beach Nourishment	No – BLM denied use of this land for dredge disposal	Yes – capacity for 3.8 mcy of dredged materials	Yes	Yes	No – could impact snowy plovers
8	Port Commercial Sand Stockpile Area	Yes	Yes – capacity for 3.3 mcy of dredged materials	Yes	Yes	Yes
9	North Spit Tsunami Protection Levee	Yes	Yes – capacity for 2.3 mcy of excavated materials	Yes	Yes	No – may have impacts on wetlands and snowy plovers
6	Western Snowy Plover Habitat			No – BLM restricted on acceptance of dredged material		No –Pink sand verbena, a state listed endangered plant species, is present
17	Weyerhaeuser Linerboard Site	Yes	Yes – capacity for 1.8 mcy of materials	Yes	Yes	Yes
23	White Point Upland Disposal Facility (DMD19B)	No	No - site is closed and not accepting new material			

a/ From Moffat & Nichol International 2007.

North Spit Beach Nourishment

This dredged material site would consist of nourishment of 4.5 miles of the dune line along the North Spit starting at the North Jetty. Beach nourishment of the North Spit has the capacity to accommodate the 3.3 mcy of material that would be hydraulically dredged during construction of

the slip and access channel. Dredged material would be placed above the MHH water line in a continuous dune fill. Dredged material would be transported hydraulically via pipeline behind a containment levee constructed at the seaward edge of the nourished dune profile. Existing beach material would be used to construct the levee. Return water would be discharged into the Pacific Ocean. Earth moving equipment would grade the containment levee and the dredged material to the desired slope.

The North Spit Beach Nourishment alternative was not selected for two reasons. First, part of the land where this alternative was proposed is owned by the BLM, and the BLM would not allow this land to be used for dredged material disposal. Second, this activity would occur within an area that is critical habitat for the federally-listed threatened Western snowy plover, and it is possible that dredged material storage at this location could have adverse impacts on the Western snowy plover.

North Spit Tsunami Protection Levee

This site would use excavated material to construct a levee that would provide some protection for the North Spit in the event of a tsunami. The possible location of the levee is approximately two miles west of the slip site. The levee would provide protection to the cities of Coos Bay and North Bend, as well as slip from the impacts of a tsunami striking the North Spit. The levee would cover approximately 60 acres and would be approximately 5,750 feet in length beginning at the southern end of the industrial wastewater pond and extending to the northeast. The excavated material (2.3 mcy) would be hauled to the disposal site by truck. The North Spit Tsunami Protection Levee alternative was not selected because it is possible that dredged material storage at this location could have adverse impacts on the federally listed threatened Western snowy plover.

Industrial Waste Pond

The Industrial Waste Pond (IWP) on the North Spit was created by Weyerhaeuser to receive and treat effluent from the company's former mill. The IWP is a 300-acre settling pond, with a 20,000 gpm ocean outfall. The Port has an option to acquire the IWP as part of the large parcel it intends to purchase from Weyerhaeuser.

The IWP is about one mile west of Jordan Cove terminal. The Port considered using about 205 acres at the IWP for placement of excavated and dredged materials. The excavated materials could be transported by truck via the Trans-Pacific Parkway or the material could be transported in a slurry pipeline. Decant water would be returned to the bay through a separate pipeline between the IWP and the Jordan Cove terminal slip. The Port indicated that it would have to construct a 25-foot-high, 12-foot-wide containment berm around the portion of the IWP to be used for dredge storage. This berm would be 12,500 feet long, and constructed of 1.0 mcy of material excavated for the slip. Excluding the material used to construct the berm, the IWP would be able to handle about 5.4 mcy.

Two main factors influenced the Port's decision not to use the IWP for dredge disposal from the Jordan Cove terminal slip and access channel. First, this action would result in the filling of wetlands. Second, the IWP is important bird habitat.

3.1.3.9 Alternative LNG Terminal off the Shore of Oregon

We considered if it is possible to construct and operate an LNG import terminal in the Pacific Ocean off the shore of Oregon as an alternative to the Jordan Cove terminal. Offshore LNG import terminals located in federal waters fall under the jurisdiction of the MARAD and the Coast Guard (pursuant to the Deepwater Port Act of 1974, as amended by the Maritime Transportation Security Act of 2002). Currently, there are no deep water LNG terminals existing or proposed off the coasts of either Oregon or Washington. There are several proposed LNG terminals off-shore in southern California, and those proposals are discussed above in section 3.1.3.4.

The main advantage of an offshore LNG import terminal would be that it would probably not impact mainland populations. Also, impacts on other commercial and recreational users of the Coos Bay waterway would be avoided. However, there would still be a need for a sendout pipeline to connect the offshore LNG terminal with an onshore existing natural gas interstate system, to get the gas to its intended markets. Depending on the routing of that pipeline, there could be potential impacts on mainland populations and other environmental resources. In addition, there could also be impacts on aquatic resources related to the installation of the undersea portion of the pipeline from an offshore LNG import terminal. The length of the sendout pipeline from an offshore LNG terminal would have to be longer than the proposed Pacific Connector pipeline if it where to serve the same purposes and connect to the GTN, Tuscarora, and PG&E systems near Malin, Oregon.

The main disadvantage of an LNG import terminal located off the coast of Oregon would be technological limitations related to typical ocean conditions in the region. In addition, an offshore LNG import terminal would have a smaller LNG storage and natural gas deliverability output than the terminal proposed by Jordan Cove, and may not be able to meet the objectives of the Jordan Cove terminal. For example, the only deep water LNG terminal currently operating off the coast of the United States, the Excelerate Gulf Gateway Deepwater Port facility in the Gulf of Mexico, can deliver up to 690 Mscfd. As discussed in more detail below, because of the ocean conditions off the coast of Oregon, and the limitations of current technologies for deep water LNG terminal, we do not think that an offshore LNG terminal would be a reasonable or feasible alternative to Jordan Cove's proposed onshore LNG terminal to be located at Coos Bay.

Offshore LNG Terminal Technologies and Strategies

Companies that have proposed to construct and operate offshore LNG import terminals have advanced various technologies and strategies for platform construction, LNG carrier mooring,

LNG transfer and storage, vaporization, and sendout (LNG Express 2003). These technologies/ strategies include:

- offshore docking/onshore storage;
- fixed offshore terminals (GBS or platforms);
- transport/regasification vessels; or
- floating, storage, and regasification units.

Below we discuss these various technologies/strategies for offshore LNG import terminals, compare their potential environmental impacts, and analyze their feasibility as an alternative the onshore LNG import terminal facilities proposed by Jordan Cove.

Offshore Docking/Onshore Storage

Where deepwater access to a coastal port or harbor is unavailable, LNG can be transported to onshore storage tanks from ships using specially designed cryogenic pipelines. Such facilities enable LNG carriers to berth and transfer their LNG cargo to the cryogenic pipeline at docking facilities in offshore areas where natural water depths exceed 40 feet. Although feasible, a number of technical factors related to transporting LNG in a pipeline place limits on the practical maximum length of such a pipeline. This approach has been used at the existing Cove Point LNG terminal where the ship docking/unloading platform is located in the Chesapeake Bay about 1 mile from the shoreline. Similar facilities have been proposed for the Irving Oil LNG site in New Brunswick, Canada, and the Keltic Petrochemicals LNG and Bear Head LNG facilities in Nova Scotia, Canada. No such facility has been proposed for the West Coast.

While it would be possible to transfer LNG to shore through a cryogenic pipeline from an offshore docking structure, such a design would still require locating LNG storage tanks and process facilities at an onshore location, therefore resulting in similar environmental impacts as an onshore LNG import terminal, in addition to the disadvantages associated with an offshore docking structure and pipeline. Because of severe winter weather conditions and significant wave heights along the Oregon and Washington coasts (ABSG Consulting Inc. [ABSG] 2006), we did not identify a site where the use of this approach appeared practical.

Fixed Offshore Terminals/Gravity-Based Structure

There are basically two different types of fixed structures that can be used as an offshore LNG import terminal, either a GBS located directly on the seafloor or a pile-based platform. A GBS would contain LNG storage tanks and vaporizers on a platform with foundations directly on the seafloor. LNG could be offloaded from conventional LNG carriers, placed in the storage tanks within the GBS, and then vaporized for delivery as natural gas to the onshore market via an undersea pipeline. A GBS is only feasible in areas of relatively shallow water, where depths range between 45 and 100 feet. Ocean depths off the coast of Oregon exceed 100 feet in depth at an average distance of 1.7 nautical miles from the coast line. Therefore, any proposed LNG terminal alternative using GBS technology off the coast of Oregon would need to be located relatively close to the shore.

Chevron received approval from the Coast Guard to build an LNG import terminal in the Gulf of Mexico (the Port Pelican Project) using a GBS that would be anchored to the sea bottom in water 83 feet deep. The Port Pelican Project has been put on hold indefinitely and license rescission is expected. The recently abandoned LNG Terminal GNL Mar Adentro de Baja, off the western coast of Mexico, also proposed by Chevron, would have used a GBS at a depth of about 65 feet.

Given the costs associated with constructing and operating a GBS, it appears that these facilities are economical for projects with relatively large LNG storage (e.g., 250,000 to 330,000 m^3) and large natural gas sendout volumes (e.g., 800 to 2,000 Mscfd). Another limitation would be the articulation of the unloading arms between the GBS and a docked LNG carrier, whose movement would be affected by high winds and large waves.

There are multiple environmental issues associated with construction of an offshore LNG terminal using a GBS. First, there would be environmental impacts from anchoring the GBS to the ocean floor. The GBS would have to be built in an onshore graving yard and towed out to

sea. Associated with the graving dock would be the necessary channel that allows the GBS to be floated out to the ocean. The creation of the graving dock could have impacts on terrestrial resources. For example, the proposed graving dock to fabricate the GBS for the Port Pelican Project was estimated to require up to 174 acres of shoreline. There would also be logistical constraints of towing the GBS to a selected terminal site offshore in Oregon that would influence the location of the graving dock.

Another strategy using a fixed offshore terminal involves constructing offshore platforms on piles or converting existing offshore platforms to LNG use. Such fixed-tower structures, could be located in deeper water than a GBS. The platforms could be fitted with docking, unloading, storage, and vaporization equipment. As with a GBS, LNG could be unloaded from a conventional LNG carrier, vaporized at the platform, and sent as natural gas to the onshore market via an undersea pipeline. A fixed platform would have limited space for LNG storage, and would need calm seas or protection from the elements (such as being located on the lee side of an island) to allow for safe LNG carrier docking.

Depending on the specific design, offshore platforms may or may not include LNG storage facilities. The Clearwater Port proposed by NorthernStar Natural Gas, Inc. would retrofit an existing offshore platform off the coast of Ventura County, California as an LNG import terminal, but would not have any LNG storage on the platform, and instead would use underground gas storage onshore to compensate for irregular deliveries of gas (LNG Express 2005). However, there are no known existing former oil or gas platforms off the coast of Oregon that could be retrofitted into an LNG import terminal.

Transport/Regasification Vessels

Several companies have proposed the installation of vaporization equipment on conventional LNG carrier ships, which would be called transport and regasification vessels. These ships would be able to dock at a floating unloading buoy and riser system where LNG could be vaporized onboard the LNG carrier and injected directly into offshore pipelines that interconnect with onshore natural gas transmission systems. The vaporization equipment located on the ships would use technology that is similar to land-based LNG terminals.

Because LNG is vaporized on board the LNG carrier, this approach eliminates the need for fixed LNG storage. Some of the tradeoffs of this approach are that it requires a dedicated LNG fleet with vaporization equipment on all of the vessels. Additionally, it takes 6 to 10 days to unload a ship at a maximum design rate of about 0.5 Bscfd.

In March 2005, the first project using this strategy began operation, and is the only existing offshore LNG import terminal of any type in North America. Excelerate's Gulf Gateway Deepwater Port includes a submerged turret loading system and about 8 miles of 20-inch-diameter pipeline that connects to two existing subsea pipelines located about 116 miles south of Cameron, Louisiana (LNG Express 2002, 2003). Excelerate ordered three LNG carriers to be constructed to include onboard vaporization equipment. One of these ships is now in service and is delivering natural gas to the United States. Excelerate has indicated that it is exploring the installation of another offshore buoy and regasification vessel system to serve offshore northern California, known as the Pacific Gateway Project (see section 3.1.3.3).

As described above in section 3.1.3.3, Woodside has proposed a project using a similar technology at an offshore location 22 miles southwest of Los Angeles, California. The Ocean Way LNG Terminal Project would consist of a ship mooring facility with a flexible connection to an underwater natural gas pipeline that would come onshore at the Los Angeles International Airport and connect to SoCal's delivery network (CEC 2007).

Floating, Storage, and Regasification Units

FSRUs are another approach being considered for importing LNG into the United States from offshore terminals. In essence, an FSRU would be an oversized LNG carrier vessel that is outfitted with LNG vaporizers and docking/unloading equipment. The FSRU would be up to 1,200 feet long, 180 to 215 feet wide, and would be able to store between 250,000 and 350,000 m^3 of LNG, which is more than twice the capacity of typical LNG carriers that are currently available. These units would be anchored offshore of the proposed market area where conventional LNG carriers could dock next to and unload LNG to the FSRU. After the LNG is unloaded, it could be vaporized and the natural gas could be transported to onshore markets through an undersea pipeline. Depending on the vaporizers and the size of the pipeline, these units could have a natural gas sendout capacity ranging from 700 to 1,500 Mscfd.

BHP Billiton's Cabrillo Port Project, proposed to be located about 14 miles off the southern California Coast (see section 3.1.3.4), would use an FSRU. The Moss-Marine LNG terminal proposed off the coast of Baja, California would also use an FSRU, as would the Broadwater LNG Project proposed for the Long Island Sound between Connecticut and New York (see FERC Docket No. CP06-54-000).

The perceived favorable attributes of an offshore LNG import terminal using FSRU technology would include its location, which would not be dependent on ocean depth, and it would have a lesser footprint on the sea bed from anchoring the unit in comparison to a GBS. Some of the negative aspects of an offshore LNG terminal using FSRU technology in comparison to Jordan Cove's proposed onshore terminal would include more difficult construction at sea; problems with unloading cargos on rough seas because of the relative motion of two vessels riding on large waves, and the potential for LNG spills during unloading; lack of safety and security infrastructure in close proximity; limited space, restricted facilities layout, and working/living quarters close to processing units; and environmental impacts on aquatic resources associated with anchoring the FSRU and construction of the undersea pipeline.

HiLoad LNG Regas Technology

The HiLoad LNG Regas technology developed by TORP (Terminal Offshore Regas Plant) is a floating L-shaped terminal that docks onto LNG carriers using a patented friction-based attachment system. The HiLoad LNG Regas unit is equipped with LNG unloading arms, pumps, and vaporizers and accommodates any LNG carrier. This technology is remotely controlled from a support platform. The LNG carrier is moored to a Single Anchor Leg Mooring and the HiLoad LNG Regas unit docks to the ship's hull for unloading. The unit's regasification equipment has a design capacity of 1.4 Bscfd. Capital cost of the HiLoad LNG Regas unit by itself, without any connecting pipelines, is estimated to be $400 million. A HiLoad LNG Regas unit is proposed for the Gulf of Mexico with anticipated operation in early 2009. A brief description of a second project proposed with this technology, as well as the reasons why this technology is not a feasible alternative, is provided below.

Esperanza Energy LLC is proposing use of TORP's Hi Load Regas unit technology for an LNG terminal at a site located 15 miles off the coast of Long Beach, California. A formal application is expected sometime in late 2007. One of the shortfalls of the HiLoad LNG Regas technology is its lack of storage capacity. In addition, the technology has not been tested in wave heights typical in winter storms off the coast of the Pacific Northwest. Finally, this technology still requires a pipeline system having both offshore and onshore environmental effects. Therefore, this technology is not a practical alternative to the proposed Jordan Cove terminal.

Conclusions About Offshore Technologies as Alternatives to the Proposed Jordan Cove Terminal

The Pacific Ocean off the coast of Oregon is subject to rough weather and high sea states. ABSG compared three wave characteristics (i.e., maximum significant wave heights, average significant wave heights, and average wave periods) for Oregon, the Gulf of Mexico, and Massachusetts. Relative to all three of these wave characteristics, conditions are less favorable for an LNG import terminal off the Oregon coast compared to the other regions. The coastline in this area provides no islands, reefs, or prominent headlands for protection from rough seas or adverse weather (ABSG 2006).

Of the offshore technologies discussed above, the transport/regasification vessel alternative (Excelerate's Energy Bridge technology) is the only one that would not be affected by rough sea conditions. For the other three technologies, LNG carriers would be able to unload only during calm sea conditions, thus leading to substantial operational limitations. While transport/regasification vessels would perform well in rough seas and weather, they generally have lower regasification rates (e.g., 0.5 Bscfd), require specially modified ships, and have no storage capabilities. These kind of offshore LNG import terminals, such as the concept for the Pacific Gateway Project, are targeted for spot market deliveries, and not for long-term storage and constant delivery as contemplated by Jordan Cove.

Locating an LNG terminal on an offshore fixed platform may have impacts on the ocean bottom and affect aquatic habitat. A GBS would need to be constructed onshore and then towed out to sea. The onshore graving dock for constructing the GBS would have associated environmental impacts that the other offshore technologies would not have. These might include impacts on terrestrial wetlands, wildlife and vegetation, and cultural resources.

The kind of vaporizers used at an offshore LNG terminal would influence the kind of impacts the facility may have on the aquatic environment. For example, ORVs that use seawater may entrap or entrain small aquatic species and ichthyoplankton during intake. Further, once the water is run through the ORVs, it would be cooled, with the discharge changing sea temperature and perhaps impacting marine life and water quality. ORVs were proposed for the Port Pelican and Gulf Landing offshore LNG terminal projects in the Gulf of Mexico. However, neither of these projects is moving forward; as indicated above, the Port Pelican Project has been put on hold indefinitely, and Shell recently announced it was discontinuing plans for the Gulf Landing terminal off the shore of Louisiana (Reuters 2007).

An offshore LNG import terminal alternative would avoid some of the environmental impacts of the proposed Jordan Cove terminal, such as effects associated with LNG marine traffic up the Coos Bay waterway, conflicts with existing commercial and recreational users of the waterway, potential impacts on communities along the waterway, visual effects, and impacts on aquatic

resources and water resources related to the dredging of the access channel and slip. However, an offshore LNG import terminal would still require a sendout pipeline that would be longer than the one proposed by Pacific Connector in order to reach the target markets in northern Nevada and northern California. That sendout pipeline would have associated impacts on aquatic and terrestrial resources. We do not consider an LNG terminal off the coast of Oregon to be a viable alternative to the proposed project because of the rough sea and weather conditions and the additional environmental impacts associated with the longer sendout pipeline.

3.1.4 Pipeline Alternatives

We assessed whether it might be possible to reduce environmental impacts associated with the construction and operation of the proposed Pacific Connector pipeline by following alternative routes. We evaluated major route alternatives that would have similar start and end points as portions of the proposed pipeline, but differ significantly for long portions of the route. We also evaluated minor route variations along specific segments of the proposed route to avoid or minimize impacts on specific, localized resources such as mature forest habitat, waterbodies, wetlands, cultural resources, or residences. Lastly, we considered if there were alternative locations for major aboveground facilities associated with the pipeline, such as the proposed compressor station, that would have lesser environmental impacts.

3.1.4.1 Alternative Pipeline Route Segments Considered but Eliminated from Detailed Analysis

During the initial phase of the routing process, Pacific Connector attempted to identify potential corridors for the pipeline between the proposed Jordan Cove LNG terminal at Coos Bay and the proposed pipeline terminus near Malin, Oregon. The goal was to determine if there were existing rights-of-way, such as roads, railroads, pipelines and powerlines, that could be paralleled by the proposed pipeline. More than 1,000 miles of route segments were reviewed. Criteria used during the route selection process included:

- Utilization of existing rights-of-way corridors;
- Minimization of the length of the pipeline;
- Avoidance of towns, population centers, commercial areas, and residential subdivisions;
- Avoidance of known designated sensitive natural resource areas, including national parks, wild and scenic rivers, scenic byways, wilderness areas, and ACECs;
- Reduction of the number of waterbody and wetland crossings;
- Avoidance of unstable geological areas, where there may be steep slopes, potential for landslides, or other issues that would make it difficult to install a natural gas pipeline;
- Maximizing ridgeline alignments where possible in rugged topography; and
- Construction feasibility, buildability, and stability for a large diameter underground welded steel pipeline, including the location of TEWAs.

During scoping, some commentors raised the question as to whether it would be possible to route the pipeline entirely on federally owned land to avoid impacts on private property. Given the patchwork nature of federal land holdings in southern Oregon, with federal blocks scattered between private tracts, there is no route that could be identified between Coos Bay and Malin that would not cross private lands. Likewise, there are no alternatives that would not cross the Coast, Cascade, and Klamath Mountain ranges, and avoid forest. Using a route that followed

U.S. Highway 101 north from North Bend to Reedsport, then east along State Highway 38 to I-5 northwest of Drain was not considered, because this route would be in a direction too far north away from the proposed pipeline terminus near Malin. All route alternatives considered go southeast from Coos Bay. Another suggestion during scoping was to follow the I-5 corridor. Again, that corridor would only go part of the way between Coos Bay and Malin, but using the I-5 corridor is discussed as part of several alternative routes considered below.

The preliminary routes considered and then eliminated from further study by Pacific Connector are shown on figure 3.1-4. Segments 1A, 1B, and 1C are alternative routes between Coos Bay and I-5. Segment 2A would parallel the I-5 corridor from Roseburg and Grants Pass, while Segment 3D would follow the I-5 corridor between Grants Pass and Medford, and Segment 3C-4A would parallel I-5 between Medford and Ashland. Segments 3A, BPA, 3B, 3C-3, 3C-4B, and 3C-6 are alternative routes located east of I-5. The reasons why various alternative route segments were rejected as infeasible or undesirable by Pacific Connector are discussed below.

Coos County Pipeline Route (Alternative Route Segments 1A-1, 1A-2, 1A-2B, 1A-4, and 1A-8b)

The Coos County pipeline provides gas service to the cities of Coos Bay and North Bend, Oregon from Williams Northwest Grants Pass lateral near Roseburg, Oregon. Initially, it appeared logical to follow this existing pipeline as a route between Coos Bay and Roseburg.

Heading east from Coos Bay, this route segment would follow the old Coos Bay Wagon Road through the community of Sumner (now called Coos Sumner Lane). It would then follow a BPA powerline between Fairview and McKinley. East of Dora, the Coos County pipeline is laid in the roadbed of the Coos Bay Wagon Road through Brewster Canyon paralleling the East Fork of the Coquille River. Following field review of this potential route, it was determined that it would be infeasible to construct the Pacific Connector pipeline following the Coos County pipeline route because:

- At its northwestern end, this route would run through residential and commercial areas in Coos Bay and Libby;
- The existing pipeline alignment in Brewster Canyon is located in the "cut" portion of the Coos Bay Wagon Road immediately adjacent to the borrow ditch. The road is narrow and bounded by steep canyon walls (many with exposed bedrock) and the East Fork of the Coquille River;
- Construction of the Pacific Connector pipeline along the Coos Bay Wagon Road would need to be done using stovepipe techniques that are time-consuming and expensive;
- The sinuous character of portions of the road would require numerous factory bends for the pipeline. There is also a fiber-optic cable co-located in the road, further encumbering construction activities;
- The road may need to be widened in places, with cutting and blasting of bedrock at currently exposed slopes. It may be difficult to stabilize the adjacent hillsides; and
- Installation of the new pipeline would require the closing of the Coos Bay Wagon Road to traffic for extended periods, and the existing Coos County pipeline would need to be taken out-of-service, removed, and replaced in certain locations.

Alternative route segment 1A-8b was eliminated from further consideration because Pacific Connector did not believe it was feasible to do an HDD under Coos Bay parallel to the existing

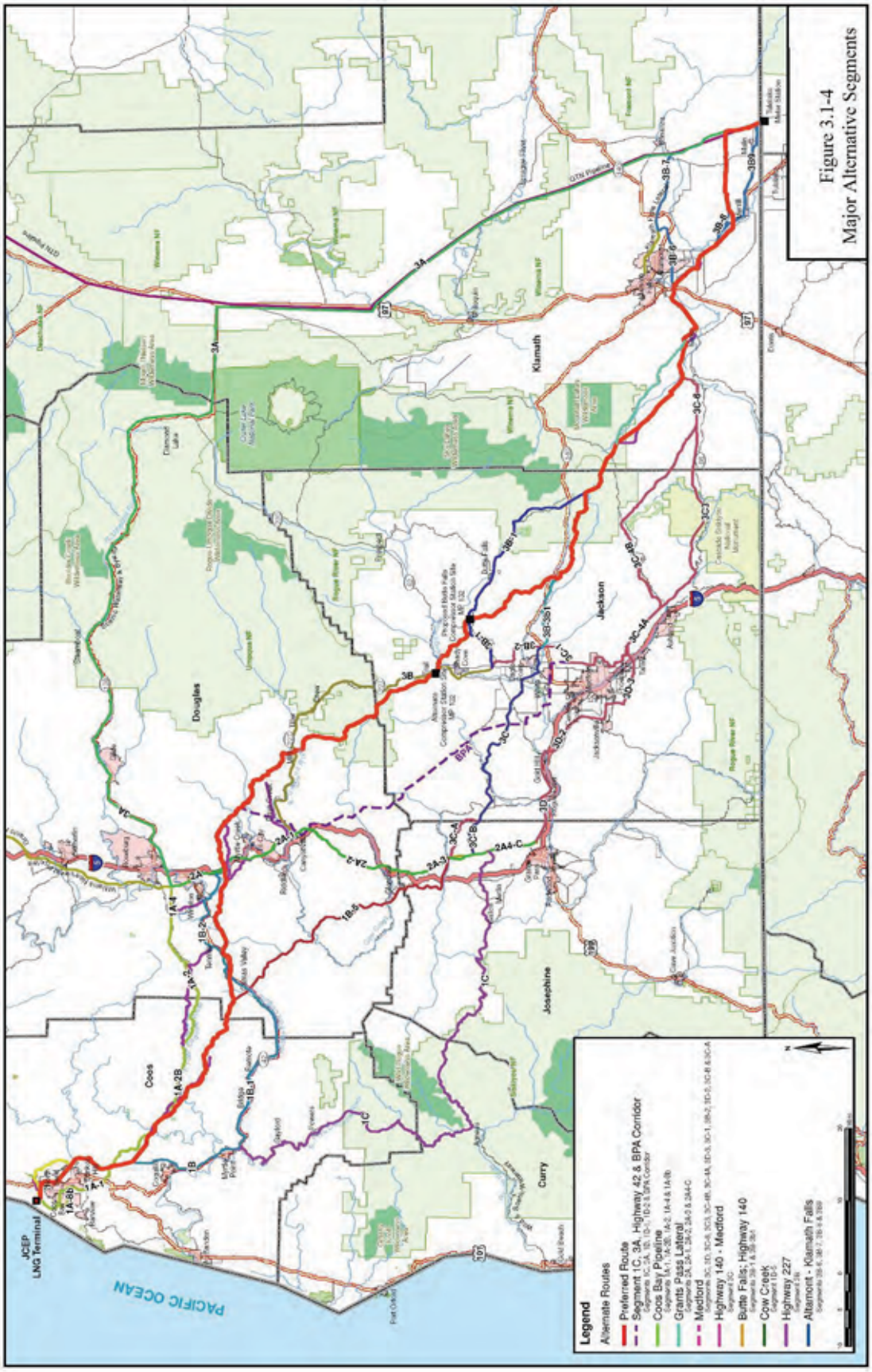


Figure 3.1-4
Major Alternative Segments

10-inch and 12-inch diameter natural gas pipelines. Limited workspace was available in this area, and the proposed alternative segment would pass through populated neighborhoods in the cities of North Bend and Coos Bay, requiring at least 0.8 mile construction in city streets. The City of North Bend filed a letter with the FERC opposing any route through residential areas.

State Highway 42 (Alternative Route Segments 1B, 1B-1, and 1B-2)

During preliminary route review, following State Highway 42 between Coos Bay and Roseburg was considered, and then eliminated from further analysis due to construction feasibility, cost, and significant environmental impacts. The highway heads west from I-5 near Roseburg, through the communities of Winston, Tenmile, Camas Valley, Remote, Bridge, Myrtle Point and Coquille. Highway 42 is a high volume, major access and truck route from I-5 to the coast. This route was rejected because:

- The Middle Fork of the Coquille River is adjacent to the highway for much of the route. Steep side slopes prevent offsetting the pipeline from the highway, which means the pipeline would need to be installed in the roadbed in places;
- In-highway construction would create a public safety issue and impede traffic for a substantial period of time;
- Fiber optic cables are buried along the highway right-of-way, creating another restriction to installing the pipeline in or near the highway;
- The Coquille River would be crossed multiple times (six or more);
- There would be potential impacts on residential and commercial areas in the towns along this route; and
- The route would cross through several parks and waysides.

Powers Highway/Shasta Costa Road (Segment 1-C)

Segment 1-C would follow an existing road network between Coos Bay and Grants Pass, Oregon. From Myrtle Point, the Powers Highway goes south to the community of Powers, then Powers South Road proceeds south to Agness, where the Shasta Costa Road heads west, to the Galice Creek Road to Galice. However, because of the following factors, this segment was eliminated from further analysis:

- Significantly increases overall pipeline length;
- Parallels the South Fork of the Coquille River between Myrtle Point and Agness;
- Crosses the Rogue River within an area designated as a Wild and Scenic Waterway;
- Skirts the Wild Rogue Wilderness Area within the Siskiyou National Forest north of Agness; and
- Constructability issues due to rugged topography and narrow river canyons.

Williams Northwest Grants Pass Lateral Route (Alternative Route Segments 2A, 2A-1, 2A-2, 2A-3 and 2A4-C)

During initial route selection, Pacific Connector assumed that it could follow the existing Williams Northwest Grants Pass lateral parallel to I-5 between the cities of Roseburg and Grants Pass. However, upon review, this route was eliminated because:

- Large volumes of rock would need to be removed to install a new pipeline along the ridges and through canyons following the lateral route;

- The lateral is installed along narrow ridgelines in areas with steep slopes that would hinder the co-location of a new pipeline in the existing easement because of limited available workspace;
- To avoid buildability issues in difficult terrain, several route realignments off of the existing lateral would be necessary, that may result in multiple crossings of I-5;
- Locating the pipeline within the existing I-5 right-of-way was not thought feasible because construction may impede traffic, and there are restrictions on placing utilities within federal highway easements; and
- There are commercial and residential areas along the I-5 corridor between Roseburg and Grants Pass, developed after the lateral was installed in 1963, that would need to be avoided by a new pipeline.

Cow Creek Route (Alternative Route Segment 1B-5)

Pacific Connector examined the possibility of following Cow Creek between the Camas Valley and I-5 south of Glendale, as a route alternative rather than a route parallel to the Grants Pass lateral. Alternative Route Segment 1B-5 could potentially provide this connection and shorten the route, but there is no existing right-of-way all the way through this area. The alternative could follow Burma Road south from the Camas Valley, then go cross-country to the existing Central Oregon Railroad and Riddle-Glendale Road adjacent to Cow Creek. This route alternative was rejected for the following reasons:

- There is no existing right-of-way along the entire alternative, and the pipeline would need to blaze a new "green-field" cross-country route between Burma Road and Riddle-Glendale Road;
- Rugged topography would make construction difficult;
- An open-cut crossing of Cow Creek would be necessary, due to geometric conditions on either side of the waterbody;
- McCullough Creek would be closely paralleled for more than a mile within a steep narrow drainage, that would likely require that the pipeline be installed within an existing road;
- Additional construction constraints with this route include exposed rock and limited available access; and
- This alternative route segment would bisect a large area (20 miles) of critical habitat for NSO (OR-62).

State Highway 138/GTN Route (Alternative Route Segment 3-A)

Pacific Connector examined an existing road and pipeline corridor between Roseburg and Malin that it labeled Segment 3-A. This alternative route would follow State Highway 138 from Roseburg east, passing by the communities of Glide, Steamboat, and Diamond Lake to I-97, then follow the existing GTN pipeline south, passing by Bonanza to Malin. This route alternative was eliminated for the following reasons:

- Increased the length of the pipeline compared to the proposed route;
- State Highway 138 is adjacent to the North Umpqua River, which has been designated as a Scenic Byway and Scenic Waterway;
- Extensive clearing and sidehill cutting necessary to install the pipeline would have visual impacts through areas of high recreational and scenic value;

- The North Umpqua River is used for whitewater rafting and fishing, with numerous access to trails and campgrounds located off of State Highway 138;
- Crosses a significant number of high-value tributaries that flow to the North Umpqua River;
- Route along State Highway 138 would be close to the Boulder Creek Wilderness and the Mount Thielsen Wilderness within the Umpqua National Forest; and
- Located in proximity (< 0.25 mile) to Crater Lake National Park.

BPA Powerline Corridor Route Alternative

During initial routing investigations, Pacific Connector evaluated following the existing BPA powerline corridor between Myrtle Creek and Medford. However, this route was determined to be infeasible and dropped from further consideration because the powerline spans severe side slopes and dissected topography that would require significant grading as well as increased cost for pipeline construction. Pipeline operation, maintenance and integrity issues were also a concern with this route.

Highway 227 Route (Alternative Route Segment 3B)

This alternative route would follow Highway 227 east of I-5 from Canyonville through the communities of Days Creek, Milo, Tiller, and Trail, to Shady Cove. This route was eliminated from serious consideration due to the following limitations:

- Numerous residences are located along the highway, especially in the vicinity of the communities of Canyonville, Days Creek, and Shady Cove;
- Steep canyon walls in the area between Trail, Drew, Tiller, and Milo would require that the pipeline be installed in the roadbed in places, creating a public safety hazard during construction and causing travel delays;
- Extensive cuts would be necessary where the pipeline would be installed adjacent to but outside of the roadbed;
- Substantial amounts of exposed rock are present along the route, affecting construction costs and schedules; and
- This route would require several waterbody crossings including potentially eight crossings of the South Umpqua River, as well as Elk Creek and Trail Creek.

Riddle to Butte Falls Route Variation (Sebesta Alternatives)

In a letter dated March 20, 2007, Paul Sebesta suggested alternative routes between about MPs 70 to 132, between Riddle and Butte Falls. In a June 2, 2008 data request, we asked Pacific Connector to evaluate Mr. Sebesta's suggested route alternatives. In a response filed on June 23, 2008, Pacific Connector indicated that these alternative routes were previously considered in its application, within Resource Report 10, under the BPA Powerline Route Alternative and the Highway 227 Route Alternative. As explained above, the BPA Powerline Route Alternative between Days Creek and Medford was eliminated from further study because it would not be feasible to follow the powerline due to dissected topography. The Highway 227 Alternative Route (Segment 3B) between Canyonville and Shady Cove was eliminated from consideration because it would pass through several communities and has the potential impact rural residences. One of Mr. Sebesta's alternative routes would place the pipeline too close to the COE's Lost Creek Lake Dam, which Pacific Connector thought would not be viable.