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Oregon Department of Energy – Energy Facility Siting Council
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RE: Jordan Cove Site Certificate Exemption Application Date: June 14th, 2018

Dear Mr. Cornett,

Please accept Jordan Cove Energy Project, LP's ("JCEP") application and fee for an exemption from a site certificate to the Energy Facility Siting Council ("EFSC") and the Oregon Department of Energy ("ODOE") as the supporting agency. Within this application JCEP demonstrates how the electrical power generating system at JCEP's proposed Liquefied Natural Gas ("LNG") Terminal in Coos Bay, Oregon meets the *high efficiency cogeneration facility* exemption definitions and criteria set forth in OAR 345-015-0360(5).

Pursuant to ORS 469.320(1), "no facility shall be constructed or expanded unless a [EFSC] site certificate has been issued for the site . . . ." A "facility" is defined as "an energy facility together with any related or supporting facilities." ORS 469.300(14). The definition of "energy facility" includes "[a]n electric power generating plant with a nominal electric generating capacity of 25 megawatts or more, including but not limited to: (i) Thermal power; (ii) Combustion turbine power plant; or (iii) Solar thermal power plant." ORS 469.300(11)(a)(A). There is a statutory exemption from the site certificate requirement for a "high efficiency cogeneration facility." ORS 469.320(2)(c); OAR 345-015-0350.

The electrical power generating system at the proposed LNG Terminal consists of three steam turbine generators ("STGs"). Each STG will generate electricity and will have a nominal electrical generating capacity of greater than 25 MW. Given the nominal electrical generating capacity of the STGs, the facility could be considered an "energy facility" under the statute. Without waiving any rights including jurisdiction over the proposed LNG Terminal, JCEP submits this application requesting a determination from EFSC that the proposed facility qualifies for an exemption from the site certificate requirement.

As shown in the application, the STGs have a nominal electric generating capacity of 50 megawatts ("MW") or more and the fuel chargeable to power heart rate value is not greater than 6000 Btu per kilowatt-hour. Therefore, the STGs meet the high efficiency cogeneration facility exemption definitions and criteria set forth in OAR 345-015-0360(5).

Pursuant to applicable rules we understand the following procedures for requesting an exemption apply. To claim an exemption from the requirement to obtain a site certificate, a party must request EFSC determine whether the proposed facility qualifies for the claimed exemption. ORS 469.320(4). EFSC's regulations set forth the required contents of the request. See OAR 345-015-0360(5).
Within 45 days after receipt of a request for exemption, ODOE shall review the request for completeness and provide the applicant with either: (1) a notice of filing of the request for exemption or

(2) a request for additional information. OAR 345-015-0370(1). When ODOE finds the request for exemption is complete, ODOE shall issue a notice of filing. *Id.* Within 60 days after issuing the notice of filing, ODOE shall review the request, prepare a proposed order for EFSC action and bring the matter before EFSC for action. *Id.* JCEP understands that EFSC's review of the proposed order does not trigger a contested proceeding under ORS 345-015-001.

JCEP's application includes trade secret information as defined under ORS 192.345. For ODOE's convenience, JCEP is submitting a public version of the application with the trade secret information redacted. JCEP requests that ODOE and EFSC maintain as confidential and not disclose the version that contains the trade secret information. JCEP has marked that version as:

Confidential Business Information
Exempt From Public Disclosure

JCEP appreciates EFSC's and ODOE's attention to this request and respectfully requests that EFSC grant the exemption per ORS 469.320(2)(c); OAR 345-015-0350.

Sincerely,

Tony Diocee
VP of LNG Projects,
Jordan Cove Energy Project, LP

Application Criteria. OAR 345-015-0360(5)

(5) In a request for an exemption based on a very efficient use of fuel (high efficiency cogeneration) under OAR 345-015-0350(3), the person shall provide the following information in support of the request:

(a) Detailed information on proposed fuel use, power plant design, steam or heat output to the thermal host and proposed electric output;

Response:

For the LNG Terminal, fuel gas is the principal source of energy from which all facility power is derived. Fuel gas is initially supplied directly from the pipeline, but once the facility is in normal operating mode, the primary source of fuel gas is derived from Boil-off Gas (BOG). BOG is produced when the LNG pressure from Liquefaction is let-down to near atmospheric pressure via the LNG Expander and pressure let-down valves, which produces 1.86 MW [1] of electrical power in the process, to the LNG Flash Drum in preparation for storage in the LNG Storage Tanks. BOG is also produced from heat in-leakage through the LNG Flash Drum and LNG Storage Tank insulation and through the run-down and keep-cool piping. The amount of BOG produced can be set by the amount of sub-cooling from the Liquefaction Process to best match facility fuel gas requirements, but once set, it is best, from an operations standpoint, to maintain the process in steady state.

The main use of fuel gas at the LNG Terminal is to run the five (5) General Electric (GE) LM6000 PF+ Combustion Gas Turbines (CGTs) which provide the mechanical power to drive the refrigeration compressors. The hot exhaust gas from each LM6000 PF+ Gas Turbine Driver is routed through the HRSGs which produces High Pressure Steam from waste heat. Each gas turbine driver produces exhaust gas which each HRSG can convert to HP Steam. Each HRSG is equipped with a duct burner which can provide supplemental firing to produce approximately 10% of additional HP Steam with a maximum 19.7 MMBtu/hr of fuel gas (HHV) [1].

Most of the HP Steam produced is used to generate electrical power by pressure let-down through the facility Steam Turbine Generators (STGs). The maximum facility electrical power demand requirement is 49.5 MW [1] which occurs when the facility is in LNG Carrier Loading Mode. In order to provide sufficient margin, the design facility power requirement is raised by approximately 10% to 55.5 MW (calculated from 18.5 MW x 3 STGs) [1]. To meet the design power demand, two (2) x 30 MW STGs were selected. In addition, in order to meet the facility sparing requirements for an N+1 configuration, three (3) x 50% STGs are required. Therefore, the facility has specified 3 x 30 MW STGs to provide the electrical power for the LNG Terminal. An additional requirement is that the spare be a “rolling spare” so that in the event of a single STG trip, the remaining two STGs pick up the lost generating capacity as quickly as possible, therefore, all three STGs are normally operated at 18.5 MW [1] each, which requires 224,000 lb/hr [1] of HP Steam to produce, or 91% of the total generated. Of the remaining 9%, 70,300 lb/hr [1] of HP Steam is used intermittently to regenerate the Dehydration (Molecular Sieve) Beds, and the balance is sent to the steam dump condenser.

The LNG Terminal requires approximately 262,000 lb/hr [1] of LP Steam for the Feed Gas Inlet Heater, the Sulfur Scavenger Heater, the Defrost Gas Heater, the Fuel Gas Heater, the Amine Regenerator Reboiler, and the Deaerator. 262,000 lb/hr (approximately 38%) of the HP Steam to the STGs, is sequentially extracted upstream of the STGs low pressure section at 72.5 psig and 357˚F with the balance continuing through the low pressure section to the vacuum condenser to produce additional electrical power.

When the LNG Terminal is shutdown the single installed Auxiliary Boiler is capable of producing 189,100 lb/hr of HP Steam. This value has been revised to include some margin to 202,000 lb/hr of HP Steam and 296.2 MMBtu/hr [1] of fuel gas (HHV) per the Air Contaminant Discharge Permit Application (ACDP, filed with DEQ in October 2017) which allows for the unit to operate up to 876 hours per year.

References

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1. Appendix A: Detailed LNG Facility Information – Trade Secret/Confidential Business Information

2. Appendix B: Detailed LNG Facility Information – Public Version

(b) Detailed information on the current facility, including fuel to be displaced, current steam or heat use and current electric output if any;

Response:

This criterion is not applicable because the LNG Terminal is not a current facility.

I, Justin M. Ellrich, Oregon PE #89886, have provided guidance and material content during the development of this application and reviewed the facility description, basis of design, and fuel input/power calculations. I agree with the methodology and results contained herein, particularly section (5)(c) of OAR 345-015-0360, as to the application for exemption from a site certificate to the Energy Facility Siting Council ("EFSC") and the Oregon Department of Energy ("ODOE") as the supporting agency.

REGISTERED PROFESSIONAL ENGINEER
89886PE
7-24-18
OREGON
JANUARY 15, 2015
JUSTIN M. ELLRICH
EXPIRES: 12-31-19

(c) A detailed engineering assessment of fuel efficiency, showing that the proposed facility is a high efficiency cogeneration facility under the definition in OAR 345-001-0010. The person shall provide calculations in sufficient detail to facilitate independent review by the Department. The person shall state c; and

Response:

The requirements to qualify for Exemption from an EFSC Site Certificate as a "high efficiency cogeneration facility" per ORS469.320(2)(c); OAR 345-015-0350 are:

A "high efficiency cogeneration facility" is an energy facility that sequentially produces electrical energy and useful thermal energy from the same fuel source and under average annual operating conditions:

a) Has a nominal electric generating capacity of less than 50 megawatts and the fuel chargeable to power heat rate value is not greater than 5550 Btu per kilowatt-hour (higher heating value); or
b) Has a nominal electric generating capacity of 50 megawatts or more and the fuel chargeable to power heat rate value is not greater than 6000 Btu per kilowatt-hour (higher heating value).[1]

Where:

***Useful thermal energy** means "the verifiable thermal energy used in any viable industrial or commercial process, heating or cooling application." OAR 345-001-0010(66).*

***Nominal electric generating capacity** means "the maximum net electric power output of an energy facility based on the average temperature, barometric pressure and relative humidity at the site during the times of the year when the facility is intended to operate." ORS 469.300(17).*

***Fuel chargeable to power heat rate** means "the net heat rate of electric power production during the first twelve months of commercial operation." OAR 345-001-0010(25). This rate "is calculated with all factors adjusted to the average temperature, barometric pressure and relative humidity at the site during the times of the year when the facility is intended to operate using the formula:*

***FCP = (FI - FD)/ P**, where:*

*a) **FCP** = Fuel chargeable to power heat rate.*
*b) **FI** = Annual fuel input to the facility applicable to the cogeneration process in British thermal units (higher heating value).*
*c) **FD** = Annual fuel displaced in any industrial or commercial process, heating, or cooling application by supplying useful thermal energy from a cogeneration facility instead of from an alternate source, in British thermal units (higher heating value).*
*d) **P** = Annual net electric output of the cogeneration facility in kilowatt-hours.*

From the information above, it can be demonstrated that the STGs meet the requirements to qualify for the exemption from an EFSC Site Certificate.

The LNG Terminal is a *"high efficiency cogeneration facility"* because it utilizes amongst the most efficient aero-derivative gas turbine drivers available to drive the refrigeration compressors and then utilizes waste heat recovery to produce High Pressure Steam which is used to generate electrical power and as *"useful thermal energy"* to regenerate the Dehydration Unit Molecular Sieve Beds. The STGs are used to convert the High Pressure Steam to electrical power. Low Pressure Steam is sequentially extracted upstream of the Low Pressure Section of the STGs and is used as *"useful thermal energy"* for process heating in the Liquefaction Process.

In order to satisfy the equation:

FCP = (FI – FD)/P

Each component of the equation must be calculated from the process information provided above.

Annual Fuel Input (FI):

For the LNG Terminal, the *Annual Fuel Input (FI)* to the cogeneration process is the fuel gas used for the Duct Burners and the fuel gas used for the Auxiliary Boiler since both sources can provide High Pressure Steam to the cogeneration process. Per the ACDP application, the Duct Burners are permitted for 4,000 hours of operation per year and the Auxiliary Boiler is permitted for 876 hours of operation per year. Also, the remaining fuel input not converted to mechanical drive of the refrigerant compressor or gas turbine air compressor portion is included as well as part of the cogeneration process.

Note that the statute sets forth the applicable nominal electric generating capacity. However, the fuel chargeable to power heat rate values referenced in ORS 469.320(2)(c) are no longer controlling. In ORS 469.320(3), the Oregon Legislature granted EFSC the authority to review and revise the fuel chargeable to power heat rate values listed in the statute. EFSC altered these values. *See* OAR 315-015-0350(3) (referencing 345-001-0010).

The potential maximum mechanical power output of each gas turbine to the refrigerant compressor is 55.46 MW with 497 MMBtu/hr of fuel input for each unit. But 55.46 MW equates to just 189.2 MMBtu/hr, so the remaining fuel input is used to mechanically drive the air compressor portion of the gas turbine at approximately 65.2 MW (222.5 MMBtu/hr) or is heat exhaust due to efficiency losses (remaining 85.3 MMBtu/hr). Only these efficiency losses are part of the cogeneration system as the rest is mechanical drive power with no impact to the net electrical power or thermal energy output of the facility. Therefore:

- 85.4 MMBtu/hr x 5 Gas Turbine exhausts = 426.3 MMBtu/hr
- 426.3 MMBtu/hr x 8760 hours/year = 3,734,791 MMBtu/year

The HRSG Duct Burners are sized to consume at most 19.7 MMBTU/hr (HHV) of fuel gas for each HRSG. Annual Duct Burner fuel gas usage is therefore:

- 19.7 MMBtu/hr x 5 HRSG Duct Burners = 98.5 MMBtu/hr
- 98.5 MMBtu/hr x 4000 hours/year = 394,000 MMBtu/year

The Auxiliary Boiler is sized to consume at most 296.2 MMBTU/hr (HHV). Annual Auxiliary fuel gas usage is therefore:

- 296.2 MMBtu/hr x 876 hours/year = 259,470 MMBtu/year

The Annual Fuel Input (FI) to the cogeneration process is therefore:

- **FI** = 3,734,791 MMBtu/year + 394,000 MMBtu/year + 259,470 MMBtu/year = **<u>4,388,261 MMBtu/year</u>**

Annual Fuel Displaced (FD):

To calculate the *Annual Fuel Displaced (FD)*, it is assumed to be the fuel gas that would be required to produce the HP Steam and LP Steam used by the LNG Processes if it were generated by an *"alternate source."* In this case, the "alternate source" is assumed to be a Package Boiler with a similar heat rate to the current facility Auxiliary Boiler.

Based on the Facility Maximum HP Steam and LP Steam requirements:

- Process HP Steam Required: 70,300 lbs/hr
- Process LP Steam Required: 262,000 lbs/hr

The LP Steam for the LNG Process is normally produced by extraction from the STGs. If this system isn't available, then LP Steam is produced via pressure let-down and de-superheating of HP Steam.

From the International Association for the Properties of Water and Steam (IAPWS-97) Steam Tables, the enthalpy for Superheated Steam at:

- 727.8˚F and 753.5 psig is: 1,357.46 Btu/lbm
- 357.0˚F and 72.5 psig is: 1,206.89 Btu/lbm

And the enthalpy for Boiler Feed-water at:

- 249.0˚F and 72.5 psig is: 217.72 Btu/lbm

To produce the required quantity of LP Steam:

- Enthalpy HP Steam = HPS lb/hr x 1,357.46 BTU/lbm = h_{hps}
- Enthalpy BFW = (262,000 lb/hr - HPS lbm/hr) x 217.72 Btu/lbm = h_{bfw}
- Enthalpy LP Steam = 262,000 lbm/hr x 1,206.89 Btu/lbm = 316,204,807 Btu/hr = h_{lps}
- $h_{hps} + h_{bfw} = h_{lps}$
- HPS x 1357.46 + (262,000 – HPS) x 217.72 = 316,204,807
- (1357.46 – 217.72) x HPS + 57,043,714 = 316,204,807

Therefore:

- HPS = (316,204,807 – 57,043,714) ÷ (1357.46 – 217.72) = 227,387 lbs/hr, and
- BFW = (262,000 – 227,387) = 34,613 lbs/hr, required for de-superheating
- Total HP Steam is therefore: 227,387 lbs/hr + 70,300 lbs/hr = 297,687 lbs/hr

The LNG Terminal Auxiliary Boiler can produce up to 202,000 lbs/hr of HP Steam and requires a maximum of 296.2 MMBtu/hr (HHV) of fuel gas. Assuming a boiler of similar heat rate to the Auxiliary Boiler, the fuel gas required to generate 297,687 lbs/hr of HP Steam is:

- 296.2 MMBTU/hr x 297,687 lbs/hr ÷ 202,000 lbs/hr = 436.5 MMBtu/hr (HHV)
- **FD** = 8760 hours/year x 436.6 MMBTU/hr = **3,823,816 MMBtu/year (HHV)**

The LNG Terminal requires 49.5 MW-hr of electrical power during LNG Carrier Loading Mode and the STGs are designed to provide approximately 10% margin for a total STG Power Generated of 55.5 MW.

The Annual Net Power Output of the Cogeneration Facility is therefore:

- **P** = 55.5 MW x 1000 kW/MW x 8760 hours/year = **486,180,000 kW-hr**

Plugging the above calculated values to equation FCP = (FI – FD) / P gives:

FI = 4,388,261 MMBtu/year (HHV)

FD = 3,823,816 MMBtu/year (HHV)

P = 486,180,000 kW-hr

FCP = (4,388,261 MMBtu – 3,823,816 MMBtu) x 10^6

÷ 486,180,000 kW-hr

FCP = 1,161 Btu/kW-hr

The LNG Terminal combined heat and power system meets the above criteria and therefore is exempt from the EFSC Site Certificate requirement.

(d) A description of the facility, including the thermal host, the proposed energy facility, the location by address as well as township and range and any associated linear equipment needed.

Response:

1. PROJECT LOCATION AND DESCRIPTION OF FACILITIES

JCEP proposes to site, construct, and operate a new LNG export terminal on the bay side of the North Spit of Coos Bay in southwest Oregon (the Project). The proposed LNG Terminal will be located in unincorporated Coos County, Oregon, primarily within land owned by Fort Chicago LNG II U.S. L.P., an affiliate of JCEP, across two contiguous parcels (Ingram Yard and South Dunes) which are connected by an Access and Utility Corridor (shown on Figure 1.1-2). The primary site for the LNG Terminal is about 7.5 miles up the existing Federal Navigation Channel, approximately 1,000 feet north of the city limit of North Bend, in Coos County, Oregon, more than 1 mile away from the nearest residence.

The proposed LNG Terminal will be located near the Pacific Ocean in the coastal lowlands ecozone. The primary site is a combination of brownfield decommissioned industrial facilities, an existing landfill requiring closure, and some open land covered by grasslands and brush (including some wetlands), as well as an area of forested dunes. Portions of the primary site have also previously been used for disposal of dredged material.

The LNG Terminal would be within Sections 4 and 5, Township (T.) 25 South (S.), Range (R.) 13 West (W.), shown on Coos County Assessor's map as tax lots 100/200/300.

2. LNG TERMINAL COMPONENTS AND FACILITIES

The LNG Terminal site is comprised of South Dunes, Ingram Yard, and the Access and Utility Corridor:

- South Dunes Site (includes construction and operational facilities, including the Workforce Housing Facility and SORSC)
- Ingram Yard (includes construction and operational facilities, including LNG tanks, liquefaction equipment and the slip and access channel)
- Access and Utility Corridor (includes construction and operational facilities, including the fire department)

These areas are shown on Figure 1.1-2. The LNG Terminal will receive a maximum of 1,200,000 Dth/d of natural gas from the Pipeline and produce a maximum of 7.8 mtpa of LNG for export. The LNG Terminal will receive natural gas from the Pipeline, process the gas, liquefy the gas into LNG, store the LNG, and load the LNG onto ocean-going LNG carriers at its marine dock. The main operational components of the LNG Terminal are shown on Figure 1.1-2 (Plot Plan of the LNG Terminal) and include a connection to the Pipeline metering station, gas inlet facilities, a gas conditioning plant, an access and utility corridor, liquefaction facilities (including five liquefaction trains), two full-containment LNG storage tanks, an LNG loading line, LNG loading facilities, a marine slip, and an access channel for LNG carriers.

All LNG Terminal facilities and components will be constructed in accordance with governing regulations, including the regulations of the USCG for Liquefied Natural Gas Waterfront Facilities, 33 CFR Part 127; the U.S. Department of Transportation ("DOT") Federal Safety Standards for Liquefied Natural Gas Facilities, 49 CFR Part 193; and the National Fire Protection Association ("NFPA") Standard 59A for LNG facilities, and the codes and standards referenced therein.

2.0 GAS INLET FACILITIES AND GAS CONDITIONING

2.0.1 Gas Inlet Facilities and Metering

Pipeline quality feed gas will be supplied to JCEP via the Pipeline. The interface point between the Pipeline and LNG Terminal occurs at the flange immediately downstream of the metering skid located on the South Dunes Site.

Inlet pipeline metering facilities consist of a pipeline pig receiver, inlet filter/separator, and flow meter, which are in the PCGP scope. The pipe connecting the metering station to the liquefaction facilities will be buried from South Dunes through the Utility and Access Corridor, and then will resurface within the LNG Terminal facility at Ingram Yard.

A High Integrity Pressure Protection System (HIPPS) will be installed, in a 2 x 100 percent configuration, downstream of the metering station and upstream of any piping branches with the exception of the fuel supply for start-up and LNG storage tank vacuum breaker.

Additionally, a feed inlet heater will provide heating of the high pressure feed gas on cold days to prevent formation of natural gas hydrates resulting from Joule-Thomson cooling when gas pressure is let down by the pressure reduction unit or units. A pressure reduction unit functions as an inlet pressure control station before the gas enters the gas conditioning unit.

2.0.2 Gas Conditioning Train

The feed gas from the pipeline meter station will be treated before the gas enters the liquefaction trains. A Gas Conditioning train, in a 1 x 100 percent configuration, will be provided and will include a system for mercury removal via sulfur impregnated activated carbon, carbon dioxide (CO_2) and other acid gases removal via an amine system, and dehydration via a molecular sieve adsorbent system.

Mercury is first removed to prevent corrosion in downstream cryogenic aluminum equipment and minimize exposure of other equipment and vent streams to mercury contamination. The feed gas will then be treated by passing through the acid gas removal unit to remove CO_2 to prevent freezing in the liquefaction process. Trace amounts of hydrogen sulfide (H_2S) and other sulfur species will also be removed.

The amine solution of the acid gas removal process saturates the dry feed gas with water. The dehydration system removes the water content of the feed gas to prevent water freeze out in the liquefaction process.

2.0.3 Mercury Removal

Mercury is removed via adsorption onto sulfur-impregnated activated carbon beds, in a 3 x 33 percent configuration, in order to prevent cold box corrosion during gas liquefaction and to minimize the exposure of other equipment and vent streams to mercury contamination. The mercury removal beds will be located downstream of the inlet filter/separator and upstream of the amine contactor, and will reduce the amount of mercury in the treated pipeline gas down to less than 0.01 micrograms per Normal cubic meter ($\mu g/Nm^3$).

The life of the mercury removal beds is designed to be three years, assuming a mercury concentration in the feed gas of 0.05 parts per billion by volume (ppbv). Spent catalyst from the mercury removal vessels will be removed periodically and sent off-site for disposal by a licensed hazardous waste management contractor.

2.0.4 Acid Gas Removal

Acid gas removal involves a closed-loop system that circulates a promoted methyl-diethanolamine solution to absorb CO_2 and sulfur species from the feed gas. The process reduces the feed gas CO_2 concentration from a maximum of approximately 2 percent on a molar basis to less than 50 parts per million on a volumetric basis (ppmv).

The CO_2 removed from the feed gas is to be vented to the atmosphere, but the vent stream must first be treated for co-absorbed contaminants. To limit emissions, absorbed H_2S and other sulfur species in the vent stream will be thermally oxidized after passing through the sulfur scavenger unit. Co-absorbed hydrocarbons, including benzene, toluene, ethylbenzene, and xylenes, will also be combusted and destroyed in the thermal oxidizer.

2.0.5 Dehydration

The water removal system is located immediately downstream of the acid gas removal system and employs four molecular sieve adsorption beds. The water removal system will reduce water in the treated feed gas to less than 0.1 ppmv. At any time, two beds will be in adsorption mode, one bed will be in regeneration/cooling mode, and one bed will be on stand- by. Regeneration of a bed involves passing dehydrated heated feed gas through it, in an up-flow direction, which drives the adsorbed water out of the bed. This water-loaded regeneration gas is then cooled to condense and remove the water, which is collected and recycled back into the acid gas removal system. This regeneration gas is then compressed and recycled upstream of the dehydration units. The regenerated bed will then be cooled by non-heated dehydrated feed gas until a low enough temperature is achieved to place it back into adsorption service.

2.1 LIQUEFACTION FACILITIES

2.1.1 Liquefaction Trains

The LNG Terminal includes five liquefaction trains utilizing the Black & Veatch proprietary PRICO® LNG technology to produce a maximum of 7.8 mtpa (1,077 MMscf/d) of LNG production net, after deduction for Boil-Off Gas ("BOG") generation. Each liquefaction train will have an anticipated maximum annual capacity of 1.56 mtpa (215.5 MMscf/d). The nominal annual capacity may be less than this value due to annual ambient temperature variation, planned non-major facility maintenance outages, unplanned facility outages, and degradation of the combustion gas turbines.

The PRICO® LNG technology utilizes a single mixed refrigerant (SMR) circuit with a two-stage compressor and a brazed aluminum refrigerant exchanger. The dry treated gas from the gas conditioning train is divided equally among the five liquefaction trains. In each liquefaction train, the dry treated gas stream flows into a refrigerant exchanger where it is turned into liquid by cooling it to approximately -260°F with the mixed refrigerant. The refrigerant exchanger consists of multiple brazed aluminum heat exchanger cores arranged in parallel inside a perlite insulated cold box. An aerial cooling system (fin-fan) rejects heat from the mixed refrigerant that is gained from the liquefaction of feed gas and compression. The cold box is purged with nitrogen gas to prevent moisture intrusion and eliminate the potential for a flammable atmosphere inside.

The refrigeration cycle is a closed-loop process that utilizes a single-body, two-stage refrigerant compressor. An aero-derivative combustion turbine directly provides the power to drive the refrigerant compressor. Exhaust-gas waste heat recovery in the form of steam generation maximizes the overall thermal efficiency of the LNG Terminal.

Heavy hydrocarbons (generally referred to as C5+ components) will be removed from the feed gas before the final liquefaction step to meet the LNG specification and prevent possible freezing at subcooled temperatures.

2.1.2 Heavies Removal

Heavy hydrocarbons or "heavies" will be removed from the feed gas before the final liquefaction step in order to meet the LNG specification and prevent possible freezing at subcooled temperatures. The system will be designed to remove the most likely-to-freeze components—benzene and octane—to less than 1 ppmv while recovering as much of the C4 and lighter molecules as economically as possible into the gas going to the final liquefaction step.

The total volume of heavies removed across the range of feed compositions is not enough to produce economically viable natural gas liquids product for sale or export; however, it will be blended into the fuel gas stream, so no tankage or disposal logistics need to be considered.

2.1.3 Refrigerant Makeup System

For many technologies, refrigerant losses occur from the closed-loop refrigeration loops primarily due to normal compressor seal leakage. However, the Black & Veatch patented seal gas recovery system will be utilized to minimize the refrigerant losses to flare by returning the normal leakage to the refrigerant compressor suction. Even with seal gas recovery, the refrigeration loop components must be replenished periodically to normal operation inventory levels. The hydrocarbons that provide make-up to the SMR circuit used in the liquefaction trains cannot be generated on-site (with the exception of methane, which comes from the treated feed gas), and will be delivered to the LNG Terminal via ISO containers or qualified trucks and stored in pressurized vessels for intermittent makeup to the SMR circuit.

2.1.4 LNG Storage and Containment

The LNG will be stored in two full-containment insulated LNG storage tanks, each of which is designed for a working capacity of 160,000 cubic meters (m^3) (42,232,000 gallons) of LNG. Each tank will have a primary 9 percent nickel inner tank and a secondary concrete outer containment wall with a steel vapor barrier.

The LNG storage tanks will have top connections only with piping that will permit top and bottom filling. Top filling operation will be done via a spray device/splash plate in order to obtain flashing and mixing of the LNG as it combines with LNG inventory. The bottom loading operation will be achieved via a standpipe to ensure effective mixing. The separated flash vapor combines with vapors from tank displacement and heat leak and flows to the boil-off gas compressors for use as a fuel.

The two full-containment LNG storage tanks are each equipped with three fully submerged LNG in-tank pumps, each rated for approximately 2,400 cubic meters per hour (m^3/hr), and one spare well, fully piped and instrumented. LNG is pumped, using five of the six installed pumps, to the marine berth and into an LNG carrier at a normal loading rate of 12,000 m^3/h. An LNG transfer line will connect the shore-based storage system with the LNG loading system. A smaller recirculation, "keep cool" line is provided from the LNG storage tank area to the marine berth in order to maintain the LNG transfer piping at cryogenic temperatures to avoid excessive boil-off losses and potential damage from thermal cycling between carrier arrivals.

LNG spills will be contained, and the bermed area around the LNG storage tanks will gravity drain to an LNG impoundment basin. An LNG spill containment trench will also collect any LNG from spills outside of the bermed area around the LNG storage tank area and gravity drain to the same LNG impoundment basin. A separate LNG trench and impoundment basin located near the marine loading system will also be provided to collect any LNG spills from the LNG transfer line or the recirculation line that would be located south of the liquefaction trains; this separate impoundment is required due to slope requirements to allow effective gravity drainage that cannot be achieved with a single impoundment basin. The LNG impoundment basins will include sump pumps to pump out rain water. In accordance with 49 CFR § 193.2173, the water removal system will have the capacity to remove water at a rate of 25 percent of the maximum predictable collection rate from a storm of ten-year frequency and one-hour duration. The discharged rainwater will be piped to the oily waste system.

2.2 MARINE FACILITIES

Overview

The LNG Terminal will include a single-use marine slip dedicated to supporting LNG exports. The east side of the slip will be utilized for the LNG carrier-loading berth and LNG loading facilities. Berths for tugboats and security vessels will be located on the north side of the slip. An emergency lay berth will be provided on the west side of the slip to allow for berthing a temporarily disabled LNG carrier in an emergency. This berth will have no product loading facility, but it will comply with and be designed to meet all of the safety and security standards of the Oil Companies International Marine Forum (OCIMF) and the USCG. THE MOF will be constructed outside of the slip to deliver construction and maintenance components of the LNG Terminal that are too large or heavy to be delivered by road or rail.

The LNG carrier loading berth will be capable of accommodating LNG carriers with a cargo capacity range of 89,000 m^3 to 217,000 m^3. The USCG Letter of Recommendation (LOR) and Waterway Suitability Report (WSR) currently allows LNG carriers up to 148,000 m^3 to dock at the LNG Terminal berth.

2.2.1 Access Channel

Access to the marine slip will be via a newly constructed access channel that will connect the slip to the Federal Navigation Channel at approximate Channel Mile 7.3 at the beginning of the confluence between the Jarvis Turn and the Upper Jarvis Range A. The access channel will flare from the narrowest portion at the mouth of the slip, with a minimum width of 780 feet, to the intersection with the Federal Navigation Channel with an approximate width of 2,200 feet. The proposed access channel will allow for the safe transit of vessels between the berth and the Federal Navigation Channel, and allow the safe turning of vessels during an inbound transit so that the LNG carrier can be backed into the slip and berthed bow out, according to industry best practice requirements.

The total access channel would cover approximately 22 acres below the Highest Measured Tide (HMT) elevation of 10.26 feet (NAVD88). The walls of the access channel would be sloped to meet the existing bottom contours at an angle of approximately 3 feet horizontal to 1 foot vertical (3:1). The marine slip and access channel will have a minimum depth of -45 feet below the mean lower low water (MLLW (-45.97 feet NAVD 88)) to ensure minimum under-keel clearance is achieved for the safe maneuvering and berthing of loaded LNG carriers. An allowance over and above the minimum depth will be made for advanced maintenance dredge and incidental over-dredge, in accordance with industry best practices. Dredging of the access channel would affect about 15 acres of currently existing deep subtidal area below -15.3 feet in depth below MLLW.

2.2.2 Marine Slip

The new marine slip will be constructed by excavating an existing upland area. The majority of the marine slip will be excavated from existing uplands owned by JCEP. Part of the marine slip would be constructed within state waters of Coos Bay to the MLLW line, for which the Port has obtained an easement from the ODSL.

The slip will be bounded on the east and west sides by sheet pile walls, creating a vertical face to support mooring structures. The northern side of the slip will be sloped to meet the existing bottom contours at an angle of 3 feet horizontal to one foot vertical (3:1). The inside dimensions at the toe of the slope of the slip will measure a minimum of 800 feet between the vertical sheet pile walls along the east/west axis, and approximately 1,500 feet and 1,200 feet along the western and eastern boundaries, respectively. The slip is sized to provide the flexibility needed to safely maneuver an LNG carrier from the access channel into the slip when another LNG carrier is already berthed on the east or west sides and for tugs to move a temporarily disabled LNG vessel away from the loading berth on the east side of the slip to the emergency lay berth on the west side of the slip if necessary.

2.2.3 LNG Carrier Berths

The marine facilities will include two LNG carrier berths, an Emergency Lay Berth and a Product Loading Berth. Each berth consists of a number of elements: the sheet pile wall, mooring structures and breasting structures. In general, the LNG loading berth will be about 1,280 feet long between the centers of the end mooring structures, and 312 feet long from the center of the northernmost breasting structure to the center of the southernmost breasting structure.

2.2.4 Sheet Pile Walls

The physical berth will be constructed of steel sheet piles to support surface structures (i.e., the loading area) or provide the foundation for the breasting and mooring structures. Under the loading facility, the wall will extend from the bottom of the slip at elevation -45.97 (minimum) to approximate elevation +34.5 (NAVD88). This face will extend north and south to capture the outermost breasting structures and then turn to the east, creating a setback wall for the remainder of the slip.

2.2.5 Mooring Structures

Mooring and breasting (see Section 1.3.6.4.3) structures will be provided at both the loading berth and the emergency lay berth for the safe breasting, berthing, and mooring of the LNG carriers docked at either berth.

Six mooring structures (three on each side of the LNG berth centerline) will be used to secure the LNG carrier at both the LNG loading berth and the emergency lay berth. The structures will be behind the sheet pile wall, set back approximately 145 feet from the face of each berth. These structures will have concrete platforms founded on steel pilings and will each have remote release mooring hooks with capstans, as well as all required equipment and instrumentation for safe mooring operations.

2.2.6 Breasting Structures

There will be four breasting structures located adjacent to the product loading facility (PLF); two will be located north of the PLF and two to the south. Like the mooring structures, each breasting structure will have a concrete platform founded on steel pilings and will have remote release mooring hooks with capstans, as well as all required equipment and instrumentation for safe mooring operations. Each breasting structure will also support a fender assembly sized to absorb and distribute berthing and mooring loads for the full range of LNG carriers that the LNG berth is designed for, thus preventing damage to the LNG carriers or the LNG berth. The fender system will allow the carriers to be moored a safe distance off the vertical face of the sheet pile wall. The emergency lay berth will have four breasting structures with fenders and capstans spaced equally about the mid-ship. There will be additional breasting fender structures, two to the north and two to the south of the main breasting structures, for a total of eight. The exact number, type, and location of the breasting structures for the emergency lay berth will be defined during detail design to meet OCIMF requirements for non-parallel vessel approach and the full range of vessel sizes.

2.2.7 Product Loading Facility

The PLF utilizes a pile-supported concrete slab that provides structural support to the marine loading arms, terminal gangway, and other ancillary equipment. The PLF is designed to support a number of elements that facilitate the safe transfer of LNG product between the LNG Terminal and the LNG carriers.

The PLF will be constructed on top of the sheet pile wall at approximate elevation +34.5, and will be about 130 feet long and 86 feet wide. The foundation will be reinforced concrete supported by steel pilings.

The transfer equipment consists of four marine loading arms and ancillary equipment. There will be two dedicated liquid loading arms, one hybrid arm, and one ship vapor return arm to meet the design loading rate of 12,000 m^3/h. The hybrid arm will be designed for dual service capable of transferring LNG to the LNG carriers or returning vapor from the LNG carriers to the BOG vapor management system. During normal operation the hybrid arm will be used in liquid service along with the two liquid arms, and the vapor return arm will be used to return vapor to the BOG vapor management system.

The loading arms are designed with swivel joints to provide the required range of movement between the LNG carrier and the shore connections. Each arm will be fitted with a hydraulically interlocked double ball valve and powered emergency release coupling to isolate the arm and the LNG carrier in the event of an emergency condition in which rapid disconnection of the connected arms is required. Each arm will be fully balanced in the empty condition by a counterweight system and maneuvered by hydraulic cylinder drives. A mezzanine-type elevated steel platform will be installed for maintenance of the triple-swivel assembly of the arms.

LNG spill containment will be accomplished by a concrete curbed and sloped area that will contain any LNG spillage and allow the spill to safely flow away from the loading area through the LNG spill collection trench to the marine area LNG impoundment basin.

Additional structures at the LNG loading berth will include an LNG carrier gangway, area lighting facilities, aids to navigation, firewater monitors, and a dry chemical firefighting system.

2.2.8 Emergency Lay Berth

An emergency lay berth on the west side of the slip will be provided with facilities to safely moor a temporarily disabled LNG carrier. Berthing facilities will be supported by the west side sheet pile wall with a top-of-wall elevation of approximately +20 feet (NAVD 88). The lay berth will have pile-supported breasting structures with fenders extending above the vertical sheet pile and mooring structures on the land side of the sheet pile. A grated platform with a gangway will be placed behind the berthing breasting structures to allow for safe access and egress from the disabled LNG carrier at berth. Support infrastructure will include an access road down from the area of the tug berth building, duct bank with cabling for powering the mooring hooks and capstans, and limited lighting of the ship access area.

Along the western property line, but on the Project side of the Henderson Property buffer zone, a tsunami flow control wall will be constructed. The flow control wall shall be of sufficient height and strength to prevent overtopping into Henderson Property and limit the drag due to the tsunami current loads on LNG carriers within the marine slip. The wall height shall be approximately 34.5 feet and determined in accordance with the design tsunami criteria. The wall will run from the southwest side of the LNG tank impoundment area down to the entrance to the slip.

2.2.9 Material Offloading Facility

The MOF will be constructed to deliver components of the LNG Terminal that are too large or heavy to be delivered by road or rail. The MOF will cover about 3 acres on the southeast side of the slip, adjacent to the RFP. The MOF will be constructed using the same sheet pile wall system as the LNG loading berth and the emergency lay berth. The top of the MOF will be at elevation approximately +13.0 feet (NAVD88), and the bottom of the exposed wall will be at the access channel elevation. The MOF will provide approximately 450 feet of dock face for the mooring and unloading of a variety of vessel types.

During construction of the LNG Terminal, in addition to receiving equipment and large modules (upwards of 6,000 short tons) by break bulk cargo carriers, roll on roll off cargo carriers, and barges, the MOF will allow other bulk materials to be delivered by sea to minimize impacts on the local road network. After project construction, the MOF will be retained as a permanent feature of the LNG Terminal to support maintenance and replacement for large equipment components that are too large to be transported by rail and road.

2.2.10 Tug Berth

The tug berth at the north side of the marine slip will accommodate four tugboats, as well as two sheriff's boats and six other visitor boats with similar characteristics as the sheriff's boats. For design purposes, the tugs are assumed to be 80-metric-ton bollard pull boats approximately 100 feet long with a beam of 40 feet. The basis for the sheriff's boat is the Willard USCG Long Range Interceptor. The tug dock will generally be about 470 feet long and 18 feet wide; in addition, there is 360 feet of 8-foot-wide floats for mooring and accessing the security vessels.

The tug dock will be concrete supported by steel piles. The security vessel docks will be precast concrete floats anchored by steel pile. The security boat dock will support two separate boat houses. The tug dock will be accessible from land by a pile-founded trestle, thus allowing vehicle and pedestrian access for service and support of operations. An onshore tug operations building will provide storage, meeting, and sanitary facilities for the crews of the tug and security boats.

2.2.11 Vessel Transit

LNG carriers would access the LNG Terminal through a waterway for LNG marine traffic, which is defined by the USCG for the Project as extending from the outer limits of the U.S. territorial waters 12 nautical miles off the coast of Oregon, and up the existing Federal Navigation Channel about 7.5 miles to the LNG Terminal.

The Project's plans for the LNG carriers calling on the LNG Terminal and their transit route in Coos Bay, as described below, are primarily within the jurisdiction of the USCG. Because the USCG has authorized carriers of approximately 950 feet length, 150 feet beam, and loaded draft of 40 feet (nominal 148,000 m^3)[1] as the size of LNG carrier, the LNG Terminal could generate a maximum of 120 LNG carrier calls per year, although the average is expected to be between 110 and 120 LNG carriers per year. The actual number of LNG carriers per year will be dependent on the capacity of the LNG carriers calling on the LNG Terminal and the actual output production of the LNG Terminal. The LNG loading berth is designed so that it could accommodate LNG carriers up to 217,000 m^3 if larger-sized carriers were to be authorized by the USCG in the future, resulting in a reduced number of LNG carrier calls each year.

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[1] Depending upon the approved LNG containment system type, carriers with these approximate dimensions may range in LNG cargo capacity from 135,000 m^3 to 170,000 m^3.

The total average LNG carrier port time is estimated to be approximately 36 hours, assuming there are no delays caused by natural environmental conditions. This estimate includes the 1.5 hours transit time from the Pilot boarding to arrival at the LNG loading berth to the Pilot drop-off at departure, time of mooring, unmooring and cast off, the bulk LNG loading time of approximately 15 hours (using the 12,000 m^3/hr loading rate), and the 8 hours of time waiting for the next available high tide cycle needed for safe departure and transit of the Federal Navigation Channel.

An LNG ship traffic study conducted by Moffatt & Nichol International (M&N 2006) concluded that the additional LNG carrier traffic associated with the Project can be accommodated in the Port and the Federal Navigation Channel. The ship traffic conditions in the Port that existed when the LNG carrier traffic study was conducted have not changed.

Resources, such as high bollard pull tractor tugs and pilots, will be required to handle the planned number of LNG carriers. JCEP has committed to provide the following marine resources as identified by the USCG in the current version of the WSR:

- Four (three operation, one standby) 80-bollard-ton tractor tugs with Class 1, firefighting capability;
- A Port differential Global Positioning System navigation system for use by the Pilots and LNG carrier bridge team while transiting the channel en route to the Project;
- Physical Oceanographic Real Time System to provide real-time channel water level, current, and weather data;
- A Vessel Traffic Information System consisting of an Automatic Identification System receiver, 2 land-based radars, and 12 low light cameras (with zoom, pan, and tilt) to monitor the transit of the LNG carriers while in Coos Bay;
- Emergency response notification system;
- Installation of private navigation aids (e.g., channel centerline range markers); and
- Gas detection capability along the LNG carrier waterway transit route.

2.3 NAVIGATIONAL RELIABILITY IMPROVEMENTS

JCEP plans to excavate four submerged areas lying adjacent to the federally-authorized Channel. These minor enhancements will allow for transit of LNG vessels of similar overall dimensions to those listed in the July 1, 2008 USCG Waterway Suitability Report, but under a broader weather window. This allows for greater navigational efficiency and reliability to enable JCEP to export the full capacity of the optimized design production of 7.8 mtpa from the LNG Terminal.

The total volume of capital dredge material from these excavations is approximately 700,000 cubic yards. Dredge material may be distributed between APCO 1 and APCO 2 upland disposal sites, or placed entirely at APCO 2 if shown to be feasible. The dredge areas are named Dredge Area 1 to 4 and located adjacent to the Channel roughly between River Mile ("RM") 2 to RM 7 respectively.

Enhancement #1 – Coos Bay Inside Range channel and right turn to Coos Bay Range: Excavation at this site will reduce the constriction to vessel passage at the inbound entrance to Coos Bay Inside Range for any ship making the 95 degree turn from the Entrance Range through the Entrance Turn and Range. JCEP proposes to widen the Coos Bay Inside Range channel from the current 300 feet to 450 feet, thereby making it easier for all vessels transiting the area to make this turn. In addition, the total corner cutoff on the Coos Bay Range side will be lengthened from the current 850 feet to about 1,400 feet from the turn's apex.

Enhancement #2 – Turn from Coos Bay Range to Empire Range channels: The current corner cutoff distance from the apex of this turn is about 500 feet, making it difficult for vessels to begin turning sufficiently early to be able to make the turn and be properly positioned in the center of the next channel range. JCEP proposes to widen the turn area from the Coos Bay Range to the Empire Range from the current 400 feet to 600 feet at the apex of the turn and lengthen the total corner cutoff area from the current 1000 feet to about 3500 feet.

Enhancement #3 – Turn from the Empire Range to Lower Jarvis Range channels: JCEP proposes to add a corner cut on the west side in this area that will be about 1,150 feet, thereby providing additional room for vessels to make this turn.

Enhancement #4 – Turn from Lower Jarvis Range to Jarvis Turn Range channels: JCEP proposes to widen the turn area here from the current 500 feet to 600 feet at the apex of the turn and lengthen to total corner cutoff area of the turn from the current 1,125 feet to about 1,750 feet thereby allowing vessels to begin their turn in this area earlier.

Maintenance materials will be disposed of in the upland dredge disposal sites located on the APCO site 1 and APCO site 2 and management of the dredge areas would be the responsibility of Jordan Cove.

2.4 TERMINAL SUPPORT SYSTEMS

2.4.1 Vapor Handling System

BOG is primarily generated from the LNG storage and loading system, and consists of flash gas from the LNG product stream entering the LNG flash drum, vapors from the heat leak into the LNG storage tanks, piping and pump systems, vapor displaced as the LNG storage tanks are filled, and vapor return from the LNG carrier during LNG loading. The BOG will be consumed as fuel. Two BOG compressor trains are included to compress the vapor from LNG storage tank pressure to fuel gas pressure. The mode of operation of the liquefaction plant when not loading an LNG carrier is known as "holding mode." The mode of operation during LNG carrier loading is known as "loading mode." One BOG compression train will be operating continuously to handle holding mode BOG volumes; the second will be needed only during loading mode or during an off-design condition that results in increased BOG generation.

During normal operation, fuel gas will be supplied from BOG and vaporized heavy hydrocarbon streams, and supplemented with gas from the inlet pipeline upstream of the gas conditioning train. After mixture in the high-pressure fuel gas mixing drum, this high-pressure fuel gas stream primarily feeds the combustion gas turbines to drive the refrigerant compressors. Some high-pressure fuel gas is let down from the high-pressure fuel gas header to the low-pressure fuel gas knockout drum before going to other smaller consumers, such as thermal oxidizer, duct burners, and flare pilots.

Normally, a small amount of makeup to the high-pressure fuel from the pipeline feed gas is required to meet demands; if the BOG/heavies mixture results in excess fuel for the demand, it can be recycled upstream of the amine unit and re-liquefied.

Steam System

The LNG Terminal will use steam as a heat transfer fluid for process heating. High pressure steam is provided to the facility from Heat Recovery Steam Generators (HRSGs), which utilize waste heat from refrigerant compressor driver exhaust gases. High-pressure steam supplies the gas conditioning train and STGs, where the steam pressure is let down from 725 pounds per square inch gauge ("psig") to produce low-pressure steam at 50 psig per gas conditioning needs and the balance is further dropped to a vacuum pressure and generates electricity for the plant. Any low-pressure steam requirement in excess of this can be made up by "de-superheating" a letdown of high-pressure steam. Process condensate is de-aerated and treated, and then returned to the cycle as boiler feed-water for the HRSGs. An auxiliary boiler is available to provide high-pressure steam to meet the requirements for one STG and any additional steam required for when the facility is not producing LNG.

2.4.2 Instrument Air

Instrument air will be provided through compression and drying packages. Air will be compressed in two x 100 percent centrifugal compressors. There will be one additional compressor with the ability to provide essential instrument air duty. Air will be dried in two x 100 percent air dryer packages, with each package containing four air dryers designed for full, continuous operation. During operations, one dryer will be in absorption mode while the other dryer regenerates. Instrument air will be used for pneumatic control of automated instrumentation, utility air, and supply for nitrogen generation.

2.4.3 Utility Air

Utility air will be used for normal maintenance activities (utility stations, control panel purges, building purges, etc.). Utility air will be dried with the instrument air but will be supplied throughout the facility from a separate header. The utility air header will be provided with a pressure regulator and on-off valve to shut off flow if the main header pressure drops to the minimum for proper functioning of actuators.

2.4.4 Nitrogen

Nitrogen will be provided through vaporization of liquid nitrogen and a pressure swing adsorption site generation package unit. Pressure swing adsorption units use swings in pressure to separate nitrogen from air; the pressure swing adsorption swings from high pressure, where nitrogen is adsorbed from air, to low pressure, where it is desorbed. Liquid nitrogen will be the only source of nitrogen used for refrigerant makeup, while the site-generated nitrogen will supply continuous utility users, such as compressor seals, cold box purges and LNG loading arm swivel joints, as well as intermittent users, such as LNG loading arm purges and utility stations. Nitrogen packages will be sized to fulfill peak demand and to handle the maximum expected instantaneous flow.

2.4.5 Utility and Potable Water System

An interconnect to the Coos Bay-North Bend Water Board ("CBNBWB") potable water pipeline will be used for all normal operational water needs in the LNG Terminal, which includes fire water makeup, utility water used for such items as equipment and area cleaning, and potable water required to supply buildings and eyewash/safety shower stations.

Utility water is fed to the demineralized water package, but storage of utility water will be combined with fire water supply in the fire water tanks.

The CBNBWB raw water pipeline (in addition to the potable water pipeline) will be used for construction water, including LNG tank hydrotesting. The pipeline tap at the LNG Terminal site will remain connected after construction, but there are no normal operational uses anticipated for this raw water supply.

Resource Report 2 provides the estimated potable and raw water demand during the construction and operation of the LNG Terminal.

2.4.6 Fire Suppression System

Fire suppression and protection measures will be provided to ensure the safety of personnel and property. Fire water systems at the LNG Terminal including fire water supply storage tanks, stationary fire water pumps, fire hydrant mains, fixed water spray systems, automatic sprinkler extinguishing systems, high expansion foam system, and remotely controlled monitored spray systems will meet the requirements of 49 CFR Part 193, NFPA 59A, American Petroleum Institute ("API") 2510, API 2510A, and 33 CFR Part 127.

The function of the fire water system is to provide water under pressure to the fire hydrants, monitors, and fixed water suppression systems throughout the LNG Terminal. The fire water supply will also be used to provide water for on-site firefighting trucks. The fire suppression distribution piping network will comprise the following:

- Underground fire water mains;
- Aboveground fire water hydrant mains;
- Fixed fire water sprinkler and spray systems;
- Fixed high-expansion foam systems;
- Portable fire suppression equipment;
- Appurtenances, including all piping and valves connecting the pumps and water supply to the plant fire suppression systems; and
- Hydrants and monitors.

The main fire water supply for the LNG Terminal is provided by two x 100 percent capacity aboveground atmospheric storage tanks (located in the Access and Utility Corridor), which allow for redundancy if one of the tanks is unavailable. This redundancy is an acceptable precautionary measure for preparing for fire water tank repairs, in accordance with NFPA 22, and to perform regular maintenance and inspection of fire water tanks in accordance with NFPA 25. Water supply for the two fire water tanks is potable water from the local CBNBWB.

The fire water tanks are dual-service supply tanks and will provide the standpipe system to ensure dedicated fire water volume for fire protection systems. Each tank will hold a minimum usable capacity of 3,240,000 gal to supply four hours of fire water supply for the Maximum Probable Fire Water Demand, which is the demand for the largest fire scenario including 1,000 gpm hose stream allowance in accordance with NFPA 59A. Providing four hours of water supply is in accordance with API 2510 which exceeds the two hours of water supply required by NFPA 59A. The atmospheric tank design will follow API Standard 650 and NFPA 22.

The fire water distribution network will be supplied via four x 33 percent capacity fire water pumps. One fire pump will be electric motor driven while three will be diesel engine driven to ensure at least three pumps remain available in the event of power failure. Two x 100 percent electric-motor-driven jockey pumps will be provided to maintain pressure in the main fire water distribution system. The entire pump installation will be designed in accordance with NFPA 20 and the fire water distribution network will be designed in accordance with NFPA 24.

2.4.7 Flare, Relief, and Blowdown System

Flare systems are a necessary safety feature of all LNG export facilities. The LNG Terminal will have three separate flare systems for pressure relief plant-protection conditions: one for warm (wet) reliefs, one for cold, cryogenic (dry) reliefs, and one for low-pressure cryogenic reliefs from the marine loading system. The "warm" relief loads are separated to ensure that wet fluids cannot freeze in the header if there were a cryogenic relieving event. The "cold" and "marine" relief loads are separated to ensure that the relief of near-atmospheric pressure vapors is not affected by back-pressure in the header if an unrelated release were to occur.

The warm and cold flares will both be within a multi-point enclosed ground flare, while the marine flare will be an enclosed cylindrical ground flare. A small pilot with electronic ignition is provided on each flare.

The flare system will be used only during plant-protection situations, maintenance activities, cases of purging and gassing-up an LNG carrier, and initial commissioning/start-up.

2.4.8 Stormwater and Wastewater Systems

The LNG Terminal and marine LNG loading area will include various drainage elements to manage segregated networks for contaminated and uncontaminated water from designated areas. Liquid effluent from the LNG Terminal and marine LNG loading area consists mainly of water from rainfall, protection of equipment with fire water, processing areas, storage areas, domestic areas, and utilities units. Water from all oil-filled equipment in LNG spill impounding basins will be pumped by submersible pumps to the oily water treatment system.

Stormwater from areas other than LNG spill impounding basins will be collected in a system of stormwater swales, a buried storm water system, infiltration basins, and other treatment facilities. Stormwater facility overflow outfalls will ultimately connect to Coos Bay. The initial runoff from all storms of a two-year return period and 24-hour duration or less will be infiltrated. Excess stormwater during storms of longer return periods will be allowed to overflow to the slip. Stormwater from some low elevation areas will be treated with cartridge filters and released to the slip.

Stormwater collected in areas that are potentially contaminated with oil or grease will be pumped or will flow to the oily water system. The oily water system will flow to the oily water separator package(s) before being treated and discharged to the IWWP.

The facility will be designed to provide drainage of surface water to designated areas for disposal in accordance with 49 CFR § 193.2159. Stormwater collection and treatment facilities will be designed to meet regulatory requirements from the National Marine Fisheries Service ("NMFS") and ODEQ.

2.4.9 Sewage and Sanitary Waste Treatment

Sanitary waste from the northwest guard house and tug building will be directed to a holding tank. A sanitary waste contractor will remove the contents of the tank as necessary and dispose of the contents at authorized disposal sites through the sanitary waste contractor's permits. Sanitary waste from the remainder of buildings will be treated by a packaged treatment system. The effluent will be directed to the IWWP. Solids will be removed from the packaged treatment system periodically by a sanitary waste contractor and will be disposed of at authorized disposal sites through the sanitary waste contractor's permits.

2.4.10 Hazard Detection and Response

Safety controls, including hazard detection and response systems, are briefly summarized below. The Project will contain "passive" and "active" hazard prevention and mitigation systems and controls.

Passive systems will generally include those that do not require human intervention, such as spill drainage and collection systems, ignition source control, and fireproofing. Thermal proofing will be considered for application to support structures, components, and equipment, as required, to maintain structural stability in a fire hazard zone, cryogenic spill zone, or area where a failure could affect a safety-related system, provide additional fuel to a fire, or cause additional damage to the unit or facility.

Active systems normally are either automatic or require some action by an operator. Active fire control systems and equipment will consist of a looped, underground fire water distribution piping system serving hydrants, fire water monitors, hose reels, water-spray, or deluge and sprinkler systems. Active spill control systems will include fixed high-expansion foam and dry chemical systems. They will also include portable and wheeled fire extinguishers that employ dry chemicals and CO_2. Fire protection in buildings will generally consist of smoke detectors, flame detectors, portable fire extinguishers, sprinkler systems, and an emergency shutdown ("ESD") system.

Process instruments will routinely monitor for potentially hazardous conditions. Specialized automatic hazard detection and alarm notification devices will be installed to provide an early warning. The Project will also contain hazard detectors designed to sense a variety of conditions, including combustible gas, low temperatures (LNG spill), smoke, heat, and flame. Each of these detector systems will trigger visual and audible alarms at specific site locations and in the control room areas to facilitate effective and immediate response.

The safety of the LNG carriers while docked and loading is a major design consideration for hazard detection and response. Safety measures include ESD spill containment and provisions to protect piping from the effects of surges. In addition, JCEP will have a Fire Department with three pumping trucks, one ladder truck, and one hazardous materials truck that can be mobilized to attend to a fire in the facility in less than 4 minutes.

2.4.11 Process Control System

Operators will control and monitor the facility through a distributed control system ("DCS"). Vendor-supplied packaged units with local control panels and numerous field-mounted instruments will be connected to remote Input/Output ("I/O") cabinets located throughout the facility. These remote I/O cabinets interface with the DCS controllers through cabling run through the plant to the control room. The DCS also includes a local historian that historicizes all process data on-site. Overall plant process control and monitoring will be performed at consoles located in the central control room, with monitoring capabilities from the remote I/O rooms. Other machine monitoring and control systems such as those used for the refrigerant compressors will have local control panels but will also be linked to the DCS and central control room.

In addition to the DCS, independent Safety Instrumented Systems ("SIS") and Fire and Gas Systems ("FGS") will be employed to monitor hazardous conditions and provide emergency shutdown capability. The SIS will utilize separate, dedicated controllers to control safety functions such as those that are required for emergency shutdown safety functions. DCS controllers will monitor the present value of a designated process parameter and adjust actuated control valves to maintain the process setpoint.

Limits will be defined to alert operators of deviation away from setpoint, and the SIS will take action if further deviation occurs. The FGS will permit activation of critical firefighting equipment from the control room and will utilize various flame, smoke, and temperature detectors as well as sirens, beacons, and manual alarm call points.

2.4.12 Electrical Systems

JCEP plans to obtain limited power from the regional electric grid for the SORSC and temporary construction activities as described in Section 1.9. With the exception of the SORSC, the LNG Terminal facilities will be islanded (with black-start capability) and will not have the means, infrastructure, or need to import or export power during operations.

The total power requirements for the LNG Terminal are 39.2 MW (holding mode) and 49.5 MW (loading mode). Electrical power will be via two 30 MW STGs and one spare 30 MW STG. The steam is efficiently generated by HRSGs using exhaust from the refrigerant compressor combustion turbine drivers. A black-start auxiliary boiler will be used to generate steam for power when gas turbines are not in operation. In addition, there are two standby diesel generators for the LNG Terminal and two for the SORSC. The facility will not be connected to the local grid, and will not import or export power. Two switchgear buses, in a main-tie-main configuration, will be connected to the STGs (minimum of one turbine to each bus). These switchgear buses will feed the plant distribution 13.8 kilovolt ("kV") switchgear, 6.9 kV switchgear and motor control center, and 480-volt switchgears and motor control center buses located throughout the plant. The plant distribution buses will contain two 6.9 kV essential power buses that power all of the essential plant loads. The LNG Terminal diesel generators have 100 percent redundancy and are connected to the 6.9 kV essential power buses.

2.4.13 Buildings

Buildings and structures required for the operation of the LNG Terminal `include:

- Administration building;
- SORSC building;
- Fire department;
- Operations building/control room/laboratory/first aid facility;
- Main gate guard house and security building;
- Secondary entrance security gate/terminal guard building;
- Plant warehouse/receiving building;
- Maintenance building;
- Tugboat, storage, and crew building;
- Lube oil, paint and compressed gas storage;
- Water treatment building;
- Inspection station shelter;
- Fire water pump buildings;
- Fire water valve houses;
- Marine control room building;
- Electrical powerhouses;
- Equipment shelters/buildings;
- Analyzer buildings;

The siting of occupied buildings will be evaluated for overpressure, toxic release, and fire hazards. Occupied buildings will be sited in accordance with industry standards. Loads, analysis, design, and construction will be in accordance with all statutory and regulatory requirements.

2.4.14 Lighting System

The lighting levels will be based on API standards. Lighting around equipment and facilities where routine maintenance activities could occur on a 24-hour basis would range from 1 to 20 foot-candles, with 20 foot-candle lighting levels within the compressor enclosures.

General process area lighting would be kept to a minimum, on the order of 2 foot-candles. Access and Utility Corridor lighting for the LNG Terminal would be 0.4 foot-candle. Perimeter security would be on the order of 1.3 foot-candles, using evenly spaced 400 watt floodlights. As a point of reference, 20 foot-candles is close to the indoor lighting in a typical home, 2 foot-candles is typical of that found in a store parking lot, and 0.4 foot-candle is typical of residential street lighting. The final lighting plan would be developed during detailed design.

Only lighting required for operation and maintenance, safety, security, and meeting Federal Aviation Administration requirements would be used on the LNG storage tanks. The light will be localized to minimize off-site effects.

2.4.15 Access and Utility Corridor, Haul Road, Access Roads, and Parking Lots

The Access and Utility Corridor will be constructed between Ingram Yard and the South Dunes Site. The corridor will be approximately 1 mile long. It will be located entirely on property owned by JCEP. The Access and Utility Corridor will cover about 26 acres.

The primary purpose of the Access and Utility Corridor is to provide a conduit for the underground feed gas supply to the LNG Terminal and a number of utility services required between the LNG Terminal and South Dunes. Utilities in the corridor will include underground power lines, fire water supply, communications lines, and metering skid control lines.

The full length of the corridor will be used during construction for the movement of equipment and materials. The road will be used to haul materials excavated from the Ingram Yard to the South Dunes Site and the Roseburg Forest Products (RFP) property. Use of the corridor for mass earth moving will reduce impacts to the Trans Pacific Parkway (TPP) and the existing RFP facility.

The western portion of the Access and Utility Corridor between the LNG Terminal and Jordan Cove Road will be paved and provide primary permanent access; it will include two lanes into the LNG Terminal and a single lane out. The remainder of the corridor, east of Jordan Cove Road, will be provided with a crushed rock track for infrequent maintenance access. Paved access between the South Dunes Site and the western portion of the Access and Utility Corridor will be provided by the existing Jordan Cove Road. A two-lane access road will be provided to the northwest of Ingram Yard to provide emergency, marine terminal, and occasional maintenance access from the TPP.

To the west of the Access and Utility Corridor and within the secured footprint of the LNG Terminal will be the guard house, security building, firefighting facility, operations building, warehouse building, maintenance building, and parking for operations personnel. Both the South Dunes Site and Ingram Yard will be provided with sufficient parking.

EFSC Plot Plan

Public

Combined Heat and Power Block Flow Diagram

Confidential Business Information

Exempt from Public Disclosure

Appendix A

Detailed LNG Facility Information

Confidential Business Information

Exempt from Public Disclosure

Appendix B

Detailed LNG Facility Information

Public