JCEP LNG TERMINAL PROJECT

Resource Report 1 - General Project Description

To Verify Compliance with this Minimum FERC Filing Requirement:	**See the Following Resource Report Section:**
1. Provide a detailed description and location map of the project facilities. (§ 380.12(c)(1)) • Include all pipeline and aboveground facilities. • Include support areas for construction or operation. • Identify facilities to be abandoned.	Section 1.1.2 Figure 1.1-1
2. Describe any nonjurisdictional facilities that would be built in association with the project. (§ 380.12(c)(2)) • Include auxiliary facilities (See § 2.55(a)). • Describe the relationship to the jurisdictional facilities. • Include ownership, land requirements, gas consumption, megawatt size, construction status, and an update of the latest status of Federal, state, and local permits/approvals. • Include the length and diameter of any interconnecting pipeline. • Apply the four-factor test to each facility (see § 380.12(c)(2)(ii)).	Section 1.9.1
3. Provide current original U.S. Geological Survey (USGS) 7.5-minute-series topographic maps with mileposts showing the project facilities. (§ 380.12(c)(3)) • Maps of equivalent detail are acceptable if legible (check with staff). • Show locations of all linear project elements, and label them. • Show locations of all significant aboveground facilities, and label them.	Figure 1.10-1
4. Provide aerial images or photographs or alignment sheets based on these sources with mileposts showing the project facilities. (§ 380.12(c)(3)) • No more than 1-year old. • Scale no smaller than 1:6,000.	Figure 1.10-2
5. Provide plot/site plans of compressor stations showing the location of the nearest noise-sensitive areas (NSA) within 1 mile. (§ 380.12(c)(3,4)) • Scale no smaller than 1:3,600. • Show reference to topographic maps and aerial alignments provided above.	Figure 1.1-2
6. Describe construction and restoration methods. (§ 380.12(c)(6)) • Include this information by milepost. • Make sure this is provided for offshore construction as well. For the offshore this information is needed on a mile-by-mile basis and will require completion of geophysical and other surveys before filing.	Section 1.3.1 Section 1.3.2 Section 1.3.3
7. Identify the permits required for construction across surface waters. (§ 380.12(c)(9)) • Include the status of all permits. • For construction in the Federal offshore area be sure to include consultation with the MMS. File with the MMS for rights-of-way grants at the same time or before you file with the FERC.	Section 1.7 Table 1.7-1
8. Provide the names and address of all affected landowners and certify that all affected landowners will be notified as required in § 157.6(d). (§ 380.12(c)(10)) • Affected landowners are defined in § 157.6(d). • Provide an electronic copy directly to the environmental staff.	Section 1.8.2
Additional Information Often Missing and Resulting in Data Requests	
Describe all authorizations required to complete the proposed action and the status of applications for such authorizations.	Section 1.7 Table 1.7-1

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ACRONYMS

ACFM	actual cubic feet per minute
AIS	Automatic Identification System
API	American Petroleum Institute
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
ATONS	Aids to Navigation System
BOG	Boil-off Gas
Bcf/d	Billion Cubic Feet Per Day
Bscf/d	Billion Standard Cubic Feet Per Day
C&H	Coast and Harbor Engineering
CBNBWB	Coos Bay-North Bend Water Board
CFR	Code of Federal Regulations
CMMS	Computerized Maintenance Management System
CO_2	Carbon Dioxide
CTG	Combustion Turbine Generator
cy	Cubic Yards
DCS	Distributed Control System
DGA	Diglycol Amine
DLCD	Department of Land Conservation and Development
DOT	U. S. Department of Transportation
DBV/PERC	Double Ball Valve/Powered Emergency Release Coupling
EFSC	Oregon Department of Energy, Energy Facility Siting Council
EIA	Energy Information Administration
EIS	Environmental Impact Statement
ESD	Emergency Shutdown System
^oF	Degrees Fahrenheit
FAQs	Frequently Asked Questions
FERC	Federal Energy Regulatory Commission
gpm	Gallons Per Minute
H	Horizontal
hp	HorsepowerH_2S Hydrogen Sulfide
HDPE	High Density Polyethylene
HRSG	Heat Recovery Steam Generator
I/O	Input/Output
IWP	Industrial Wastewater Pipeline
JCEP	Jordan Cove Energy Project
kV	Kilovolt
LNG	Liquefied Natural Gas
m^3	Cubic Meter
m^3/hr	Cubic Meters Per Hour
mgd	million gallons per day
MMTPA	Million Metric Tons Per Annum
MW	Megawatt

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ACRONYMS (Continued)

NAVD88	North American Vertical Datum of 1988
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NGA	Natural Gas Act
NRCS	Natural Resources Conservation Service
OCIMF	Oil Companies International Marine Forum
ODEQ	Oregon Department of Environmental Quality
ODOE	Oregon Department of Energy
PCGP	Pacific Connector Gas Pipeline
PF	Pre-filing
ppmv	Parts Per Million Volume
Port	Oregon International Port of Coos Bay
PORTS	Physical Oceanographic Real Time System
psig	Pounds Per Square Inch Gauge
SIGTTO	Society of International Gas Tanker and Terminal Operators
SIS	Safety Instrumented System
SMR	Single Mixed Refrigerant
STG	Steam Turbine Generator
Tcf	Trillion Cubic Feet
UPS	Uninterruptable Power Supplies
U.S.	United States
USACE	United States Army Corps of Engineers
USCG	United States Coast Guard
USGS	United States Geological Survey
UV/IR	Ultraviolet/Infrared
V	Vertical
WSA	Waterway Suitability Assessment
WSR	Waterway Suitability Report

RESOURCE REPORT 1
GENERAL PROJECT DESCRIPTION

1.0 INTRODUCTION

On December 17, 2009, Jordan Cove Energy Project, L.P. (JCEP) received Natural Gas Act (NGA) Section 3 authorization from the Federal Energy Regulatory Commission (FERC) to site, construct, and operate a liquefied natural gas (LNG) import and regasification facility on the bay side of the North Spit of Coos Bay, Oregon. The authorized facilities included: an LNG ship unloading berth, cryogenic service pipelines, two 160,000 m^3 (1,006,000 barrels) cryogenic LNG storage tanks, regasification facilities, and facilities to send out natural gas from the terminal. The import facility was authorized by the FERC and the U.S. Coast Guard (USCG) to be capable of handling LNG ships ranging in capacity from 87,000 m^3 to 148,000 m^3 (the LNG ship berth has been designed to accommodate LNG ships up to 210,000 m^3). FERC also certificated Pacific Connector Gas Pipeline (PCGP) to construct and operate a new pipeline to connect the import facility to existing intrastate and interstate pipeline systems.

On February 29, 2012, JCEP advised FERC that, given current natural gas market conditions, JCEP is now proposing to construct and operate a natural gas liquefaction and export facility and does not currently intend to construct the facilities specific to import and regasification of LNG. On March 6, 2012, FERC granted JCEP's request to initiate pre-filing review of facilities that would be required for liquefaction and export of LNG and assigned that request to Docket No. PF12-7-000. On April 16, 2012, FERC issued an order vacating the authorizations granted in 2009 for the import facility, noting that "Jordan Cove's pre-filing application for export authorization pursuant to Section 3 of the NGA is pending in Docket No. PF12-7-000 and will be considered on its own merits in that separate proceeding." Accordingly, JCEP is now seeking authority under Section 3 of the NGA to site, construct and operate a natural gas liquefaction and LNG export facility (LNG Terminal or Project), located on the bay side of the North Spit of Coos Bay, Oregon. The site is more than one mile from the nearest residential area and has sufficient area to serve as a buffer from other facilities and activities within the Project site area. The Project also involves the construction of the South Dunes Power Plant, although the South Dunes Power Plant is a non-FERC jurisdictional facility and the Oregon Energy Facility Siting Council (EFSC) will lead its regulatory permitting.

The siting of the LNG Terminal in Coos Bay will provide a number of direct and indirect benefits to Coos County including the following:

- The Project will provide Coos County with a new significant and stable source of revenue including pipeline transportation fees and property taxes.
- The Project will provide economic benefits to the area through temporary jobs during construction, as well as permanent jobs during the operation of the LNG Terminal.
- Procurement of local goods and services during both the construction and operational phases of the Project will provide additional economic benefits.
- The additional 90 LNG ships calling on the Oregon International Port of Coos Bay (Port) each year will increase the number of ship calls at the port, improving total port utilization and helping to sustain port operations.
- The additional ship calls will provide increased employment for longshore workers, harbor pilots, tugboat operators, and marine service and supply provisioners.

- The Project will enhance maritime safety through improved navigational aids and increased tug capability (including waterborne firefighting capability).

JCEP has prepared this application, and the accompanying Resource Reports 1 through 13, in compliance with the requirements of the FERC Regulations. Information supplied in these Resource Reports will be available to FERC in the preparation of an Environmental Impact Statement (EIS) under a third-party contractor agreement with JCEP as the Applicant and FERC as the lead agency for the National Environmental Policy Act (NEPA) process.

Section 1.8 of this Resource Report 1 provides a description of the public outreach and consultation activities that have been conducted as part of the pre-filing process.

This Resource Report 1 provides a description of the Project and its purpose and need from both national and regional perspectives, as well as a specific description of the Project facilities and certain nonjurisdictional facilities. It also includes a description of the benefits to the local Project area, land requirements, construction and operation procedures, and applicable regulatory approvals and coordination. The current construction schedule for the Project is also addressed in this Resource Report.

Reports 2 through 9 provide descriptions of the existing environment by resource, the potential impacts associated with the construction and operation of the Project, and proposed measures to mitigate these impacts. Resource Report 10 provides a description of the alternatives to the Project that were considered. Resource Report 11 provides a description of the design, construction, operation and maintenance measures incorporated into the Project to minimize potential hazards to the public associated with the Project. Resource Report 12 is not applicable because there are no polychlorinated biphenyls-contaminated facilities to be removed, replaced or abandoned. Resource Report 13 provides engineering information. Each Resource Report includes a compliance table showing how the FERC filing requirements (18 Code of Federal Regulations (CFR) § 380.12) have been met.

The Resource Reports are consistent with and meet or exceed all applicable minimum requirements for FERC. FERC approval and issuance of an Order authorizing the siting, construction, and operation of the Project by October 2013 is needed to allow for Project startup in the Fourth Quarter of 2017.

1.1 PROJECT DESCRIPTION

1.1.1 Purpose and Need

The proposed Project is a market-driven response to the availability of burgeoning and abundant natural gas supplies in the United States (U.S.) and Canada and rising and robust international demand for natural gas. Exports from the Project will promote healthy domestic and international natural gas markets and otherwise assist the Administration's efforts to expand exports, create jobs and stimulate the beleaguered U.S. economy.

1.1.1.1 Purpose

Specifically, the purpose of the Project is to meet each of the primary objectives listed below:

- The Project will be the first U.S. West Coast LNG terminal.
- The Project will be strategically located to provide market outlets, through new and existing pipeline infrastructure, for the increasing gas supplies from both the western Canadian and the U.S. Rocky Mountain supply basins.

- The Project will be advantageously located to serve growing international, particularly Asian, markets for natural gas.
- The Project will also be well located to serve domestic needs, including the isolated markets of Hawaii and Alaska and the markets of Oregon along the route of the new PCGP to be constructed in conjunction with the Project.
- The Project is geographically positioned to serve the nascent market for LNG as a low sulfur marine fuel for use within the newly established North American Emission Control Area (ECA) on the U.S. Pacific Coast.
- The Project will be well positioned to serve domestic need should natural gas markets shift from the current supply abundance, by adding the facilities necessary to accommodate the import of LNG.
- The Project will be developed on a site that is consistent with existing industrial land uses, meets all applicable regulations, and accommodates industry standard LNG carriers and that will minimize community and environmental impacts.
- The Project will use proven technology that can safely process significant volumes of natural gas.

1.1.1.2 Need

The Project is needed to link gas producers that have excess supplies with markets in which they can sell to both foreign and domestic gas consumers that have increasing requirements. Recognizing that this need is a new development, JCEP commissioned Navigant Consulting, Inc. (Navigant) to analyze gas supply and demand outlooks. Navigant's report, titled *Jordan Cove LNG Export Project Market Analysis Study* and dated January 2012 (Navigant Study), is included with this Resource Report as Appendix B.1. After the January 2012 release by the Energy Information Administration (EIA) of a case study evaluating the impacts of LNG exports, Navigant at JCEP's request provided comments in a document titled *Whitepaper: Analysis of the EIA Export Report 'Effect of Increased Natural Gas Exports on Domestic Energy Markets' Dated January 19, 2012* and dated February 2012 (Navigant Whitepaper). It is included with this Resource Report as Appendix C.1.

As related by the Navigant Study, the outlook on North American gas supplies has undergone a dramatic reversal since 2008 when the general consensus was that supplies would be insufficient to keep pace with growing demand and that foreign-sourced LNG would need to be imported. The Navigant Study identifies shale gas production growth as the biggest contributor to overall gas supply abundance in both the United States and Canada. The development and continuing improvement of hydraulic fracturing technology have led to increasingly efficient shale gas production and in turn a 28 percent increase in U.S. total gas production from 2005 (49.7 billion cubic feet per day (Bcf/d)) to 2011 (63.6 Bcf/d). Estimates of dry natural gas resources in the United States have likewise grown, reflecting significantly increased estimates of shale gas resources. The EIA's Annual Energy Outlook 2011 estimates shale gas and total gas reserves at 827 trillion cubic feet (Tcf) and 2543 Tcf, respectively, which constitute sufficient supply at current usage rates for about 94 years.

According to the Navigant Study, figures for both gas reserves and gas production are likely to continue to rise, again driven by shale gas. Navigant points to the high rate at which new shale resource plays are being identified, noting that "North America is clearly in the early phases of discovery for the resource" (Navigant, 2012a), and to the increases in the estimates made by other independent evaluators of gas resources in both the United States and Canada. Navigant states that it "expects this trend towards identifying a larger resource base to continue in the near term in both the U.S. and Canada" (Navigant, 2012a). Navigant also expects that gas production will continue to grow steadily throughout the Navigant Study's forecast period to 2045. Navigant's Spring 2011 Reference Case, on which the Navigant Study built, projects U.S. dry gas production to grow to 81.6 Bscf/d by 2045 and Navigant allows that "[p]roduction could go higher in response to demand from proposed LNG export terminals and/or independent increases in the robust supply resource base" (Navigant, 2012a). Indeed, the growth potential is enhanced by the fact that the reduced geologic risk and resulting reliability of shale gas discovery and production make it responsive to demand and by the fact that presence of natural gas liquids in some shale formations creates an added incentive for development.

As to the demand outlook, Navigant projects steady growth, led by electric generation demand, with modest contributions from industrial, residential, commercial and vehicle demand. It also projects that natural gas will remain competitive with oil and other fuels. Navigant concludes that, even as that domestic demand is projected to grow throughout the forecast period to 2045, North American gas resources, especially given the size of the shale gas resources in North America, are wholly adequate to satisfy domestic demand as well as the added demand of LNG exports by the Project even when other LNG exports are also assumed.

In the current and foreseeable environment, LNG exports are needed to enhance the development of a healthy natural gas market – one that achieves a balance of supply and demand. As stated by Navigant, "reliable demand is a key to underpinning reliable supply and a sustainable gas market" (Navigant, 2012a). Shale gas, for which the exploration risk is significantly reduced and the production process is significantly more manageable and dependable than for conventional gas, "has the potential to improve the phase alignment between supply and demand, which will in turn tend to lower price volatility" (Navigant, 2012b), a welcome prospect in the current market environment of oversupply and low prices.

Navigant finds it "increasingly evident that the slow development of new markets for natural gas is the only thing currently restricting even more gas resource development" (Navigant, 2012a). It also finds that "[t]he vast shale gas resource will support a much larger demand level than has heretofore been seen in North America, and at prices that are less volatile due to its production process characteristics" (Navigant, 2012b). For these reasons, Navigant concludes that "LNG exports, including those from the proposed Project, should be seen as instrumental in providing the increased demand to spur exploration and development of gas shale assets in North America for the long-term benefit of the country and others" (Navigant, 2012b). The importance of developing new markets is underscored by recent reports that the decline in the price of gas in the United States has led producers, including Chesapeake Energy, ConocoPhillips and BG Group, to cut back their gas production. *See* Dan Milmo, *BG cuts back on fracking for shale gas as prices slide*, The Guardian, February 12, 2012; available at http://www.guardian.co.uk/business/2012/feb/09/bg-cuts-back-on-fracking-shale-gas-prices.

In addition, the Project is needed to serve current domestic needs. The growth in demand among natural gas customers in Oregon situated along the route of the new PCGP is not alone sufficient to justify the investment in a pipeline like the PCGP, but these customers, particularly those west of the Cascades, will stand to benefit from its construction in conjunction with the Project. The incremental capacity available on PCGP will bring additional natural gas supplies to their otherwise isolated market area with concomitant beneficial price effects.

Likewise, the demand of isolated markets in Hawaii (where electricity is generated using primarily fuel oil and coal and consumers pay the highest price in the U.S. for electricity (EIA State Electricity Profiles; available at http://www.eia.gov/electricity/state)) and the Cook Inlet region of Alaska (where there is dwindling deliverability of natural gas) is not alone sufficient to justify the Project, but the Project will be able to serve these needs by providing access to LNG. Indeed, JCEP has had ongoing discussions with utilities in both locales. More specifically, utilities in these states are looking for a West Coast terminal that would offer gas at prices indexed to a North American basis and be able to service the smaller ships appropriate to their demand quantities (which likely would not transit the more significant distances from terminals on the other U.S. coasts). The Project will be able to meet these needs.

Finally, if current natural gas market conditions shift and additional gas supplies are needed to serve demand in the contiguous United States, JCEP will be able to meet that demand by importing LNG and delivering revaporized gas into the domestic grid. JCEP has retained the capability within the LNG Terminal design to add import and regasification facilities if market conditions were to change in the future. The financial threshold to adjust to these new conditions will be much lower because the LNG Terminal and PCGP infrastructure will already be in place. JCEP would thus be well positioned to continue to contribute to the development of a healthy gas market characterized by balanced supply and demand conditions.

1.1.2 Project Facilities

The Project will occupy approximately 168 acres (LNG terminal, slip, and access/utility corridor) within the 400 acres of land owned by Fort Chicago LNG II U.S. L.P., an affiliate of JCEP. The Project site is located on the bay side of the North Spit of Coos Bay, Oregon, in unincorporated Coos County to the north of the towns of North Bend and Coos Bay, Oregon (Figure 1.1-1). The zoning for the site is established in the Coos Bay Estuary Management Plan and Coos County Land Use Plan. All of the property to be used by the Project is classified as either “Marine Dependent Industrial” or “Industrial”. No rezoning will be required for the Project.

In the proposed Project, natural gas will be delivered to the site by the PCGP, where it will be cooled into a liquid, stored in two LNG storage tanks and loaded on to LNG carriers at newly constructed marine facilities. LNG carriers will be loaded at the rate of 10,000 m^3 per hour (m^3/hr) (with a peak capacity of 12,000 m^3/hr). Approximately six million metric tons per annum (MMTPA) of LNG will be produced by the Project, which is the equivalent of approximately 0.8 Bscf/d of natural gas. It is anticipated that approximately 90 ships per year will be required to transport the LNG from the Project based on the estimated size of the LNG carriers expected to call upon the facility.

The FERC jurisdictional facilities, as shown in Figure 1.1-2, are described in detail below. The following facilities will be constructed for the Project:

- A pipeline gas conditioning facility consisting of two feed gas cleaning and dehydration trains with a combined natural gas throughput of approximately 1 Bcf/d;
- Four natural gas liquefaction trains, each with the export capacity of 1.5 MMTPA of LNG;
- A refrigerant storage and resupply system comprised of a total of three horizontal storage bullets each holding one of the three hydrocarbon refrigerants that provide make-up to the single mixed refrigerant (SMR) cryogenic loop;
- An Aerial Cooling System (Fin-Fan) to reject heat removed during the LNG liquefaction process;
- An LNG storage system consisting of two full-containment LNG storage tanks, each with a net capacity of 160,000 m^3 (1,006,000 barrels), and each equipped with two fully

submerged LNG in-tank pumps sized for approximately 11,600 gallons per minute (gpm) each;

- A boil off gas (BOG) recovery system used to control the pressure in the LNG storage tanks, consisting of three cryogenic centrifugal BOG compressors, rated for approximately 10,160 actual cubic feet per minute (ACFM) each;
- An emergency vent system, an LNG spill containment system; a fire water system; fuel gas, nitrogen, instrument/plant air and service water facility systems; and, various hazard detection, control, and prevention systems;
- A protected LNG carrier loading berth constructed on an Open Cell technology sheet pile slip wall and capable of accommodating LNG carriers ranging in capacity from 89,000 m^3 to 160,000 m^3 (the berth has been designed to accommodate larger LNG carriers, up to 217,000 m^3, should they be authorized for future transit in the navigation channel).
- An LNG carrier cargo loading system consisting of three, 16-inch loading arms and one 16-inch vapor return arm, a gangway tower, firewater monitors, service utilities, and associated valves and piping (designed for 10,000 m^3/hr rate with a peak capacity of 12,000 m^3/hr).
- An LNG transfer line consisting of one 2,300-foot-long,36-inch-diameter line that will connect the shore based storage system with the LNG loading system;
- Utilities, buildings and support facilities; and
- The improvement of an existing, on-site unimproved road and utility corridor to become the primary roadway and utility interconnection between the South Dunes Power Plant (described immediately below) gas conditioning units and the liquefaction trains.

All facilities and components will be constructed in accordance with governing regulations, including 33 CFR Part 127 for the marine facilities both 49 CFR Part 193 and National Fire Protection Association (NFPA) Standard 59A for LNG facilities, and the codes and standards referenced therein.

The following facility, although not jurisdictional to FERC, will also be constructed to support the Project:

- The South Dunes Power Plant, a nominal 340 megawatt (MW) natural gas fired combined-cycle electric power plant inclusive of heat recovery steam generator (HRSG) units for the purpose of powering the refrigeration systems in the natural gas liquefaction process and supplying steam to the conditioning units.

1.1.2.1 Liquefaction Facilities

Pipeline Gas Conditioning

The incoming natural gas (feed gas) from the PCGP will be treated in facilities located on the South Dunes Power Plant site. The gas conditioning units remove substances that would freeze during the liquefaction process, namely carbon dioxide (CO_2) and water. Mercury is also removed to prevent corrosion in downstream equipment. Trace amounts of hydrogen sulfide (H_2S) are removed as well in the CO_2 removal system, due to the characteristics of the absorbent employed.

The pipeline gas conditioning unit consists of two parallel trains, each containing two systems in series: a CO_2 removal process which utilizes a primary amine to absorb CO_2, followed by a dehydration system which uses two distinct solid adsorbents to remove water and mercury from the feed gas. Each train will process approximately 460 MMscf/d of natural gas.

CO_2 removal involves a closed-loop system that circulates approximately 1,350 gpm of diglycol amine (DGA) agent to absorb CO_2 from the feed gas and reject it to an atmospheric vent. The process reduces the feed gas CO_2 from a maximum of approximately two percent on a molar basis to less than 50 parts per million volume (ppmv). After contacting the feed gas in the amine absorber tower, the DGA agent is then let down in pressure at roughly 57 pounds per square inch gauge (psig), to flash off the absorbed hydrocarbon gases. This gas is recovered as fuel through compression to approximately 700 psig. The DGA agent is then let down a final time into the Amine Stripper at 35 psig, where it is stripped of CO_2 and H_2S via steam. The off gas is rejected to an atmospheric vent after the trace H_2S and any other reduced sulfur species are oxidized.

Water is removed from the feed gas via molecular sieve beds. There are three water removal beds. At any one time, two beds are adsorbing water while the third is regenerating. Regeneration of a bed involves passing hot gas through it that drives the water out of the bed at approximately 500 °F. This water-laden gas is then cooled to condense the water, which is recovered back into the CO_2 removal system. The regeneration gas is then re-heated and sent back to a bed in a closed-loop process. An activated carbon is utilized to irreversibly absorb any mercury that may be present. Spent mercury absorbent will be disposed of in a licensed landfill.

Liquefaction Trains

Once the feed gas is treated, it is then sent to four parallel trains of a PRICO® (Black & Veatch proprietary) liquefaction process. The PRICO® process utilizes a SMR circuit with a two-stage compressor and a refrigerant exchanger. The conditioned gas, at 745 psig and 95 degrees Fahrenheit (°F), is divided equally among the four liquefaction trains. In each train the conditioned gas stream flows into a refrigerant exchanger and exits the exchanger as LNG at 730 psig and -245 °F.

The refrigerant exchanger consists of ten brazed aluminum cores arranged in a cold box. The cores are installed vertically inside the cold boxes. The refrigeration is supplied by a closed loop refrigeration cycle in which the refrigerant is compressed, partially condensed, cooled, expanded, and then heated as it supplies refrigeration and flows back to the compressor.

Low pressure refrigerant is compressed in a refrigerant compressor and is cooled by a refrigerant condenser and flows to a refrigerant discharge separator. The partially condensed refrigerant is separated into vapor and liquid in this vessel. The high-pressure refrigerant vapor and liquid from the refrigerant discharge separator flow through separate lines to the cold box. The vapor and liquid are recombined internally in the cold box as they enter each of the brazed aluminum cores.

The high pressure refrigerant flows downward through the cold box and exits each core from the bottom, totally condensed and sub-cooled. It then flows through a Joule-Thompson valve, reducing the pressure. This pressure reduction causes some vaporization of refrigerant, reducing the temperature further. This cold, low-pressure refrigerant reenters the cold box at the cold end and flows upward, removing heat from the feed gas and high pressure refrigerant streams in the exchanger as it vaporizes. The low-pressure refrigerant from the cold box then flows back to the refrigerant compressor inlet.

LNG exits the four trains at 730 psig and -245 °F and is directed to an LNG expander where electricity is generated while the pressure is reduced to 30 psig. The LNG is then sent through a second expansion where the pressure is reduced to 1 psig. This expansion lowers the LNG temperature, but also causes approximately 5 percent (volume basis) of the LNG to be vaporized. The two-phase stream exits the valve at around -260 °F and is then sent to the LNG storage tanks.

Refrigerant Makeup System

During operation it is normal for refrigerant losses to occur from the four closed-loop PRICO® refrigeration trains. Accordingly, the refrigeration loop components must be replenished periodically. Three of the hydrocarbon refrigerants used in the four closed-loop PRICO® trains cannot be generated on-site: ethane, propane and isopentane. These components are delivered to and stored in pressure vessels on site. At a minimum, the stored refrigerant capacity is equal to the estimated loss of refrigerant from one train in a year of continuous operation. When needed, operator action adds the desired component to one of the refrigeration loops through a low pressure sweep system.

LNG Storage Tanks

The LNG will be stored in two full containment LNG storage tanks each designed to store 160,000 m^3 (1,006,000 barrels) of LNG at a temperature of -270 °F and a normal pressure of one to four psig. Each tank will have a primary nine percent nickel steel inner container and a secondary post-stressed concrete outer container wall, a reinforced concrete outer container bottom, a reinforced concrete domed roof and an aluminum insulated support deck suspended from the outer container roof over the inner container (Figure 1.1-3). These tanks are designed and will be constructed so that both the primary container and the secondary container are capable of independently containing the stored LNG. The primary container contains the cryogenic liquid under normal operating conditions. The secondary container is capable of containing the cryogenic liquid and of controlling vapor resulting from product release from the inner container. The outside diameter of the outer container will be approximately 267 feet and the height of the top of the dome is approximately 180 feet above grade.

The space between the inner container and the outer container will be insulated with expanded perlite that will be compacted to reduce long term settling. This insulation permits LNG to be stored at a temperature of -270 °F while maintaining the outer container at near ambient temperature. The insulation under the inner container's bottom will be a cellular glass, load-bearing insulation. The outer concrete container above the approximately thermal corner protection system is lined on the inside with carbon steel plates. This carbon steel liner will serve as a barrier to moisture migration from the atmosphere reaching the insulation inside the outer container. This liner also forms a barrier that prevents vapor from escaping from inside the tank during normal operations. To increase the safety of the tank, there will be no penetrations through the inner container or outer container sidewall or bottom below the maximum liquid level. All piping into and out of the tank will enter from the top of the tank.

The LNG storage tanks will be located within an area that will be enclosed by a storm surge barrier that has a peak elevation of plus 65 feet. The storm surge barrier will be designed to contain the contents of one 160,000 m^3 LNG storage tank. The barrier and the elevation of the LNG storage tanks, as well as the minimum 46 foot elevation for all Project process facilities, including the South Dunes Power Plant, have been designed to meet state guidelines for protection from anticipated storm surges and tsunami inundation.

LNG Transfer Line

LNG transfer from the LNG storage tanks to the LNG loading berth will be through one 2,300-foot-long, 36-inch-diameter cryogenic loading line.

1.1.2.2 Marine Facilities

Slip

A slip and access channel connecting the slip to the Coos Bay Navigation Channel at approximate Channel Mile 7.3 (Figure 1.1-2) will be constructed. JCEP will utilize the east side of the slip for the LNG ship berth. Tug-assist berths will be located on the north side of the slip. At present the west side of the slip will be undeveloped. JCEP will construct the LNG ship loading facilities (loading arms, piping, impoundments, control buildings, and hazard detection and prevention systems) from the shoreside on the east berth.

The new slip will be created from an existing upland area. The inside dimensions at the toe of the slope of the slip measure approximately 700 feet along the north boundary and approximately 1,500 feet and 1,200 feet along the western and eastern boundaries, respectively. The minimum water depth within the slip is minus 45 feet NAVD88 (North American Vertical Datum of 1988). Side slopes are anticipated to be initially constructed at 3 horizontal (H):1 vertical (V), and the top of the slope is proposed at elevation +25 feet NAVD88. The eastern side of the slip will be used for an LNG berth and the northern end will be used for a tractor tug dock (Figure 1.1-2).

The eastern side of the slip will be formed by the Open Cell Sheet Pile Technology developed by PND Engineers, Inc. Unlike conventional sheet pile retaining walls that maintain a clean linear berth face, the Open Cell Sheet Pile structure face is designed to uniformly deform into a scalloped face as the land side static loads are applied.

The Open Cell Sheet Piling will allow the LNG carriers to be moored approximately one meter from the side of the slip. With the exception of one mooring dolphin, the LNG carrier mooring bollards, breasting fenders and LNG loading/unloading arms and structures will be constructed on the upland area formed by the Open Cell Sheet Piles. One mooring dolphin will be constructed in the water after the slip has been excavated and the isolation berm removed.

The layout of the Project facilities and the LNG loading berth was designed on the basis that the thermal and vapor exclusion zones would not constrain the use of the west side of the slip in the event that the Port develops plans and secures a tenant for the uplands they control adjacent to the west side of the slip.

Construction of the slip will require the excavation and dredging of approximately 4.3 million cubic yards (cy) of material (1.0 million cy excavated and 3.3 million cy dredged) and construction of the access channel will require the dredging of approximately 1.3 million cy for a total of 5.6 million cy.

The volume of maintenance dredged material from the slip and access channel was preliminarily estimated to be approximately 350,000 cy every two years. At the time that the original estimate was developed, there was limited information on coastal geomorphological changes for Coos Bay. Once additional information was available, JCEP requested Coast and Harbor Engineering (C&H) to review the previous modeling predictions and update the modeling. The studies described in Volume 1 of the C&H report determined that the bottom slope of the navigation channel reach adjacent to the LNG Terminal was getting deeper on the north side, mostly due to the meandering of the thalweg of the tidal channel. The bottom deepening would progressively reduce the depth differences between the natural bottom slope and the dredging cut, therefore minimizing trapping effects for sediment transport. This implies that sedimentation rates in the terminal area and the access channel would reduce in time with progression of natural bottom deepening.

C&H determined (and or reviewed previous predictions of) sedimentation rates in the terminal area and in the access channel for the current geomorphologic conditions and extrapolated the predictions to the future, accounting for long-term geomorphologic trends. Once long-term sedimentation rates were estimated, maintenance dredging requirements, including dredging volumes and schedules were developed. Sedimentation rates in areas of the LNG Terminal slip were estimated using a combination of three methods: prototype analysis, empirical methods, and numerical modeling. Based on evaluation of all different estimates, the design sedimentation rate for the LNG Terminal slip and the access channel dredging are 0.16 ft per year and 0.56 ft per year, respectively. This translates to approximately 8,500 cy per year and 29,200 cy per year, respectively.

Sedimentation and maintenance dredging requirements would likely be reduced at the access channel area over time due to natural stabilization and adjustment processes. Predicted volumes for maintenance dredging in the access channel are 26,100 cy per year after 10 years, 21,900 cy per year after 25 years, and 14,800 cy per year after 50 years.

Approximately 37,700 cy is the total maintenance dredging volume expected at year 1 and 34,600 cy is the total maintenance dredging volume expected at year 10. In the first 10 years, an approximate total of 360,000 cy would be removed and in the next 10 years approximately 330,000 cy would be removed for an approximate total of 690,000 cy in comparison to the earlier prediction of 1.75 million cy. This is a substantial reduction in volume which in turn will reduce the demand for disposal space at Site F.

The original estimate for the frequency of dredging was every two years. Now, with the additional information from the modeling, the recommended future maintenance dredging requirements are approximately 115,000 cy would need to be dredged every 3 years for the first 9-12 years (10 years approximately) and after 10 years it would be safe to reduce the volume of dredging to some values in the range of 115,000 to 160,000 cy for a frequency of 5 years between dredging events.

With the exception of the material from the maintenance dredging, all 5.6 million cy will be used beneficially by the Project in raising both the LNG Terminal site and the South Dunes Power Plant site to elevations above the tsunami inundation zone. A total of 1.9 million cy will be placed on the LNG Terminal site while the remaining 3.7 million cy will be placed on the South Dunes Power Plant site.

The 37,700 cy of material per year from the maintenance dredging will be placed in the Coos Bay Site F as is current maintenance dredge practice. On the basis of detailed sediment transport modeling conducted in Coos Bay, it was determined that the material to be removed during maintenance dredging for the Project is largely the same material that is currently removed during the existing every two year maintenance dredging of the navigation channel. Due to the development of the slip, the material that is currently removed during maintenance dredging will now collect in the slip due to the hydraulics of the bay system as modeled. The model demonstrated that over time the amount of material to be removed will gradually decrease.

LNG Carriers

The Project will include the construction of LNG carrier loading facilities on the shore side of the slip. It is anticipated that approximately 90 LNG carriers per year will be required to transport the designed output capability of the Project. The actual number of LNG carriers will be dependent on the capacity of the LNG carriers calling on the Project and the actual output production of the Project.

An LNG ship traffic study conducted by Moffatt & Nichol International (2006) concluded that the additional LNG carrier traffic associated with the Project can be accommodated in the Port and the Coos Bay Navigation Channel (Figure 1.1-4). Additional resources, such as high bollard pull tractor tugs and pilots, will be required to handle the anticipated number of LNG carriers and support the anticipated growth within the Port.

USCG has issued a Waterway Suitability Report (WSR) and a Letter of Recommendation for the Coos Bay navigation channel, finding that the channel can be made suitable for LNG marine traffic if a number of conditions are met. JCEP has notified the Captain of the Port that any changes created by the Project will be addressed in the annual Waterway Suitability Assessment (WSA). The Captain of the Port has affirmed this approach and has requested that the Letter of Intent, the WSA and the Emergency Response Plan be amended to reflect the Project. Copies of this correspondence are provided in Appendix A.1.

JCEP has committed to provide the following marine resources as identified by USCG in the current version of the WSR:

- Three, 80 bollard ton tractor tugs with Class 1, fire-fighting capability;
- LNG carrier navigation system for LNG carrier use while in route to the Project;
- Physical Oceanographic Real Time System (PORTS) to provide real time river level, current and weather data;
- Automatic Identification System (AIS) receiver and camera system to monitor the transit of the LNG ships while in Coos Bay;
- Emergency response notification system; and
- Installation of private navigation aids (e.g., targets).

LNG Loading Facilities

A total of four marine loading arms will be installed at the berth, three arms for transferring LNG to the LNG carriers and one arm for vapor return to the storage tanks. Space will be provided for one additional LNG loading arm. The two middle arms will be piped for dual service capable of loading LNG to the ships or returning vapor to the storage tanks. The loading arms will be designed with swivel joints to provide the required range of movement between the ship and the shore connections. Each arm will be fitted with a hydraulically interlocked double ball valve and powered emergency release coupling (DBV/PERC) to isolate the arm and the ship in the event of an emergency condition where rapid disconnection of connected arms is required. Each arm will be fully balanced in the empty condition by a counterweight system and maneuvered by hydraulic cylinder drives.

Additional equipment at the berth will include a ship gangway, area lighting facilities, navigation aids (ATONS), firewater monitors and a dry chemical fire fighting system.

The facilities have been designed to provide the safe transfer of LNG from the storage tanks to the cargo tanks of the carriers. Design is in accordance with applicable codes and standards, including but not limited to Oil Companies International Marine Forum (OCIMF), Society of International Gas Tanker and Terminal Operators (SIGTTO), American Petroleum Institute (API) and American Society of Civil Engineers (ASCE).

1.1.2.3 Access Road and Utility Corridor

An existing access road and utility corridor will be improved to provide access between the LNG Terminal and the gas conditioning facilities located on the South Dunes Power Plant site. The corridor is approximately one mile in length and 150 feet wide (toe of slope to toe of slope) on existing JCEP property. The access corridor will be utilized initially for the movement of earthwork equipment for the grading and cut/filling of the two sites, then for the movement of equipment and materials during construction and finally during operations for control of access to and security of the LNG Terminal. By upgrading this corridor, JCEP will reduce the traffic and impacts on the existing Trans Pacific Parkway in the area of the LNG Terminal and the South Dunes Power Plant.

The access corridor will include a two lane 24-feet-wide roadway, with 12-foot-wide shoulder and bridge structures to minimize impacts to wetlands and to fly-over the access road and rail spur serving the Roseburg Forest Products terminal. Additionally the corridor will contain overhead 230 kilovolt (kV) power transmission lines and an underground pipeway corridor that includes the feed gas supply to the Project, a fuel gas pipeline to the South Dunes Power Plant, backup pilot gas line, telecommunications lines and redundant control circuitry. A cross section drawing of the access road and utility corridor is provided as Figure 1.1-5.

1.1.2.4 Other Facility Systems

Vapor Handling System

During normal operation, approximately five percent of the produced LNG is vaporized during let-down to storage pressure. The produced LNG also displaces some LNG storage tank vapor. In addition, ambient heat input into the LNG system will cause a small amount of LNG to be vaporized. Some vaporization of LNG will also be caused by other factors, such as barometric pressure changes, heat input due to pumping, and ship flash vapor. The vapor handling system will recover these vapors for use in the facility fuel gas system that supplies the South Dunes Power Plant.

During LNG ship loading operations, vapors are also released from the LNG ship storage tanks due to simple displacement as the tanks are filled. This vapor will be returned to the LNG storage tanks.

Hazard Detection and Response

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. Active systems normally are either automatic or require some action by an operator. Active spill and fire control systems and equipment will consist of:

- A looped, underground firewater distribution piping system serving hydrants, firewater monitors, hose reels, water spray or deluge and sprinkler systems;
- A fixed high expansion foam system;
- Fixed dry chemical systems;
- Portable and wheeled fire extinguishers employing dry chemical and CO_2, the latter intended primarily for energized electrical equipment;
- Fire protection in buildings, generally consisting of smoke detectors, ultraviolet/infrared (UV/IR) flame detectors, and portable fire extinguishers;
- Sprinkler systems, and
- An emergency shutdown (ESD) system.

Process instruments will routinely monitor conditions such as pressure, flow and temperature, which can give an early indication of a potentially hazardous condition. In addition, 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 systems will trigger visual and audible alarms at specific site locations and in the control room areas to facilitate effective and immediate response.

Safety of the LNG carrier while docked and loading is a major design consideration for hazard detection and response. Safety measures include: ESDs; spill containment; and provisions to protect piping from the effects of transient pressure surges.

Electrical Systems

Electrical power for the Project will be provided from dedicated power generation provided by the South Dunes Power Plant. This power generation facility will be rated at approximately 340 MW and will be an independent power generation system exclusively for the Project and associated facilities. A PacifiCorp connection will be provided by tapping the high voltage side of PacifiCorp's Jordan Point substation, which is currently located on the proposed South Dunes Power Plant site but is planned to be relocated to a position adjacent to the PCGP metering station. The PacifiCorp 115 kV feed will be transformed to 13.8 kV distribution to provide basic "house power" to the terminal and power generation sites. The South Dunes 230 kV substation will collect power from the site generators and distribute power to the Project's 230 kV substation. Each 230 kV substation will have 13.8 kV area distribution for lower utilization voltages and power distribution within the two process areas.

The total maximum operating load of the Project will be approximately 310 MW. This electrical load will be experienced during warm weather operations when LNG compression is required and LNG carriers are being loaded. Most of the facility's electrical load is comprised of motors, with the largest motors (the four liquefaction loop compressor drivers) rated at approximately 65,000 horsepower (hp) each. Two stand-by emergency generators and Uninterruptable Power Supplies (UPS) will provide back-up power for critical loads and for safe shutdown of the facility.

Nitrogen

Liquid nitrogen vaporizers will be used to supply gaseous nitrogen for various uses in the Project. The nitrogen required for pre-commissioning and Project start-up, which includes providing inert gas to the tanks, drying out and cool down activities, will be provided by either trucks or temporary on-site production facilities.

Fuel Gas System

During normal operation, fuel gas will be supplied from BOG, supplemented with gas from the inlet gas conditioning facility. For plant commissioning and start up, fuel gas will be supplied from the Northwest Natural 12-inch-diameter natural gas distribution system that is located adjacent to the Trans Pacific Parkway. Once the PCGP is in service, the Northwest Natural interconnection will be used solely for facility space heating requirements.

Gas Metering

Metering of the natural gas feed to the facility will be supplied by PCGP and will be located at the South Dunes Power Plant site.

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 in the facility. Overall plant process control and monitoring will be performed at consoles located in the control room with monitoring capabilities from the jetty control room.

Storm and Wastewater Systems

The facility will be designed to provide drainage of surface water to designated areas for disposal in accordance with 49 CFR § 193.2159. Proper drainage and disposal of stormwater is accomplished by a system of ditches and swales. Stormwater collected in areas that have no potential for contamination will be allowed to flow or be pumped directly to a system of stormwater ditches, which ultimately drain 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 collection sumps. Collected stormwater from these sumps will flow to the oily water separator packages before discharging to the industrial wastewater pipeline.

Sanitary waste from the LNG loading berth 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 contractor's permits. Sanitary waste from the remainder of buildings will be directed to on-site septic systems.

1.1.2.5 Port Related Projects

The Port has agreed to provide the western side of the slip and adjacent upland area to serve as a potential staging area for the transportation of materials for an offshore wind turbine project.

Other projects that might be located on the North Spit in the future, such as coal export facilities or a container terminal, would need a deeper and wider navigation channel. At this time, no commitment has been made by any container or coal companies to locate there, and no letter of intent or other agreements to occupy the site have been signed. No environmental studies have begun or been planned or scoped for such projects. Therefore, neither coal export facilities nor a container terminal can be considered "reasonably expected" to locate on the Spit. The Port and the U.S. Army Corps of Engineers (USACE) have entered into an agreement under Section 203 of the Rivers and Harbors Act of 1899 to study the deepening and widening of the channel to accommodate future generations of container ships.

1.1.3 FERC Nonjurisdictional Facilities

The South Dunes Power Plant will be a natural gas fueled combined cycle generating plant located on the North Spit on Coos Bay, in Coos County, Oregon, across from the city of North Bend, on the former Weyerhaeuser linerboard mill site, closed in 2003 and since demolished. Access to the site will be from US-101 then west on the Trans Pacific Parkway, 2 miles north of North Bend.

The site is currently clear of any significant structures or vegetation, with the exception of a water tank and the PacifiCorp Jordan Point substation. The site elevation will be built up using material dredged from the marine slip. The PacifiCorp Jordan Point substation will be relocated on the site after the new substation location has been raised to final grade elevation of approximately 40 feet. It is anticipated that except for structures with high overturning moments, spread footing and slab on grade foundations will be used to support the plant equipment and buildings.

The South Dunes Power Plant will produce a nominal 340 MW of electrical power and process steam for gas conditioning prior to delivery to the LNG Terminal. JCEP will construct and operate the South Dunes Power Plant, which will consist of two 170 MW blocks of high-efficiency combined cycle combustion turbine generation. Three combustion turbine generators (CTG), three heat recovery steam generators (HRSG), and one steam turbine generator (STG), will collectively compose each power block.

Each CTG will produce electricity, with the exhaust gases from the CTG(s) supplying heat to the HRSG(s). Steam produced in the HRSG(s) will be used to power the STG to produce additional electricity and process steam. Duct burners fueled by natural gas in the HRSG(s) will allow for production of additional steam and additional electricity from the STG(s) when needed. Steam exhausted from the STG(s) will be condensed in air-cooled condensers, with the resultant condensate returned to the HRSG(s) to remake steam.

Fuel will be supplied primarily in the form of BOG from the Project. Some additional natural gas will be supplied from the PCGP which will connect to a metering station to be located in the southern portion of the South Dunes Power Plant site. The pipeline and metering station will be installed, owned and operated by others. Water will be supplied by the Coos Bay-North Bend Water Board (CBNBWB) through an existing pipeline that connects to the South Dunes Power Plant site.

One new switchyard with generator transformers will be constructed onsite to switch/direct the power produced by both power blocks. The voltage will be stepped up to 230 kV for transmission to the LNG Terminal.

The CTG(s), HRSG(s), and STG(s) will be outdoor units, given the relatively moderate ambient conditions of the area. A control and administrative building will provide space for plant controls and offices for plant personnel. A separate water treatment area will provide a location for the equipment necessary to purify the raw water, producing demineralized water for use in the power plant steam cycle and amine solution for CO_2 removal. The site will also support metering and conditioning facilities for the natural gas supply used by both the South Dunes Power Plant and the LNG Terminal.

1.2 LAND REQUIREMENTS

The Project site will be located on the bay side of the North Spit of Coos Bay, Oregon, located in unincorporated Coos County to the north of the Cities of North Bend and Coos Bay, Oregon. The Project facilities will be constructed on approximately 168 acres (LNG terminal, slip, and access/utility corridor) within the approximately 400 acres of land owned by Fort Chicago LNG II U.S. L.P., an affiliate of JCEP. A summary of the land areas affected by the construction and operation of the LNG Terminal is provided in Table 1.2-1 and shown on Figure 1.2-1.

An additional area of 32 acres outside of the land owned by Fort Chicago LNG II U.S. L.P. will be leased from Roseburg and used for temporary construction areas (office, laydown, fabrication, craft break/lunchroom, and parking). A plot plan of the temporary construction facilities is shown in Figure 1.2-2.

1.3 CONSTRUCTION SCHEDULE AND PROCEDURES

1.3.1 Liquefaction Facilities

1.3.1.1 Site Preparation

Construction site preparation will require clearing, filling and grading of the site to an approximate elevation of +30 feet for the base of the LNG storage tank area and approximately

+46 feet for the process areas. Temporary ditches, sediment fences and silt traps will be installed as necessary. Individual excavations will then be made for equipment foundations. Following completion of foundations, the site will be brought up to final grade. Final grading and landscaping will consist of gravel surfaced areas, asphalt surfaced areas, concrete paved surfaces, grass areas, and construction of the storm surge barrier.

Grading of the areas to be occupied by the Project facilities will entail approximately 1.3 million cy of cut and fill. Any material remaining from that work, including final grading and landscaping, will be used to raise the South Dunes Power Plant site utilized for the gas conditioning facility and raise the access/utility corridor between the LNG Terminal and the South Dunes Power Plant site. The South Dunes Power Plant and access/utility corridor will be raised to approximately 46 feet elevation.

1.3.1.2 Relocation of Roseburg Fire Water System Supply Line

The Roseburg chip terminal currently uses two, one million gallon water tanks supplied from wells to charge their firewater system. Both of these obsolete tanks will be decommissioned once the Project is placed in-service. In order to maintain the water supply to the Roseburg Fire Water System, a new 12-inch-diameter tap from the existing CBNBWB water line will be made and connected to the Roseburg fire water system.

1.3.1.3 Foundations

Geotechnical studies have been completed to determine the soil properties of the existing subsurface materials and to identify the foundation design criteria. Based on the results of these studies, the foundations for all equipment and structures, including the LNG storage tanks, process equipment, and pipe racks, will be mat type. Foundations for all critical process equipment and structures located outside of the storm surge barrier will be installed at an elevation of +46 feet.

1.3.1.4 Materials and Equipment Delivery

Final transportation to the Project site will be undertaken by road, rail, and possibly marine transport. An existing rail line is located adjacent to the Project site. JCEP is reviewing the transportation of the large pieces of equipment and is considering the development of a temporary construction dock to be used for material or equipment shipment during construction. Alternatively JCEP is reviewing the capabilities and logistics to utilize another barge dock within two miles of the site. Traffic surveys have been conducted of the anticipated construction related traffic and measures have been proposed to mitigate adverse effects. These are discussed in detail in Resource Report 5 - Socioeconomics.

JCEP further envisions some bulk materials, such as insulation, will be shipped in standardized containers. Fabrication shops will be used to fabricate pipe spool pieces and other prefabricated units of equipment and skid mounted process equipment modules with delivery to the site in accordance with the construction schedule. Where practical, skid mounted equipment will be used to minimize the pieces that must be delivered and installed at the site.

1.3.1.5 LNG Storage Tank Construction Sequence

Construction of the LNG storage tanks constitutes the most schedule sensitive element in the development of the Project. The description below provides a brief outline of the construction procedures for the LNG storage tanks.

LNG Tank Foundation

The construction of the full containment LNG tanks below the top of the base slab foundation consists of the following activities:

- Removal of top layer of soil (the depth of the soil to be removed is a function of the foundation depth);
- Installation of the formwork and reinforcement steel and concrete for base slab;
- Installation of vertical pre-stressing sheath, settlement monitoring system;
- Pouring the pedestal columns, installation of the friction pendulum bearings on top and erection and installation of the form work, installation of reinforcement steel for the elevated slab; and
- Pouring of the tank slab.

LNG Tank Above the Base Slab Foundation

The construction of the full containment LNG tanks above the top of the base slab foundation consists of the following activities:

- Construction of the post-tensioned outer concrete container wall will follow the completion of the tank bottom. Temporary construction openings will be constructed during the initial concrete lifts and located below the thermal corner protection top horizontal embedment anchorage. Rebar and embeds will be installed. Nine percent nickel and carbon steel insert strips will be cast into the concrete wall for the attachment of the wall liner plates, thermal corner protection along with external support embedments for piping, stairways and other connections and structures. The concrete for the pre-stressed concrete wall will then be poured.
- A temporary access opening will be built into the outer-concreted container wall to permit future access into the outer container and to permit construction of the inner container, etc.
- The bottom carbon steel vapor liner will then be installed.
- During the construction of the outer concrete container wall, construction of the steel dome roof and suspended deck will be undertaken on temporary supports inside the outer container. The suspended deck and dome roof will be raised into final position during the air raising operation.
- At the top of the outer concrete container wall, the steel dome roof compression ring will be cast into the concrete.
- Tendons will be installed in some of the ducts and the wall is then partially post-tensioned prior to the roof air raising procedure.
- On completion of the upper concrete ring beam, the steel dome roof will be air raised into position and secured to the embedded compression ring. Construction openings will be temporarily closed during the roof air raise operation.
- The pre-stress cable installation will then be completed, tensioned and the ducts grouted.
- After securing the dome roof to the compression ring, installation of all roof nozzles, penetrations and studs plus steel reinforcement and concrete covering of the steel dome

roof will be undertaken. Concurrent with this activity, work will commence on the inner container, initiated with installation of lights, air circulation and ventilation equipment. The roof slab will be constructed in two or three layers. Each layer will consist of circumferential rings varying in width and poured to progress simultaneously on opposite sides of the dome. The temporary construction opening(s) will again be closed and the tank pressurized to provide internal vapor pressure support of the roof during placement of the first concrete layer. The internal pressure will be maintained until all the first layer concrete pours are completed and the concrete has cured sufficiently to be self-supporting.

- The concrete plinths will be constructed to receive the roof platform steelwork.
- Internal work will include the installation of vapor barriers to the inside face of the concrete container, placement of concrete leveling screeds, base insulation and sand layers, etc. Insulation will be extended up the inside face of the outer concrete container vapor barrier to a height of approximately 15 feet to provide thermal protection to the bottom corner of the concrete wall to base slab.
- Installation of the nine percent nickel steel “secondary bottom” and bottom corner protection will then be completed.
- A concrete upper leveling course screed will be placed on top of the nine percent nickel steel secondary bottom.
- Installation of the nine percent nickel steel inner container annular and bottom plates will be undertaken on completion of the upper leveling course screed.
- After installation of the inner container annular plates, work will commence on erection of the inner tank shell with provision for a temporary opening into the inner container at the same location as the outer tank opening.
- The tank internal accessories such as pump columns, bottom and top fill, instrument wells, and purge and cool-down piping will be installed. Roof platforms, walkways, and piping will be installed. The construction opening door sheet in the inner container will be installed and closed. Hydrotesting of the tank will follow.
- External attachments such as structural, platforming and pipe support installation are then completed.
- After completion of the tank internal piping, the temporary opening in the outer tank wall will again be closed. The inner tank will be filled with water to the required hydrostatic test height. Settlement monitoring will be conducted throughout the period of water filling, testing and emptying. The external tank will be pneumatically tested per API 620 procedures. Closing of the outer concrete container opening will be required prior to the outer tank pneumatic test being undertaken.
- Process piping from tank top to grade will be installed.
- Following a successful inner container hydrotest, the tank will be washed down and cleaned. The resilient blanket will then be installed on the outside of the inner tank shell, followed by finalizing installation of the instrumentation inside the tank and annular space. The temporary construction opening will then be closed permanently. Installation of insulation systems will commence. Installation of the perlite requires the tank to be completely dry.

- The tank insulation systems are then completed. Perlite insulation will be expanded and installed using vibration into the tank annular space. The suspended deck blanket insulation will be installed along with completion of external piping insulation.
- After completion of all insulation system installations, the tank will be visually inspected and cleaned. LNG pumps will then be installed; the tank will be closed and purged with nitrogen to a positive gauge pressure.

At this point in the construction process, the tank will be ready for cool-down with LNG.

1.3.1.6 Construction of Other Above Ground Facilities

Construction of the foundations, pipe racks and terminal buildings, together with installation of major mechanical equipment, process and utility piping, and electrical and instrumentation will occur once LNG storage tank construction is underway. These facilities will be completed and pre-commissioned in readiness for mechanical completion. The process will consist of the following steps:

- Construction mobilization will commence with the initial clearing and grubbing of the site. Once the site has been cleared of debris, underbrush, and vegetation, rough grading can commence to bring the site up to a level work platform.
- The initial work will consist of cut/fill and compaction of the areas including the LNG tank area.
- Once a level work platform can be obtained for the LNG storage tanks, foundation work can commence in the LNG storage tank area.
- As the LNG storage tank area is turned over for commencement of foundation work, site preparation activities will continue in the terminal area until areas are brought to rough grade.
- Construction of foundations for buildings, major equipment, and pipe racks within the terminal area will commence as soon as the final designs are adequately advanced and will take into consideration the needs of the schedule interfaces between the various disciplines. Typically, the start of this work will follow commencement of LNG tank construction. Building construction will follow completion of the applicable foundation.
- Major equipment, including vaporizers, compressors, send out pumps, heat exchangers, and vents will be delivered to the site as required by the construction schedule and equipment manufacturing durations. JCEP envisions the delivery will occur some months after LNG storage tank construction is initiated. Large equipment items will be set on their foundations upon delivery.
- As the pipe racks are completed, work will commence on the installation of the process and utility piping on these routes. As piping installation activities are completed, electrical will begin installation of cable tray, conduit, and wire.
- As mechanical equipment is received and installed, piping installation will commence, followed by electrical and instrumentation installation. Once adequate piping is completed and tested, piping insulation will be field installed.
- As the construction of the process portion of the terminal progresses, work will commence on the pre-commissioning activities, so that these activities will be completed concurrent with the completion of the LNG storage tanks and be ready for nitrogen purging.

1.3.1.7 Testing

All testing will be carried out in accordance with applicable codes and requirements. The following indicate some of the tests to be carried out:

Hydrotesting

The inner container of the LNG storage tanks will be hydraulically tested (hydrotested) in accordance with the requirements of API 620. The hydrotest water source will be potable and raw water from the existing CBNBWB water lines. The potable water line runs along Trans Pacific Parkway from the point that is crosses under Coos Bay. The raw water line runs along Trans Pacific Parkway from the South Dunes Power Plant site to the CBNBWB North Spit treatment plant located one-mile west of Ingram Yard.

The CBNBWB has indicated their capability to provide the necessary quantities of water from their water supply system consisting of wells and reservoirs (Appendix A.2 of Resource Report 2 - Water Quality and Use). The existing 12-inch potable water line has the necessary pressure and capacity to deliver 20 million gallons over a two to three week period during the months of September through May and a three to four week period during the months of June through August.

The current construction sequence has the fire water pond as one of the first completed facilities. Upon completion, the 10 million gallon fire water pond will be filled with water from the CBNBWB potable water line. At the start of hydrotesting, approximately 350 gpm will be withdrawn from the fire water pond and 700 gpm from the CBNBWB potable water line so as not to put undue strain on the CBNBWB line. It will take approximately 20 days to fill the first tank with the 28 million gallons required for the hydrotest. No biocides or chemicals will be added to the hydrostatic test water, since it is essentially potable water that has already been treated by the CBNBWB.

In advance of filling the tanks, the hydrotest water source will be tested to ensure that the water will meet all applicable code requirements. To minimize water usage, the two tanks will be hydrotested with the same water by transferring the water at the conclusion of the hydrotesting of one tank to the other tank. Water will be introduced into the inner tank container through a manhole in the outer container concrete roof at a rate that will not exceed the limitations specified in API 620. The duration that the water remains in the tanks will be strictly controlled, therefore it is not expected that any contamination or discoloration will be present on discharge, even after being passed through both LNG storage tanks. However, the water will be tested to confirm composition prior to the water being transferred between each individual tank and before the water is discharged from the last tank. In each case the small amount of water that remains in the tank after the bulk transfer/emptying operation has taken place will be treated as appropriate to meet discharge water quality criteria prior to discharge.

The quantity of water required for hydrotesting one tank is estimated to be approximately 28 million gallons. The tanks will be tested in succession. The water will be transferred to the next tank, once the testing of the previous tank is completed. Due to the inability to transfer the residual heel in each tank at the conclusion of the hydrotest, it is estimated that approximately 0.25 million gallons of additional water will be required for testing the second tank. Therefore, the total required volume of hydrotest water is estimated to be 28.25 million gallons. The total duration of the hydrotest of the first tank from start of filling to emptying is expected to be approximately 34 days, with the second tank taking approximately three weeks.

On completion of hydrotesting the final tank, the water will be pumped from inside the inner tank using electrically driven submersible pumps suitably sized for the required lift height out of the tank as there are no bottom or side outlets on the LNG tanks. The temporary piping used to initially fill and transfer water between the tanks will be modified to enable the water to be pumped to the point of disposal. The planned discharge point of the hydrotest water is the firewater pond. The rate of discharge is expected to be approximately 1.8 million gallons per day (mgd) for the bulk pumping operation with substantially lower rates being achieved when removing the final amounts of water from the tank bottom. From the firewater pond, the hydrotest water will be discharged into the industrial wastewater pipeline via an overflow, which connects to a previously existing, permitted ocean discharge. Ten of the 28.25 million gallons used to hydrotest the LNG storage tanks will be retained in the fire water pond, effectively using that quantity of water a second time and reducing the amount of water required from the CBNBWB.

The industrial wastewater pipeline has a design capacity of 30 mgd. At its peak use the pipeline handled approximately 2.5 to 3.5 mgd from the paper mill. The only flow currently through the industrial wastewater pipeline is 500,000 gpd that is purchased from the CBNBWB and passed through the pipeline to keep the ocean diffusers operational. The Port has no present commitments for use of capacity on the industrial wastewater pipeline thereby allowing sufficient capacity of the overflow from the fire water pond of 1.8 mgd from the hydrostatic test water. Water will be sampled and tested for suitability prior to discharge. If treatment is found to be required, treatment procedures will be developed prior to discharge.

During consultation with the Oregon Department of Environmental Quality (DEQ), it was determined that the DEQ could issue a letter of authorization to discharge the hydrotest water. In order to initiate this process, JCEP would submit a formal request accompanied with information on the type of testing to be conducted, source of water, chemicals to be added to the hydrotest water (if any), the potential for the test water to acquire contaminants during the hydrotest, and the types of chemical analyses to be conducted on the hydrotest water prior to discharge to ensure that it meets DEQ discharge requirements.

Pneumatic Testing

A pneumatic test of the LNG storage tank outer container will be performed in accordance with API 620. The outer container will be held at 1.25 times design pressure for one hour.

Testing of Pipework

Piping will be tested using hydrostatic or pneumatic testing. In general, cryogenic piping will be pneumatically tested with dry air or nitrogen at 1.1 times design pressure. Non-cryogenic piping will be hydrotested using clean water at 1.5 times design pressure. Testing will be performed in accordance with the American Society of Mechanical Engineers (ASME) B31.3.

1.3.1.8 Restoration

Areas disturbed by construction of the Project facilities will be stabilized with temporary erosion controls until construction is complete unless covered by equipment, gravel or other covering. Following construction, the site will be final graded and best management practices will be applied to prevent erosion. In order to minimize the potential for erosion, JCEP has modified the FERC's Upland Erosion Control, Revegetation, and Maintenance Plan (Plan) and Wetland and Waterbody Construction and Mitigation Procedures (Procedures), creating Project-specific Plan and Procedures. Copies of the Project-specific Procedures are provided in Appendix B.2 of Resource Report 2 – Water Use and Quality and a copy of the Project-specific Plan is provided in Appendix B.7 of Resource Report 7 – Soils.

1.3.2 Marine Facilities

1.3.2.1 Industrial Wastewater Pipeline Relocation

In order to initiate the marine facilities development, the existing industrial wastewater pipeline will have to be relocated. The relocation of the pipeline will be done as part of the site clearing, grading, and excavation activities for the Project (described below). Currently, the pipeline carries approximately 500,000 gpd, which is water purchased from the CBNBWB to keep the ocean diffusers operational. This water discharge will be temporarily curtailed for approximately one week while the pipeline is relocated. The time required to relocate the pipeline, approximately one week, during which water will not be flowing through the pipeline will not be long enough to adversely affect the operation of the diffusers.

The industrial wastewater pipeline transports the water discharged from the two basins on the South Dunes Power Plant site (formerly the water treatment basins for the Weyerhaeuser Linerboard Mill site). This treatment system has been approved for closure by the ODEQ and the basins will be filled and restored prior to the development of the South Dunes Power Plant site. Prior to the closure of the basins, a new industrial wastewater line will be routed from the point where the existing line crosses the Trans-Pacific Parkway on its western end, along the Trans-Pacific Parkway to the South Dunes Power Plant site. The relocated pipeline will be installed completely prior to cutting of the existing pipeline.

A connection will be made between the fire water pond and the industrial wastewater pipeline near the point where the relocated pipeline route passes the fire water pond (Figure 1.1-2), allowing the Project to use the industrial wastewater pipeline for discharge of the hydrostatic test water. The CBNBWB potable water line will be connected to the fire water pond, as it will be the source of water for the pond and will serve as a backup source of water during operation of the LNG Terminal.

1.3.2.2 Construction of Open-Cell Sheet Pile Wall

Prior to the excavation work starting for the slip, the Open Cell Sheet Pile bulkhead and retaining wall will be installed. The sheetpile system will serve as a retaining wall for the shoreline on the east side and support the LNG ship loading dock and associated berthing and mooring facilities. The sheetpile system will be designed to support the dead loads of the soils and structures and the live loads of the LNG ship and equipment, as well as for the seismic criteria for the facility and water imposed loads.

The Open Cell Sheet Pile wall system consists of face sheetpiles for retaining the soils as well as tailwalls for anchorage of the retaining wall. All sheetpiles and tailwalls will be driven from the land while the slip construction activities are isolated from Coos Bay.

1.3.2.3 Slip Formation

In order to minimize the impacts of construction of the marine facilities on fisheries, reduce the total period of estuary turbidity, and extend the time available for construction, a two phase construction methodology will be used to construct the multi-user slip. The basic concept of the two phase construction methodology is to excavate (either wet or dry) the majority of the proposed multi-user slip area and construct most of the in-water structures while maintaining a natural physical barrier between the excavated/dredged multi-user slip and Coos Bay. This will be accomplished by retaining a natural earthen berm to provide a physical partition between Coos Bay and the Phase 1 marine facilities construction activities. This construction methodology will allow year-round work on Phase 1 (the northern portion of the multi-user slip) without being in contact with or causing an impact to the waters of Coos Bay. Phase 2 work will include excavation/dredging of the berm and the access channel and in-water construction. Phase 2 will be constructed during period(s) when fisheries considerations allow in-water work between October 1 and February 15 (as such window may be modified by agencies having jurisdiction). Details of each of the steps involved during both of Phases 1 and 2 are outlined below. It should be noted that there are numerous scenarios for constructing these facilities to honor the intent of minimizing the impact of construction on the waters of Coos Bay. The sequence that follows is one such constructible scenario. The actual means and methods employed by the contractor for performing the work behind the berm quite likely will vary to some degree from this description.

Phase 1 Construction Details

<u>Clearing and Grubbing</u> - The slip area consists of two types of topography; (1) natural sand dunes forested with a small amount of harvestable timber and scrub brush and (2) a level area, which was created from dredge material placed on the site by the USACE during 1972 and 1973, covered with low scrubs and grasses. The merchantable timber will be salvage logged and sold while the unmerchantable timber, timber slash and brush will be pulverized in a tub grinder and stockpiled as mulch. The mulch will be saved for future erosion control of recontoured sand dunes created during the construction process. Only surfaces that need to be recontoured to accommodate the slip or supporting structures will be grubbed and cleared. All areas where the existing topography can be maintained will be kept in the current, natural state. Efforts will be made to minimize the surface area to be grubbed and cleared.

<u>Dry Excavation</u> - The existing natural ground surface is at an elevation of approximately +20 feet NAVD88. The water table across the proposed multi-user slip occurs at an elevation of approximately +10 feet NAVD88. All excavated material above an elevation of approximately +10 feet NAVD88 will be removed by conventional earthmoving equipment such as scrapers, bulldozers, and front-end loaders. A berm will be maintained as a barrier to the bay during this construction phase. In all areas other than where the Open Cell Sheet Pile is installed, a side slope of 3 H: 1V will be maintained on the slip side to preserve the integrity of the berm during excavation and dredging. Excavation during this step will remove only material essential for creating the slip and constructing upland structures. Contouring of the slip perimeter above +10 feet NAVD88 will be performed during this step. Side slopes of 3 H:1V will be maintained around the perimeter of the slip to maintain slope stability. The materials stockpiled for future mulching operations will be applied as ground cover to the newly exposed sandy slopes to prevent erosion upon completion of the site contouring of elevations above +10 feet NAVD88.

The volume of material to be excavated and dredged from the slip is 4.3 million cy (2.3 million cy excavated and 2.0 million cy dredged) and the volume to be dredged from the access channel is 1.3 million cy for a total of 5.6 million cy. Current plans for management of the material involve the placement of the 1.9 million cy of excavated material on the LNG Terminal site and the placement of 3.7 million cy on the South Dunes Power Plant site.

Excavated material will be hauled by trucks or transported hydraulically to the disposal sites. The haul truck route will follow an easement through the Roseburg Forest Products Company wood chip facility until it intersects with the existing Jordan Cove Road, following Jordan Cove Road until it intersects with an existing road used by Weyerhaeuser during operation of the linerboard facility. The trucks will not cross the Trans-Pacific Parkway at any time and the only potential conflict will be with chip truck traffic to the Roseburg wood chip facility. Wood chip truck traffic will be given the right-of-way over haul truck traffic by using flag men to halt haul truck traffic until passing vehicles have passed the intersection. The haul truck route will be on JCEP-owned land or easements granted by Roseburg to JCEP. Pipelines used for hydraulic transportation of excavated materials will follow existing road corridors and/or rail lines and will not result in additional land disturbance.

Excavation of Dredge Launch Pond – Several wide-tread excavators will be used to remove material down to elevation 0.0 feet NAVD88, thereby creating a 300 foot long by 200 foot wide by 10 foot deep launch pond. Preferably, the launch pond will be located near the slip perimeter and road access. The material will be moved to the upland disposal sites by trucks as described in the previous section.

The launch pond will receive the dredging equipment that will be used to complete the Phase 1 dredging of the slip. All the material to be excavated that is located at or below the level of the water table will be removed by means of hydraulic dredging and transported to the South Dunes Power Plant site.

The pipeline for the hydraulic dredging will be approximately 1.3 miles in length. It will be placed along the access road and utility corridor and it is anticipated that the pipeline can span any affected wetlands or waterbodies without the need to place any structures in the wetlands or waterbodies. The hydraulic pipeline will be a fused polypropylene (seamless) pipeline and will be provided with secondary containment at the wetland and waterbody crossings to ensure that those bodies will not be affected by any breaks or leaks.

Slip Dredging – One or more disassembled hydraulic dredge plants will be transported to the slip site by truck. The hydraulic dredge plants may be in the 18-inch to 24-inch size range, since this is the maximum size range for transportability and the minimum size range capable of dredging to an elevation of minus 45 feet NAVD88. The plants will be assembled on site and lifted by crane into the dredge launch pond. A transport pipeline will connect the dredge(s) to the South Dunes Power Plant site.

The hydraulic dredges, capable of transporting a slurry of 30 percent solids by weight at a flow rate of 6,000 gpm or greater will create an ever increasing dredge prism that will, in the end, create the fully defined slip within the confines of the berm. The hydraulic dredges are capable of dredging to the final multi-user slip depth of minus 45 feet NAVD88, while creating side slopes for the slip at a ratio of 3H:1V. Dredging of the slip prism will be conducted outside of the normal Coos Bay dredging window because the slip will be isolated from the waters of Coos Bay by the berm.

Driving of Piling for Marine Structures – All but two of the mooring dolphins will be constructed “in-the-dry” and as such piles can be driven prior to or concurrent with the dredging of the slip. Land based mobile cranes with pile driving equipment will be located on the land-side of the Open Cell Sheet Pile walls. Piles will be driven under the area for the LNG loading structure as well as for all but two of the mooring dolphins. The majority of the in-water structure construction, including pile driving, will be conducted while the slip remains isolated from Coos Bay by the berm.

Slope Armoring – The northern and western slip faces will then be armored. The south slip face created by the berm will remain unarmored as it will be removed during Phase 2 to create the final configuration of the slip and the access channel. The sequence for pile driving, slope dressing and armoring may vary depending upon the means and methods chosen by the contractor performing the work.

Phase 2 Construction Details

Breaching and Removing the Berm – Once all Phase 1 construction is complete, work will begin on breaching and removing the berm (500,000 cy). Dredging will be conducted from both the

Coos Bay side and the slip side to reduce the duration of the breaching and removal activity. Material removed by the hydraulic dredges will be sent to the South Dunes Power Plant site.

Final Contouring and Slope Armoring – Removing the berm will open the slip to Coos Bay. Additional dredging to contour the access channel will complete the construction dredging activities. Armoring of the remaining unarmored slip side slopes will be completed. Although not anticipated, the construction of any remaining in-water structures required to complete the slip and associated in-water structures will be installed. In-water work will be performed during the allowable construction window between October 1 and February 15 (as such window may be modified as noted above).

Dredging Access Channel – The access channel connecting the slip to the Coos Bay Navigation Channel can be dredged either before or after the berm is removed. This work, along with all in-water removal activities performed from the Coos Bay (southerly) side of the berm will be performed during an allowable in-water construction window between October 1 and February 15 (as such window may be modified as noted above).

Restoration – Following the dredging activities, all disturbed areas, including exposed slopes will be stabilized with a seed mixture specified by the Natural Resources Conservation Service (NRCS) as being capable of surviving in highly permeable, xeric regimes, binding loose sand, and withstanding burial and deflation from aeolian processes. Native species will be used and if any non-native species are required for specific problem areas, species will be selected that will not become nuisance species to the surrounding areas. The slurry and decant water pipelines will be removed and any areas disturbed by these pipelines will be restored to pre-construction conditions. It is not anticipated that the haul truck route will affect any areas that have not been previously disturbed by the existing road. However, if any areas are disturbed by the haul truck route, they will also be restored to pre-construction condition. Since the slurry pipeline route and all temporary structures will be located within the existing railroad right-of-way and along the existing berm of the industrial wastewater pond, no new disturbance is anticipated and limited restoration activities are anticipated.

1.3.2.4 LNG Carrier Loading Facilities

The LNG carrier loading facilities will be constructed once the eastern side of the slip is formed using the Open Cell sheet pile technology. All of the loading facilities will be on the shore side of the slip, with no facilities, other than two mooring dolphins, located in the water of the slip. The platform with the loading arms (inclusive of the loading and vapor return arms) will be constructed on a concrete pad located at the edge of the slip. The foundation of the pad will contain a number of piles that will be tied into the concrete pad to provide a stable foundation for the breasting dolphins and the loading arm platform. Separate piles will be driven for the breasting dolphin and the loading arm platform. The loading arm platform will be constructed on columns raised from the concrete pad and accessed through stairways to the ground surface. The LNG transfer piping will be located within troughs that will contain any spills and divert the LNG to a containment sump.

The LNG carrier loading facilities will be constructed using land based equipment to install the required structural elements for the loading platform and mooring bollards, except for the one mooring dolphin to be constructed in the open water of the slip. The proposed construction sequence for the single mooring dolphin is as follows:

- Drive piling to design penetration and cut off heads;
- Set precast concrete caps with mooring hooks and weld out;

- Hookup and commission mooring hooks; and
- Install walkway.

Actual installation of berth piping and equipment, and hookup and commissioning of the loading system, and utilities will follow.

1.3.2.5 Shoreline Protection

The LNG basin shoreline will be protected from wave action and wind erosion using stone or articulated block reinforcement. Extensive hydrodynamic modeling by C&H has indicated that LNG ship and tug propeller scour protection will not be required on the east side of the slip. The north side and east side will be protected extending from the toe trench to above the water line where it will be tied into other slope stabilization techniques (concrete cellular mattresses), grout injected geotextile fabric mattresses (fabriform), soil improvement techniques, and/or geotextile reinforced vegetative planting. For the portion of the berth basin which is not expected to be subjected to wind wave and water level conditions under operating conditions, alternative erosion protection means will be used. This includes the area above elevation +25 ft NAVD88. This area may be protected using concrete cellular mattresses, grout injected geotextile fabric mattresses (fabriform), and/or geotextile reinforced vegetative planting. The erosion control methods will be designed to withstand expected rainfall runoff.

The LNG ships will average five knots within the Coos Bay Navigation Channel. At this speed, the LNG ships do not create waves that are any greater than the waves generated by the more than 200 ships per year that once called on the Port of Coos Bay. During this peak period of ship activity, no excessive channel erosion was reported. Accordingly, with the lack of channel erosion under previously higher shipping levels and of appreciable wakes at the speed limitation of the LNG ships anticipated for the channel, no excessive erosion due to LNG ships is anticipated. Therefore no measures for protecting the shoreline are anticipated. Extensive hydrodynamic modeling has confirmed this assertion.

1.3.3 Schedule

In order to meet a Fourth Quarter 2017 in-service date, construction activities for the Project are expected to begin in Second Quarter 2014. Construction of the LNG Terminal and slip is expected to take approximately 42 months as shown on the general schedule for the major Project construction activities in Figure 1.3-1. As shown in the schedule the dredging required to remove the berm and create the access channel will occur during the allowable in water dredging window (October 1 through February 15).

1.4 OPERATION AND MAINTENANCE PROCEDURES

All operations and maintenance personnel at the terminal will be trained to properly and safely perform their jobs. The terminal operators will be trained in the potential hazards associated with LNG, cryogenic operations, and the proper operations of all the equipment. The operators will meet all the training requirements of the USCG, U.S. Department of Transportation (DOT), Oregon State Fire Marshall, Oregon Department of Energy (ODOE) and other regulatory entities.

The terminal full-time maintenance staff will conduct routine maintenance and minor overhauls. Major overhauls and other major maintenance will be handled by bringing in maintenance personnel specifically trained to perform the maintenance. All scheduled and unscheduled maintenance will be entered into a computerized maintenance management system (CMMS).

1.5 SAFETY CONTROLS

The Project will be designed, constructed, operated, and maintained in accordance with DOT Federal Safety Standards for Liquefied Natural Gas Facilities, 49 CFR Part 193. The facilities will also meet the NFPA Standard 59A for LNG facilities. The marine cargo transfer system and any appurtenances found between the last valve immediately before the LNG storage tanks and the LNG ships will comply with the USCG regulations for Liquefied Natural Gas Waterfront Facilities, 33 CFR Part 127 and Executive Order 10159. Safety controls and the role they play are addressed in more detail in Resource Report 11 - Reliability and Public Safety.

1.5.1 Spill Containment

The LNG spill containment systems for the Project will be designed and constructed to comply with DOT regulations 49 CFR Part 193, Sections 193.2155 through 193.2185. These regulations require that each LNG container and each LNG transfer system be provided with a means of secondary containment which has been sized to hold the quantity of LNG that could be released as a result of the design spill which is appropriate for the area and LNG equipment. The design spills are defined in NFPA 59A.

The LNG storage tank concrete outer container will be designed to contain 110 percent of the contents of the nine percent nickel steel inner container. The storm surge barrier dike will be designed to hold the contents of one 160,000 m^3 LNG storage tank.

The transfer piping spill containment system will be sized to contain the volume of LNG that could be released in ten minutes from a single pipe rupture that would produce the highest release rate. The LNG spill containment system consists of spill collecting troughs that drain to one of two LNG spill containment sumps. The loading and LNG tank sumps are sized to contain a ten minute spill from a line at the design rate. Each spill containment sump will be 65 feet long by 65 feet wide by 25 feet deep with a usable depth of 20 feet. The usable volume of the sump will provide for containment of a 10-minute spill from a single pipe rupture that will produce the highest release rate in accordance with NFPA requirements. A storm water drainage system will be provided consisting of low lift stations for the collection and transfer of storm water runoff within the LNG spill containment sumps.

1.5.2 Thermal Exclusion and Vapor Dispersion Zones

Thermal exclusion zones were calculated using the LNG Fire computer models as required by 49 CFR § 193.2057(a). In these calculations the weather conditions from the area that produced the furthest exclusion distance were utilized as required in 49 CFR § 193.2057(b). The analysis shows that the thermal radiation requirements for siting the facility have been met in compliance with 49 CFR § 193.2057.

Vapor dispersion exclusion zones were calculated using FLACS as outlined in 49 CFR § 193.2059(a). These calculations for weather conditions followed the requirements in 49 CFR § 193.2059(b)(2a). The analysis shows that the vapor dispersion requirements for siting the facility have been met in compliance with 49 CFR § 193.2059.

1.5.3 Hazard Detection System

Hazard detectors will be installed throughout the Project facilities to give operations personnel a means for early detection and location of released flammable gases and fires. The hazard detection system will consist of separate detection units for combustible gas, fire, smoke, high and low temperature and will be hard wired to the main Fire & Gas control system for alarm and operator action. Smart area gas detectors will be provided to monitor flammable gases within the LNG Terminal.

Low temperature sensors will be located in the spill impoundment basin to shut down and/or prevent the storm water pumps from starting in the event of an LNG spill. Smart UV/IR fire and flame detectors will also be located throughout the LNG Terminal and high temperature detectors will be located to detect a fire on the vent pipes of the LNG storage tank relief valves.

A fiber optic low temperature detection system will be located in the LNG trenches and impoundment basins to detect any LNG spill. These systems will be continuously monitored by the plant control system.

1.5.4 Hazard Control System

Several different types of fire suppression agents will be available for fighting fires within the Project facilities. The type of agent that will be used in a specific situation will depend on the characteristics of a particular event and on the relative effectiveness of the various agents on that particular type of fire. A high expansion foam system will be provided for the LNG spill containment sumps and at the dock. High expansion foam concentrate is metered or proportioned into the firewater system by means of a typical balanced pressure foam proportioning system. The resulting foam solution is delivered via underground piping to the high expansion foam generators. The high expansion foam generator, ANGUS or equivalent, will be water motor powered, thus no electrical power will be required. The foam generator produces nominal 500:1 high expansion foam, that is, 500 parts air for every part foam solution. This foam is applied to LNG spills, whether ignited or unignited. Applied to ignited spills, the foam controls the fire, greatly reducing the level of radiant heat to the surroundings. If the spill remains unignited, the foam serves to reduce the downwind distance to lower flammable limit by warming the LNG vapors. High expansion foam systems will be in accordance with NFPA 11A. Dry chemical fire suppression systems will be provided for the LNG storage tank relief valves and will be automatically activated to extinguish any potential fires at the valves. Manually operated dry chemical fire suppression systems will be strategically located throughout the facilities.

1.5.5 Firewater System

The Project facilities will have firewater supply and distribution systems for extinguishing fires, cooling structures and equipment exposed to thermal radiation, and dispersing flammable vapors. Hydrants, manual monitors, automatic sweep monitors, and hose reels will be located throughout the LNG Terminal. Internal building water sprinkler systems will be located at the main control room, warehouse, and office.

The main components of the firewater distribution system will include:

- Freshwater storage pond with a storage capacity of approximately 5.3 million gallons;
- One electric motor-driven firewater "jockey" pump, having a rated capacity of 40 gpm at 160 psig discharge pressure;
- Three diesel engine-driven and one electric motor-driven firewater pumps, each with a rated capacity of 4,000 gpm at 183 psig discharge pressure. Freshwater firewater pumps will be designed and installed in accordance with NFPA 20. Per NFPA 20, diesel engine-driven firewater pumps will have individual fuel tanks that will allow for up to eight hours of continuous pump operation;
- Fifty firewater monitors and two elevated firewater monitors will be provided. The elevated monitors located at the marine loading/unloading berth will be remotely operated from a safe distance with a view of the loading/unloading berth. Firewater

monitor nozzles will be adjustable from straight stream to full fog. In locating firewater monitors, an effective coverage range of 200 feet diameter is assumed;

- Hydrants are integrated with most monitors and offer the opportunity for direct action by means of 2.5 inch hose lines, as well as the capability to deliver pressurized firewater to wheeled fire apparatus equipped with a fire pump;
- Hose reels, each including 100 feet of hard rubber non-collapsible 1.5 inch fire hose and adjustable fog nozzle for a rapid first response with firewater;
- An automatic sprinkler system in accordance with NFPA 13 will be installed in the administration and warehouse/workshop buildings. In addition, hose reels will be mounted on building vertical steel members; and
- An underground firewater piping distribution system, with strategically-located post indicating isolation valves, located in order to minimize system impairment due to maintenance or repair. The firewater piping material will be high density polyethylene (HDPE) for all underground piping and carbon steel for all aboveground piping. The system will be designed and installed in accordance with NFPA 24.

1.5.6 Fail Safe Shutdown System

The Project will have an emergency Safety Instrumented System (SIS) with shutdown and control devices designed to leave the facility in a safe state. The SIS will be used for major incidents and would result in either total plant shutdown, shutdown of ship loading, and/or individual pieces of equipment, depending on the type of incident. Three levels of shutdown will be configured for the Project as follows:

- Level 1 shutdowns are to be used for a major incident and will carry out a total LNG Terminal shutdown.
- Level 2 shutdowns will only shutdown the appropriate jetty loading/unloading area and can be initiated manually, automatically by local instrumentation, by a Level 1 shutdown, or by ship-to-shore operation.
- Level 3 shutdowns for shutting down individual pieces of equipment will be initiated automatically by trip input signals to the SIS.

1.5.7 Warning Systems

The LNG Terminal will include sirens that will be audible in all locations. The sirens will have a distinctive tone for easy recognition between alarms and emergency events.

1.5.8 Security System

JCEP has prepared security procedures and will incorporate these into a plan in close coordination with the USCG, FERC, the DOT's Office of Pipeline Safety, ODOE and local law enforcement. The procedures contain a written program for physical security for all facilities at the LNG Terminal. The procedures and plan will comply with all applicable regulations and provide for risk-based levels of security to be carried out by trained personnel during all operation shifts and, if necessary, by governmental law enforcement officers in response to serious threats. JCEP continues to conduct periodic meetings with all parties involved in the development and execution of the security plan.

1.6 FUTURE PLANS AND ABANDONMENT

There are no FERC jurisdictional facilities to be abandoned as part of the Project. JCEP has retained the capability within the Project design and set aside the space within the LNG Terminal to add the equipment necessary for import of LNG and, should natural gas market conditions change in the future, JCEP would add the equipment necessary for import of LNG provided that it has the necessary FERC authorization. Other than the possibility of adding vaporization facilities to the Project, there are no current plans which will result in the future expansion of the Project.

As evidenced by the operating histories at existing LNG terminals, robust construction techniques and proper maintenance and operating procedures have resulted in the useful life of these facilities far surpassing their 25 plus year design life. Based on this solid history, JCEP does not anticipate abandonment of the Project in the foreseeable future. In the event it becomes necessary, JCEP has signed an agreement with the ODOE that details the procedures to be followed for the proper abandonment of the Project.

1.7 PERMITS AND APPROVALS

Construction, operation, and maintenance of the Project will be in accordance with all applicable permits and approvals. Applicable permits and approvals for the Project are summarized in Table 1.7-1 along with the schedule for filing of all major permits or appropriate documentation. Major permit and approval actions for the Project involving multiple regulatory agencies will include environmental reviews by the FERC for authorization of the Project under Section (3) of the NGA, the Oregon Department of Land Conservation and Development (DLCD) for a coastal zone management consistency determination, and the ODEQ for an Air Quality Permit. It is anticipated at this time, that the Air Quality Permit will include the Project and the nonjurisdictional South Dunes Power Plant.

The Port has the lead responsibility for obtaining the applicable permits and approvals for the construction of the slip and for the placement of excavated materials in the upland disposal facilities. JCEP is providing the necessary information in support of the Port's efforts in this permitting activity. All potential environmental impact analyses associated with the Port's activities will be included in the applicable Resource Reports submitted in support of JCEP's FERC application.

1.8 AGENCY AND PUBLIC COMMUNICATIONS

As part of the FERC pre-filing Process (Docket PF12-7-000), JCEP has contacted federal, state, and local agencies that may have regulatory approval or other interest in the Project and has also identified potential stakeholders and other interested parties. A listing of the stakeholders and other interested parties is included in Table 1.8-1. In addition, property owners within both a one-half mile radius and a one mile radius of the Project site (defined as the distance from the center of the southern-most LNG storage tank) have been identified and are listed in Appendix D.1, which is being filed as Privileged and Confidential.

JCEP is committed to stakeholder communications and effective public outreach. To this end, JCEP has established a Public Participation Plan that includes the following actions:

- Establish Local Presence – JCEP has maintained an office in Coos Bay since 2004. The Project Manager uses this office to facilitate public accessibility to Project personnel and information. The Coos Bay office remains staffed and operational and will continue to be so throughout the permitting and construction phases of the Project.

- Address Concerns When They Arise – JCEP will continue to identify and meet with local associations, neighborhood groups and other non-governmental organizations to inform them about the Project and address any issues that may be raised.
- Keep Local, State and Federal Agencies Informed – JCEP will continue to meet with all key Federal, state and local agencies to identify other stakeholders and to initiate pre-filing activities, such as identifying concerns, scoping studies, reviewing draft resource reports, and resolving issues.
- Actively Engage the Community – JCEP will continue to hold community meetings in order to provide information to all of the interested elected officials, federal, state, and local, and adjacent industries and residences about LNG in general, and more specifically about safety and risk assessment and emergency response planning.
- Assist FERC – JCEP will provide all required support needed for the FERC to conduct a public scoping meeting(s).
- Hard copies of public environmental reports and permit applications will be placed in local libraries.
- Establish a Website – JCEP established a website for the Project www.jordancoveenergy.com that went on-line on August 19, 2004 and has been updated numerous times during the development of the Project. Items available on this website include:
    - Project description and related information;
    - Maps and Images;
    - Project Schedule;
    - Project Benefits;
    - Fact Sheets about LNG ;
    - Links to other LNG Information Websites;
    - Environmental Aspects of the Project;
    - Safety Concerns for the Transport and Storage of LNG;
    - Status of Permit Applications;
    - Frequently Asked Questions, with responses (FAQs);
    - Newsletter Contents;
    - Recommended Readings;
    - Description of the Permitting and Approvals Process;
    - Issues Raised During Open Houses and Jordan Cove's response;
    - Environmental Documents Issued by FERC and Other Agencies;
    - Public Draft Environmental Resource Reports submitted to the FERC;
    - Public Environmental Reports and Permit Applications;
    - Contact Information;
    - Press Releases and News Articles relevant to LNG or the Project;

- o Information about the South Dunes Power Plant EFSC Process; and
- o Link to the PCGP website.

The website has been continuously updated on Project events and to address issues that may arise based upon current news events (e.g., risks associated with a tsunami).

A single point of contact has been established. The contact is Robert L. Braddock, Project Manager. A telephone number, mailing address and e-mail address are included in the website as follows:

Jordan Cove Energy Project L.P.
Robert L. Braddock, Project Manager
125 Central Avenue, Suite 380
Coos Bay, OR 97420
(541) 266-7510 (office)
(303) 748-3746 (cell)
bobbraddock@attglobal.net

A public open house was held on March 27, 2012 in Coos Bay, Oregon, for the Project. Experts in each of the topical areas listed below were present to address questions from the public. The following types of information were available to the public:

- Background on Jordan Cove Energy Project, L.P. partners, including experience with LNG or related projects;
- Current Tsunami Inundation Models and potential facility affects;
- Description of liquefaction facilities and liquefaction processes;
- Description of Safety and Environmental Issues of liquefaction of natural gas;
- Description of the South Dunes Power Plant;
- Uses of LNG as Marine Fuel;
- Use of Natural Gas as a Substitute for Gasoline/diesel;
- Natural Gas Reserves in North America, contributions of shale gas;
- Description of LNG Vessel Transit of Coos Bay;
- Construction and Operational Benefits of Project;
- Southwest Oregon Community College Collaboration – LNG Fire Training Center;
- North Spit Southwest Oregon Regional Safety Center and Jordan Cove Fire Station;
- Collaboration with other state and local emergency response and security agencies; and
- Description of Environmental Impacts and tradeoffs.

JCEP is working closely with the FERC staff in coordinating interagency meetings and briefings and will participate in all meetings that will be held. The first interagency meeting was held on March 26, 2012 in Roseburg, Oregon.

1.8.1 Agency Contacts

Beginning in June 2011, JCEP has held either group or one-on-one meetings with the following agencies to provide information about the Project:

- U.S. Army Corps of Engineers;
- National Marine Fisheries Service;
- U.S. Fish and Wildlife Service;
- U.S. Bureau of Land Management;
- U.S. Coast Guard, Sector Columbia River;
- U.S. Coast Guard, Group/Air Station North Bend;
- U.S. Coast Guard Station Coos Bay;
- Oregon Department of Fish and Wildlife;
- Oregon Department of Environmental Quality;
- Oregon Department of Energy;
- Oregon Economic & Community Development Department;
- Oregon Department of State Lands;
- Oregon Governor's Economic Revitalization Team;
- Coos County Sheriff's Department;
- Coos County Emergency Management;
- Coos Bay Police and Fire Departments;
- North Bend Police and Fire Departments;
- North Bay Fire District;
- Charleston Fire District;
- Hauser Fire Protection District;
- Southwest Oregon Community College and Fire Academy;
- Coos Bay North Bend Water Board;
- Oregon International Port of Coos Bay;
- Coos County Planning Department;
- South Coast Development Council; and
- Oregon State Fire Marshall's Office.

1.8.2 Affected Landowners

All of the activities associated with the Project will occur on land owned by Fort Chicago LNG II U.S. L.P., an affiliate of JCEP. Adjacent landowners, Oregon International Port of Coos Bay, Roseburg Forest Products Company, Weyerhaeuser NR Company, Oregon Department of State Lands, Oregon Dunes National Recreation Area, and the U.S. Bureau of Land Management have been contacted. The names and mailing addresses of landowners within both a one-half and a one mile radius of the LNG Terminal site are listed in Appendix D.1 (filed as Privileged and Confidential).

1.9 NONJURISDICTIONAL FACILITIES DETERMINATION

1.9.1 Identified Nonjurisdictional Facilities

The only FERC nonjurisdictional facility is the South Dunes Power Plant which will be located on a site approximately one mile from the Project site.

1.9.2 Determination of the Need for FERC to Conduct an Environmental Review

Under certain circumstances, nonjurisdictional facilities may be subject to FERC's environmental review. In making this determination, the FERC requires applicants to address four factors that indicate the need for FERC to do an environmental review of project-related nonjurisdictional facilities. These factors include:

1. Whether or not the regulated activity comprises "merely a link" in a corridor type project (such as a transportation or utility transmission project);
2. Whether there are aspects of the nonjurisdictional facility in the immediate vicinity of the regulated activity which affect the location and configuration of the regulated activity;
3. The extent to which the entire project will be within the FERC's jurisdiction; and
4. The extent of cumulative federal control and responsibility.

The application of this procedure to the South Dunes Power Plant follows:

With respect to factor (1), the South Dunes Power Plant is not a corridor type project, nor does the regulated activity comprise any kind of link in a corridor type project. Therefore, this factor does not support a review of the nonjurisdictional facility.

With respect to factor (2), the South Dunes Power Plant does connect directly to the regulated activity but does not affect the configuration and location of the regulated activity. This factor does not support a review of the nonjurisdictional facility.

With respect to factor (3), the South Dunes Power Plant is entirely outside of FERC's jurisdiction as the siting, construction, and operation of the South Dunes Power Plant are under the jurisdiction of the ODOE's EFSC . Only the facilities that the South Dunes Power Plant connects to at the LNG Terminal are within the FERC's jurisdiction. Accordingly, this factor weighs against inclusion of this nonjurisdictional facility in a review by FERC.

With respect to factor (4), the cumulative level of federal control and responsibility over the project, federal control is determined by the amount of federal financing, assistance, direction, regulation, or approval inherent in a project. The South Dunes Power Plant will be developed by an affiliated company of JCEP. No federal financing or guarantees will be granted to this party. JCEP is an independent company and the nonjurisdictional facilities will be constructed by affiliated companies under state and local regulatory jurisdiction. Some federal permits may be involved, but no federal lands are involved. Therefore, cumulative federal control is minimal and this factor does not warrant FERC environmental review.

1.10 TOPOGRAPHIC MAPS AND AERIAL PHOTOGRAPHY

1.10.1 U.S. Geological Survey (USGS) Maps

An original USGS 7.5-minute series topographic map depicting the location of the Project is included as Figure 1.10-1.

1.10.2 Aerial Photographs

An aerial photograph of the location of the Project site is included as Figure 1.10-2.

1.11 REFERENCES

Coast and Harbor Engineering. 2010. Technical Report – DRAFT Volume 1 – Jordan Cove Energy Project and Pacific Connector Gas Pipeline Coastal Engineering Modelling and Analysis. Coast and Harbor Engineering.

Navigant Consulting, Inc. 2012a. *Jordan Cove LNG Export Project Market Analysis Study*, January 2012 (Navigant Study).

Navigant Consulting, Inc. 2012b. *Whitepaper: Analysis of the EIA Export Report 'Effect of Increased Natural Gas Exports on Domestic Energy Markets' Dated January 19, 2012,* February 2012 (Navigant Whitepaper).

U.S. Energy Information Administration. 2012. *Effect of Increased Natural Gas Exports on Domestic Energy Markets*. January 19, 2012. Washington, D.C.

U.S. Energy Information Administration. 2011. *Annual Energy Outlook*. April 2011. Washington, D.C.

TABLES

TABLE 1.2-1
Summary of Land Requirements for the Liquefaction Project

Area(1)	Land Area (acres)	Land Temporarily Affected by Construction (acres)	Land Permanently Affected by Operation (acres)	Comments
PROJECT FACILITIES				
Batch Plant and Tank Assembly (1)	11.92	11.92		
Access and Administration (2)	5.68	5.68		
Marine Access Pipeway (3)	16.48	16.48		
Liquefaction Process Area (4)	21.81	21.81		
Laydown Area (4F)	11.89	11.89		
LNG Tank Area (5)	20.69	20.69		
Fire Water Pond (6)	3.11	3.11		
Gas Processing Area (7)	4.34	4.34		
Access/Utility Corridor (R1)	9.14	9.14		
UNDISTURBED AREAS ON LNG TERMINAL SITE				
Wetlands Area (E1)	29.17	29.17		
Sand Dune Area (E2)	8.77	8.77		
Wetlands Area (E3)	13.93	13.93		
LNG Unloading Berth Dune (E4)	15.09	15.09		
Sand Dune Area (E5)	2.72	2.72		
Firewater Tanks Area (E6)	2.53	2.53		
TOTAL LNG TERMINAL SITE	176.64	176.64		
PORT FACILITIES				
Slip and Access Channel	63.16	63.16		
TOTAL PORT FACILITIES	63.16	63.16		

TABLE 1.2-1

Summary of Land Requirements for the Liquefaction Project

Area[1]	Land Area (acres)	Land Temporarily Affected by Construction (acres)	Land Permanently Affected by Operation (acres)	Comments
NONJURISDICTIONAL FACILITIES				
South Dunes Power Plant	64.54	64.54		
TOTAL NONJURISDICTIONAL FACILITIES	64.54	64.54		
CONSTRUCTION AREAS				
Temporary Construction Areas				
Offices (A, B)	1.4	1.4	0.0	
Laydown (K, L)	13.1	13.1	0.0	
Parking (D)	0.9	0.9	0.0	
Craft Areas (F, G)	0.7	0.7	0.0	
Warehouse/Storage (E, H, J)	1.4	1.4	0.0	
Fabrication (M1, M2, M3, M4)	3.7	3.7	0.0	
Open Areas	10.5	10.5	0.0	
Total Construction Areas	31.7	31.7	0.0	

(1) Numbers in brackets refer to area designations shown on Figures 1.2-1 and 1.2-2.

Table 1.7-1

Major Permits, Approvals, and Consultations for the JCEP Project

Agency	Permit/Approval	Contact	Anticipated Filing Date
FEDERAL			
Federal Energy Regulatory Commission	Section 3 of the Natural Gas Act	Paul Friedman (202) 502-8059	October 2012
U.S. Environmental Protection Agency (EPA)	Spill Prevention, Containment and Cleanup Plan (Clean Water Act [CWA], 33 U.S.C.§1321(j))	Oregon Department of Environmental Quality is Key Agency (See State Agency Section for more detail)	Prior to Construction
U.S. Army Corps of Engineers (USACE)	Section 404 (CWA) Section 10 (Rivers and Harbors Act)	Michele E. Hanson (541) 465-6878	October 2012
U.S. Coast Guard (USCG)	Amended Letter of Intent	Capt. B. C. Jones (503) 861-2606	March 2012
	Spill Prevention and Spill Response Plan (CWA, 33 U.S.C.§1321(j))		Prior to Operation
U.S. Fish and Wildlife Service (USFWS)	Section 7 of Endangered Species Act Consultation	Joe Zisa (503) 231-6179	Ongoing
National Marine Fisheries Service (NMFS)	Section 7 of Endangered Species Act Consultation Magnuson-Stevens Fishery Management and Conservation Act Essential Fish Habitat (EFH) Consultation Marine Mammal Protection Act Consultation	Ken Phippin (541) 957-3385	Ongoing
Federal Aviation Administration (FAA)	Notification of Proposed Construction Possibly Affecting Navigable Air Space		Prior to Operation, if required

Table 1.7-1

Major Permits, Approvals, and Consultations for the JCEP Project

Agency	Permit/Approval	Contact	Anticipated Filing Date
STATE			
Oregon Department of Energy (DOE)	Lead Coordinating State Agency for FERC Pre-filing Process	Hillary Dobson (503) 378-8692	Ongoing
Oregon Department of Environmental Quality (DEQ) Air Quality Division	Air Permit	Martin Abts (541) 269-2721 Ext. 22	October 2012
Oregon Department of Environmental Quality (DEQ) Water Quality Division	Construction Storm Water Discharge Permit	Steve Nichols (541) 269-2721 Ext 223	Prior to Construction
	Hydrostatic Test Water Disposal Permit		Prior to Construction
	Operation Storm Water Discharge Permit	Steve Nichols (541) 269-2721 Ext 223	Prior to Operation
	Industrial Discharge Permit	Del Cline (541) 269-2721 Ext 21	Prior to Operation
	Water Quality Certification	Steve Nichols (541) 269-2721 Ext 223	October 2012
Oregon Department of Land Conservation and Development	Coastal Zone Management Compliance	Dave Perry (541)-574-1584	October 2012
Oregon Division of State Lands (DSL)	Joint Permit with the USACE	Bob Lobdell (503) 378-3805 Ext 282	October 2012

Table 1.7-1

Major Permits, Approvals, and Consultations for the JCEP Project

Agency	Permit/Approval	Contact	Anticipated Filing Date
Oregon Department of Fish and Wildlife (DFW)	Threatened and Endangered Species Consultation	Mike Gray (541) 888-6860	Ongoing
Oregon State Historic Preservation Office (SHPO)	Section 106 Consultation	SHPO (503) 986-0679	October 2012
Native American Heritage Commission (NAHC)	Consultation		October 2012
LOCAL			
Coos County Planning Department	Building Permit	Patty Evernden (541) 396-3121 Ext 210	Prior to Construction

Table 1.8-1

Stakeholder List for the JCEP Project

FEDERAL	
The Honorable Jeff Merkley U.S. Senate 313 Hart Senate Office Building Washington, DC 20510-3704 (202)224-3753	The Honorable Ron Wyden U.S. Senate 223 Dirksen Senate Office Building Washington, DC 20510-3703 (202)224-5244
The Honorable Peter DeFazio U.S. House of Representatives 2134 Rayburn House Office Building Washington, DC 20515-3704 (202) 225-6416 Peter.defazio@mail.house.gov	Captain B. C. Jones U.S. Coast Guard (USCG) 6767 North Basin Avenue Portland, OR 97217 (503) 240-9585
Michele E. Hanson Regulatory Project Manager/Biologist USACE Portland District/ Eugene Section 1600 Executive Parkway Ste 210 Eugene, Oregon 97401-2156 PH: 541-465-6878 FAX: 541-465-6888 michele.e.hanson@usace.army.mil	Federal Aviation Administration (FAA) Air Space Branch 1601 Lind Avenue SW Renton, WA 98055-4056 (425) 227-1389
National Marine Fisheries Service (NMFS) Attn: Rick Applegate, Habitat Division Director 525 NE Oregon Street, Suite 500 Portland, OR 97232	U.S. Fish and Wildlife Service (USFWS) Attn: Joe Zisa 2600 SE 98th Avenue, Suite 100 Portland, OR 97266 (503) 231-6179
Wes Yamamoto FS Project Coordinator, PCGP Project Forester - Range, Engineering, Lands & Minerals Tiller Ranger District - Umpqua National Forest Direct: (541) 825-3150 Cell: (541) 863-9850 Fax: (541) 825-3110 wyamamoto@fs.fed.us	Holly Orr National Project Manager BLM Washington D.C. (WO-350) 28910 Hwy 20 West Hines, Oregon 97738 541-573-4501 horr@blm.gov

Table 1.8-1

Stakeholder List for the JCEP Project

STATE OF OREGON	
The Honorable John Kitzhaber Governor of Oregon Oregon State Capitol 900 Court Street NE #25 Salem, OR 97301-4047 (503) 378-3111	The Honorable Joanne Verger State Senator Oregon State Legislature 900 Court Street NE S-301 Salem, OR 97301 (503) 986-1705 Sen.joanneverger@state.or.us
The Honorable Arnie Roblan State Representative Oregon State Legislature 900 Court Street NE H-378 (503) 986-1409 Rep.arnieroblan@state.or.us	Oregon Department of Agriculture 635 Capitol St., NE Salem, OR 97310-0110 (503) 378-3810
Christopher W. Claire Habitat Protection Biologist Oregon Dept. of Fish and Wildlife P.O. Box 5003 Charleston, OR 97420 (541) 888-5515 christopher.w.claire@state.or.us	Oregon Department of Environmental Quality 2020 SW 4th, Suite 400 Portland, OR 97201 (503) 229- 5937
Hillary Dobson Oregon Department of Energy 625 Marion Street NE Salem, OR 97301-3737 (503) 378-8692 Dobson.Hillary@doe.state.or.us	Mary Camarata Western Region-Eugene Office 165 East 7th Avenue Suite 100 Eugene, OR 97401-3049 (541) 687-7435 Camarata.mary@deq.state.or.us
Mr. Steve Nichols Oregon Department of Environmental Quality Coos Bay Branch West Region 381 N. Second Street Coos Bay, OR 97420 (541) 269-2721 x 223 Nichols.Steve@deq.state.or.us	Mr. Martin Abts Oregon Department of Environmental Quality Coos Bay Branch West Region 381 N. Second Street Coos Bay, OR 97420 (541) 269-2721 x 222 Martin.Abts@deq.state.or.us

Table 1.8-1

Stakeholder List for the JCEP Project

Mike Gray Oregon Department of Fish and Wildlife P.O. Box 5430 Charleston, OR 97420 Phone: (541) 888-5515 Fax: (541) 888-6860 Email: Michael.E.Gray@state.or.us	Bill Burns Department of Geology & Mineral Industries 800 NE Oregon Street #28 Suite 965 Portland, OR 97232 (503) 731-4100 Bill.Burns@dogami.state.or.us
Jon Germond Habitat Resources Program Manager Wildlife Division Oregon Department of Fish and Wildlife 3406 Cherry Avenue NE Salem, OR 97303 (503) 947-6088 Jon.p.germond@state.or.us	Jason Brandt Oregon Department of Fish and Wildlife Southwest Regional Office 4192 N Umpqua Highway Roseburg, OR 97470 (503) 440-3383 Jason.r.brandt@state.or.us
Mr. Robert Lobdell Oregon Department of State Lands 775 Summer Street NE, Suite 100 Salem, OR 97301 (503) 378-3805 x 282 Bob.Lobdell@state.or.us	Dave Perry Oregon Department of Land Conservation and Development South Coast Regional Representative 810 S.W. Alder Street, Unit B Newport, OR 97365 (541) 574-1584 Dave.perry@state.or.us
Patty Snow Oregon Department of Land Conservation and Development Ocean and coastal Services Division 635 Capitol Street NE, Suite 150 Salem, OR 97301 (503)373-0050 ext.281 patty.snow@state.or.us	Dennis Griffin, Ph.D., RPA SHPO Lead Archaeologist Parks and Recreation Department Heritage Conservation Division 725 Summer Street NE, Suite C Salem, OR 97301-1271 (503) 986-0679 Dennis.griffin@state.or.us

Table 1.8-1

Stakeholder List for the JCEP Project

COOS COUNTY	
Robert Main Coos County Commissioner 250 N. Baxter Coquille, OR 97423 (541) 396-3121 ext. 770 bmain@co.coos.or.us	Fred Messerle Coos County Commissioner 250 N. Baxter Coquille, OR 97423 (541) 396-3121 ext. 247 fmesserle@co.coos.or.us
Cam Parry Coos County Commissioner 250 N. Baxter Coquille, OR 97423 (541) 396-3121 ext. 281 cparry@co.coos.or.us	Patty Evernden Coos County Planning Director Coos County Court House 250 N. Baxter Coquille, OR 97432 (541) 396-3121 ext. 210
Craig Zanni Sheriff Coos County Sheriff's Office 250 N. Baxter Coquille, OR 97423 (541) 396-3121 Coosso@co.or.us	Glenda Hales EM Program Manager Coos County Sheriff's Office 250 N. Baxter Coquille, OR 97423 (541) 756-8213 ghales@co.coos.or.us
LOCAL	
Crystal Shoji Mayor City of Coos Bay 500 Central Avenue Coos Bay, OR 97420 (541) 267-2491 shoji@uci.net	Rick Wetherell Mayor City of North Bend 835 California Street North Bend, OR 97459 (541) 756-8500
Roger Craddick City Manager City of Coos Bay Coos Bay, OR 97420 (541) 269-8912 rcraddick@coosbay.org	Terrence O'Connor City Administrator City of North Bend 835 California Street North Bend, OR 97459 (541) 756-8536 toconnor@northbendcity.org

Table 1.8-1

Stakeholder List for the JCEP Project

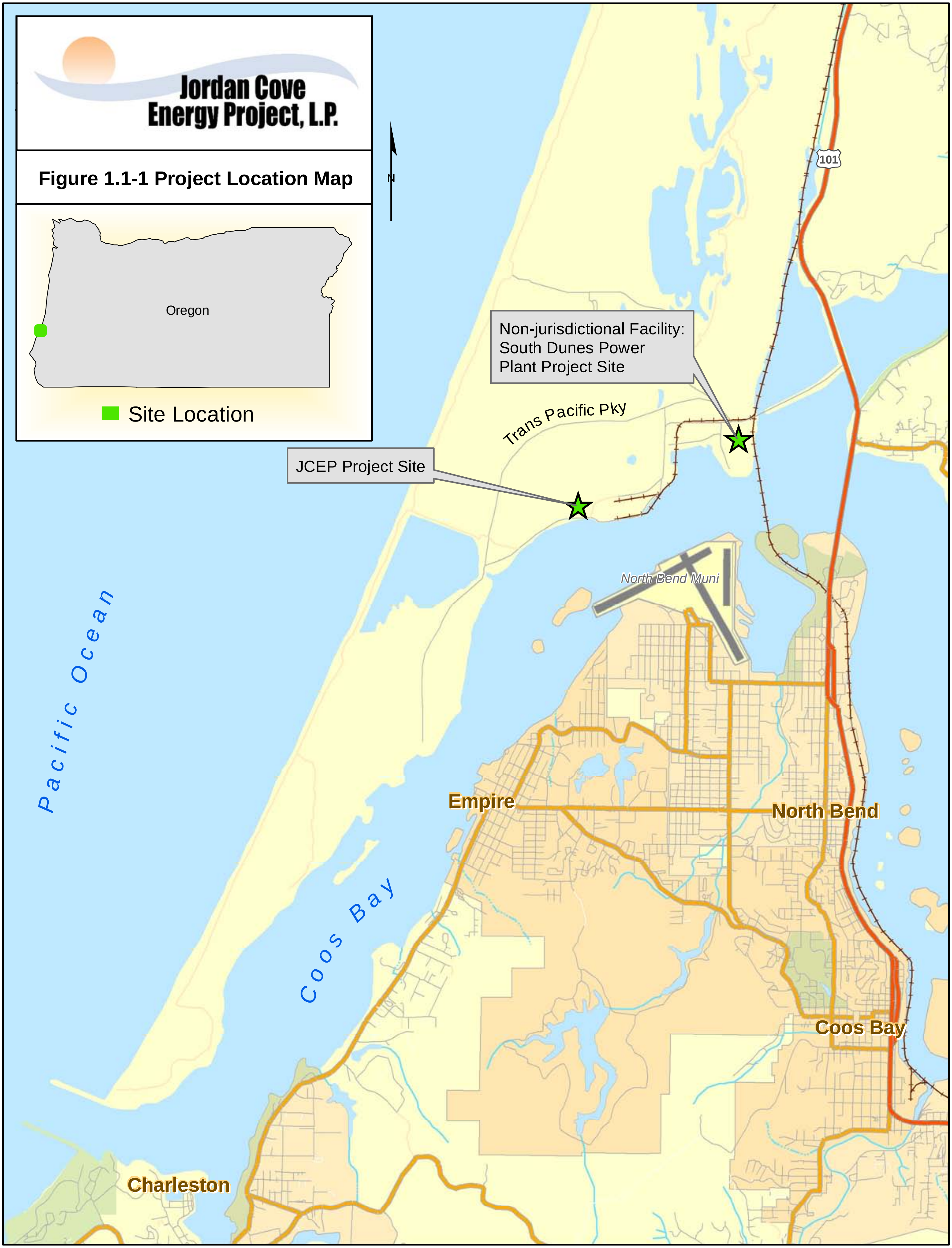
Gary McCullough Police Chief City of Coos Bay 500 Central Avenue Coos Bay, OR 97420 (541) 269-8912	Steve Scibelli Police Chief City of North Bend 835 California Street North Bend, OR 97459 (541) 756-3161 s.scibelli@northbendcity.org
Stan Gibson Fire Chief Coos Bay Fire and Rescue 450 Elrod Avenue Coos Bay, OR 97420 (541) 269-1191	Scott Graham Fire Chief City of North Bend 835 California Street North Bend, OR 97459 (541) 756-7757 Fireman97459@yahoo.com
Howard Crombie Environmental Coordinator Confederated Tribes of Coos , Lower Umpqua and Suislaw Indians 1245 Fulton Avenue Coos Bay, OR (541) 888-9577 hcrombie@ctclusi.org	Jim Aldrich Fire Chief North Bay Rural Fire District P.O. Box 664 North Bend, OR 97459 (541) 756-3501
Donald B. Ivy Cultural Resources Program Coquille Indian Tribe P.O. Box 783 North Bend, OR 97459	Robert Kentta Cultural Resource Program Director Confederated Tribes of Siletz Indians P.O. Box 549 Siletz, OR 97380
David R. Koch Executive Director Oregon International Port of Coos Bay 125 Central Avenue, Suite 300 Coos Bay, OR 97420-0311 (541) 267-7678 dkoch@portofcoosbay.com	Martin L. Callery Chief Commercial Officer Oregon International Port of Coos Bay 125 Central Avenue, Suite 300 Coos Bay, OR 97420-0311 (541) 267-7678 mcallery@portofcoosbay.com
Jody McCaffree 2650 Cedar Street North Bend, OR 97549	Doug Heiken 909 W. 10th Avenue Eugene, OR 97402

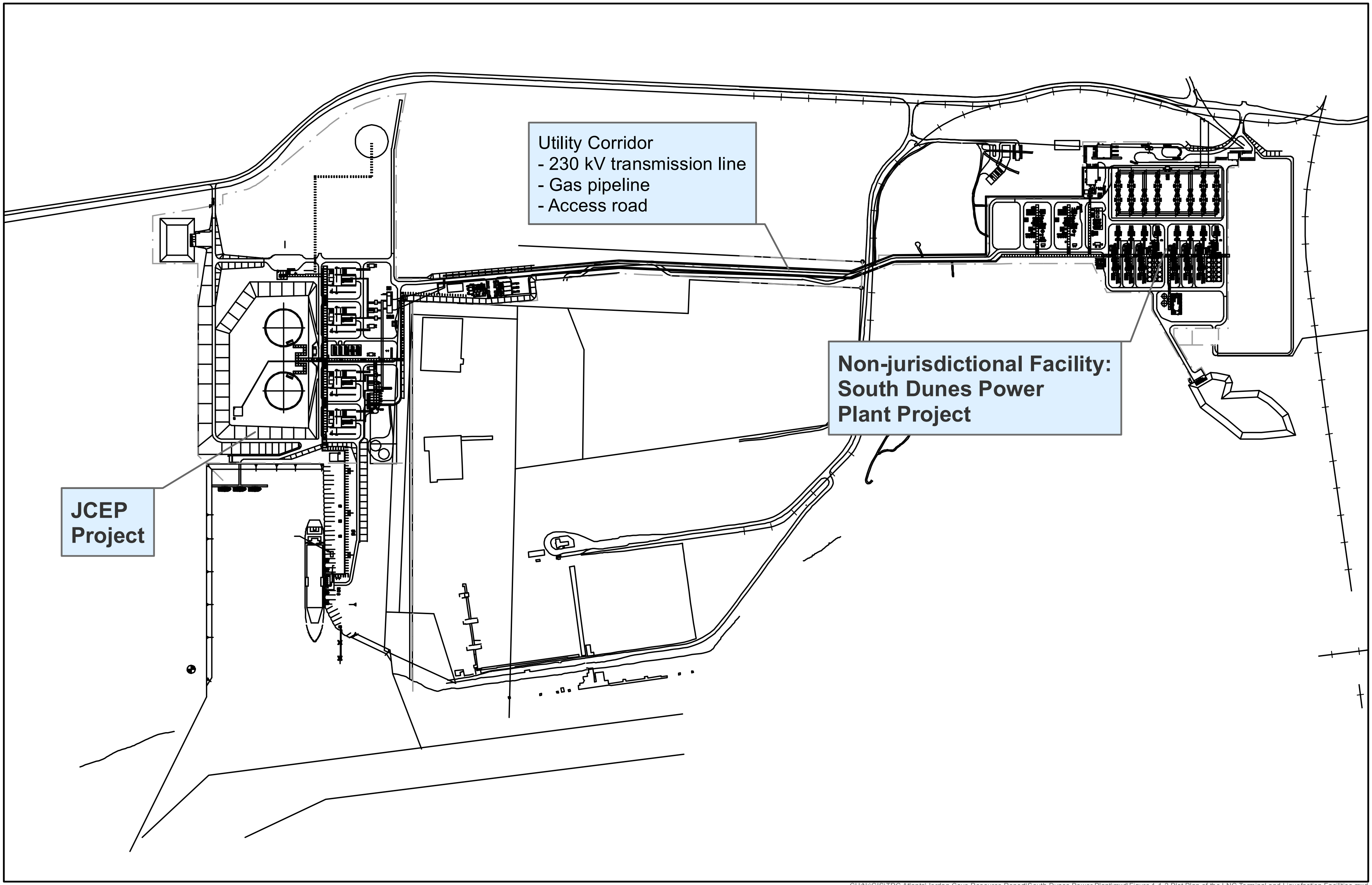
Table 1.8-1

Stakeholder List for the JCEP Project

Mr. Daniel R. Serres, M.S. FLOW Program Coordinator Friends of Living Oregon Waters (FLOW) P.O. Box 2478 Grants Pass, OR 97528 dserres@oregonwaters.org	

FIGURES


Jordan Cove
Energy Project, L.P.
Figure 1.1-1 Project Location Map
Oregon
Site Location
N
101
Non-jurisdictional Facility:
South Dunes Power
Plant Project Site
Trans Pacific Pky
JCEP Project Site
North Bend Muni
Pacific Ocean
Empire
North Bend
Coos Bay
Coos Bay
Charleston



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Jordan Cove Energy Project, L.P.

4/3/2012

Figure 1.1-2
Plot Plan of the LNG Terminal and Liquefaction Facilities

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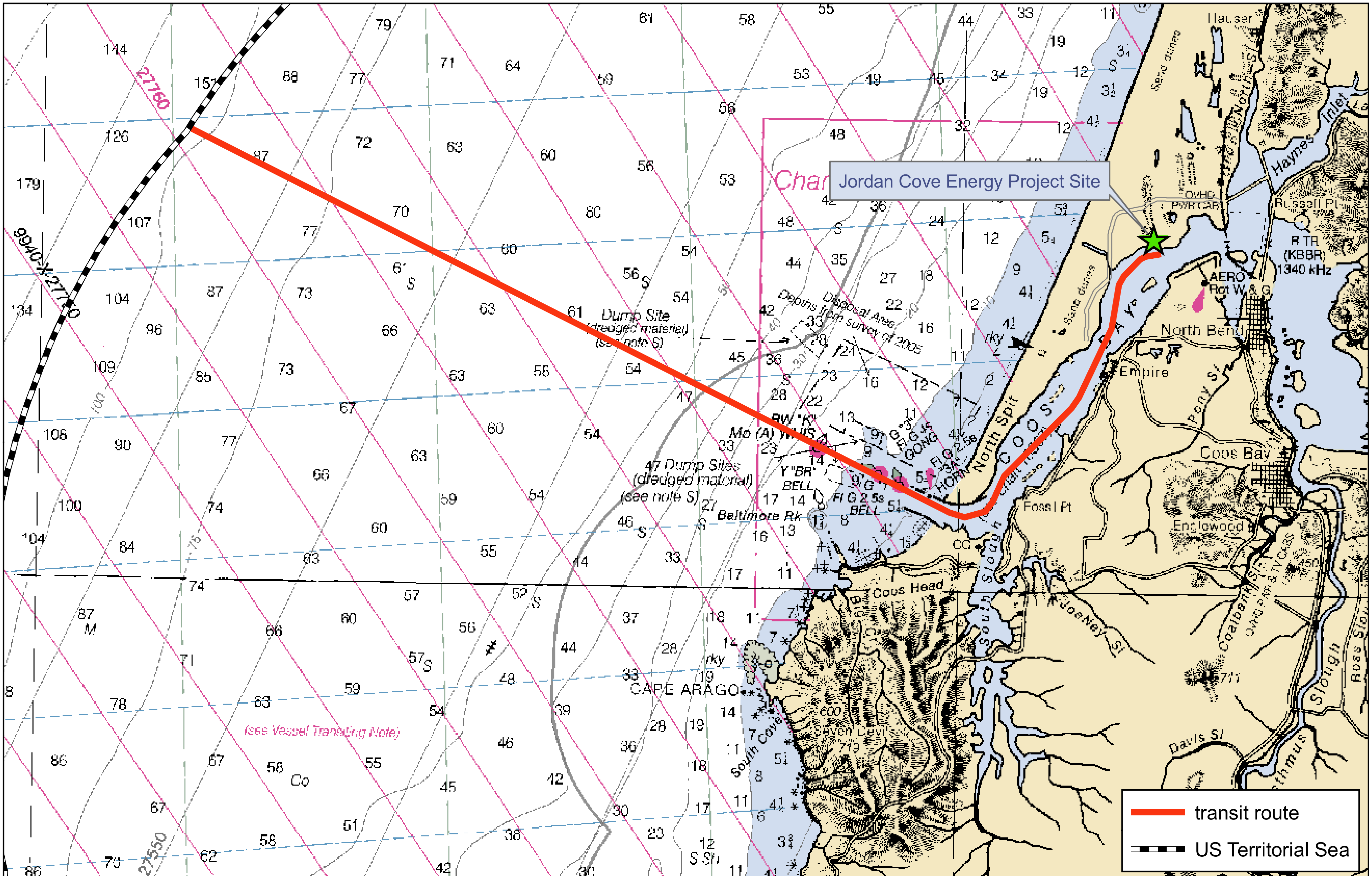
Figure 1.1-3
Conceptual Design of LNG Storage Tank
(Critical Energy Infrastructure Information)



Jordan Cove Energy Project, L.P.

Figure 1.1-4
LNG Ship Transit Route

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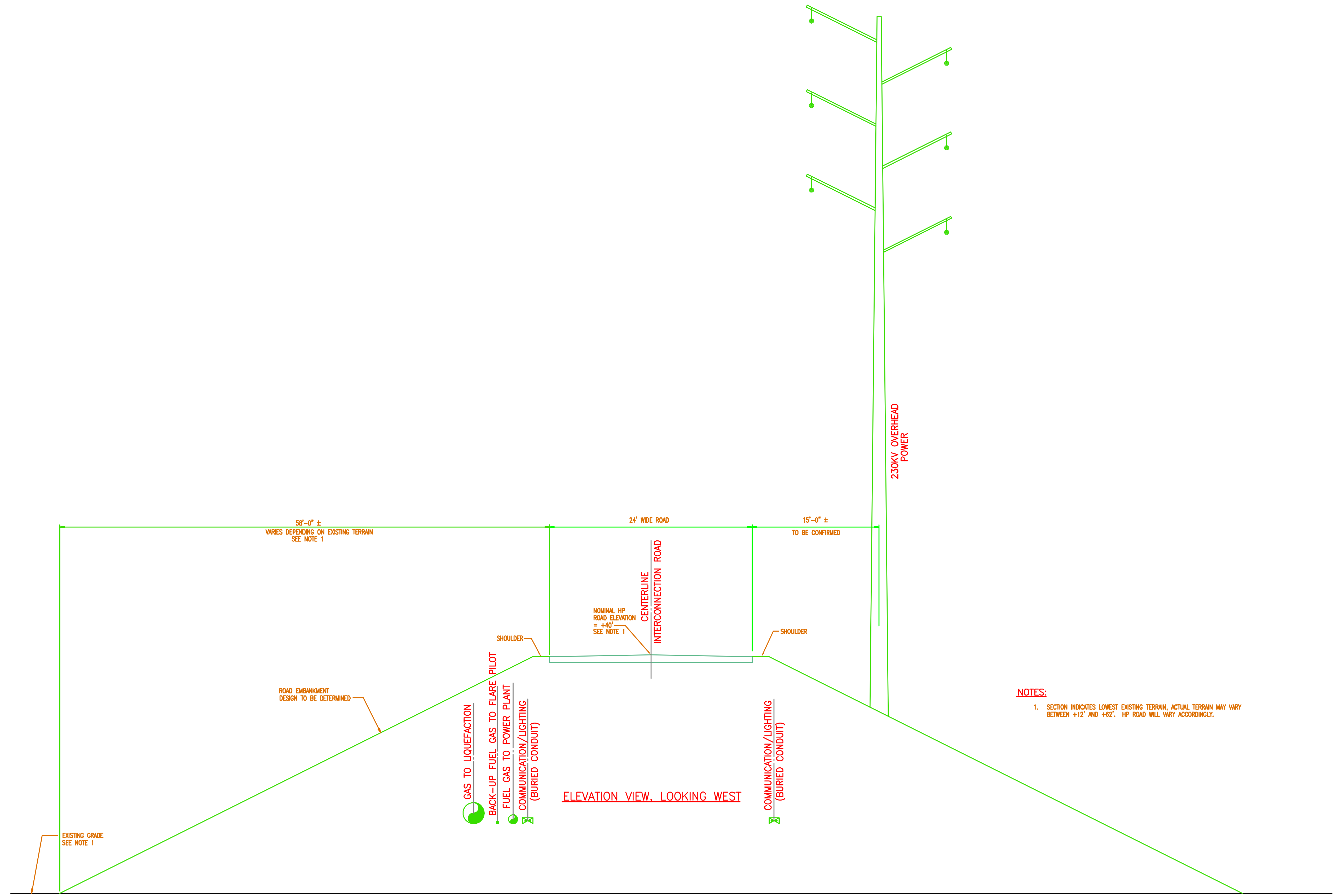
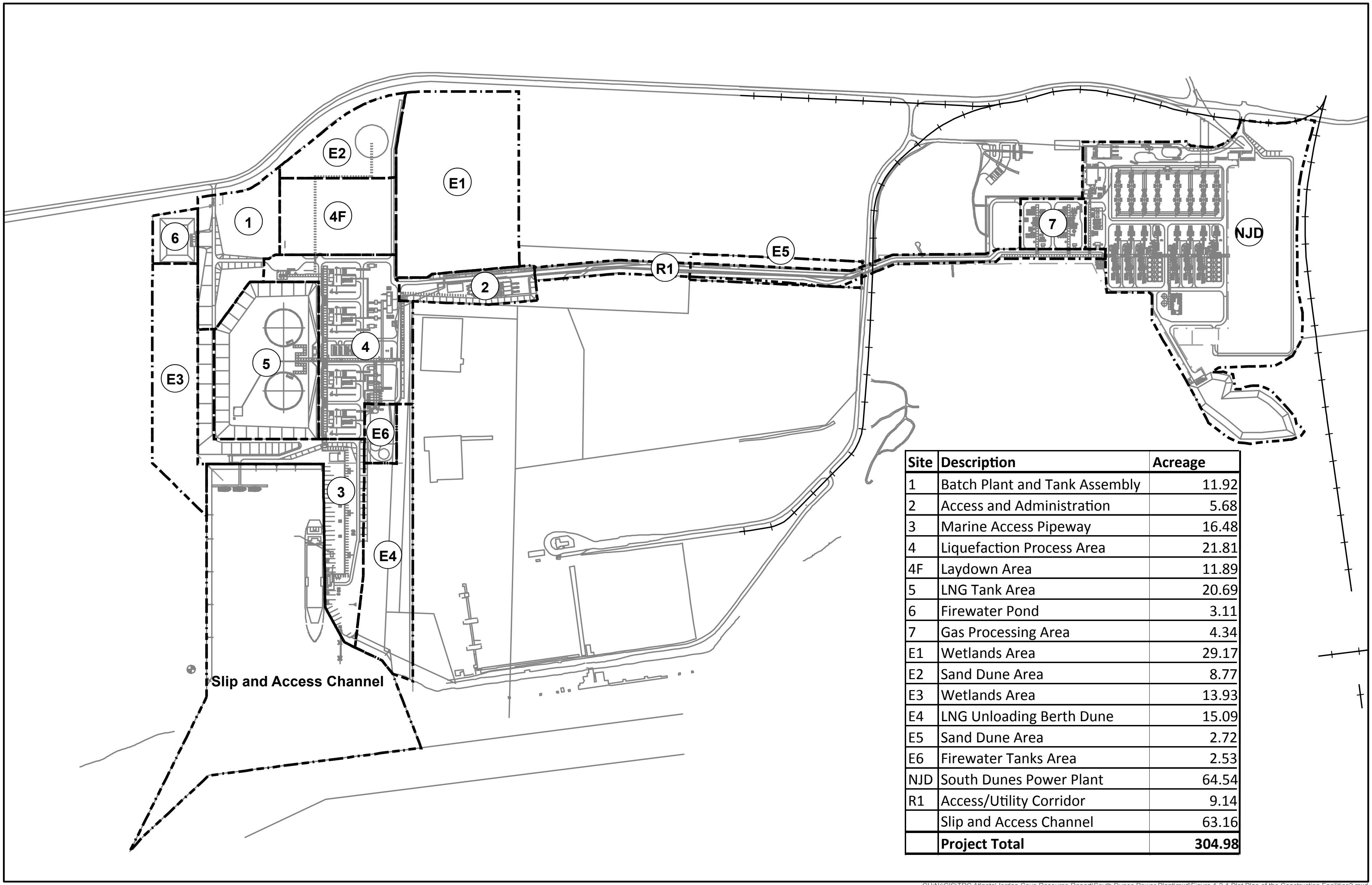
map by R. Carlisle Haworth



Path: N:\GIS\TRC Atlanta\Jordan Cove Resource Report\JCEP LNG Terminal Project\mxd\Figure 1-1-4 Cross Section Drawing of the Access Road and Utility Corridor.mxd

Jordan Cove Energy Project, L.P.

Figure 1.1-5
Cross Section Drawing of the Access Road and Utility Corridor
JCEP LNG Terminal Project



Site	Description	Acreage
1	Batch Plant and Tank Assembly	11.92
2	Access and Administration	5.68
3	Marine Access Pipeway	16.48
4	Liquefaction Process Area	21.81
4F	Laydown Area	11.89
5	LNG Tank Area	20.69
6	Firewater Pond	3.11
7	Gas Processing Area	4.34
E1	Wetlands Area	29.17
E2	Sand Dune Area	8.77
E3	Wetlands Area	13.93
E4	LNG Unloading Berth Dune	15.09
E5	Sand Dune Area	2.72
E6	Firewater Tanks Area	2.53
NJD	South Dunes Power Plant	64.54
R1	Access/Utility Corridor	9.14
	Slip and Access Channel	63.16
	Project Total	**304.98**

CH:N:\GIS\TRC Atlanta\Jordan Cove Resource Report\South Dunes Power Plant\mxd\Figure 1-2-1 Plot Plan of the Construction Facilities2.mxd

Jordan Cove Energy Project, L.P.

4/3/2012

Figure 1.2-1
Plot Plan of the Construction Facilities

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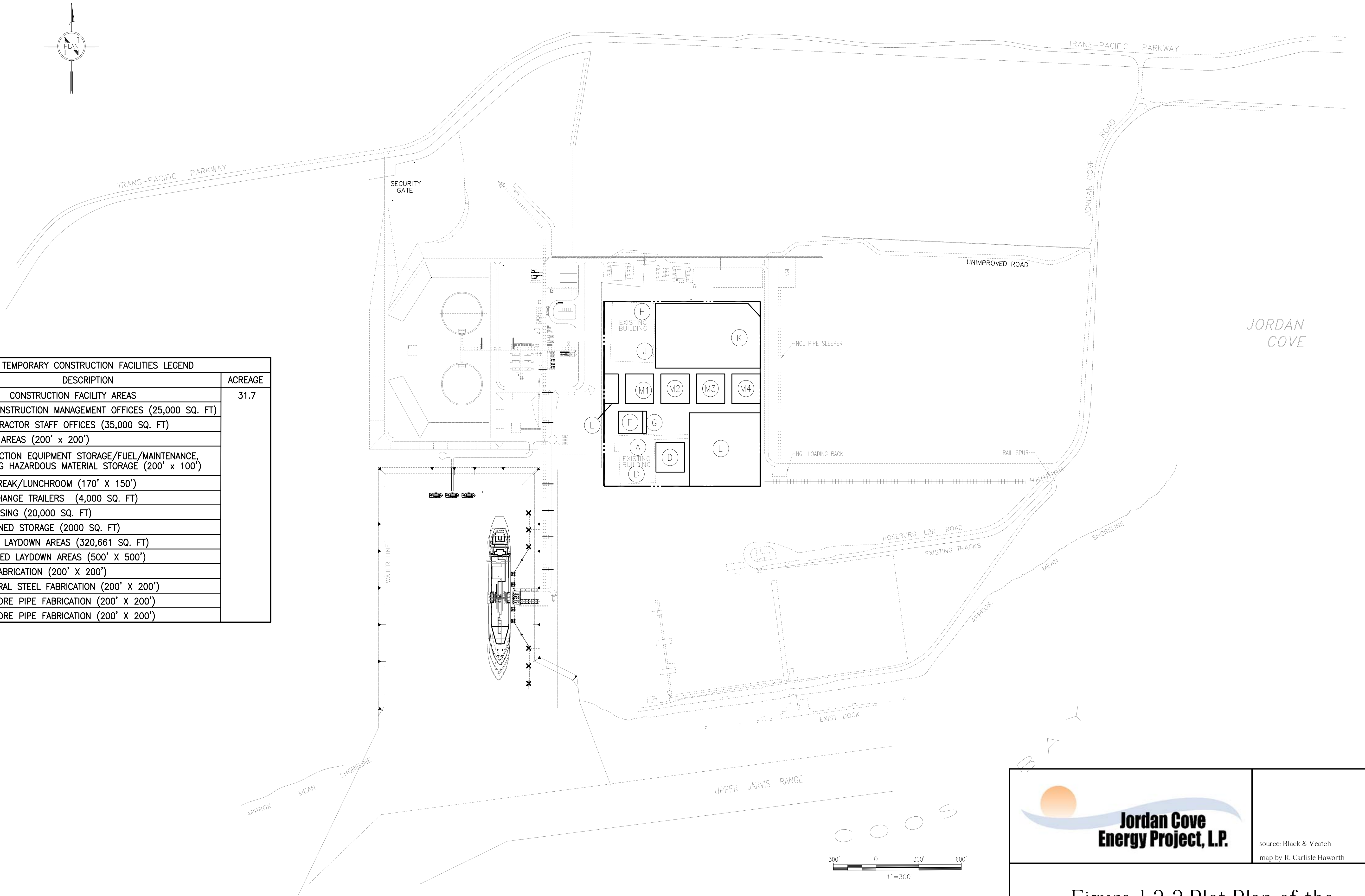


TEMPORARY CONSTRUCTION FACILITIES LEGEND		
TAG	DESCRIPTION	ACREAGE
	CONSTRUCTION FACILITY AREAS	31.7
A	FIELD CONSTRUCTION MANAGEMENT OFFICES (25,000 SQ. FT)	
B	SUBCONTRACTOR STAFF OFFICES (35,000 SQ. FT)	
D	PARKING AREAS (200' x 200')	
E	CONSTRUCTION EQUIPMENT STORAGE/FUEL/MAINTENANCE, INCLUDING HAZARDOUS MATERIAL STORAGE (200' x 100')	
F	CRAFT BREAK/LUNCHROOM (170' X 150')	
G	CRAFT CHANGE TRAILERS (4,000 SQ. FT)	
H	WAREHOUSING (20,000 SQ. FT)	
J	CONDITIONED STORAGE (2000 SQ. FT)	
K	SECURED LAYDOWN AREAS (320,661 SQ. FT)	
L	UNSECURED LAYDOWN AREAS (500' X 500')	
M1	REBAR FABRICATION (200' X 200')	
M2	STRUCTURAL STEEL FABRICATION (200' X 200')	
M3	LARGE BORE PIPE FABRICATION (200' X 200')	
M4	SMALL BORE PIPE FABRICATION (200' X 200')	

Jordan Cove Energy Project, L.P.

source: Black & Veatch

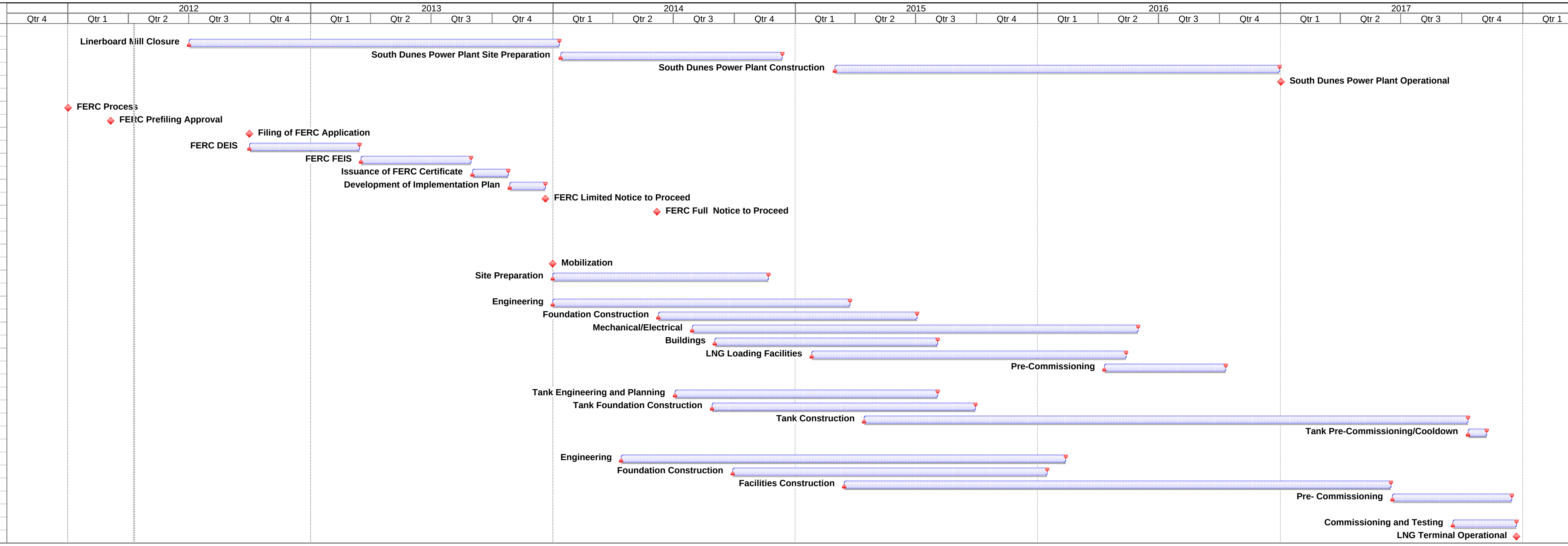
map by R. Carlisle Haworth

Figure 1.2-2 Plot Plan of the Temporary Construction Facilities

4/3/2012

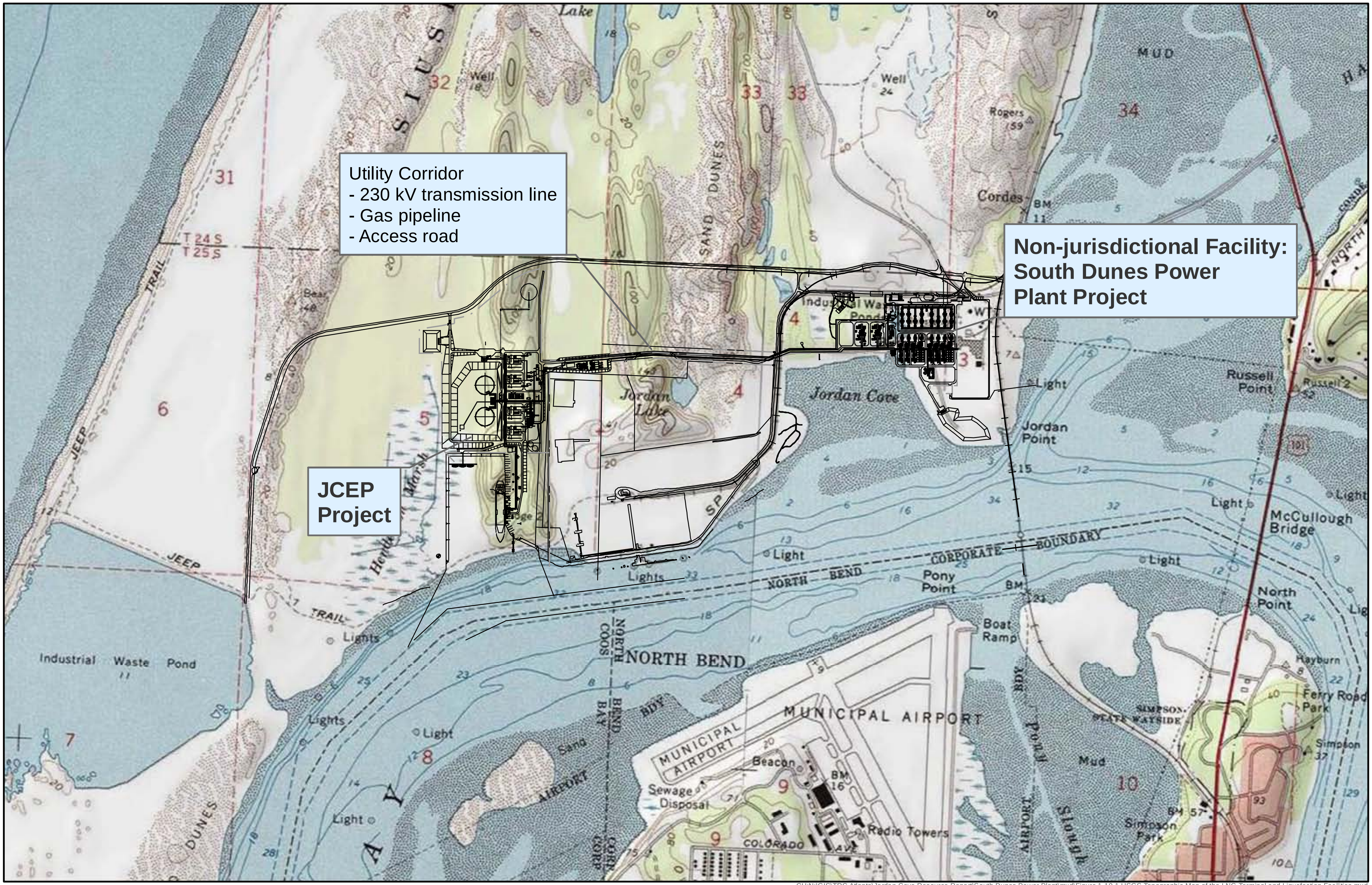
Figure 1.3-1
Jordan Cove Energy Project
Construction Schedule

ID	Task Name
1	Nonjurisdictional Facilities
2	Linerboard Mill Closure
3	South Dunes Power Plant Site Preparation
4	South Dunes Power Plant Construction
5	South Dunes Power Plant Operational
6	FERC Process
7	FERC Process
8	FERC Prefiling Approval
9	Filing of FERC Application
10	FERC DEIS
11	FERC FEIS
12	Issuance of FERC Certificate
13	Development of Implementation Plan
14	FERC Limited Notice to Proceed
15	FERC Full Notice to Proceed
16	
17	
18	LNG Terminal Facilities
19	**Mobilization**
20	**Site Preparation**
21	**LNG Terminal**
22	Engineering
23	Foundation Construction
24	Mechanical/Electrical
25	Buildings
26	LNG Loading Facilities
27	Pre-Commissioning
28	**LNG Storage Tanks**
29	Tank Engineering and Planning
30	Tank Foundation Construction
31	Tank Construction
32	Tank Pre-Commissioning/Cooldown
33	**Liquefaction Facilites**
34	Engineering
35	Foundation Construction
36	Facilities Construction
37	Pre- Commissioning
38	
39	**Commissioning and Testing**
40	**LNG Terminal Operational**



Project: JC Schedule
Date: Mon 4/9/12

Task | Milestone | Project Summary | External Milestone | Progress
Split | Summary | External Tasks | Inactive Task | Deadline



CH:N:\GIS\TRC Atlanta\Jordan Cove Resource Report\South Dunes Power Plant\mxd\Figure 1-10-1 USGS Topographic Map of the LNG Terminal and Liquefaction Facilities.mxd

Jordan Cove Energy Project, L.P.

4/3/2012

Figure 1.10-1
USGS Topographic Map of the LNG Terminal and Liquefaction Facilities

N

1:24,000

0 1,000 2,000 4,000 ft

CH:N:\GIS\TRC Atlanta\Jordan Cove Resource Report\South Dunes Power Plant\mxd\Figure 1-10-2 Aerial Photography of the LNG Terminal and Liquefaction Facilities.mxd

Jordan Cove Energy Project, L.P.

4/3/2012

Figure 1.10-2
Aerial Photography of the LNG Terminal and Liquefaction Facilities

N

1:12,000

0 500 1,000 2,000 ft

APPENDICES

APPENDIX A.1
Correspondence

10 February 2012

Coast Guard Sector Columbia River
Attn: Capt Bruce Jones
2185 SE 12th Place
Warrenton, OR 97146

Subj: 2012 JCEP WSA update

Dear Captain Jones:

On behalf of the Jordan Cove Energy Project, I would like to confirm that for purposes of the WSA process, Jordan Cove is allowed to update the WSA as part of our annual update to include the export of LNG from the marine facility. We clearly understand that the WSA will need to be updated for any changes in the Port in addition to the change of exporting vice importing of LNG.

This issue had been raised before at our Emergency Planning Meeting and we are seeking confirmation.

Sincerely,

Frank Whipple

Copy: Capt Daniel LeBlanc, USCG; Russell Berg, USCG; Deanna Henry, OR DOE
problem

U.S. Department of Homeland Security
United States Coast Guard

Captain of the Port
U. S. Coast Guard
Sector Columbia River

2185 SE 12th Place
Warrenton, Oregon 97146
Phone: (503) 861-6206
FAX: (503) 861-6355

16711/JORDAN COVE
21 February 2012

Amergent Techs
Attn: Mr. Frank Whipple
3553 N. Atlantic Ave. Suite A-158
Long Beach, CA 90807

JORDAN COVE ENERGY PROJECT WATERWAY SUITABILITY ASSESSMENT (WSA) ANNUAL UPDATE

Dear Mr. Whipple:

I have received your letter of 10 February 2012 in which you seek confirmation that adding export operations to your proposed facility can be handled through the annual WSA update. I concur that your annual WSA update should amend the WSA to include your intention to export LNG from your proposed terminal. In addition to the WSA, your Letter of Intent and Emergency Response Plan should also be reviewed and amended as appropriate. Import and export operations should be incorporated in the development of your Operations Manual and Facility Security Plan.

The waterway impacts associated with export operations at the Jordan Cove terminal should not change or exceed those envisioned in the original Environmental Impact Statement and WSA. If you have questions, please contact Mr. Russ Berg of my staff at (503) 240-9374.

Sincerely,

B. C. JONES

Copy: Jordan Cove Energy Project
Oregon Dept. of Energy
FERC

APPENDIX B.1

Navigant Study

NAVIGANT

JORDAN COVE LNG EXPORT PROJECT MARKET ANALYSIS STUDY

Prepared for:
Jordan Cove Energy Project, L.P.

Jordan Cove Energy Project, L.P.

Navigant Consulting, Inc.
3100 Zinfandel Drive
Suite 600
Rancho Cordova, California 95670

(916) 631-3200
www.navigantconsulting.com

January 2012

NAVIGANT

Disclaimer: This report was prepared by Navigant Consulting, Inc. for the benefit of Jordan Cove Energy Project, LP. This work product involves forecasts of future natural gas demand, supply, and prices. Navigant Consulting applied appropriate professional diligence in its preparation, using what it believes to be reasonable assumptions. However, since the report necessarily involves unknowns, no warranty is made, express or implied.

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Summary of Assignment

Jordan Cove Energy Project, LP (Jordan Cove or JCEP) is considering the export of liquefied natural gas (LNG) at Coos Bay, Oregon, where it has already received Federal Energy Regulatory Commission (FERC) authority to construct an LNG import facility. In support of this possible export project, JCEP requested Navigant Consulting, Inc. to provide an outlook for the North American natural gas market to 2045, with an emphasis on supply. It also asked Navigant to model the potential price impacts of its proposed export operations. As part of its integrated internal energy modeling process for natural gas and electricity, Navigant develops a forecast of the North American natural gas market in the spring and fall of each year. This report for JCEP builds on Navigant's Spring 2011 Reference Case forecast released in July 2011 and Navigant's market expertise and market research. Where appropriate, Navigant's supply forecast has been benchmarked to the latest U.S. Energy Information Administration's 2011 Annual Energy Outlook forecast as well as other supply forecasts that are publicly available.

Navigant developed four scenarios to model realistic circumstances under which JCEP exports may occur. These scenarios were designed to test the potential effect that the JCEP export project may have on prices, given certain assumptions regarding future supply, demand, infrastructure development, and economic activity. These assumptions are based on market fundamentals and the best professional judgment of Navigant.

As part of our modeling analysis, Navigant reviewed key factors such as:

- Gas drilling trends
- Hydro fracturing – its impact and risk factors
- Infrastructure developments
- The effects and outlook for oil and gas prices
- Gas pricing relative to oil
- Price volatility
- Outlook for economics of gas supply
- Imports (Canada, Mexico, regasification) / exports (LNG, Mexico, Canada)
- Supply balance overview by region
- Frontier gas supply
- Comparative analysis of supply forecasts
- Demand as a factor for gas supply sustainability in a surplus market
- Demand factors affecting gas supply – electric generation (coal, nuclear, renewables, NGVs)

Executive Summary

Domestically produced natural gas has become an abundant fuel in North America. In fact, gas supply is currently surplus to demand. This is due to the advent of economically-producible shale gas as a result of technological breakthroughs over the last four years.

It is Navigant's assessment that North American gas resources are ample to support the creation and ongoing operation of a domestic LNG export industry through the study period, including JCEP's proposed liquefaction facilities at Coos Bay, Oregon.

It is also Navigant's finding that the effect of the Jordan Cove LNG export project on natural gas commodity prices in the national gas market is negligible. In the local Pacific Northwest market at Sumas, prices remain essentially flat in 2025 and 2035 compared to the Reference Case; in 2045 Sumas prices increase 3.9 percent. At Malin on the California-Oregon border, prices increase by 2.7 percent in 2025, 3.1 percent in 2035 and then by 7.2 percent in 2045.

Importantly, Navigant finds that absolute prices at Henry Hub, Sumas, and Malin in the Jordan Cove Export Case are below $8.00 until 2045 at the very end of our analysis term.

Several facts support Navigant's findings.

- Dry gas production in the U.S. is up 28 percent, from about 49.5 Bcfd to 63.4 Bcfd, from 2004 through the first nine months of 2011.

- Navigant projects U.S. dry gas production alone (excluding Canada) to grow to 81.6 Bcfd by 2045 in its Spring 2011 Reference Case. Production could go higher in response to demand from proposed LNG liquefaction facilities and/or independent increases in the robust supply resource base.

- The EIA's most recent estimate of dry natural gas resources in the United States is 2,543 Tcf. This is more than 100 years of supply at current usage rates of approximately 24 Tcf per year. Even at Navigant's projected 2045 rate of consumption of 84.6 Bcfd (30.9 Tcf per year), this represents more than 82 years of supply. (The difference between U.S. demand of 84.6 Bcfd and U.S. supply of 81.6 Bcfd is made up primarily by pipeline imports from Canada, plus a small amount of LNG imports.) Using Navigant's 2008 estimate of 2,247 Tcf for dry natural gas resources, U.S. supplies would last 94 years.

- New shale discoveries have been identified and the productive potential of others has been revised upward with regularity over the past three years. For example, several plays now appear on the 2011 version of the EIA map that did not appear on the 2010 version, including the Niobrara, Heath, Tuscaloosa, Excello-Mulky, and Monterey. The areal extent of others, notably the Eagle Ford, has enlarged significantly. The National Energy Board of Canada recently estimated total gas in place for the Horn River Basin alone to be a minimum of 372 Tcf. The previous estimate of minimum gas in place for the *combined* Horn River Basin, Liard

Basin, and Cordova Embayment was 144 Tcf. Thus the current NEB estimate reflects an increase of 258 percent for the Horn River Basin alone, excluding the other two basins. Navigant expects this trend towards identifying a larger resource base to continue in the near term in both the U.S. and Canada, with natural gas from both countries available for export via the Jordan Cove export project.

- Navigant's modeling shows that the gas feedstock for Jordan Cove will initially be provided mainly from Canadian resources. Over the term of our analysis, Navigant forecasts increasing supply from U.S. sources. GTN is expected to have significant excess pipeline capacity due to gas-on-gas competition with Ruby Pipeline, which was designed to displace Canadian supply from the California market in favor of Rockies supply. Ruby has been operating in such a fashion since commencing operations in July 2011. In 2017, Jordan Cove is supplied 70 percent by Canadian gas and 30 percent by Rockies gas, shifting to 35/65 by 2045. Over the timeframe of the study (2012-2045), Navigant's modeling indicates that the aggregate total feedstock flowing through the Jordan Cove export project will be supplied in roughly equal parts by U.S. and Canadian supplies.

Before 2008, the general consensus was that domestic North American gas supplies would be unable to keep pace with growing demand, and that liquefied natural gas would have to be imported from foreign supply sources. That consensus is no longer operative. The situation in North America has reversed from an expectation of domestic supply deficit to an expectation of domestic supply abundance. Prices that were expected to be high and volatile are now expected to be moderate and relatively stable as a result of the technological breakthrough of gas shale development.

The new consensus, which Navigant was instrumental in establishing, is that North American gas resources are more than adequate to satisfy domestic demand for the time frame covered by this report, even as demand grows.

An unappreciated but very important aspect of the North American gas market is that reliable demand is a key to underpinning reliable supply and a sustainable gas market. Demand and supply are two parts of a single dynamic. Domestically manufactured LNG for export can be an integral part of that demand. By providing a steady baseload demand, it can help support ongoing supply development and help keep domestic gas prices stable. This is based on the fundamental resource being available – which we believe will be the case.

In all scenarios Navigant prepared for Jordan Cove in this analysis, natural gas maintains its steep discount to the price of crude oil on a heating value equivalent basis. In 2045, Navigant forecasts the price of oil to be $158 per barrel, which is equivalent to $27.25 per MMBtu. In the highest gas price scenario modeled, the GHG Demand Case, gas prices only attain $10.30 per MMBtu in the national market at Henry Hub and less than $10.00 per MMBtu in the regional Pacific Northwest market closest to the Jordan Cove export project (see Table 1 below). The price comparison of natural gas to oil is important to the longer term competitiveness of natural gas in North America.

Year	Metric	Reference Case	Jordan Cove Export	Aggregate Export	GHG Demand
2025	*Henry Hub*	$5.51	$5.55	$5.92	$6.88
	Malin	$5.15	$5.29	$5.55	$6.49
	Sumas	$5.28	$5.26	$5.53	$6.46
2035	*Henry Hub*	$7.31	$7.35	$7.66	$9.33
	Malin	$6.81	$7.02	$7.29	$8.55
	Sumas	$6.97	$6.98	$7.25	$8.23
2045	*Henry Hub*	$8.28	$8.30	$8.55	$10.31
	Malin	$7.57	$8.11	$8.39	$9.72
	Sumas	$7.75	$8.05	$8.32	$9.47

Table 1: Sample Output Prices of Selected Locations[1]

[1] In this report, totals may not equal sum of components due to independent rounding.

Supply Outlook to 2045

Overall supply growth in the U.S. continues to be remarkable. Due to the vast size of the shale gas resource and the high reliability of shale gas production, the overall supply-demand balance has the potential to be synchronized for the foreseeable future, even as natural gas demand grows. This is predominantly attributable to the presence of prolific supplies of unconventional gas which can now be produced economically. Unconventional gas includes shale gas, tight sands gas, coalbed methane, and gas produced in association with shale oil, but it has been the ramping rates of gas shale production growth that has been the biggest contributor to overall gas supply abundance.

Before the advent of significant shale gas production, natural gas development was susceptible to booms and busts. Investment in both production and usage seesawed on the market's perception of future prices. That perception was driven by uncertainty around the exploration risk associated with finding gas supply to meet demand, both for the short and long terms. The investment cycle for supply was frequently out of phase with demand, due to the uncertainty of the exploration process (and at times the availability of capital to fund such discovery) required for the development of the LNG industry (on the supply side) and for the development of gas fired electric generating facilities and other large users (on the demand side).

To connect supply and demand, pipeline infrastructure was required and is another large-scale investment that at times has suffered from underutilization or has become a bottleneck, as a result of the second order effects of uncoordinated cycles of supply and demand investment.

These factors all help to foster a dynamic of natural gas price volatility. The volatility itself affected investment decisions, amplifying the feedback loop of uncertainty. In the end, price volatility has been a major cause of limits on the more robust expansion of natural gas as a fuel supply source.

The dependability of shale gas production as a result of its abundance has the potential to improve the phase alignment between supply and demand, which will in turn tend to lower price volatility. The vast size of the shale gas resource will support a much larger demand level than has heretofore been seen in North America at prices that are less volatile.

Navigant expects gas production to continue to grow steadily throughout the forecast period, as shale gas is a relatively new resource in the early stages of development. Our forecast for production, based on our Spring 2011 Reference Case, is shown in ***Figure 1:*** *North American Natural Gas Supply Projection*. Navigant projects that North American-produced supply will be 107.1 Bcfd by the year 2045. By that year, U.S.-produced supply alone is projected to be 81.7 Bcfd, as shown in ***Figure 2:*** *U.S. Natural Gas Supply Projection*.

As we point out in further detail in the report, both Canadian and U.S. gas supply resources are important for the Jordan Cove export project. Over the forecast period, modeling indicates that most of the gas exported at the Jordan Cove export project in the first decade of operation will be Canadian supply. The ongoing continuation of net pipeline imports in aggregate to the large U.S. market over the term of the study period is shown in Figure 2 below. A portion of these Canadian imports will supply the Jordan Cove LNG export project.

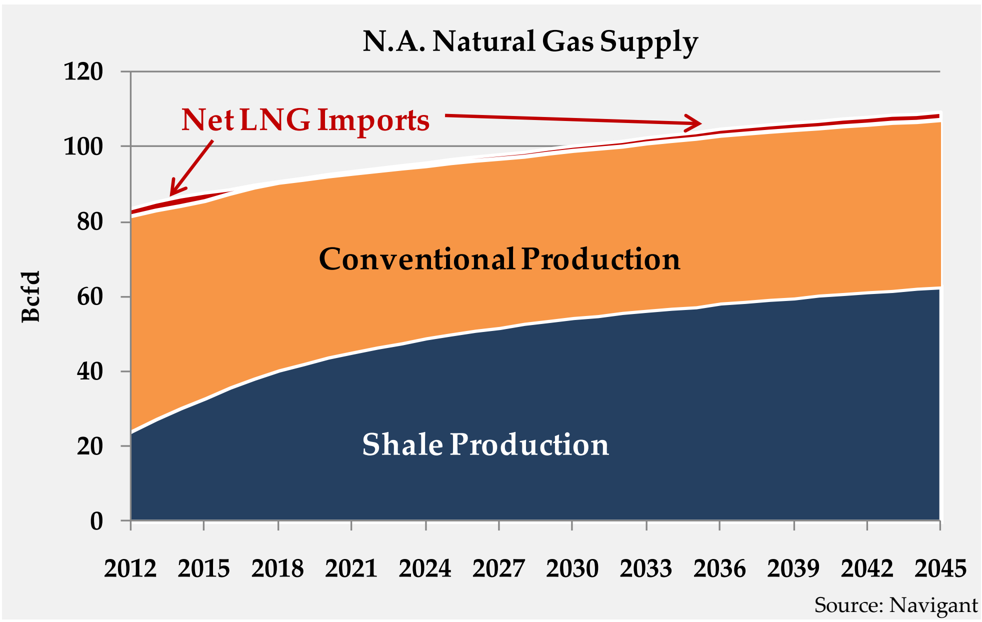

Figure 1: North American Natural Gas Supply Projection

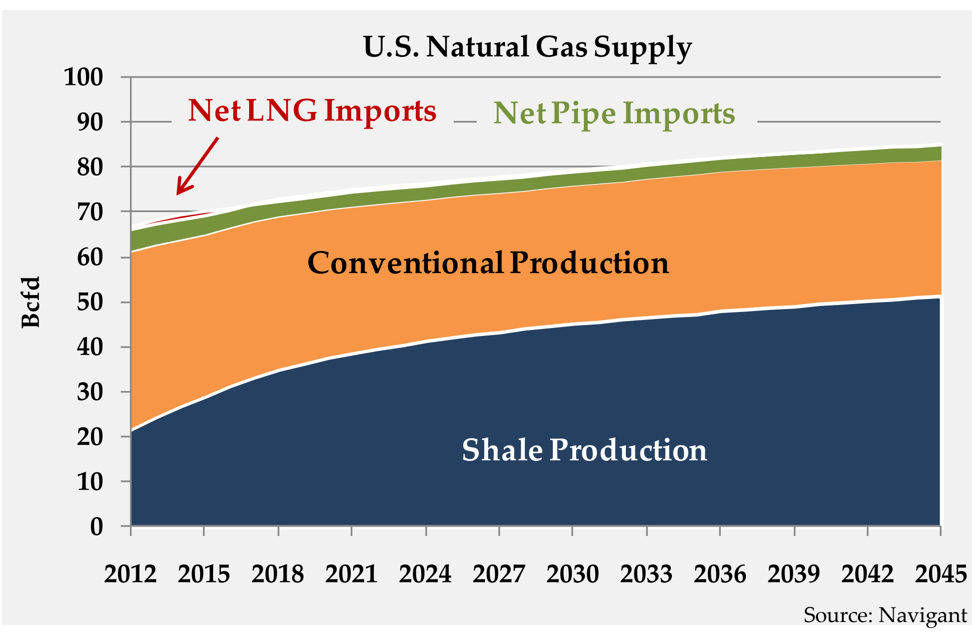

Figure 2: U.S. Natural Gas Supply Projection

With this moderated and controlled supply growth, demand and pipeline investment are expected to grow in a measured fashion, with price volatility relatively limited. This will tend to create a healthier and more stable long-term market for natural gas, with the ability for supply and demand to be in much closer balance in aggregate than has been the case in the past.

The majority of production growth is likely to be driven by unconventional gas development, as opposed to conventional gas, which has been in decline. Plans to develop large known deposits of conventional frontier gas, such as the Mackenzie Pipeline Project in Arctic Canada and the Alaska Pipeline Project have been put in jeopardy due not to any change in the resource itself but to the high cost of those projects relative to unconventional resource development opportunities closer to markets. In Navigant's modeling for Jordan Cove, neither the Mackenzie Pipeline Project nor the Alaska Pipeline Project has been forecast to be on-stream during the term of our Jordan Cove analysis. We note that the governor and legislature of Alaska recently announced they favor a pipeline project from Alaska's North Slope gas resources that delivers to the south coast of the state where it could be liquefied into LNG instead of connecting to the larger North American grid in Canada. (A portion of the flow would be used to meet the needs of the City of Anchorage.)

Factors Underpinning the Forecasted Increase in Gas Supply

In 2008, Navigant first identified the rapidly expanding development of natural gas from shale. While geologists and natural gas production companies had been aware of shale gas resources, (trace amounts of methane were often detected as drillers penetrated shale on the way to a conventional reservoir), such resources had been uneconomic to recover.

Improvements in Hydraulic Fracturing and Horizontal Drilling

Natural gas prices increased substantially in the first decade of this century, and culminated in significantly higher prices in 2007-2008, as shown in **Figure 3:** *Henry Hub Price History*. These increasing prices induced a boom in LNG import facility construction in the late 1990s and 2000s, which was very conspicuous due to the size of the facilities. As late as 2008, conventional wisdom held that North American gas production would have to be supplemented increasingly by imported LNG owing to domestic North American supply resource decline.

Far less conspicuously, high prices also supported the development of horizontal drilling and hydraulic fracturing, existing technologies which were refined and systematized in ways that dramatically increased drilling and production efficiencies, reduced costs, and improved the finding and development economics of the industry. In mid-2008, when Navigant released its groundbreaking report,[2] domestic gas production from shale began to overtake imported LNG as the gas supply of choice in North America. The evolution of these cost-effective technologies was the key to unlocking that potential.

[2] North American Natural Gas Supply Assessment, prepared for the American Clean Skies Foundation, July 4, 2008, available at http://www.navigant.com/~/media/Site/Insights/Energy/NCI_Natural_Gas_Resource_Report.ashx

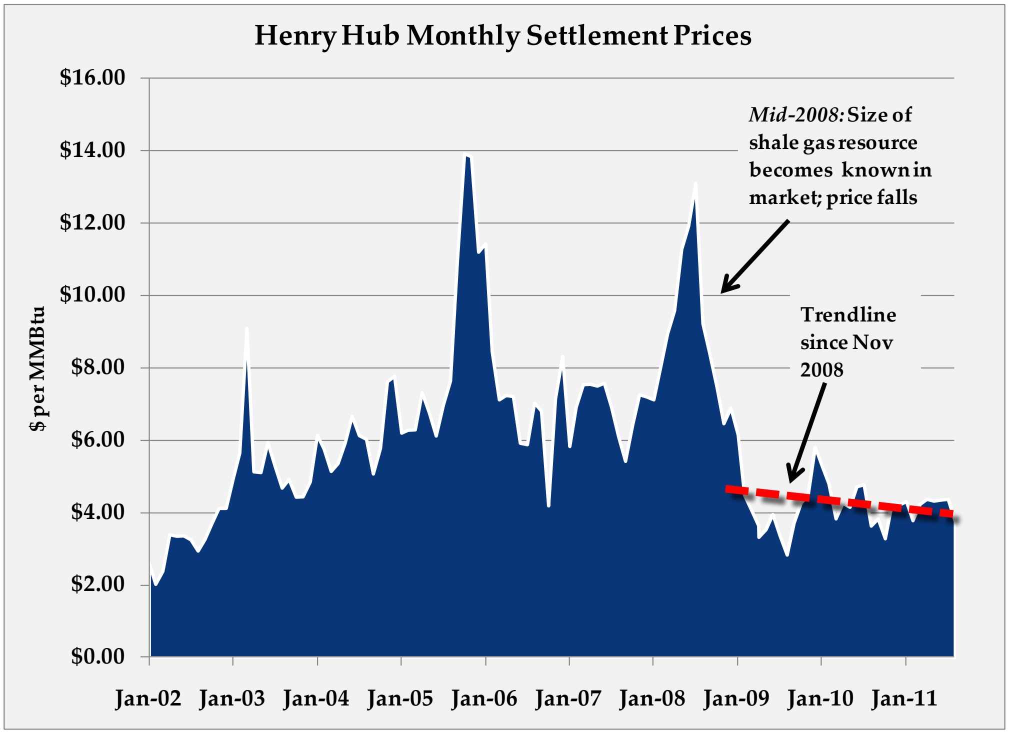

Figure 3: Henry Hub Price History

Shale gas production efficiency has continued to improve over time. In many locations, 10 wells can be drilled on the same pad. The lengths of horizontal runs, once limited to several hundred feet, can now reach up to 10,000 feet. The number of fracture zones reportedly has increased from four to up to 24 in some instances.

Improvements continue in other aspects of hydraulic fracturing technology. Much attention is being focused on water usage and disposal. Several states, including Texas and Wyoming, have passed legislation that requires the contents of chemicals used in the hydraulic fracturing process to be disclosed. The U.S. Environmental Protection Agency is investigating the potential impacts of hydraulic fracturing on drinking water resources. Range Resources is pioneering the use of recycled flowback water, and by October 2009 was successfully recycling 100 percent in its core operating area in southwestern Pennsylvania. Range estimates that 60 percent of Marcellus shale operators are recycling some portion of flowback water, noting that such efforts can save significant amounts of money by reducing the need for treatment, trucking, sourcing, and disposal activities.[3] Chesapeake Energy is also actively exploring methods of reducing and reusing water.

These efforts to continue to improve water management will tend to enhance the ability of shale operations to expand.

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[3] "Range Answers Questions on Hydraulic Fracturing Process ," Range Resources, http://www.rangeresources.com/Media-Center/Featured-Stories/Range-Answers-Questions-on-Hydraulic-Fracturing-Pr.aspx

Size of the Shale Gas Resource

To illustrate the size of the shale gas resource across the U.S., its rapid development, and increasing efficiency, consider the following. U.S. total natural gas production increased from about 49.7 Bcfd in August 2005 to about 63.6 Bcfd in August 2011, even as overall rig counts fell from 1,170 to 890. (September was not used for this calculation to discount the production losses from Hurricanes Katrina and Rita in 2005.) This is an increase in gas production of 28 percent in six years. The increase in overall gas production has been driven by shale gas, as evidenced by the increase in horizontal drill rig counts and the decrease in vertical (conventional) rig counts. (See **Figure 4:** *U.S. Gas Production and Rig Count History* and ***Figure 5:*** *U.S. Gas Rig Type Shift*.)

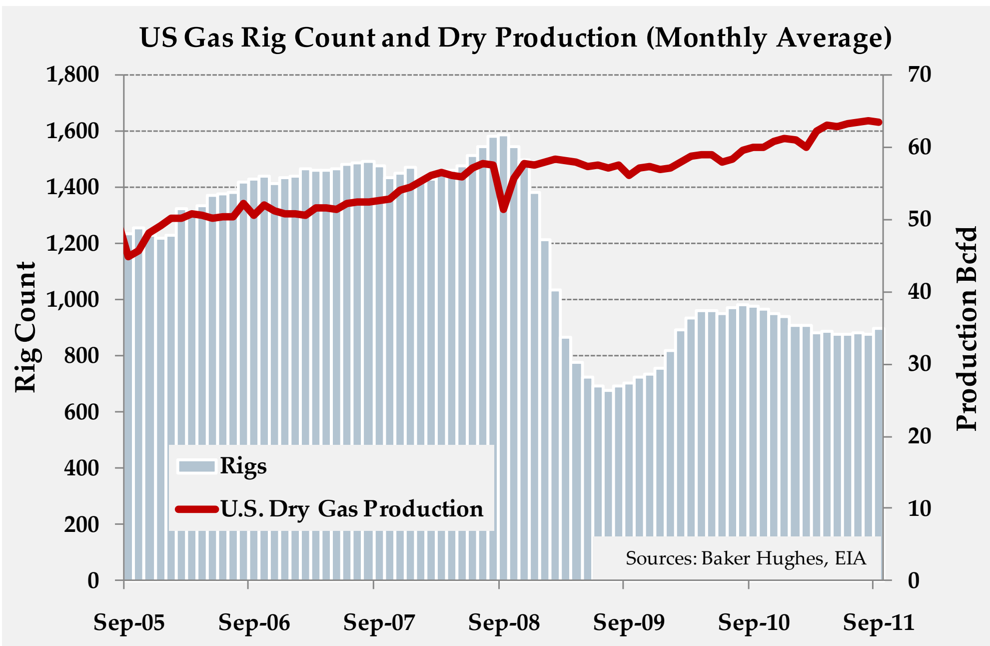

Figure 4: U.S. Gas Production and Rig Count History

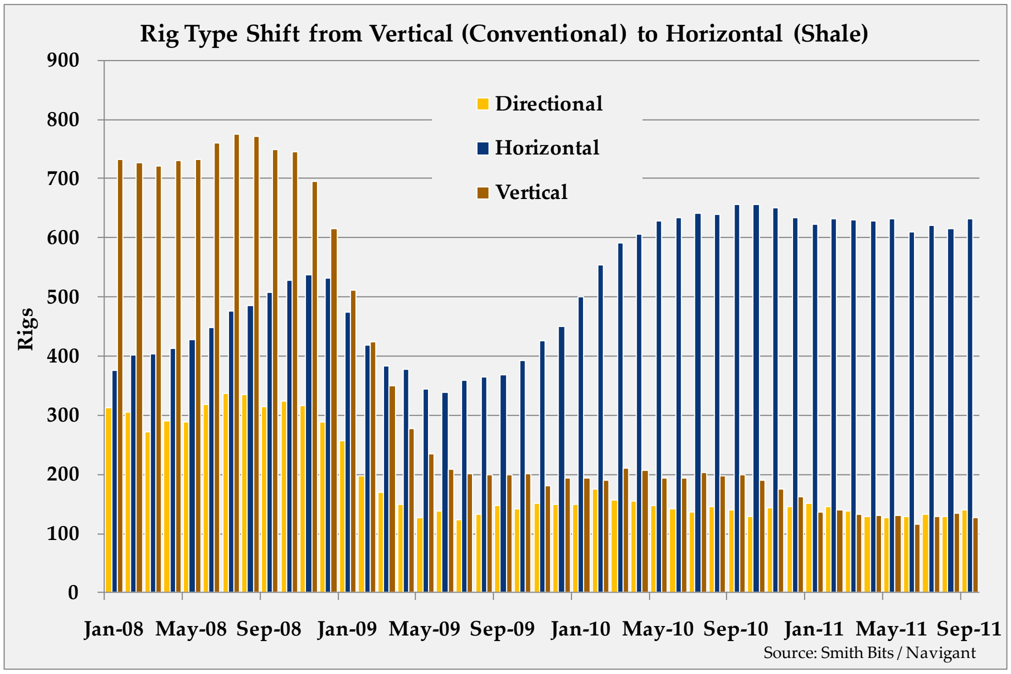

Figure 5: U.S. Gas Rig Type Shift

The growth in shale gas production has been prolific, as shown in the graph in **Figure 6:** *Shale Production 2007-2011*. Shale output from eight major basins under development in North America grew from 3.0 Bcfd in the first quarter of 2007 to 20.7 Bcfd in the second quarter of 2011, an increase of more than 580 percent in a little more than four years.

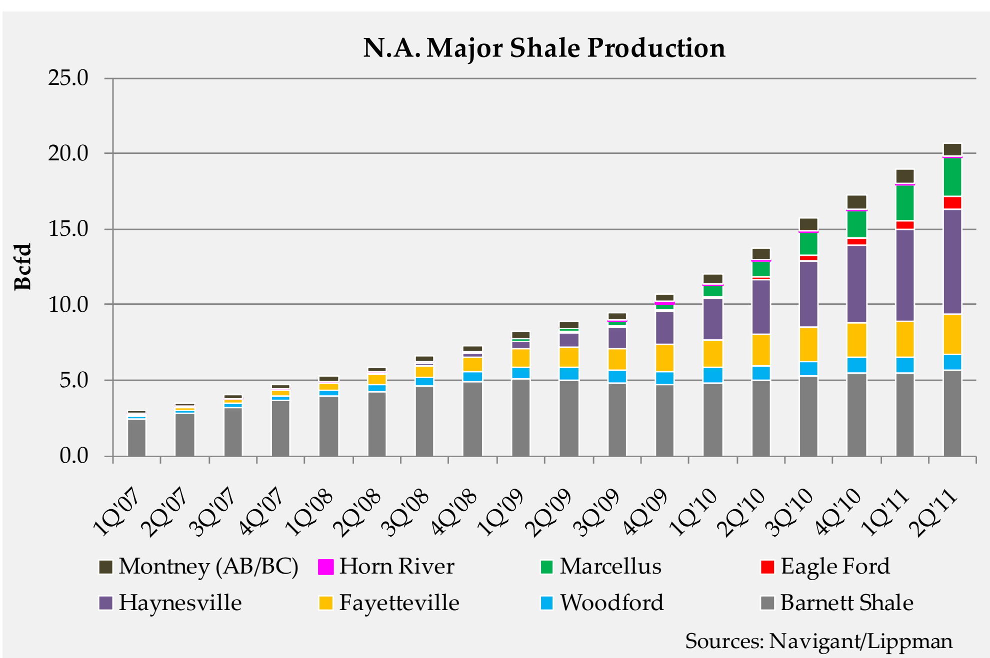

Figure 6: Shale Production 2007-2011

The geographic scope of the U.S.'s shale gas resource can be seen in the map from the Energy Information Administration, shown in **Figure 7:** *EIA Lower-48 Shale Play Map (2011)*. In Navigant's study on the subject of emerging North American shale gas resources released in 2008, we estimated the maximum recoverable reserves from shale in the U.S. to be 842 trillion cubic feet (Tcf), boosting the maximum recoverable reserves for all of the U.S. to 2,247 Tcf.[4] This is sufficient to satisfy U.S. current annual demand of approximately 24 Tcf per year for 94 years. In its *Annual Energy Outlook 2011*, the EIA's estimate for technically recoverable unproved shale gas resources in the U.S. in its reference case is 827 Tcf not far from Navigant's estimate of 842 Tcf in 2008.[5] The EIA's estimate of *total* dry natural gas resources in the United States is 2,543 Tcf. This is more than 100 years of supply at current usage rates.

New shale resource plays are being identified at a high rate. For example, several plays now appear in the 2011 analysis by the EIA that did not appear in similar analysis in 2010. These include the Niobrara, Heath, Tuscaloosa, Excello-Mulky, and Monterey. The areal extent of others, notably the Eagle Ford, has enlarged significantly. North America is clearly in the early phases of discovery for the resource.

[4] *North American Natural Gas Supply Assessment*, by Navigant Consulting for American Clean Skies Foundation, July 4, 2008, available at http://www.cleanskies.org/pdf/navigant-natural-gas-supply-0708.pdf
[5] *Annual Energy Outlook 2011*, EIA, p. 2.

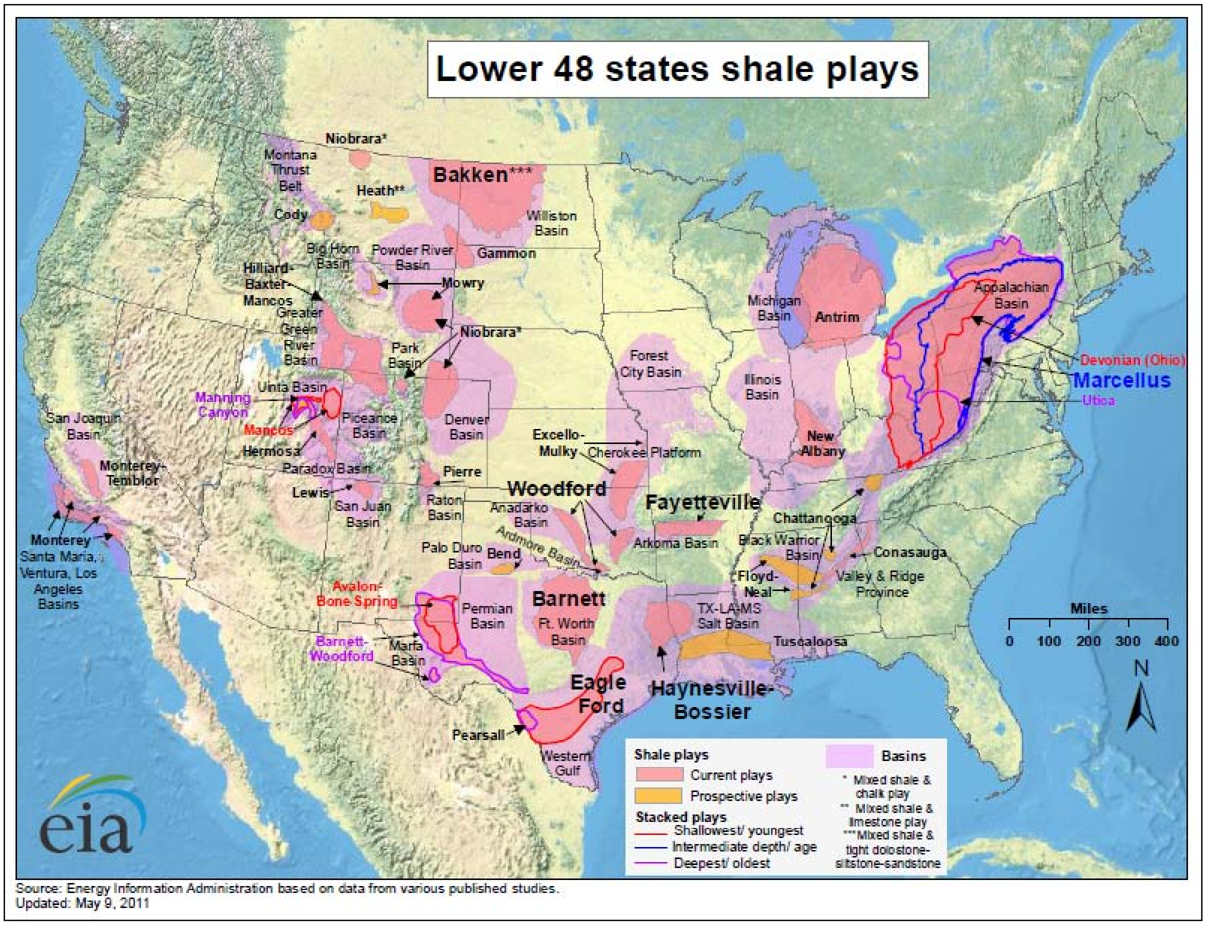

Figure 7: EIA Lower-48 Shale Play Map (2011)

The Marcellus Shale formation in central Appalachia is notable in any discussion of the North American gas resource base. The Marcellus was not well known in 2007. Dr. Terry Engelder, a professor of geology at Penn State University and one of the leading scientists in the study of the Marcellus, estimated in 2009 that the Marcellus has a 50 percent chance of containing 489 Tcf of recoverable gas.[6] In 2010, the entire United States used about 24 Tcf per year, or less than five percent of the Marcellus's potential production.[7] Another recent study by Penn State estimates that production from the Marcellus will grow from 327 million cubic feet per day during 2009 to 13.5 billion cubic feet per day by 2020.[8]

[6] Basin Oil & Gas magazine, August 2009, p. 22, available at http://www.geosc.psu.edu/~engelder/references/link155.pdf

[7] EIA, Natural Gas Consumption by End Use, annual table, release date 5/31/2011, available at http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_a.htm

[8] *The Economic Impacts of the Pennsylvania Marcellus Shale Natural Gas Play: An Update,* Penn State University, May 24, 2010, p. 19.

In the final version of its recently published study ***The Future of Natural Gas***, the Massachusetts Institute of Technology stated that "The current mean projection of the recoverable shale gas resource [in the U.S., excluding Canada] is approximately 650 Tcf … approximately 400 Tcf [of which] could be economically developed with a gas price at or below $6/MMBtu at the well-head."[9] In 2009, the Potential Gas Committee of the Colorado School of Mines estimated that the recoverable natural gas resource in North America is 2,170 Tcf, an increase of 89 Tcf over their previous evaluation. This is enough to supply domestic needs at 2010 usage rates (66.1 Bcfd) for 90 years. Of this total, 687 Tcf is shale gas.[10]

Of significant importance to the Jordan Cove export project is the state of the natural gas resource base in Canada which is expected to supply a large portion of the natural gas to be converted to LNG at Jordan Cove.

The British Columbia Ministry of Energy and Mines and the National Energy Board (BCMEM) recently estimated the marketable gas in place in the Horn River Basin alone to be between 61 and 96 trillion cubic feet, with a mean expectation of 78 Tcf.[11] This estimate excludes the Montney natural gas play further to the south, resources in the territories to the north such as the Liard Basin and the Cordova Embayment, conventional gas, and any as-yet-to-be-discovered resources. Total gas in place for the Horn River Basin alone was estimated to be a minimum of 372 Tcf. Other estimates for the Horn River have been even higher. RBC Capital Markets estimates that 500 Tcf of gas is in place. At recoverable estimates of 20 to 40 percent, that resource would support 100-200 Tcf of recoverable reserves.[12] In other estimates by the BCMEM, the minimum estimate of gas in place for the *combined* Horn River Basin, Liard Basin, and Cordova Embayment is 144 Tcf.[13] Thus the current NEB estimate reflects an increase of 258 percent for the Horn River Basin alone, excluding the other two basins. Navigant expects this trend towards identifying a larger resource base to continue in the near term in both the U.S. and Canada, with natural gas from both countries available for export via the Jordan Cove export project.

For the other major gas shale basin in B.C., the Montney play has been estimated by the James A Baker III Institute for Public Policy at Rice University to contain 65 Tcf of mean technically recoverable resources.[14] Based upon 2009 gas demand in B.C. (about 386 Bcf) and the estimates of marketable supply for the Horn River and recoverable reserves for the Montney basins, the combined

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[9] Massachusetts Institute of Technology, *The Future of Natural Gas*, Ernest J. Moniz, et al, Chapter 1, p. 7, http://web.mit.edu/mitei/research/studies/documents/natural-gas-2011/NaturalGas_Full_Report.pdf.

[10] Potential Gas Committee press release, April 27, 2011, http://potentialgas.org/

[11] *Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin*, May 2011, British Columbia Ministry of Energy and Mines and the National Energy Board, pp 18-24.

[12] RBC Capital Markets Equity Research, Horn River Shale Gas – Awakening the Northern Giant, September 27 2010, p. 5.

[13] Ibid., p 11.

[14] T*he Rice World Gas Trade Model: A Discussion of Reference Case Results*, Kenneth B. Medlock III, James A Baker III Institute for Public Policy, Rice University, April 19, 2011, p. 20.

resource base for these two BC basins alone would support consumption in B.C. for more than 370 years.[15]

As indicated by the above, there is little doubt that the shale gas resource in North America is extremely large. It is Navigant's view that the size of the shale gas resource in North America is more than adequate to serve all forecast domestic demand through the study period to 2045 as well as the demand added by JCEP's proposed liquefaction facilities at Coos Bay. It has also been our finding that the price impact of such increased demand is marginal as we show in our detailed modeling that is key to our report.

Character of the Shale Gas Resource

The character of the shale gas resource reinforces its future growth potential. Finding economically producible amounts of conventional gas has historically been expensive due largely to geologic risk. Dry or quickly depleted wells are not uncommon in the conventional gas world. Conventional gas is usually trapped in porous rock formations, typically sandstone, under an impermeable layer of cap rock. It is produced by drilling through the cap into the porous formation, liberating the gas. Despite advances in technology, finding and producing conventional gas still involves a significant degree of risk, with the possibility that a well will be a dry hole or will produce at very low volumes that do not allow the well to be economical.

In unconventional shale gas, geologic risk is significantly reduced. Resource plays have become much more certain to be produced in commercial quantities. The reliability of discovery and production has led shale gas development to be likened more to a manufacturing process rather than an exploration process with its attendant risk. This ability to control the production of gas by managing the drilling and production process allows supplies to be produced in concert with market demand requirements and economic circumstances.

Gas in a shale formation is entrained in the rock itself. It does not accumulate in pockets under cap rock. It tends to be distributed in relatively consistent quantities over great volumes of the shale. The most advanced gas shale drilling techniques allow a single well-pad to be used to drill multiple horizontal wells up to two miles in length into a given formation, with each bore producing gas. Since the shale formations can be dozens or even hundreds of miles long and often several hundred feet thick and, in many cases, are in existing gas fields wherein the shale was penetrated regularly but not able to be produced economically from vertically drilled wells, the risk of not finding a producible formation is much lower compared to some types of conventional gas structures.

The horizontal well, properly located in the target formation, is enabled to produce gas volumes large enough to be economic through the use of hydraulic fracturing. Water, sand (or some other proppant to keep the fractures open), and a small amount of chemicals are injected at high pressure to fracture the shale so that it releases the gas. As is the case with most shale wells, initial production (IP) rates are high, but drop off steeply within the first two years. However, once a well has declined to 10-20

[15] National Energy Board, *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, Appendix 2, Table A2.3; Navigant calculations, available at http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/nrgyftr-eng.html#s7

percent of initial production, the expectation is that production will then continue at that lower rate with a very slow decline for many years. The graph below typifies a shale well decline curve. [16]

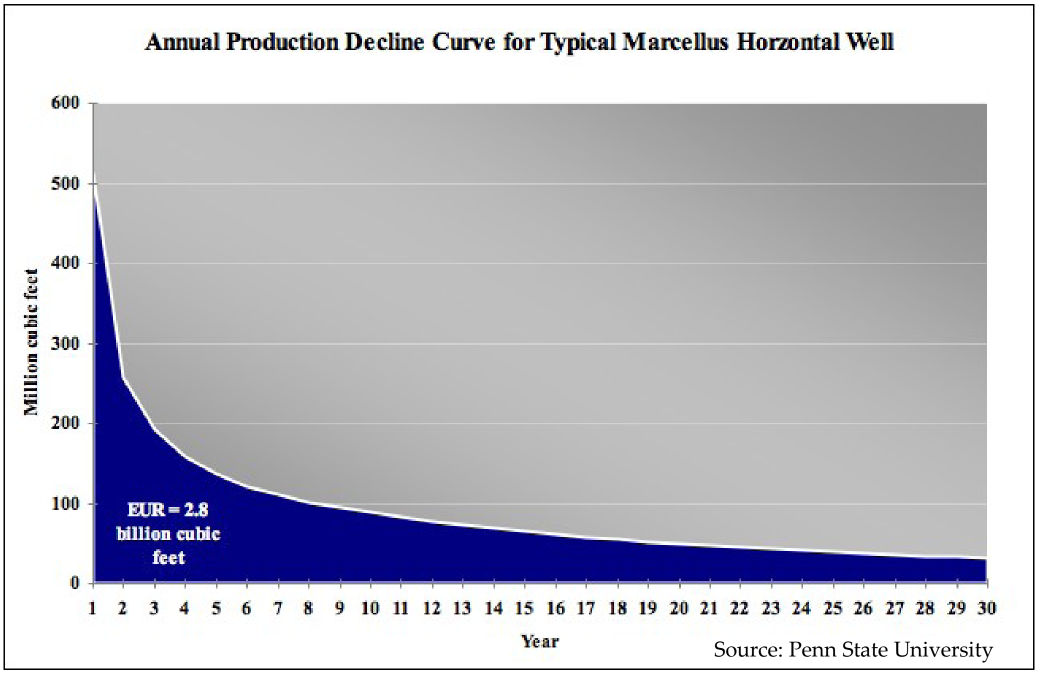

Figure 8: Shale Gas Well Decline Curve[17]

The certainty of production allows shale gas to be managed in response to demand. If demand is growing, additional zones and/or shale wells can be drilled and fractured to meet that demand and mitigate the initial production or IP decline rates from earlier wells. If demand subsides, drilling rates can be reduced or discontinued completely in response to the negative market signal.

Shale gas development has been further reinforced recently by the fact that some shale formations also contain natural gas liquids (NGLs), which strengthens the economic prospects of shale. Associated gas is generally produced when NGLs are produced. Therefore, gas production is being incented not only by the economics of natural gas itself, but by NGL prices, that track crude oil prices. Oil prices can offer a significant premium to natural gas on a per-MMBtu basis, as is currently the case. Oil at $100 per barrel equates to about $17.25 per MMBtu.

For example, several energy companies including Enbridge, Enterprise Products Partners, Buckeye Partners, Kinder Morgan, and Dominion have recently announced plans to build or enhance NGL gathering and transmission systems in the Marcellus shale formation; the Eagle Ford formation in Texas is being developed as an NGL play as much as a natural gas play. Recently, discoveries in the Utica formation in eastern Ohio have led Chesapeake Energy to state that it is "likely most analogous,

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[16] *The Economic Impacts of the Pennsylvania Marcellus Shale Natural Gas Play: An Update*, Considine, Watson, and Blumsack, Penn State University, May 24, 2010, p. 16, available at http://www.energyindepth.org/wp-content/uploads/2009/03/PSU-Marcellus-Updated-Economic-Impact.pdf

[17] Typo in title is in the original as published by Penn State.

but economically superior, to the Eagle Ford."[18] The development of estimates for associated gas reserves are in the early stages and run from 2.0 Tcf to 69 Tcf but in any event are very significant in their own right. [19]

Similarly, in April 2011, the Canadian natural gas producing company Encana announced the acquisition of liquids-rich Duvernay Shale acreage in Alberta to exploit natural gas liquids in addition to shale gas. This has the potential to incent additional gas shale production in Alberta.

While the cost of producing commercial quantities of gas does vary from play to play, and even within a play, the overall trend has been for drilling and completion costs to decline as producers gain knowledge of the geology, develop efficiencies thereby and leverage investments in upstream drilling and completion activities across greater volumes of gas. In some pure gas shale plays, costs have been reported as below $3.00 and even below $2.00 per MMBtu to find and develop. These costs appear to be at the lower end of the spectrum of minimum prices required across the entire gas shale resource. Most shale gas plays appear to be economic in the $4.00 to $6.00 range.

In NGL and crude oil plays such as the Eagle Ford, the cost to produce gas can be much lower, as long as the price of the NGLs and oil production supports drilling. As noted above, the price of liquids is several multiples higher than the price of natural gas on a per-MMBtu basis. Navigant forecasts NGL and crude oil prices to be higher than natural gas on a per MMBtu basis for the term of the Jordan Cove analysis.

The EIA, in its *International Energy Outlook 2011*, projects worldwide demand for liquid fuels to grow from 85.7 million barrels a day in 2008 to 112.2 million barrels per day, driven largely by strong economic growth and increasing demand for liquids in the transportation and industrial sectors in Asia, the Middle East, and Central and South America. The EIA forecasts oil prices to increase to $125 per barrel by 2035.[20] This is approximately $21.50 per MMBtu and compares to gas prices in 2035 that Navigant forecasts to be $7.31 per MMBtu in the Jordan Cove Reference Case. High oil prices are expected to encourage liquids production which will be accompanied by additional associated gas production.

[18] Chesapeake Energy, *October 2011 Investor Presentation*, available at http://www.chk.com/Investors/Documents/Latest_IR_Presentation.pdf
[19] http://oilshalegas.com/uticashale.html
[20] *International Energy Outlook 2011*, EIA, p. 25, available at http://www.eia.gov/oiaf/ieo/liquid_fuels.html

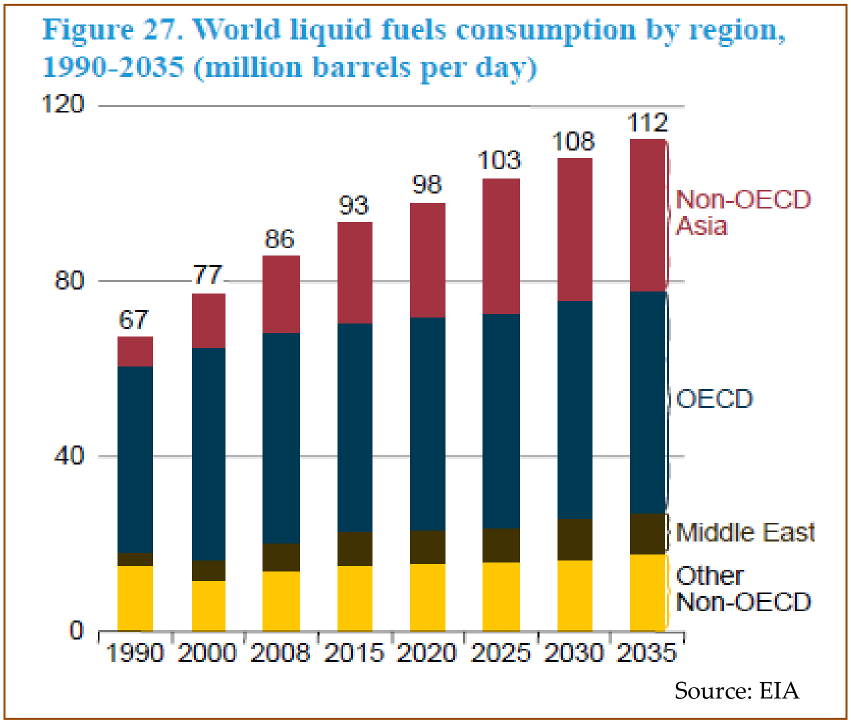

Figure 9: World Liquids Consumption from EIA International Energy Outlook 2011

Comparison of Navigant's Supply Outlook to Other Outlooks

In **Figure 10:** *Supply Outlook Comparison: Navigant and EIA*, Navigant's Spring 2011 shale production forecast calls for more gas to be brought on between now and 2020 than does EIA in its *Annual Energy Outlook 2011*. Navigant is comfortable in its production estimates and believes them to be conservative. After 2020, growth rates between the Navigant and EIA forecasts are roughly parallel. As the graph also shows, both Navigant and EIA increased their post-2020 estimates for shale production this year compared to 2010 by roughly the same amounts.

EIA has historically lagged in the recognition of the size of the shale gas resource in its forecasts. As shown in **Figure** *6: Shale* Production 2007-2011, above, shale production in the U.S. in the second quarter of 2011 is over 20.0 Bcfd. EIA's forecast of 15.0 Bcfd for 2011 therefore has already been eclipsed. The growth in gas production has been so rapid that most forecasters have had difficulty keeping up.

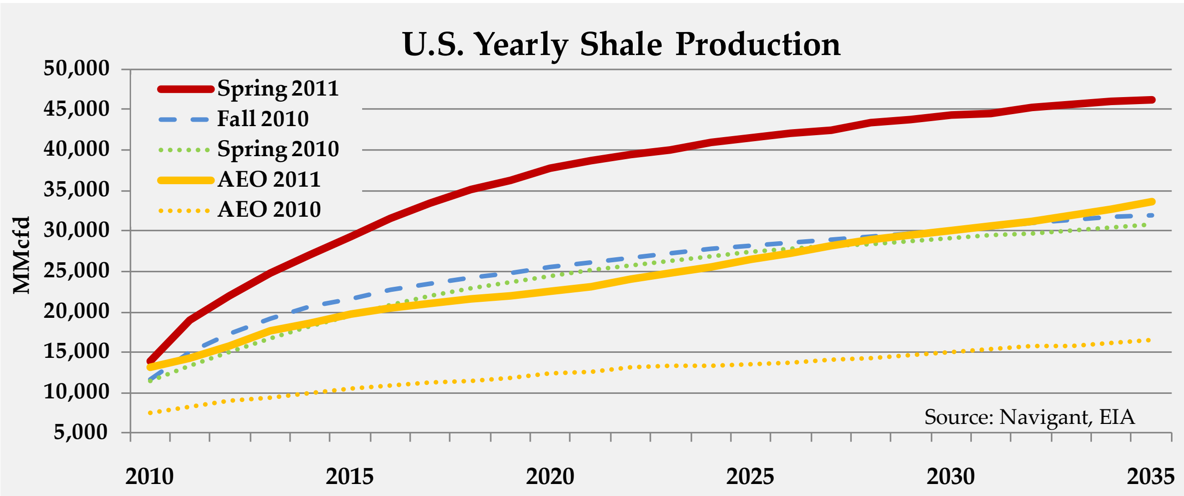

Figure 10: Supply Outlook Comparison: Navigant and EIA

Year	Navigant Spring 2011	Navigant Fall 2010	Navigant Spring 2010	EIA AEO 2011	EIA AEO 2010
2010	**13,976**	11,665	11,478	13,151	7,534
2015	**29,276**	21,659	19,586	19,726	10,548
2020	**37,823**	25,550	24,451	22,493	12,356
2025	**41,521**	28,196	27,328	26,548	13,534
2030	**44,250**	30,049	29,155	29,973	15,068
2035	**46,127**	31,850	30,743	33,562	16,438

Table 2: Supply Outlook Comparison: Navigant and EIA

Demand Is Likely to Increase Steadily

Reliable demand is a key to underpinning reliable supply and a sustainable gas market. Supply is unlikely to be developed unless demand is there to absorb it, and demand will not develop unless supply is there to support it. Demand and supply are two parts of the same dynamic.

In Navigant's view, demand is likely to increase over the coming years. Many factors support this outlook.

The chief driver of steadily growing gas demand is the abundance of reliable and economic supply. With the advent of significant shale gas resources, end-use infrastructure and pipeline project developers can be assured that gas will be available to meet growing market demand.

Further, the prospect of steadily growing and reliable supply portends relatively low price volatility. Because of the manufacturing-type profile of shale gas production, production rates can be better matched to demand growth. Low price volatility, like supply growth, is supportive of long-life end-use infrastructure development and pipeline projects.

Demand growth in the North American gas market is supported by the existing pipeline network. The delivery infrastructure for natural gas is mature and, with the exception of a few highly urban areas such as greater New York City, relatively cost-effective and quick to expand. Since shale resources are widely dispersed around the continent, the need for significant long-line pipeline capacity such as the recently built Ruby Pipeline, which extends from Opal, Wyoming to markets in California, is likely not required with the possible exception of the Florida market.

Demand by Sector

Navigant projects that the overwhelming majority of growth in natural gas demand will come from the electric generation (EG) sector of the market. EG is expected to grow at an annual rate of 1.8 percent through the study period, with a higher rate of 4.9 percent through 2015. These expectations are based mainly on expected coal-fired power plant retirements, described later in this report.

Navigant projects industrial demand in the North America to grow annually by an average 0.5 percent, driven largely by demand from the prolific oil sands development in Alberta and a slowly recovering economy in general.

Residential, commercial, and vehicle demand for natural gas is expected to grow very modestly, at 0.2 percent annually as a result of increasing energy efficiency efforts in the sector.

Navigant's sectoral outlook for natural gas demand from its Spring 2011 Reference Case is shown in ***Figure 11:*** *North American Natural Gas Demand Projection*.

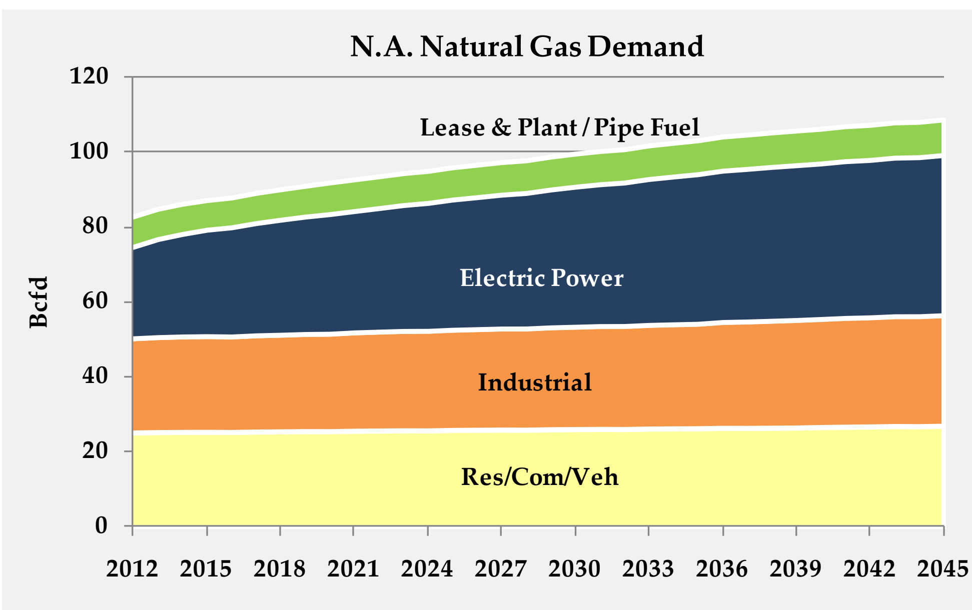

Figure 11: North American Natural Gas Demand Projection

As supply abundance creates the potential for an unbalanced market due to relatively slow but steady demand growth, the development of LNG exports can be viewed as a positive development to the long term sustainability of the gas market. Five LNG projects, including JCEP, have received U.S. Department of Energy approval to export natural gas from the U.S. to countries with which the U.S.

has entered Free Trade Agreements (FTA) requiring national treatment for trade in natural gas and LNG. The four projects other than JCEP have also applied for authority to export to non-FTA countries. In May, Cheniere Energy received U.S. Department of Energy approval for the export to non-FTA countries of up to 2.0 Bcfd of LNG from their Sabine Pass terminal. Other applicants whose non-FTA applications are pending are Dominion Cove Point LNG LP, Freeport LNG Development LP, and Lake Charles Exports LLC (with partner BG LNG Services LLC).

LNG export facilities offer the potential for a new baseload market for natural gas and to support ongoing development of the resource. So far, Cheniere is the only U.S. facility in the Lower 48 to have received DOE approval to export domestically-sourced LNG to non-free-trade-agreement countries.

Cheniere's Sabine Pass export facility is not scheduled for start-up until 2016 and will not have market impact in 2011. In fact, none of the announced plans to export U.S.-sourced LNG anticipate start-up before 2016. However, over the mid and long term, emerging LNG exports should provide a new market in the currently oversupplied natural gas market in the U.S. It is becoming increasingly evident that the slow development of new markets for natural gas is the only thing currently restricting even more gas resource development. It is possible that LNG exports may overtake fuel switching from coal plant retirements at some future time as a primary mechanism for balancing oversupply conditions in the gas market.

Competition from Oil and Other Fuels

Annual average natural gas prices are projected to increase slowly in the JCEP Reference Case from $4.12 per MMBtu in 2012 to $8.28 per MMBtu. On a per-MMBtu basis, this is expected to be well below oil prices and competitive with coal prices, which are also expected to increase over time.

Oil

In earlier times, gas and oil competed for some of the same markets, particularly in the electric generation and industrial markets. For the past 20 years, however, oil has become increasingly pushed out of those markets due to gas's lower cost and superior environmental profile. Oil is now used chiefly as a motor fuel and lubricant. The prices of gas and oil are generally acknowledged to have decoupled in North America, as they serve largely separate markets. This is illustrated in the chart at **Figure 12:** *Comparison of Oil and Gas Prices per MMBtu*.

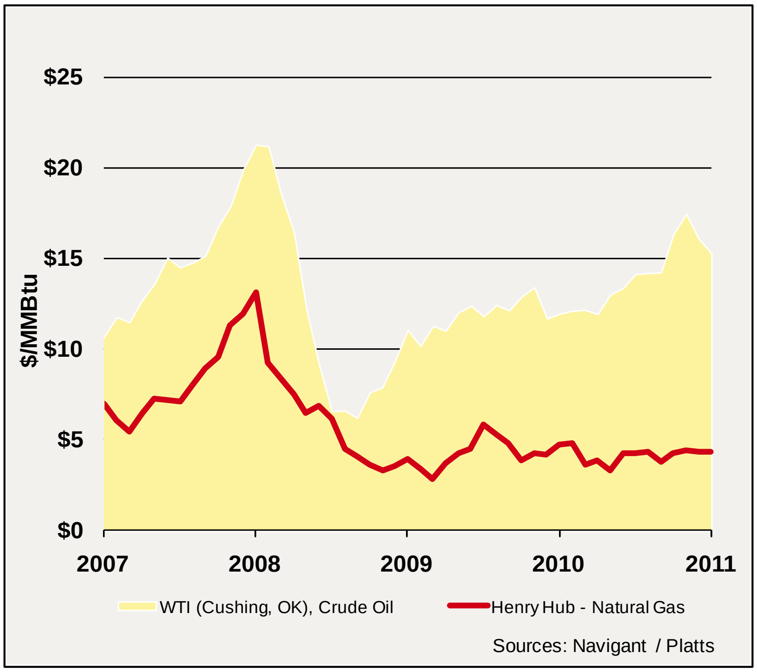

Figure 12: Comparison of Oil and Gas Prices per MMBtu

In any case, the price of oil is likely to continue to be at a significant premium to gas. Gas is domestically plentiful, relative to demand. Oil is not. The United States imports nearly two-thirds of the oil it consumes.[21] Conventional oil resources in the U.S. have largely been identified. Over the last two decades, the motivation to drill for oil in the U.S. has shifted to opportunities around the globe with better returns. It is unlikely that the total oil resource potential in North America has changed recently, especially given restrictions still in place on offshore drilling in the wake of Deepwater Horizon in the Gulf of Mexico.

Coal

Coal is still widely used for electric generation. However, due largely to tightening environmental regulations, natural gas has been steadily displacing coal as a percentage of megawatt hours generated in the U.S., as shown in ***Figure 13:*** *Coal and Natural Gas as a Percent of Total Megawatt Hours Generated*. While coal accounted for 53 percent of annual electric generation in 1997, it accounted for only 45 percent in 2010. Natural gas, on the other hand, accounted for 14 percent of electric generation in 1997, and grew to 24 percent by 2010.

[21] Data from Petroleum Supply Annual, Volume 1, U.S. Energy Information Administration, available at http://www.eia.gov/petroleum/supply/annual/volume1/pdf/table1.pdf

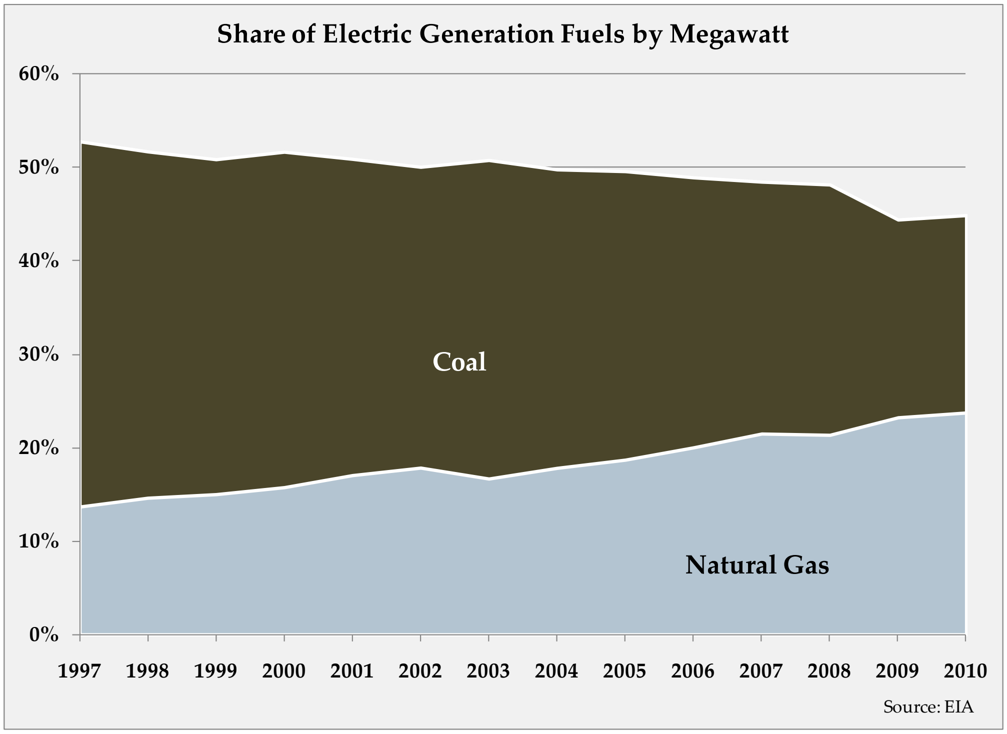

Figure 13: Coal and Natural Gas as a Percent of Total Megawatt Hours Generated

Some of the recent displacement of coal by gas as an electric generation fuel is driven by economics. The delivered cost of coal per kilowatt hour of generation has recently averaged slightly more than that of natural gas in the Central Appalachian region. This relationship is perpetuated in the forward price curves of the two commodities as of July 2011, as shown in **Figure 14:** *Comparison of Electric Generation Fuel Costs*.

Studies by Navigant show that the volume of coal-to-gas switching in the U.S. will increase from the 2.0 Bcfd that has already switched to more than 4.0 Bcfd by 2017. This switching has been based on commodity price competition, not on any new regulatory or government mandates.

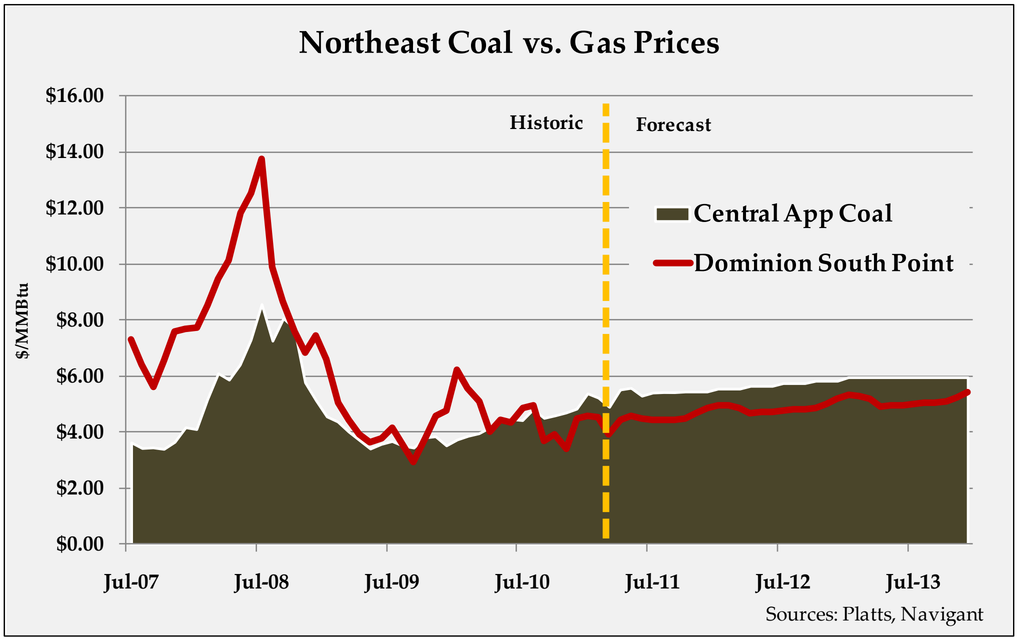

Figure 14: Comparison of Electric Generation Fuel Costs

Additional switching may be driven by other factors. Clean coal in the form of carbon capture and sequestration (CCS) has run into further delays, as seen with American Electric Power's July 14 announcement to discontinue its CCS pilot project at its Mountaineer coal-fired power plant in West Virginia.[22]

Coal-fired electric generation is likely to continue to be under pressure from increasingly stringent environmental regulations. According to the news service SNL, the Federal Energy Regulatory Commission recently issued an informal report stating that up to 81 gigawatts[23] of coal- and oil-fired electric generation is "likely" or "very likely" to be retired due to new environmental restrictions, including the Environmental Protection Agency's recently proposed maximum achievable control technology requirement within the proposed Cross-State Air Pollution Rule.[24] CSAPR would institute a stringent national standard on emissions of mercury, arsenic, and other pollutants found in coal and oil, but not in natural gas. While the very large 81 gigawatt estimate is highly fluid and based on assumptions subject to review, it indicates the direction and potential scope of the shift away from fuels with higher emissions burdens than natural gas.

Several major utilities have announced or are actively executing programs to retire coal-fired facilities. For example, Tennessee Valley Authority signed a settlement with the EPA to idle or retire 2,700 megawatts of its 17,000 MW of coal fired capacity (from 18 units) by 2018. Southern Company

[22] AEP press release, "AEP Places Carbon Capture Commercialization on Hold, Citing Uncertain Status of Climate Policy, Weak Economy," July 14, 2011, available at http://www.aep.com/newsroom/newsreleases/?id=1704.
[23] 1.0 gigawatt equals 1,000 megawatts.
[24] "FERC staff: 81 GW of capacity could be retired due to EPA rules," August 5, 2011, SNL News.

announced that the CSAPR rules would expect to retire 4,000 MW of its 12,000 MW coal-fired fleet, and replace coal and oil with natural gas for another 3,200 MW. American Electric Power states that it will retire almost 6,000 MW of coal-fired generation and refuel 1,070 MW with natural gas in response to the new EPA rules.

The New York Times states that up to 80,000 MW of coal-fired capacity could be supplanted by other fuels or conservation in the U.S. as a result of the new EPA rules.[25] This number is consistent with the FERC number of 81 gigawatts. It represents about eight percent of the U.S.'s electric generating capacity. The EPA's estimate is much lower, 10,000 MW. The rule is still subject to public comment. However, Navigant's view is that the trend toward large-scale coal plant retirements is clear, and that natural gas is the leading replacement fuel choice.

Nuclear, Renewables, and Efficiency

The disaster at the Fukushima nuclear generating facility in Japan has pushed utilities in North America to reexamine the safety of the existing nuclear generation fleet, and may result in additional demand for natural gas. Several states have already conducted nuclear power workshops. The eventual impact of the Fukushima disaster on the U.S. nuclear industry is still too early to assess with any precision. However, in the event significant risks are identified, this would likely require the replacement of planned or even existing nuclear generation, with one of the options being gas-fired generation.

Some countries, such as Japan itself and Germany, have already announced plans to reduce their nuclear generation fleet. Germany plans to accelerate the closure of 17 nuclear reactors by 2022. Other countries such as Switzerland and Italy have also indicated signs of retreating from nuclear energy.

On the other hand, France points to the rational cost and carbon emissions advantages of nuclear generation and has reiterated its support for nuclear generation. The UK, Russia, and India have also indicated they are in favor of additional nuclear capacity in their respective countries.

Natural gas is also well-positioned to support renewable generation. For the support of wind and solar generation, dispatchable gas-fired generation is ideal to "shape" the output profile or support the intermittency of both these forms of renewable electric generation.

Increases in efficiency on the demand side of the gas and electric markets are substitutes for additional fuel supply. Improved energy efficiency is viewed as a positive for the gas market and for the country, and not as competition. As it tends to dampen gas demand in one market segment, it will make the resource base more readily available to serve another.

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[25] New York Times, August 12, 2011, p. B3. available at http://www.nytimes.com/2011/08/12/business/energy-environment/new-rules-and-old-plants-may-strain-summer-energy-supplies.html?pagewanted=2&_r=4&ref=energy-environment

Risks to the Supply and Demand Forecasts

While the gas supply outlook is strong, and Navigant expects that production will have the capacity to grow, there are risks in the development of the resource that will need to be met.

Environmental Issues

Hydraulic fracturing of shale formations to produce gas (or oil) has become a topic of discussion inside and outside the industry. Concern has been raised over its possible environmental impact from water use, water well contamination, and water and chemical disposal techniques.

Hydraulic fracturing has been used for years as a means to increase production, whether gas or oil, or whether shale or conventional. It is however with gas shale where the process in combination with horizontal drilling has had the most dramatic effect to date.

The industry has taken positive steps to address the issue of potential water contamination. For example, *FracFocus.org*, a voluntary registry for disclosing hydraulic fracturing chemicals, was recently formed.[26] Many states are considering the mandatory disclosure of hydraulic fracturing chemicals; Wyoming, Texas, and Colorado already require it.

In general, the incentives for operators to use efficient water management and best practices in the hydraulic fracturing process aligns well with the interests of regulators and the environment. The process of water handling and treatment can add to the cost of the well in certain cases (e.g., where water is in short supply) but nevertheless becomes part of the process of the modern gas well operator. As noted on page 8, significant efforts are already underway to improve water management techniques, including reuse in the production of shale gas. As reported in the July 2011 edition of the Journal of Petroleum Technology, flowback water is being treated on site and recycled not merely to comply with regulations but to reduce water acquisition and trucking costs in many places.[27]

Recently, the Natural Gas Subcommittee of the Secretary of Energy Advisory Board (SEAB) in its 90-day report recommended that drillers fully disclose the chemicals used in hydraulic fracturing, and institute several other practices designed to assure the environmental acceptability of hydraulic fracturing. [28] The SEAB 90-day report also states that "Natural gas is a cornerstone of the U.S. economy… there are many reasons to be optimistic that continuous improvement of shale gas production in reducing existing and potential undesirable impacts can be a cooperative effort among the public, companies in the industry, and regulators."[29]

In addition, the U.S. Environmental Protection Agency is studying the impact of hydraulic fracturing on drinking water, and is expected to issue an interim report in 2012.

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[26] http://fracfocus.org/

[27] Journal of Petroleum Technology, July 2011, pp. 49-51

[28] The SEAB Shale Gas Production Subcommittee Ninety-Day Report – August 11, 2011, available at http://www.shalegas.energy.gov/resources/081111_90_day_report.pdf

[29] Ibid, pp. 1, 9.

Navigant expects hydraulic fracturing to be subject to continuing scrutiny and increasing disclosure requirements. This should mitigate environmental risks and concerns so that shale resource development in North America will continue. In some regions, such as New York State, where the Marcellus play lies beneath the New York City watershed, opposition to hydraulic fracturing may continue. The risk of sustained, organized opposition to gas shale development should however be ameliorated by increasingly close collaboration between the interests of the producers and the interests of the community at large.

The area of greenhouse gas emissions is another potential risk for the natural gas industry. Carnegie Mellon University released a study report which states that "[n]atural gas from the Marcellus shale has generally lower life cycle GHG emissions than coal for production of electricity in the absence of any effective carbon capture and storage processes, by 20–50% depending upon plant efficiencies and natural gas emissions variability."[30] The research firm IHS Cambridge Energy Research Associates released a statement that "[e]stimates used by the United States Environmental Protection Agency (EPA) and others for greenhouse gas emissions from upstream shale gas production are likely significantly overstated."[31] The National Energy Technology Laboratory stated in May 2011 that natural gas baseload power generation has a life cycle global warming potential that is 54 percent lower than coal baseload generation. NETL included shale gas in its analysis.[32] A recent study conducted by the University of Maryland found that "arguments that shale gas is more polluting than coal are largely unjustified" and that "the greenhouse footprint of shale gas and other unconventional gas resources is about 11% higher than that of conventional gas for electricity generation, and still 56% that of coal." [33]

The emissions profile of natural gas has a clear comparative advantage versus other fossil fuels including coal. The increasing displacement of coal use by natural gas will be a positive development for the environment, and supportive of gas development.

The SEAB has called for independent studies of the life cycle emission from shale gas wells. Navigant views this and any additional study and fact-finding as to the comparative advantages of natural gas to be a positive step forward, and expects the final results to be in line with other studies that have found natural gas to be the cleanest fossil fuel.

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[30] *Life cycle greenhouse gas emissions of Marcellus shale gas*, Jiang, Griffin, Hendrickson, Jaramillo, VanBriesen, and Venkatesh, Carnegie Mellon University, available at http://iopscience.iop.org/1748-9326/6/3/034014/fulltext

[31] *Recent Estimates for Greenhouse Gas Emissions from Shale Gas Production are Likely Significantly Overstated, IHS CERA Study Finds*, IHS Cambridge Energy Research Associates, August 24, 2011, available at http://press.ihs.com/press-release/recent-estimates-greenhouse-gas-emissions-shale-gas-production-are-likely-significantl

[32] *Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States*, Timothy J. Skone, May 12, 2011, slide 34, http://www.netl.doe.gov/energy-analyses/pubs/NG_LC_GHG_PRES_12MAY11.pdf

[33] *The greenhouse impact of unconventional gas for electricity generation*, Nathan Hultman, Dylan Rebois, Michael Scholten, and Christopher Ramig, October 25, 2011, available at http://iopscience.iop.org/1748-9326/6/4/044008

Commodity Prices / Reallocation of Drilling Capital

Will the higher price of oil and NGLs result in a shift of drilling resources from gas, and cause a drop-off in gas supply?

Within the drilling industry, there is currently a shift from gas to natural gas liquids (NGLs, such as ethane and propane) and oil, owing to the decided price advantage for producers at a given heat value. This shift can be seen in drilling rig numbers. The number of oil rigs in the U.S. operating as of the end of September is up from 581 in 2010 to 922 in 2011, or 59 percent.[34]

Despite the shift to oil directed drilling and the fact that gas prices at Henry Hub have declined below the $4.00 per MMBtu area and oil prices have hovered in the $15.00 to $17.00 per MMBtu range (approximately $90 to $100 per barrel), gas production is continuing to increase. Although the number of horizontal gas rigs in the U.S. drilling on any one day has declined on average in the past year from 664 to 636,[35] or four percent, dry U.S. gas production has increased from 60.0 Bcfd to 64.0, or 6.7%, over that same period.[36]

Over the last two decades, oil drilling has shifted from the U.S. to more lucrative opportunities elsewhere around the globe. Oil imports comprised 53% of U.S. supply in 2011 through October.[37] Given restrictions put in place on offshore drilling in the wake of Deepwater Horizon, it is believed unlikely, even if those restrictions are lifted, that oil drilling will expand to pre-event levels in the near future. In addition, in oil shale plays such as the Bakken field in North Dakota, large volumes of associated natural gas are being produced which further adds to the availability of natural gas in the country.

As noted earlier in this report, the cost of finding and developing shale gas continues to drop.

Overall, it is Navigant's view that oil drilling will encounter limits in the U.S., due largely to the declining U.S. oil resource base and the prohibition against oil drilling in substantial geographic areas, such as federal parks and certain areas of the outer continental shelf such as California and Florida, and will not cause a drop-off in gas supply.

The fundamental attributes of the natural gas industry including gas shale should allow the market to balance supply and demand. Navigant's Spring 2011 price forecast indicates stability in the $4.00 to $5.00 per MMBtu for the next decade, rising somewhat after 2025 and approaching $8.00 per MMBtu in the late 2030's. At these levels, gas prices will continue to be extremely competitive with oil, which Navigant projects to be two and a half to three times as costly as gas per MMBtu throughout the forecast period.

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[34] Smith Bits.

[35] Smith Bits.

[36] EIA Short-Term Energy Outlook Table 5a.

[37] EIA, *Weekly U.S. Product Supplied of Petroleum Products* (WRPUPUS2) and *Weekly U.S. Net Imports of Crude Oil* (WCRNTUS2), Navigant calculation.

Overview of Proposed Energy Operations of Jordan Cove Export Project

The proposed Jordan Cove Energy Project is located at Coos Bay in southern Oregon. JCEP received FERC approval in Docket No. CP07-444 to construct an LNG import facility. FERC also approved the construction of the Pacific Connector Pipeline. JCEP has received authorization from the Department of Energy in Docket No. 11-127-LNG to export LNG from the site to FTA countries. It intends to file applications in 2012 to export to non-FTA countries and to amend its FERC authorization to include authority to construct a dual-use import-export facility.

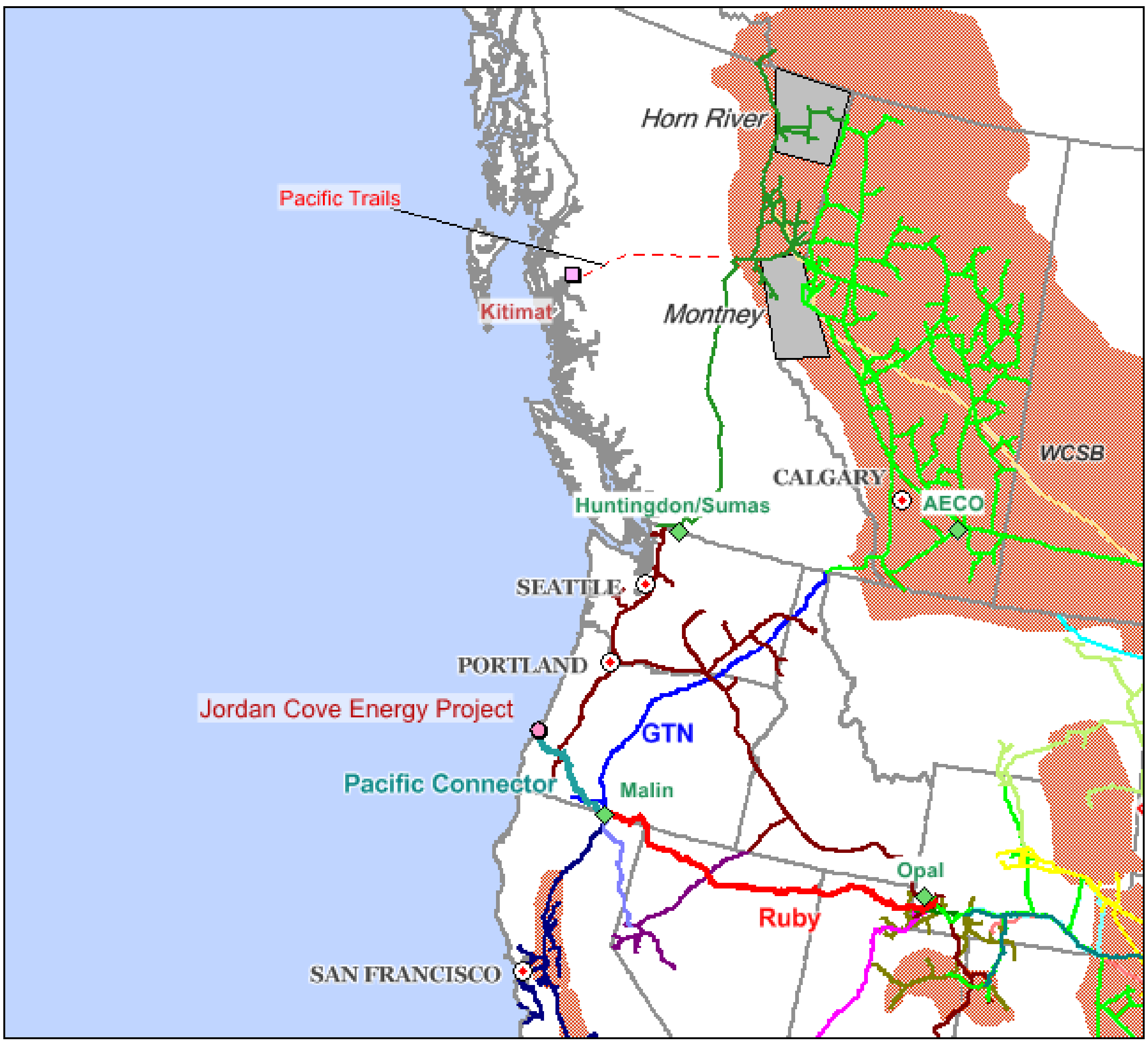

Figure 15: Jordan Cove Energy Project Location Map

The Pacific Connector Pipeline, originally intended to carry natural gas derived from imported LNG from Coos Bay to Malin, will transport gas from Malin to the JCEP liquefaction facility Coos Bay. At Malin, Pacific Connector will interconnect with Gas Transmission Northwest Pipeline and Ruby Pipeline. GTN is a 2.2 Bcfd pipeline originally designed to transport Canadian gas to the California border, including gas from the prolific shale resources in eastern British Columbia (Montney and Horn River) as well as conventional gas resources in Alberta. Ruby is a 1.5 Bcfd pipeline that delivers gas to Malin and the California market from the Opal trading hub in Wyoming, which has access to gas supply in the Rocky Mountain basin.

The Pacific Connector Pipeline has an initial capacity of 1.2 Bcfd, more than adequate to carry gas to the proposed 0.9 Bcfd liquefaction facility. Pacific Connector plans to expand to 1.5 Bcfd in 2022. In order to address the Pacific Connector for the present analysis, the Pacific Connector was modeled as a "bullet" line from Malin to Coos Bay. The pipeline may in fact interconnect with Northwest Pipeline, LDCs in Oregon and other systems to meet regional market demand.

Initially, the gas feedstock for Jordan Cove will be provided mainly from Canadian resources. GTN is expected to have significant excess pipeline capacity due to gas-on-gas competition with Ruby Pipeline, which was designed to displace Canadian supply from the California market in favor of Rockies supply. Ruby has been operating in such a fashion since commencing operations in July 2011. Navigant's modeling shows that gas initially exported at Jordan Cove will be 70 percent Canadian gas and 30 percent Rockies gas, shifting to 35/65 by 2045, for an overall ratio across the study period of 50/50.

The Canadian National Energy Board estimates that the Horn River Basin has between 372 Tcf and 529 Tcf of gas in place, with a median value of 448 Tcf. The median estimate of marketable volumes is 78 Tcf. While estimates for the Montney formation are uncertain at this time, Rice University has estimated the Montney mean technically recoverable gas shale resources at 65 Tcf. In addition, significant gas exploration and infrastructure development is taking place in the Montney region. The NEB states in its report ***Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin***: "There are a number of other unconventional natural gas plays in British Columbia … which, if developed, could substantially increase the resources available for Canadian use and export purposes."[38]

[38] NEB, *Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin*, available at http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/ntrlgs/hrnrvr/hrnrvrm-eng.html#s3.

Modeling Overview and Assumptions

Twice a year, Navigant produces a long-term forecast of monthly natural gas prices, demand, and supply for North America. The forecast incorporates Navigant's extensive work on North American unconventional gas supply including the rapidly growing gas shale supply resources. It projects natural gas forward prices and monthly basis differentials at 90 market points, and pipeline flows throughout the entire North American grid. Current projections go through 2035. Navigant's Spring 2011 Forecast (issued in June 2011) forms the basis of the Jordan Cove Export Project analysis. To develop the Reference Case for JCEP, Navigant extended the term to 2045.

Price projections for purposes of this report focus on Henry Hub, which is the underlying physical location of the natural gas NYMEX futures contract and the key North American pricing reference point. Prices at Malin on the California-Oregon border and Sumas at the U.S.-Canadian border are also included in this study to demonstrate the possible effect that JCEP may have on supply and demand on key natural gas markets in the vicinity of the export facility. All prices are adjusted for future inflation and are shown in constant 2010 dollars.

Gas volumes (by state or region), imports and exports (including gas by pipeline and LNG by terminal), storage, sectoral gas demand, and prices are modeled on a monthly basis. Annual averages are generally presented for the purposes of this report.

The following basic assumptions remain constant for all scenarios, unless otherwise noted.

Supply

All domestically-sourced supply in the Reference Case model comes from currently established basins in North America. The forecasts assume no new gas supply basins beyond those already identified as of Spring 2011. This should be regarded as a conservative assumption, given the rate at which new shale resources have been identified over the past few years and the history of increasing estimates of the North American natural gas resource base.

The Jordan Cove Reference Case supply projection is that U.S. natural gas supply will grow from 61.4 Bcfd in 2012 to 81.6 Bcfd in 2045, an increase of 33 percent.

As a rule, Navigant's approach towards production capacity is the same for all cases modeled for JCEP. Estimates of production capacity are based largely on empirical production data. For example, the Utica Shale, a very large but undeveloped liquids-rich resource co-located with the Marcellus on the East Coast, is assumed to produce only 0.7 Bcfd in 2045. It is arguable that the Utica Shale could be producing many multiples of that number by that date, given the rapid ramp-up in development of other liquids-rich shales such as the Eagle Ford in Texas. Nevertheless, Navigant's conservative approach towards assessing supply results in a very small production forecast for the Utica shale. Similarly, no increase in production is modeled for gas that may be produced from other basins that may yet be developed.

An exception is made in the GHG Demand case. In this case, an increase in supply availability across key basins, driven by government policy, is the precipitator of additional demand growth. While no "blanket" additions to supply were made, nor were any new resource plays hypothesized, supply capability was added to certain fields (e.g., the Eagle Ford) as an input assumption.

Reflecting the elasticity of the supply basin to demand signals, the GHG Demand Case supply projection has U.S. natural gas supply growing from 61.2 Bcfd in 2012 to 86.9 Bcfd in 2045, an increase of 42 percent, and 5.3 Bcfd higher in 2045 than in the Jordan Cove Reference case.

Navigant's model also allows for additional supply to come into North America from existing LNG import projects. The model solves for such imports as a response to demand and the price of gas in North America.

Demand

Navigant's basic modeling assumption is that natural gas supply will respond dynamically to demand in a reasonably short time—months, not years. The shale gas resource is so large that it can be readily produced more or less on demand if economics and policy are supportive.

Gas demand growth in our forecasts is supported by growth in the deployment of renewable electric generation. Gas, which is transported continually in pipelines, is far more suited to respond in real time to intermittent generation from wind and photovoltaics than coal. Coal-to-liquids and coal-to-gas technologies still appear to be expensive and energy-intensive. Oil and its products are not seen as viable electric generation fuels due to price and their significantly less favorable GHG impacts. Navigant sees the price of oil maintaining its current multiple premium to that of gas per MMBtu for the duration of the study period. While renewable technologies will improve and may be augmented by improved electrical storage, and coal technologies may also improve, gas-fired generation will increasingly be the dominant mode of smoothing intermittent electric generation for the foreseeable future.

Navigant's market view is that domestic supply is abundant to such a degree that it will support domestic market requirements as well as the demand for LNG from North America. LNG exports offer the potential for a steady, reliable baseload market which will serve to underpin ongoing supply development. The existence of growing domestic and export demand will also tend to support additional supply development and as a result tend to reduce price volatility. While our modeling shows that the U.S. will be a net exporter of LNG, it also shows that LNG imports will continue on a limited basis. The model makes no assumptions about international prices. Imports are assumed to respond to prices in our North American market model. In any event, LNG imports tend to be minimal over the time horizon of the study due to supply abundance in North America .

All cases assume that fuel switching from coal to gas has occurred for economic reasons, extrapolating a trend recently observed in the market. Only the GHG Demand Case includes increased gas demand effects from greenhouse gas reduction legislation.

Navigant has paid particular attention to the concern that exporting LNG from North America will tend to link domestic gas prices to overseas pricing, which has historically been linked to higherpriced oil. In the high-demand GHG Demand Case (detailed below), the annual call on supply is 31.7 trillion cubic feet in 2045. Using the EIA's recent estimate of U.S. technically recoverable reserves of 2,543 Tcf,[39] this would represent only 1.2 percent of total reserves, too small a volume of production to have any appreciable effect upon gas prices in North America.

Navigant furthermore believes it is very unlikely that exports at these levels will increase the need for significant amounts of imported LNG in any of the modeled scenarios. It is more likely that spot LNG cargoes from overseas will land from time to time in the U.S. and accept U.S. domestic pricing when overseas demand is at lower levels, as overseas LNG production capacity is projected to grow, and the U.S. is likely to remain the most liquid market for natural gas in the world, supported by its superior infrastructure (particularly storage) and dependable demand. However, if the modeled imports did not materialize in the future, U.S. supply would be ample to serve both domestic demand and LNG exports.

Infrastructure

Navigant's modeling was based upon the existing North American pipeline and LNG import terminal infrastructure, augmented by planned expansions that have been publicly announced and that are likely to be built. Pipelines are modeled to have sufficient capacity to move gas from supply sources to demand centers. Some local expansions have been assumed and built into the model in future years to relieve expected bottlenecks. In these cases, supply has been vetted to provide a reasonable expectation that it will be available.

In general, no unannounced infrastructure projects were introduced into the model. This means that no specific new infrastructure has been applied to the model post-2014, except as it directly supports the modeled export projects (e.g., Pacific Connector is specifically modeled to support JCEP) or has been announced. This is a highly conservative assumption. It is likely that some measure of new pipeline capacity will be constructed to support the ongoing development of the gas supply resource and the accompanying demand between 2014 and 2045. In the absence of specific information, Navigant limits its infrastructure expansion to those instances where an existing pipeline has become constrained. The remedy consists of adding sufficient capacity to relieve the constraint only.

In the case of the GHG Demand scenario, we assumed an expansion of GTN and the western legs of Nova and Foothills Pipeline, by 1.0 Bcfd in 2028. In the absence of such an expansion, the GHG Demand model showed interseasonal instability that would not realistically occur in the market.

Some proposed pipeline projects have been excluded from the Reference Case model, most notably the Mackenzie Pipeline in northern Canada, which we believe to be uneconomic and facing large environmental challenges, absent significant new developments in the marketplace. Likewise, the Alaska Gas Pipeline project is also assumed to be nonoperational over the study period term. In fact, the governor and state legislature of Alaska recently announced they favor a pipeline project from Alaska's North Slope gas resources that delivers to the south coast of the state where it could be

[39] *Shale Gas and the Outlook for U.S. Natural Gas Markets and Global Gas Resources*, presentation of Richard Newell, EIA Administrator to the Organization for Economic Cooperation and Development (OECD), June 21, 2011, p. 13, available at http://www.eia.gov/pressroom/presentations/newell_06212011.pdf

liquefied into LNG instead of connecting to the larger North American grid in Canada. (The project would also serve the needs of the City of Anchorage.) On the other hand, several large regional pipelines are assumed to be operational by 2015, including Fayetteville Express and Tiger.

In Appendix B we attach a complete list of all future pipelines and projected capacity levels that are included in the model.

Storage facilities in the model reflect actual in-service facilities as of Spring 2011, as well as a number of announced storage facilities that are judged likely to be in operation in the near future. No unannounced storage facilities were introduced into the model. The inventory, withdrawal, and injection capacities of storage facilities are based on the most recent information available, and are not adjusted in future years. Assuming no new storage facilities beyond those announced and judged likely to be built is a highly conservative assumption.

These highly conservative assumptions that limit future new pipeline and storage within the model may tend to put upward pressure on prices as supply and demand grow, especially in the later years of the forecast.

LNG Facilities

No assumptions are made regarding international prices for natural gas. Navigant's market model allows each LNG facility to import or export in response to domestic prices exclusively.

It is important to note that the Reference Case includes two specific LNG export facilities. These are the Sabine Pass export facility in Louisiana and the Kitimat facility on the coast of British Columbia, Canada. Sabine Pass is assumed to have four liquefaction trains with a capacity of approximately 0.5 Bcfd each. The first Sabine Pass train begins operation in May of 2015, with the second coming on in January 2016, the third in February 2017, and the final train in October 2017. Kitimat begins operations at a capacity of approximately 0.7 Bcfd in October 2015. These export facilities are assumed to be operating at a 90 percent load factor year-round in all scenarios. This is a conservative assumption, since 90 percent is what is operationally possible, and actual load factors are expected to be lower. The likelihood is that the LNG export facilities will operate initially and perhaps during certain seasonal periods at less than 90 percent of capacity thereby requiring less gas and having an even smaller impact than what is assumed in the analysis.

In order to provide stress scenarios to examine the effect of exporting domestically–sourced LNG, additional LNG export capacity is included in the Aggregate Export and GHG Demand cases. Generic facilities were developed to represent possible additional liquefaction demand without presupposing which specific facilities may be approved and successfully constructed. LNG export assumptions per case are shown below. Each facility is phased in sometime in the 2016-2018 timeframe, as each liquefaction train is assumed to be completed.

LNG Facility	Export Capacity (Bcfd)	Location	Scenario			
			Ref	*Jordan Cove*	*Aggregate*	*Extreme*
Sabine Pass	2.0	Cameron Parish, LA	•	•	•	•
Kitimat	0.7	District of Kitimat-Stikine, BC	•	•	•	•
Jordan Cove	0.9	Coos Bay, OR		•	•	•
Gulf of Mexico	2.0	Texas			•	•
Mid-Atlanctic	1.0	Maryland			•	•
Total	**6.6**					

Table 3: LNG Export Capacity Assumed Online

LNG import capacity is assumed to be 18.5 Bcfd from 2015 onward. The load factor of each facility is solved by the model as a function of domestic supply and demand. The model is calibrated to minimize LNG imports in light of the modeled export activity. This assumes that a reduction in exports is likely to occur if U.S. prices at any time attract overseas LNG before significant imports occur, as the domestic suppliers and exporters would take advantage of the arbitrage with domestic supply. Some imported LNG would still be expected to occur, as overseas shippers may have contractual obligations or other motivations to ship to the U.S. In the New England area, the present-day constraints on pipeline infrastructure are assumed to remain; therefore, LNG imports occur in the model at the Everett, Northeast Gateway, and Neptune facilities in Boston Harbor and Massachusetts Bay much as they do today.

Other Assumptions

Oil Prices

The chart below shows the prices of West Texas Intermediate crude oil assumed in the model. The price of oil is assumed to escalate in a constant manner beginning in 2015. Prior to 2015, Navigant used an average of settles in the NYMEX WTI futures contract to establish a forward projection. The price of WTI in 2015 is $96 per barrel, in 2010 dollars. In 2045, the price per barrel is $158. For comparison, the EIA's Reference Case projects the price of imported low-sulfur light crude oil to be $94.58 per barrel in 2015 and $124.94 in 2035, in 2009 dollars.

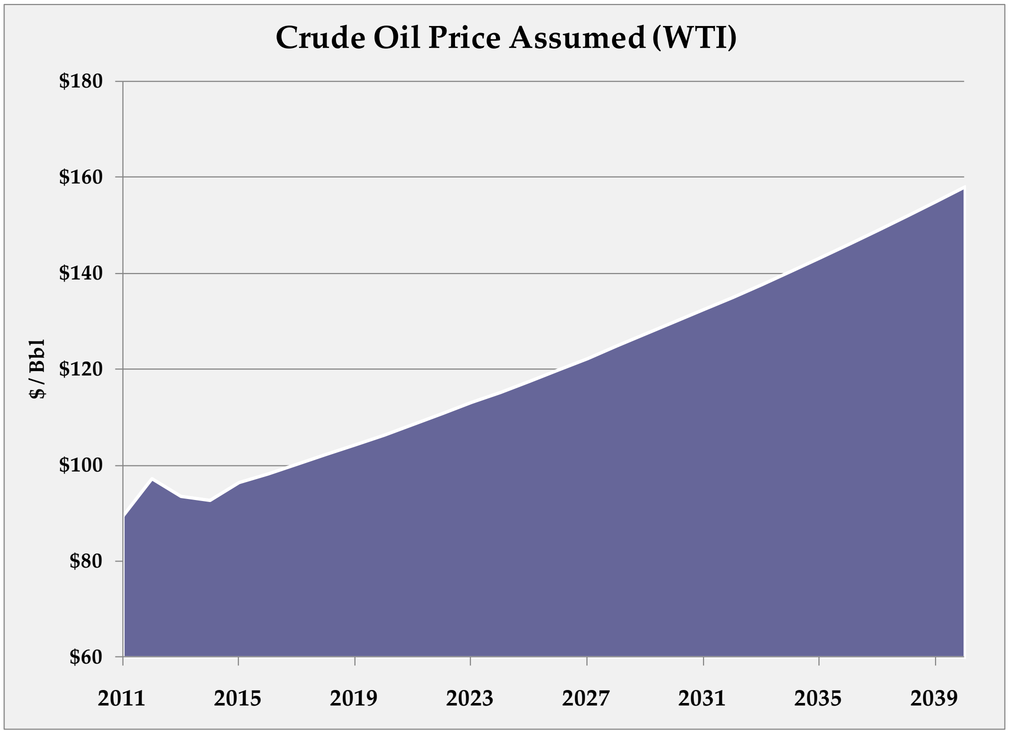

Figure 16: WTI Price Assumed in Natural Gas Price Forecast

Economic Growth

Navigant uses GDP figures from the Congressional Budget Office's Budget and Economic Outlook of January 2011. To extend the outlook beyond the last year, the final year GDP of 2.4 percent is continued to the end of the forecast period.

2011	2012	2013	2014	2015	2016	2017	2018
2.7%	3.1%	3.1%	3.5%	3.8%	3.0%	2.5%	2.4%

Table 4: Economic Growth Assumptions

Natural Gas Vehicles

Natural gas vehicle demand is embedded with residential and commercial demand, and is roughly similar to EIA projections from its 2011 Annual Energy Outlook, extrapolated to 2045.

Price Points

Prices for Henry Hub, the location of the North American futures market, are modeled in all outputs. In addition, two other market points are examined. Sumas, Washington, on the British Columbia border, represents the Pacific Northwest market. Malin, Oregon, at the California border, represents the California market.

NAVIGANT

Scenario Descriptions

Case Name	*Description*
Jordan Cove Reference Case	The **Jordan Cove Reference Case** is developed from Navigant's Spring 2011 Forecast of June 2011. The Spring 2011 Forecast incorporates Navigant's extensive work on North American gas shale supply resources. The Spring 2011 Reference Case has been modified to refine the infrastructure assumptions in the Pacific Northwest market based on improved information. The Reference Case assumes that two other LNG export facilities in North America will be operational prior to and concurrent with Jordan Cove: Sabine Pass in Louisiana and Kitimat in British Columbia. Sabine Pass is modeled as exporting 0.5 Bcfd of gas in LNG form beginning in May 2015, ramping up to 2.0 Bcfd by October 2017. Kitimat is modeled as exporting 0.7 Bcfd beginning in October 2015.
Jordan Cove Export Case	The **Jordan Cove Export Case** augments the Reference Case with exports from the Jordan Cove export facility of approximately **0.9 Bcfd** beginning January, 2017. No other changes are made. The effects on prices are the specific focus.
Aggregate Export Case	The **Aggregate Export Case** adds to the Jordan Cove Export Case additional LNG export capacity. In the Gulf of Mexico, 2.0 Bcfd of generic LNG export capacity is assumed. On the U.S. eastern seaboard, 1.0 Bcfd of generic export capacity is assumed. In total, all North American LNG export facilities modeled in the Aggregate Export Case when all export facilities are fully online is approximately 6.6 Bcfd. The effects on prices are the specific focus.
GHG Demand Case	The **GHG Demand Case** uses the same infrastructure and LNG export assumptions as the Aggregate Export Case, but demand is increased by using figures from the Navigant Spring 2011 *Carbon Case* Forecast. The Carbon Case incorporates the increased gas demand effects of coal-to-gas substitution driven by assumed laws and regulations that favor natural gas's much lower GHG byproducts from combustion compared to coal. The effects on prices are the specific focus.

Jordan Cove Reference Case

The **Jordan Cove Reference Case** was derived from Navigant's Spring 2011 Reference Case. Certain refinements to the infrastructure in the Northwest were made, based on more detailed information that was incorporated subsequent to the Navigant Spring 2011 Reference Case. For example, Ruby Pipeline capacity was increased from 1.2 Bcfd to 1.5 Bcfd, based on the actual increase implemented by Ruby in mid-October 2011. In addition, BC Pipeline (formerly Westcoast) was expanded to accommodate increased shale production for the Montney-Horn River area and adjacent shale resources (e.g., Cordoba Embayment).

The Reference Case includes two LNG liquefaction and export facilities as active. Sabine Pass LNG in Louisiana, the only liquefaction facility to receive DOE authority to export LNG to both FTA and non-FTA countries, is specifically modeled, with a capacity of 2.0 Bcfd. It is assumed to come online in 2015 at 25 percent capacity. Exports ramp up to 90 percent capacity by late 2017. Similarly, Kitimat LNG near Prince Rupert, British Columbia, the only LNG export facility approved by the Canadian National Energy Board is also assumed to come on line in 2015 with exports at 90 percent capacity.

Supply

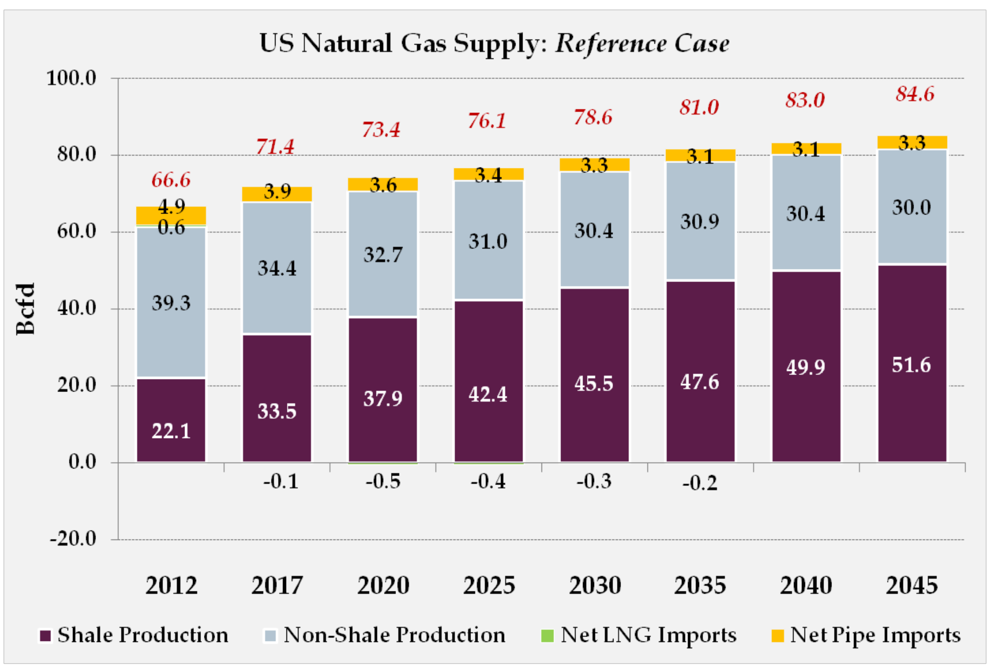

Figure 17: Reference Case Supply

Beginning around 2020, net LNG imports to the U.S. are negative, as the U.S. becomes a net exporter of LNG.[40]

Demand

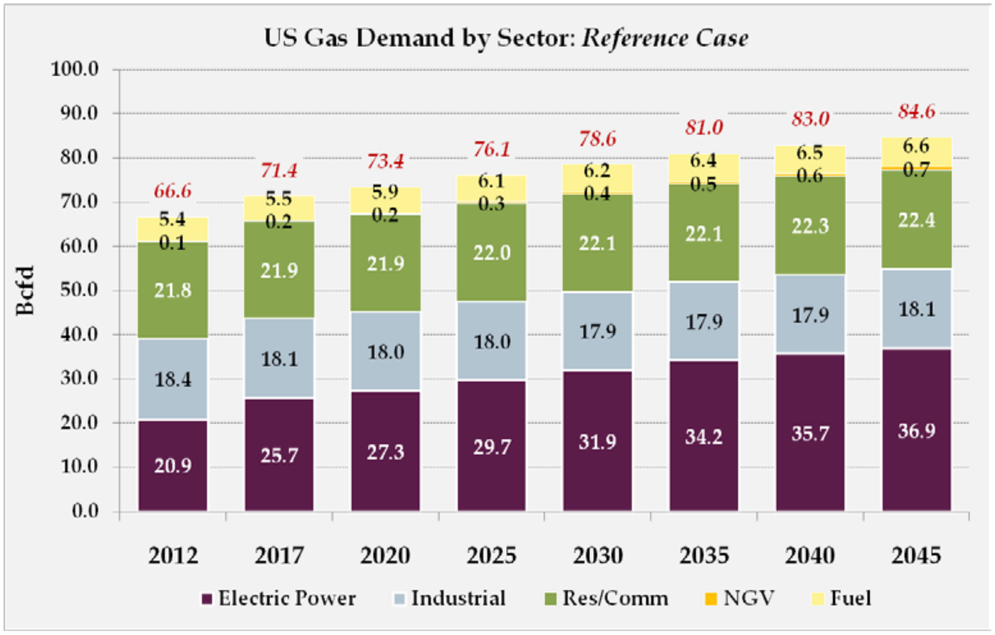

Figure 18: Reference Case Demand

Domestic U.S. demand is satisfied across the planning horizon in balance with supply, above.

[40] The exports from the U.S. appear as negative numbers below the zero line on the supply graph. Due to scale, the column areas associated with the exports are not visible.

Resultant Gas Prices

Prices at Henry Hub remain below $5.00 per MMBtu through 2020. After 2020, prices rise due to generally increasing marginal costs of additional domestic production. Henry Hub reaches $8.28 per MMBtu in 2045. Prices at Sumas and Malin show a negative basis to Henry Hub throughout the forecast period.

For comparison, the U.S. EIA's Reference Case price forecast for Henry Hub for 2035 (the last year of its forecast) is $7.07 per MMBtu,[41] and Canada's National Energy Board's Henry Hub U.S. dollar denominated price forecast for 2035 is $8.00 per MMBtu.[42] Navigant's Henry Hub price projection for 2035 is $7.31 per MMBtu.

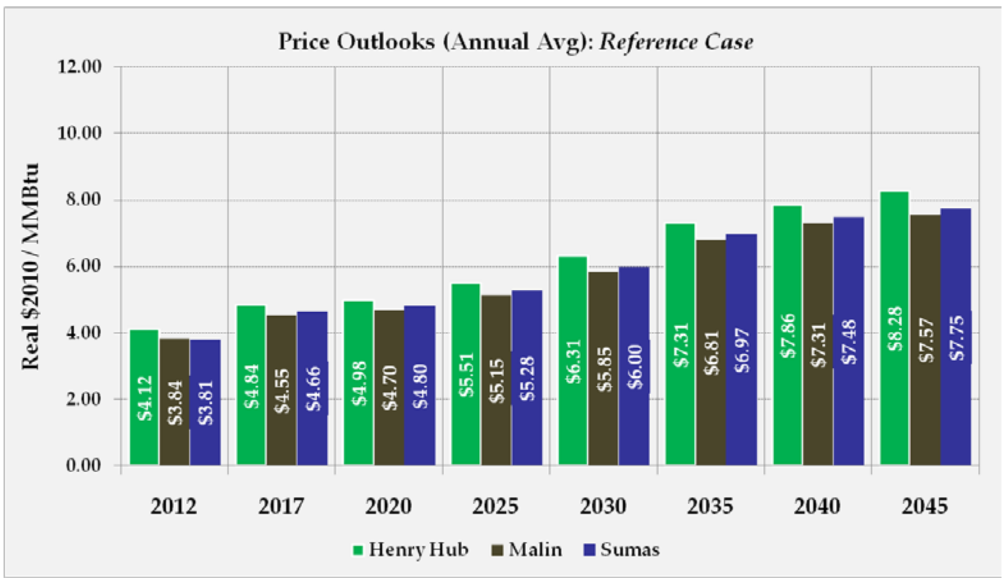

Figure 19: Reference Case Prices

[41] EIA Annual energy Outlook 2011, interactive table Natural Gas Supply, Disposition, and Prices, Reference Case.

[42] National Energy Board, ***Canada's Energy Future: Energy Supply and Demand Projections to 2035***, Reference Case, p. viii.

Jordan Cove Export Case

The **Jordan Cove Export Case** tests the effects of liquefying and exporting 0.9 Bcfd of North American gas from the Jordan Cove Energy Project facility beginning January 2017. All other inputs and assumptions remain the same as in the Jordan Cove Reference Case. Instantaneous daily demand at JCEP is 1.0 Bcfd, if 10% fuel consumption is included. However, on an annual basis, fuel use is offset by a 10% annual maintenance downtime. Therefore, the net average demand of JCEP is 0.9 Bcfd.

The Jordan Cove Export Case also assumes the concurrent commissioning of the Pacific Connector Pipeline from the Malin trading hub to Coos Bay. Pacific Connector is assumed to transport gas delivered to Malin from Canada via Gas Transmission Northwest Pipeline (capacity 2.2 Bcfd) and gas from the Rocky Mountain supply region via Ruby Pipeline (1.5 Bcfd). Pacific Connector was modeled as a "bullet" line, with no interconnections to other pipelines.

Supply

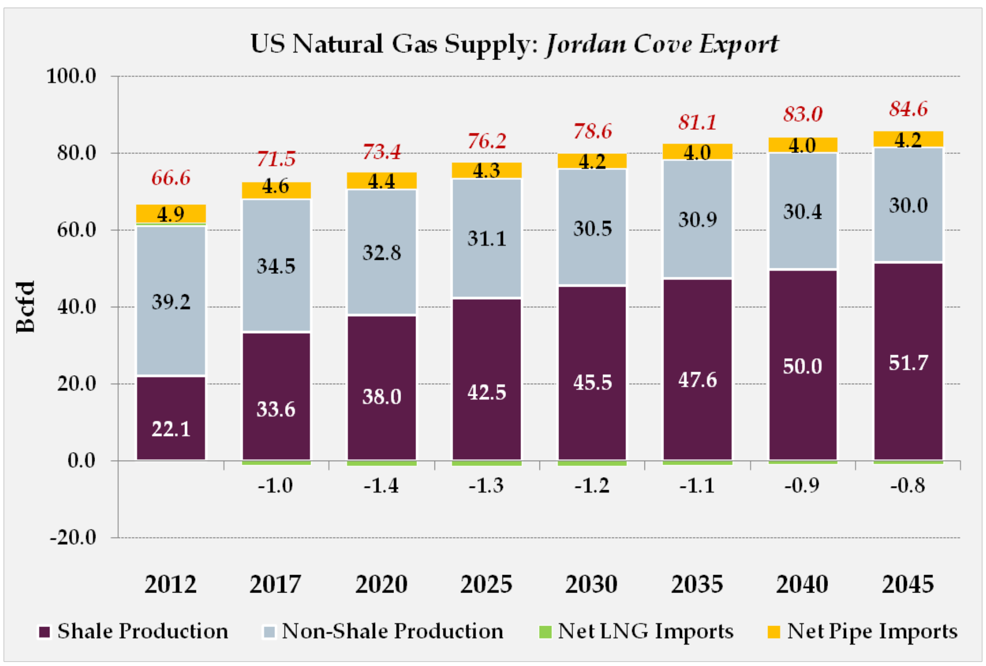

Figure 20: Jordan Cove Export Case Supply

The addition of 0.9 Bcfd of LNG exports from Jordan Cove increases pipeline imports from Canada by 0.7 to 0.9 Bcfd, indicating that feedstock comes primarily from increased output from British Columbia shale supplies, either directly or through displacement. Note that Total Supply (above the zero line) remains essentially constant. This is exemplified in 2045, which shows total supply of 84.6, which is the same Total Supply in the Reference Case. Net LNG Exports (below the zero line) reflect the disposition of any increased supply. Net exports decrease as time moves forward, reflecting a small increase in LNG imports in pipeline-constrained parts of North America (e.g., New England and the Canadian Maritimes).

Year	Metric	Reference Case	Jordan Cove Export	Difference
2025	*Shale Production*	42.4	42.5	0.1
	Non-shale Production	31.0	31.1	0.1
	Net LNG Imports	-0.4	-1.3	-0.9
	Net Pipe Imports	3.4	4.3	0.8
	Total Supply	**76.1**	**76.2**	**0.1**
2035	*Shale Production*	47.6	47.6	0.1
	Non-shale Production	30.9	30.9	0.0
	Net LNG Imports	-0.2	-1.1	-0.9
	Net Pipe Imports	3.1	4.0	0.9
	Total Supply	**81.0**	**81.1**	**0.1**
2045	*Shale Production*	51.6	51.7	0.0
	Non-shale Production	30.0	30.0	0.0
	Net LNG Imports	0.1	-0.8	-0.9
	Net Pipe Imports	3.3	4.2	0.9
	Total Supply	**84.6**	**84.6**	**0.0**

Table 5: Changes in Supply in Jordan Cove Export Case[43]

[43] "Total supply" includes a small net storage and balancing component. Due to this, the sum of dry production, LNG, and pipe imports may not equal total supply.

Demand

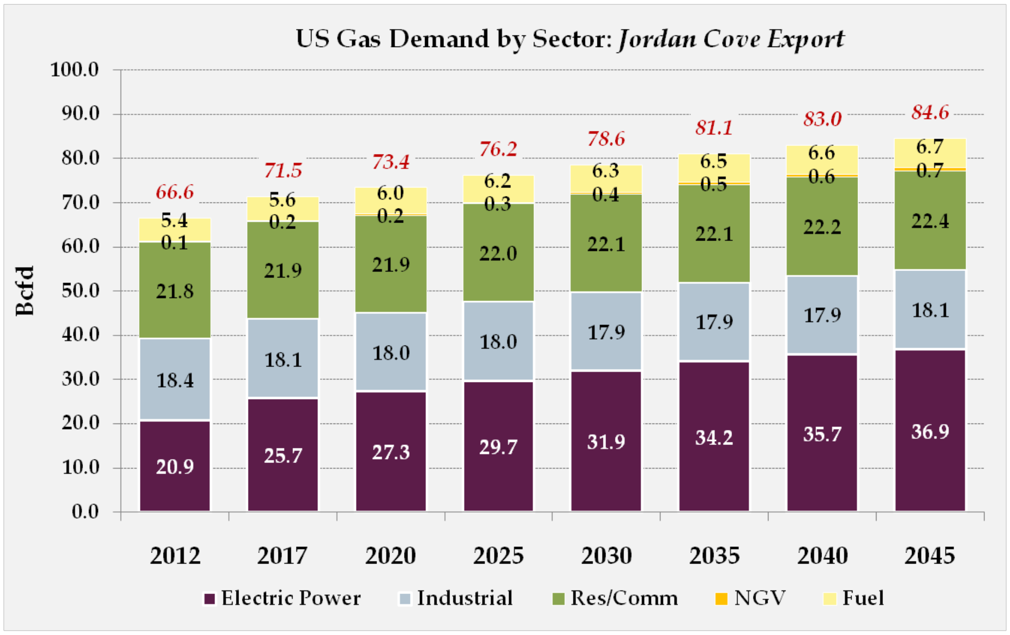

Figure 21: Jordan Cove Export Case Demand

LNG exports at Jordan Cove have a negligible effect on the distribution of demand among the major sectors, with very small amounts shaved from each to contribute to an approximate 0.1 Bcfd increase in fuel usage across the U.S.

Year	Metric	Reference Case	Jordan Cove Export	Difference
2025	*Electric Power*	29.7	29.7	0.0
	Industrial	18.0	18.0	0.0
	Res/Comm	22.0	22.0	0.0
	NGV	0.3	0.3	0.0
	Total Consumption	**76.1**	**76.2**	**0.1**
2035	*Electric Power*	34.2	34.2	0.0
	Industrial	17.9	17.9	0.0
	Res/Comm	22.1	22.1	0.0
	NGV	0.5	0.5	0.0
	Total Consumption	**81.0**	**81.1**	**0.1**
2045	*Electric Power*	36.9	36.9	0.0
	Industrial	18.1	18.1	0.0
	Res/Comm	22.4	22.4	0.0
	NGV	0.7	0.7	0.0
	Total Consumption	**84.6**	**84.6**	**0.0**

Table 6: Changes in Demand in Jordan Cove Export Case

Resultant Gas Prices

Prices at Henry Hub, Sumas, and Malin in the Jordan Cove Export Case remain below $5.00 per MMBtu through 2020. The maximum incremental price increase at Henry Hub compared to the Reference Case is $0.07 per MMBtu, which occurs in 2020. Incremental price increases at Sumas are between $-0.02 and $0.03 per MMBtu until 2045, when the increment reaches $0.30 per MMBtu. Incremental price increases at Malin are between $0.14 and $0.25 per MMBtu until 2045, when the increment reaches $0.54 per MMBtu. The 2045 Sumas price of $8.09 per MMBtu and the Malin price of $8.11 per MMBtu remain below the Reference Case Henry Hub price of $8.28.

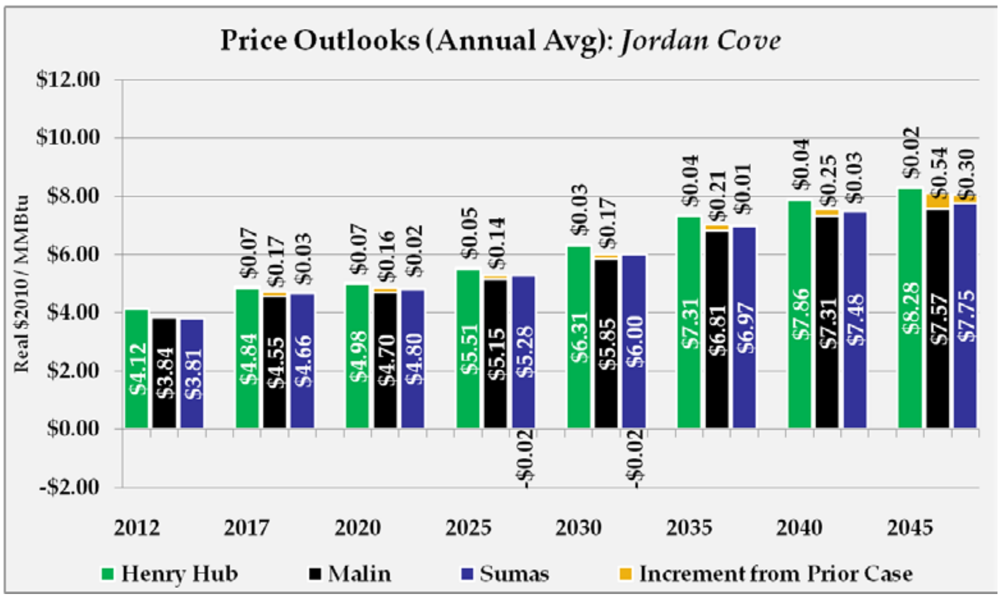

Figure 22: Jordan Cove Export Case Prices

		A	B	C=A-B	D=A/B-1
Year	**Metric**	**Jordan Cove Export**	**Reference Case**	***Absolute* Difference**	***Percentage* Difference**
2025	*Henry Hub*	**$5.55**	**$5.51**	*$0.05*	*0.8%*
	Malin	**$5.29**	**$5.15**	*$0.14*	*2.7%*
	Sumas	**$5.26**	**$5.28**	*-$0.02*	*-0.4%*
2035	*Henry Hub*	**$7.35**	**$7.31**	*$0.04*	*0.5%*
	Malin	**$7.02**	**$6.81**	*$0.21*	*3.1%*
	Sumas	**$6.98**	**$6.97**	*$0.01*	*0.1%*
2045	*Henry Hub*	**$8.30**	**$8.28**	*$0.02*	*0.2%*
	Malin	**$8.11**	**$7.57**	*$0.54*	*7.2%*
	Sumas	**$8.05**	**$7.75**	*$0.30*	*3.9%*

Table 7: Changes in Jordan Cove Export Case Prices

Aggregate Exports Case

The **Aggregate Export Case** builds on the Jordan Cove Export Case. In the **Aggregate Export Case**, other U.S. LNG exports are assumed in addition to Sabine Pass, Kitimat, and JCEP. This includes an additional 2.0 Bcfd of LNG liquefaction and export capacity in the Gulf of Mexico and 1.0 Bcfd on the U.S. East Coast. Several such LNG export facilities have been proposed, and more may be. Therefore, Navigant makes no judgment as to which specific ones will be approved and ready to operate by the start-up date of JCEP, and models these export volumes generically

Supply

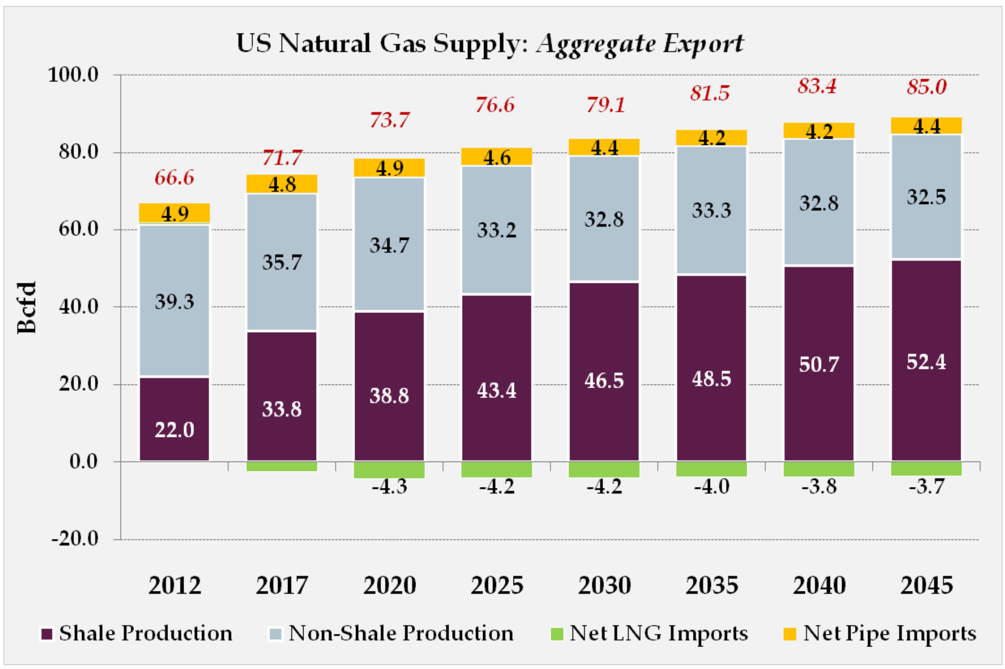

Figure 23: Aggregate Export Case Supply

The addition of 3.0 Bcfd of LNG exports in addition to Kitimat, Sabine Pass, and JCEP stimulates supply production in the U.S. In 2020, shale production rises from 33.6 Bcfd in the Jordan Cove Export Case to 34.0 Bcfd. Similarly, non-shale U.S. production rises from 34.5 Bcfd to 35.3 Bcfd. Pipeline imports increase from 4.6 Bcfd in 2020 to 5.0 Bcfd. Total supply increases by about 0.4 Bcfd in 2020.

Year	Metric	Jordan Cove Export	Aggregate Export	Difference
2025	*Shale Production*	42.5	43.4	1.0
	Non-shale Production	31.1	33.2	2.1
	Net LNG Imports	-1.3	-4.2	-2.9
	Net Pipe Imports	4.3	4.6	0.4
	Total Supply	**76.2**	**76.6**	**0.4**
2035	*Shale Production*	47.6	48.5	0.9
	Non-shale Production	30.9	33.3	2.4
	Net LNG Imports	-1.1	-4.0	-2.9
	Net Pipe Imports	4.0	4.2	0.2
	Total Supply	**81.1**	**81.5**	**0.4**
2045	*Shale Production*	51.7	52.4	0.7
	Non-shale Production	30.0	32.5	2.5
	Net LNG Imports	-0.8	-3.7	-2.9
	Net Pipe Imports	4.2	4.4	0.2
	Total Supply	**84.6**	**85.0**	**0.4**

Table 8: Changes in Supply in Aggregate Export Case[44]

Demand

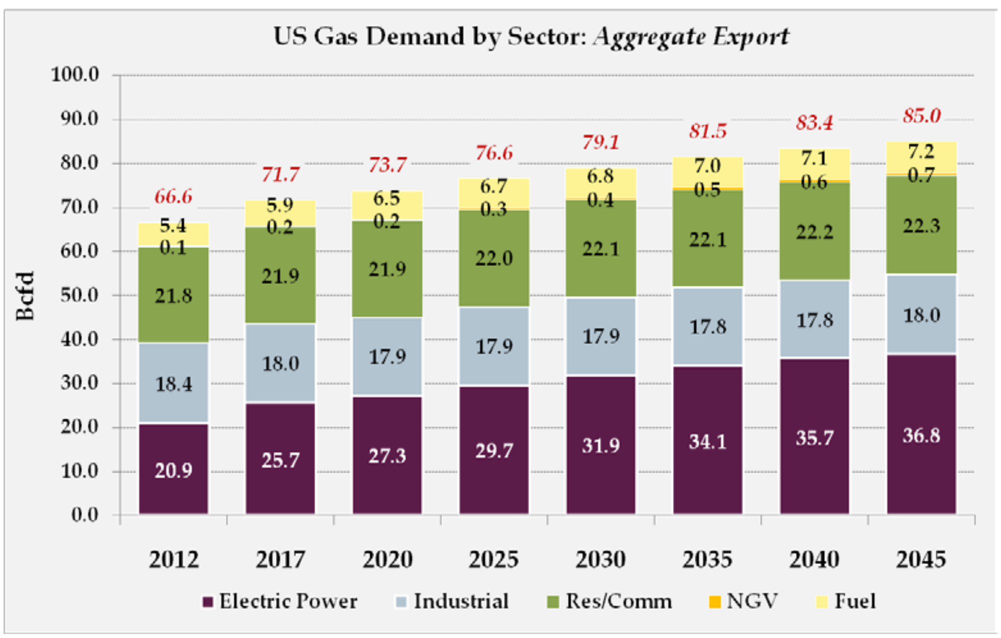

Figure 24: Aggregate Export Case Demand

[44] "Total supply" includes a small net storage and balancing component. Due to this, the sum of dry production, LNG, and pipe imports may not equal total supply.

Aggregate LNG exports add approximately 0.5 Bcfd increase in fuel usage across the U.S. in the later years of the forecast. Otherwise, the distribution of demand is largely unaffected.

Year	Metric	Jordan Cove Export	Aggregate Export	Difference
2025	*Electric Power*	29.7	29.7	0.0
	Industrial	18.0	17.9	-0.1
	Res/Comm	22.0	22.0	0.0
	NGV	0.3	0.3	0.0
	Total Consumption	**76.2**	**76.6**	**0.4**
2035	*Electric Power*	34.2	34.1	0.0
	Industrial	17.9	17.8	0.0
	Res/Comm	22.1	22.1	0.0
	NGV	0.5	0.5	0.0
	Total Consumption	**81.1**	**81.5**	**0.4**
2045	*Electric Power*	36.9	36.8	0.0
	Industrial	18.1	18.0	0.0
	Res/Comm	22.4	22.3	0.0
	NGV	0.7	0.7	0.0
	Total Consumption	**84.6**	**85.0**	**0.4**

Table 9: Changes in Demand in Aggregate Export Case

Resultant Gas Prices

Prices at Henry Hub, Sumas, and Malin in the Aggregate Export Case remain below or near $5.00 per MMBtu through 2020 (as they do in the two previous cases). The maximum incremental price increase at Henry Hub compared to the Jordan Cove Export Case is $0.54 per MMBtu, which occurs in 2020, reflecting the step-change impact of the near-concurrent addition of several large export facilities. In later years, the increase is smaller as the steady ramp-up of supply equilibrates to demand. Incremental price increases at Sumas are between $0.17 and $0.41 per MMBtu. Incremental increases in price at Sumas and Malin are less than the incremental increase at Henry Hub. The total price at Sumas and Malin also remains below the Reference Case Henry Hub price for all years.

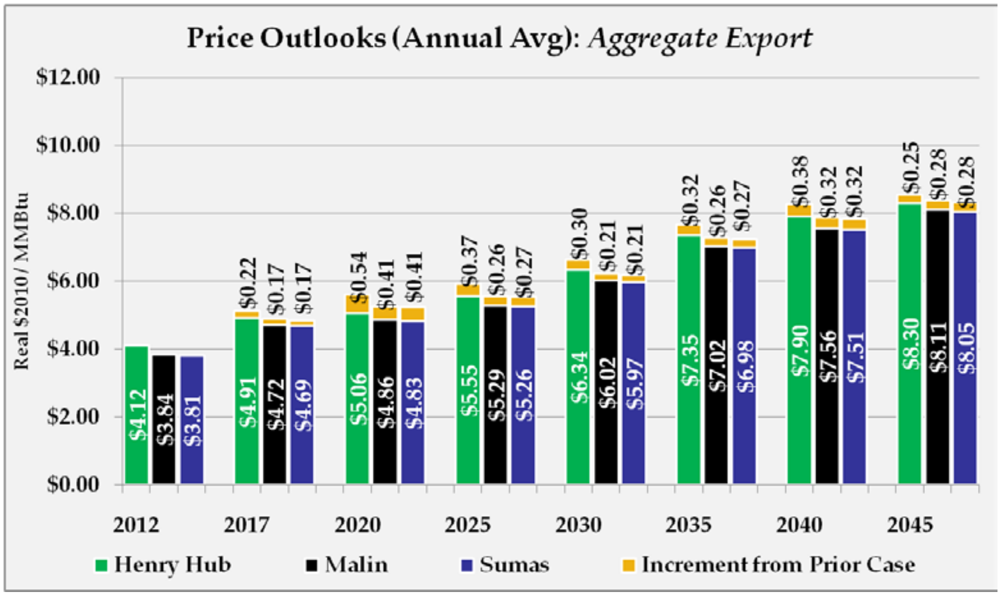

Figure 25: Aggregate Export Case Prices

Year	Metric	A Aggregate Export	B Jordan Cove Export	C=A-B *Absolute Difference*	D=A/B-1 *Percentage Difference*
2025	*Henry Hub*	$5.92	$5.55	*$0.37*	*6.7%*
	Malin	$5.55	$5.29	*$0.26*	*4.9%*
	Sumas	$5.53	$5.26	*$0.27*	*5.1%*
2035	*Henry Hub*	$7.66	$7.35	*$0.32*	*4.3%*
	Malin	$7.29	$7.02	*$0.26*	*3.8%*
	Sumas	$7.25	$6.98	*$0.27*	*3.8%*
2045	*Henry Hub*	$8.55	$8.30	*$0.25*	*3.0%*
	Malin	$8.39	$8.11	*$0.28*	*3.4%*
	Sumas	$8.32	$8.05	*$0.28*	*3.4%*

Table 10: Changes in Aggregate Export Case Prices

GHG Demand Case

The **GHG Demand Case** builds on the Aggregate Export Case. In the **GHG Demand Case**, U.S. and Canadian policy are assumed to promote the use of natural gas in order to reduce greenhouse gas emissions, notably carbon dioxide. Oil and coal are assumed to be disadvantaged by legislation, regulation, a carbon price, or similar mechanism such that natural gas demand is increased.

In such a scenario, it is almost certain that natural gas infrastructure would experience a concurrent build-out. Navigant's modeling methodology, however, does not attempt to specify particular infrastructure to account for this likely outcome. Some infrastructure was adjusted in a generic fashion to alleviate bottlenecks. An exception was made to accommodate the assumed growth in gas supply and demand in the West, and in particular growth in Canadian shale supply, which otherwise caused unrealistic oscillations in seasonal pricing in the later years of this scenario. Gas Transmission Northwest and the western legs of Nova and Foothills Pipeline were assumed to expand by 1.0 Bcfd in response to policy-driven supply and demand growth, starting in 2028.

We emphasize that our infrastructure methodology is intended to be conservative and that many other such expansions, as well as new pipeline and storage construction, would most certainly take place in such a regulatory environment, to support the increase in gas-fired generation.

Supply

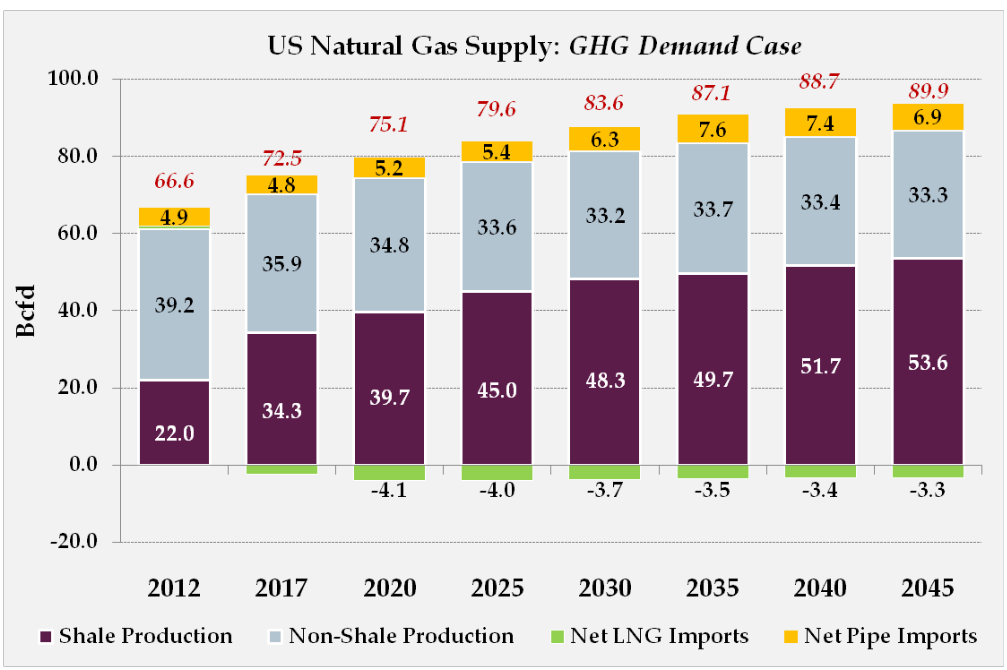

Figure 26: GHG Demand Case Supply

In 2025, incremental supply in the GHG Demand Case is 3.0 Bcfd higher than in the Aggregate Export Case. This increment grows to 5.6 Bcfd in 2035, and pulls back slightly to 4.9 Bcfd in 2045.

Year	Metric	Aggregate Export	GHG Demand	Difference
2025	*Shale Production*	43.4	45.0	1.6
	Non-shale Production	33.2	33.6	0.4
	Net LNG Imports	-4.2	-4.0	0.2
	Net Pipe Imports	4.6	5.4	0.7
	Total Supply	**76.6**	**79.6**	**3.0**
2035	*Shale Production*	48.5	49.7	1.2
	Non-shale Production	33.3	33.7	0.4
	Net LNG Imports	-4.0	-3.5	0.5
	Net Pipe Imports	4.2	7.6	3.4
	Total Supply	**81.5**	**87.1**	**5.6**
2045	*Shale Production*	52.4	53.6	1.2
	Non-shale Production	32.5	33.3	0.8
	Net LNG Imports	-3.7	-3.3	0.4
	Net Pipe Imports	4.4	6.9	2.5
	Total Supply	**85.0**	**89.9**	**4.9**

Table 11: Changes in Supply in GHG Demand Case[45]

[45] "Total supply" includes a small net storage and balancing component. Due to this, the sum of dry production, LNG, and pipe imports may not equal total supply.

Demand

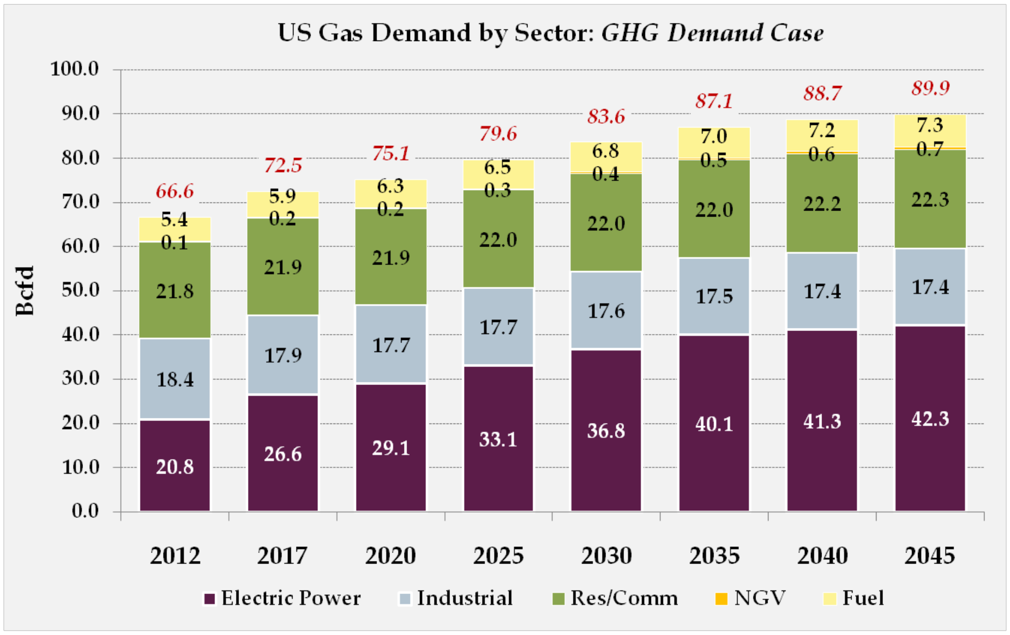

Figure 27: GHG Demand Case Demand

U.S. demand increases in the GHG Demand Case by 1.4 Bcfd in 2020, ramping up to an incremental 4.9 Bcfd by 2045. This demand excludes North American production used for LNG exports.

Year	Metric	Aggregate Export	GHG Demand	Difference
2025	*Electric Power*	29.7	33.1	3.4
	Industrial	17.9	17.7	-0.2
	Res/Comm	22.0	22.0	0.0
	NGV	0.3	0.3	0.0
	Total Consumption	**76.6**	**79.6**	**3.0**
2035	*Electric Power*	34.1	40.1	6.0
	Industrial	17.8	17.5	-0.4
	Res/Comm	22.1	22.0	-0.1
	NGV	0.5	0.5	0.0
	Total Consumption	**81.5**	**87.1**	**5.6**
2045	*Electric Power*	36.8	42.3	5.5
	Industrial	18.0	17.4	-0.6
	Res/Comm	22.3	22.3	-0.1
	NGV	0.7	0.7	0.0
	Total Consumption	**85.0**	**89.9**	**4.9**

Table 12: Changes in Demand in GHG Demand Case

Resultant Gas Prices

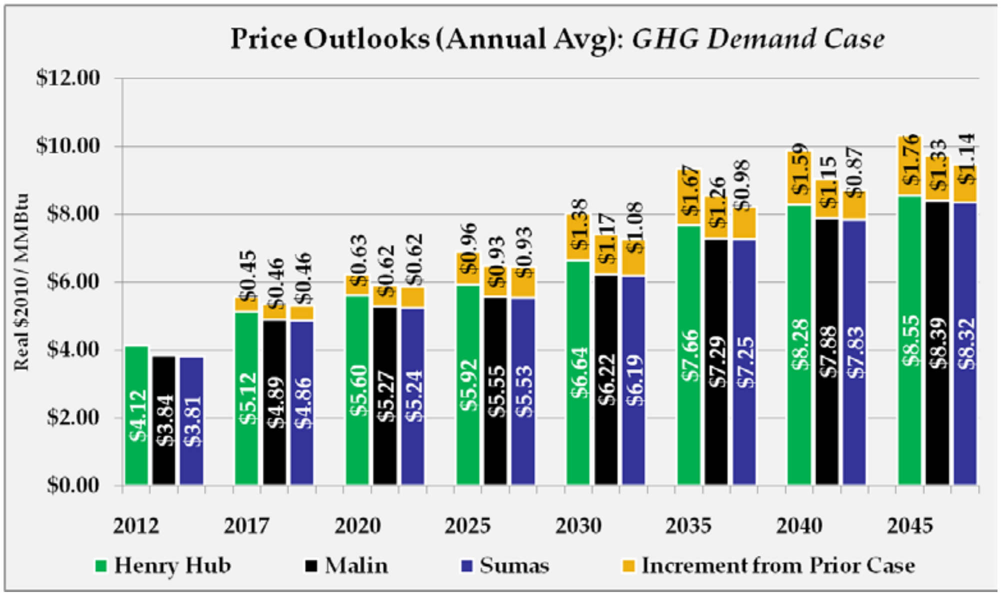

Figure 28: GHG Demand Case Prices

		A	B	*C=A-B*	*D=A/B-1*
Year	**Metric**	**GHG Demand**	**Aggregate Export**	***Absolute Difference***	***Percentage Difference***
2025	*Henry Hub*	**$6.88**	**$5.92**	*$0.96*	*16.2%*
	Malin	**$6.49**	**$5.55**	*$0.93*	*16.8%*
	Sumas	**$6.46**	**$5.53**	*$0.93*	*16.9%*
2035	*Henry Hub*	**$9.33**	**$7.66**	*$1.67*	*21.8%*
	Malin	**$8.55**	**$7.29**	*$1.26*	*17.3%*
	Sumas	**$8.23**	**$7.25**	*$0.98*	*13.6%*
2045	*Henry Hub*	**$10.31**	**$8.55**	*$1.76*	*20.6%*
	Malin	**$9.72**	**$8.39**	*$1.33*	*15.9%*
	Sumas	**$9.47**	**$8.32**	*$1.14*	*13.7%*

Table 13: Changes in GHG Demand Case Prices

Policy-driven growth in demand, combined with Navigant's highly conservative modeling methodology of minimizing assumed future infrastructure additions, results in higher natural gas prices (incrementally 10 percent or more) throughout North America, beginning in 2020. By 2045, modeled Henry Hub prices increase by more than 20 percent, compared to the Aggregate Export Case. Resultant incremental price increases at Malin and Sumas are lower than that at Henry Hub. Malin is about 16 percent higher, and Sumas about 14 percent higher.

Appendix A: Abbreviations and Acronyms

AEO	Annual Energy Outlook (EIA publication)
Bcf	Billion cubic feet
Bcfd	Billion cubic feet per day
CCS	Carbon capture and sequestration
CSAPR	Cross-State Air Pollution Rule
DOE	Department of Energy
DOE/FE	Department of Energy / Office of Fossil Energy
Dth	Dekatherm
EG	Electric generation
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
FTA	Free Trade Agreement
GPCM	Gas Pipeline Competition Model
GW	Gigawatt (one billion watts; 1,000 megawatts)
IEA	International Energy Agency
IP	Initial production
JCEP	Jordan Cove Energy Project
LNG	Liquefied natural gas
Mcf	Thousand cubic feet (approx. 1.0 MMBtu)
MMBtu	Million British thermal units
MMcf	Million cubic feet
MW	Megawatt (one million watts)
NEB	National Energy Board (Canada)
NETL	National Energy Technology Laboratory
NGL	Natural gas liquid
NGV	Natural gas vehicle
SEAB	Secretary of Energy Advisory Board
Tcf	Trillion cubic feet
USGS	United States Geological Survey

Appendix B: Future Infrastructure in Reference Case

Storage New and Expansion Projects 2011 and Beyond			
Storage Facility	**State**	**Date**	**Working Capacity (MMcf)**
Blue Sky	CO	Apr-2011	4,400
Cadeville	LA	Jun-2012	11,500
Central Valley Gas Storage	CA	Jul-2011	5,500
Copiah	MS	Apr-2014	3,000
East Cheyenne	CO	Jun-2011	18,900
Golden Triangle	TX	Apr-2011	12,000
Leaf River (Expansion)	MS	Apr-2011	16,000
Leaf River (Expansion)	MS	Apr-2013	24,000
Leaf River (Expansion)	MS	Apr-2014	32,000
Pine Prairie (Expansion)	LA	May-2011	26,000
Pine Prairie (Expansion)	LA	May-2013	42,000
Pine Prairie (Expansion)	LA	May-2016	45,000
Tricor Ten Section Hub	CA	Jan-2012	22,400
Western Energy Hub	UT	Apr-2012	5,600
Windy Hill	CO	Jul-2011	6,000
Windy Hill (Expansion)	CO	Apr-2012	12,000
Windy Hill (Expansion)	CO	Apr-2013	18,000
Windy Hill (Expansion)	CO	Apr-2014	24,000
Windy Hill (Expansion)	CO	Apr-2015	32,000

Future Pipelines and Expansions in Spring 2011 Reference Case*					
Pipeline	Date	Capacity (MMcfd)	Pipeline	Date	Capacity (MMcfd)
Bison Pipeline	Jan-11	477	LNG Manzanillo	Jul-14	500
Houston Pipeline (HPL S Tx)	Jan-11	400	Algonquin (Algonquin NJ NY)	Nov-14	800
TCO 1278 Line-K Project	Jan-11	150	TETCO NJ/NY Expansion	Nov-14	800
Inergy North-South Project	Jan-11	325	IGT NYMarc Connector	Nov-14	500
Transco Springville Pipeline	Jan-11	450	CrossTex North Texas (N Texas)	Jan-15	750
Florida Gas Phase VIII Exp	Apr-11	820	El Paso (Samalayuca Line)	Jan-15	312
Ruby Pipeline	Jul-11	1,250	Enterprise Jonah Gathering	Jan-15	600
LNG Golden Pass	Jul-11	1,000	Florida Gas (Mkt Panhandle)	Jan-15	500
TGP 300 Line	Jul-11	345	Florida Gas (Zone 3)	Jan-15	500
Acadian Pipeline (HH)	Sep-11	1,200	Grasslands Pipeline	Jan-15	200
				Nov-11	160
Gulfstream Pipeline	Nov-11	35	NFGS Line N Project	Jan-12	195
				Nov-11	350
Algonquin (Algonquin J)	Jan-12	400	Empire Tioga County Extension	Nov-13	350
Midcontinent Express Z1	Jan-12	200	Gulf Crossing	Jan-15	1,000
PNGT (N & S of Westbrook)	Jan-12	310	TGT (Fayetteville)	Jan-15	150
EQT Sunrise Project	Jan-12	313	Wyoming Interstate (Mainline)	Jan-15	225
Millennium Minisink Compr.	Jan-12	150	Questar (Fidlar to KRGT)	Jan-18	400
TETCO TEAM 2012	Jan-12	300	Rockies Express (REX Z1 Wam)	Jan-18	332
TGP NE Supply Diversif.	Jan-12	250	White River Hub	Jan-18	500
Transco Mid Atl Connect Exp	Jan-12	150	Wyoming Interstate (Kanda Lat)	Jan-18	400
Transco Northeast Connector	Jan-12	688	Alliance Pipeline (CAN BC)	Jan-20	850
Inergy Marc I Hub Line	Apr-12	550	Kern River (CA/Mainline/NV)	Jan-20	500
NW Pipeline (Plymouth)	Nov-12	239	KM Border Pipeline	Jan-20	300
DTI Appalachian Gateway	Nov-12	484	KM Mexico	Jan-20	425
DTI Northeast Expansion	Nov-12	200	KM Texas Pipeline (AguaDulce)	Jan-20	250
NFGS Northern Access	Nov-12	320	Mojave-Kern Common Facilities	Jan-20	200
IGT Wright Transfer Comp.	Nov-12	250	Nova (Gordondale Gr Prairie)	Jan-20	4,500
TETCO TEAM 2013	Jan-13	500	Wyoming Interstate (Mainline)	Jan-20	500
NFGS West to East	Jan-13	425	Cypress Pipeline	May-20	500
DTI Tioga Area Expansion	Nov-13	270	Nova (Groundbirch)	Jan-22	1,344
Florida Gas (Mkt Northern)	Jan-14	500	White River Hub	Jan-23	500
Southern Crossing	Jan-14	400	Kern River (Opal to Muddy Ck)	Jan-25	440
TGP Northeast Upgrade	Jan-14	636	KM Border Pipeline	Jan-25	300
Transco NE Supply Link	Jan-14	250	Transwestern (Topock- Calpine)	Jan-25	80
Transco Rockaway Lateral	Jan-14	625	DCP E TX Carthage Gathering	Jan-27	250
Enterprise Texas	Jun-14	200			

Appendix C: Supply Disposition Tables

U.S. Supply Disposition (Bcfd) – *Navigant Reference Case*							
		NET IMPORTS					
Year	Dry Production	Net Pipeline Imports	Net LNG Imports	Total Net Imports	Net Storage	Balancing Item	Consump-tion
2012	*61.3*	4.9	0.6	5.5	-0.2	0.0	**66.6**
2013	*62.7*	4.7	0.9	5.6	-0.1	0.0	**68.2**
2014	*63.8*	4.5	1.1	5.6	-0.1	0.0	**69.3**
2015	*65.0*	4.2	1.0	5.2	0.0	-0.2	**70.0**
2016	*66.5*	3.9	0.4	4.2	0.0	-0.3	**70.5**
2017	*67.9*	3.9	-0.1	3.7	0.0	-0.3	**71.4**
2018	*69.0*	3.8	-0.5	3.3	0.0	-0.3	**72.1**
2019	*69.8*	3.7	-0.5	3.2	0.1	-0.3	**72.8**
2020	*70.6*	3.6	-0.5	3.1	0.0	-0.3	**73.4**
2021	*71.2*	3.7	-0.5	3.2	0.0	-0.3	**74.1**
2022	*71.8*	3.7	-0.5	3.2	0.0	-0.3	**74.6**
2023	*72.3*	3.6	-0.5	3.1	0.1	-0.3	**75.1**
2024	*72.8*	3.5	-0.5	3.1	-0.1	-0.3	**75.4**
2025	*73.4*	3.4	-0.4	3.0	0.0	-0.3	**76.1**
2026	*73.9*	3.5	-0.4	3.0	0.0	-0.3	**76.6**
2027	*74.3*	3.4	-0.4	3.0	0.1	-0.3	**77.1**
2028	*74.7*	3.4	-0.4	3.0	-0.1	-0.3	**77.4**
2029	*75.4*	3.4	-0.4	3.0	0.0	-0.3	**78.1**
2030	*75.9*	3.3	-0.3	3.0	0.0	-0.3	**78.6**
2031	*76.4*	3.3	-0.3	3.0	0.1	-0.3	**79.0**
2032	*76.8*	3.2	-0.3	3.0	-0.1	-0.3	**79.3**
2033	*77.5*	3.2	-0.2	2.9	0.0	-0.3	**80.0**
2034	*77.9*	3.1	-0.2	2.9	0.0	-0.3	**80.5**
2035	*78.4*	3.1	-0.2	3.0	0.0	-0.3	**81.0**
2036	*79.0*	3.0	-0.1	2.9	0.1	-0.3	**81.6**
2037	*79.4*	3.0	0.0	2.9	0.0	-0.4	**81.9**
2038	*79.7*	3.0	0.0	3.0	0.0	-0.4	**82.3**
2039	*80.0*	3.0	0.0	3.1	0.0	-0.4	**82.7**
2040	*80.3*	3.1	0.0	3.1	0.0	-0.4	**83.0**
2041	*80.6*	3.1	0.1	3.2	0.0	-0.4	**83.4**
2042	*80.8*	3.2	0.1	3.3	0.0	-0.4	**83.7**
2043	*81.2*	3.2	0.1	3.3	0.0	-0.4	**84.1**
2044	*81.3*	3.2	0.1	3.3	0.0	-0.4	**84.2**
2045	*81.6*	3.3	0.1	3.4	0.0	-0.4	**84.6**

NAVIGANT

U.S. Supply Disposition (Bcfd) – *Jordan Cove Export Case*							
		NET IMPORTS					
Year	Dry Production	Net Pipeline Imports	Net LNG Imports	Total Net Imports	Net Storage	Balancing Item	Consump-tion
2012	*61.3*	4.9	0.6	5.5	-0.2	0.0	**66.6**
2013	*62.6*	4.9	0.8	5.7	0.0	0.0	**68.2**
2014	*63.7*	4.8	0.9	5.8	-0.1	0.0	**69.3**
2015	*64.7*	4.6	1.0	5.5	0.0	-0.2	**70.1**
2016	*66.3*	4.2	0.4	4.6	-0.1	-0.3	**70.5**
2017	*68.2*	4.6	-1.0	3.5	0.1	-0.3	**71.5**
2018	*69.3*	4.5	-1.4	3.1	0.0	-0.3	**72.1**
2019	*70.0*	4.5	-1.4	3.1	0.0	-0.3	**72.8**
2020	*70.8*	4.4	-1.4	3.0	0.0	-0.3	**73.4**
2021	*71.4*	4.5	-1.4	3.1	0.0	-0.3	**74.2**
2022	*72.0*	4.5	-1.4	3.1	0.0	-0.3	**74.7**
2023	*72.5*	4.4	-1.4	3.0	0.1	-0.3	**75.2**
2024	*72.9*	4.3	-1.4	3.0	-0.1	-0.3	**75.5**
2025	*73.6*	4.3	-1.3	2.9	0.0	-0.3	**76.2**
2026	*74.0*	4.3	-1.3	3.0	0.0	-0.3	**76.7**
2027	*74.4*	4.3	-1.3	3.0	0.1	-0.3	**77.2**
2028	*74.9*	4.3	-1.3	3.0	-0.1	-0.3	**77.5**
2029	*75.5*	4.2	-1.3	3.0	0.0	-0.3	**78.1**
2030	*76.0*	4.2	-1.2	2.9	0.0	-0.3	**78.6**
2031	*76.5*	4.2	-1.2	3.0	0.1	-0.3	**79.1**
2032	*76.9*	4.1	-1.2	2.9	-0.1	-0.4	**79.4**
2033	*77.6*	4.0	-1.1	2.9	0.0	-0.4	**80.1**
2034	*78.0*	4.1	-1.1	3.0	0.0	-0.4	**80.6**
2035	*78.5*	4.0	-1.1	3.0	0.0	-0.4	**81.1**
2036	*79.1*	3.9	-1.0	2.9	0.0	-0.4	**81.7**
2037	*79.5*	3.9	-0.9	2.9	0.0	-0.4	**82.0**
2038	*79.8*	3.9	-0.9	3.0	0.0	-0.4	**82.4**
2039	*80.1*	3.9	-0.9	3.1	0.0	-0.4	**82.7**
2040	*80.3*	4.0	-0.9	3.1	0.0	-0.4	**83.0**
2041	*80.6*	4.0	-0.8	3.2	0.0	-0.4	**83.5**
2042	*80.9*	4.1	-0.8	3.3	0.0	-0.4	**83.7**
2043	*81.2*	4.1	-0.8	3.3	0.0	-0.4	**84.2**
2044	*81.3*	4.1	-0.8	3.3	0.0	-0.4	**84.2**
2045	*81.7*	4.2	-0.8	3.4	0.0	-0.4	**84.6**

U.S. Supply Disposition (Bcfd) – *Aggregate Export Case*							
		NET IMPORTS					
Year	Dry Production	Net Pipeline Imports	Net LNG Imports	Total Net Imports	Net Storage	Balancing Item	Consump-tion
2012	*61.3*	4.9	0.6	5.5	-0.2	0.0	**66.6**
2013	*62.6*	4.9	0.8	5.7	0.0	0.0	**68.2**
2014	*63.8*	4.8	0.9	5.6	0.0	0.0	**69.4**
2015	*65.0*	4.4	0.9	5.3	0.0	-0.2	**70.1**
2016	*66.8*	4.1	0.3	4.4	-0.3	-0.3	**70.6**
2017	*69.6*	4.8	-2.6	2.2	0.3	-0.4	**71.7**
2018	*71.3*	4.9	-3.4	1.5	0.0	-0.4	**72.3**
2019	*72.4*	4.9	-3.9	1.0	0.0	-0.4	**73.1**
2020	*73.5*	4.9	-4.3	0.7	0.0	-0.5	**73.7**
2021	*74.3*	5.0	-4.3	0.7	0.0	-0.5	**74.5**
2022	*74.9*	4.9	-4.3	0.7	0.0	-0.5	**75.1**
2023	*75.4*	4.8	-4.3	0.6	0.0	-0.5	**75.6**
2024	*76.0*	4.7	-4.3	0.5	0.0	-0.5	**75.9**
2025	*76.7*	4.6	-4.2	0.4	0.0	-0.5	**76.6**
2026	*77.1*	4.6	-4.2	0.4	0.0	-0.5	**77.1**
2027	*77.6*	4.6	-4.2	0.4	0.0	-0.5	**77.6**
2028	*78.0*	4.6	-4.2	0.4	0.0	-0.5	**77.9**
2029	*78.7*	4.5	-4.2	0.3	0.0	-0.5	**78.6**
2030	*79.2*	4.4	-4.2	0.3	0.0	-0.5	**79.1**
2031	*79.7*	4.4	-4.2	0.3	0.1	-0.5	**79.5**
2032	*80.1*	4.4	-4.1	0.3	-0.1	-0.5	**79.8**
2033	*80.8*	4.3	-4.1	0.2	0.0	-0.5	**80.5**
2034	*81.3*	4.3	-4.0	0.2	0.0	-0.5	**81.0**
2035	*81.8*	4.2	-4.0	0.2	0.0	-0.5	**81.5**
2036	*82.4*	4.1	-3.9	0.2	0.1	-0.5	**82.1**
2037	*82.7*	4.1	-3.9	0.2	0.0	-0.5	**82.4**
2038	*83.0*	4.1	-3.8	0.2	0.0	-0.5	**82.8**
2039	*83.3*	4.1	-3.8	0.3	0.0	-0.5	**83.1**
2040	*83.5*	4.2	-3.8	0.4	0.0	-0.5	**83.4**
2041	*83.8*	4.2	-3.8	0.5	0.0	-0.5	**83.8**
2042	*84.1*	4.3	-3.8	0.6	0.0	-0.5	**84.1**
2043	*84.4*	4.4	-3.7	0.6	0.0	-0.5	**84.5**
2044	*84.5*	4.3	-3.8	0.5	0.0	-0.5	**84.5**
2045	*84.8*	4.4	-3.7	0.7	0.0	-0.5	**85.0**

U.S. Supply Disposition (Bcfd) –*GHG Demand Case*							
		NET IMPORTS					
Year	Dry Production	Net Pipeline Imports	Net LNG Imports	Total Net Imports	Net Storage	Balancing Item	Consump-tion
2012	*61.3*	4.9	0.6	5.5	-0.2	0.0	**66.6**
2013	*62.6*	4.9	0.8	5.7	0.0	0.0	**68.2**
2014	*63.8*	4.8	0.9	5.6	0.0	0.0	**69.4**
2015	*65.0*	4.4	0.9	5.3	0.0	-0.2	**70.1**
2016	*66.8*	4.1	0.3	4.4	-0.3	-0.3	**70.6**
2017	*69.6*	4.8	-2.6	2.2	0.3	-0.4	**71.7**
2018	*71.3*	4.9	-3.4	1.5	0.0	-0.4	**72.3**
2019	*72.4*	4.9	-3.9	1.0	0.0	-0.4	**73.1**
2020	*73.5*	4.9	-4.3	0.7	0.0	-0.5	**73.7**
2021	*74.3*	5.0	-4.3	0.7	0.0	-0.5	**74.5**
2022	*74.9*	4.9	-4.3	0.7	0.0	-0.5	**75.1**
2023	*75.4*	4.8	-4.3	0.6	0.0	-0.5	**75.6**
2024	*76.0*	4.7	-4.3	0.5	0.0	-0.5	**75.9**
2025	*76.7*	4.6	-4.2	0.4	0.0	-0.5	**76.6**
2026	*77.1*	4.6	-4.2	0.4	0.0	-0.5	**77.1**
2027	*77.6*	4.6	-4.2	0.4	0.0	-0.5	**77.6**
2028	*78.0*	4.6	-4.2	0.4	0.0	-0.5	**77.9**
2029	*78.7*	4.5	-4.2	0.3	0.0	-0.5	**78.6**
2030	*79.2*	4.4	-4.2	0.3	0.0	-0.5	**79.1**
2031	*79.7*	4.4	-4.2	0.3	0.1	-0.5	**79.5**
2032	*80.1*	4.4	-4.1	0.3	-0.1	-0.5	**79.8**
2033	*80.8*	4.3	-4.1	0.2	0.0	-0.5	**80.5**
2034	*81.3*	4.3	-4.0	0.2	0.0	-0.5	**81.0**
2035	*81.8*	4.2	-4.0	0.2	0.0	-0.5	**81.5**
2036	*82.4*	4.1	-3.9	0.2	0.1	-0.5	**82.1**
2037	*82.7*	4.1	-3.9	0.2	0.0	-0.5	**82.4**
2038	*83.0*	4.1	-3.8	0.2	0.0	-0.5	**82.8**
2039	*83.3*	4.1	-3.8	0.3	0.0	-0.5	**83.1**
2040	*83.5*	4.2	-3.8	0.4	0.0	-0.5	**83.4**
2041	*83.8*	4.2	-3.8	0.5	0.0	-0.5	**83.8**
2042	*84.1*	4.3	-3.8	0.6	0.0	-0.5	**84.1**
2043	*84.4*	4.4	-3.7	0.6	0.0	-0.5	**84.5**
2044	*84.5*	4.3	-3.8	0.5	0.0	-0.5	**84.5**
2045	*84.8*	4.4	-3.7	0.7	0.0	-0.5	**85.0**

Appendix D: Consumption Disposition Tables

U.S. Natural Gas Consumption by End Use (Bcfd) – *Navigant Reference Case*							
Year	**Lease & Plant Fuel**	**Pipeline & Distribu-tion Use**	**Res/ Comm**	**Industrial**	**Vehicle Fuel**	**Electric Power**	**Total Consump-tion**
2012	3.2	2.1	21.8	18.4	0.1	20.9	**66.6**
2013	3.3	2.2	21.9	18.4	0.1	22.4	**68.2**
2014	3.3	2.2	21.9	18.3	0.1	23.5	**69.3**
2015	3.3	2.1	21.9	18.2	0.1	24.4	**70.0**
2016	3.3	2.1	21.8	18.1	0.2	25.0	**70.5**
2017	3.3	2.2	21.9	18.1	0.2	25.7	**71.4**
2018	3.3	2.2	21.9	18.1	0.2	26.3	**72.1**
2019	3.4	2.3	22.0	18.1	0.2	26.9	**72.8**
2020	3.7	2.3	21.9	18.0	0.2	27.3	**73.4**
2021	3.7	2.3	22.0	18.1	0.2	27.9	**74.1**
2022	3.7	2.3	22.0	18.0	0.2	28.4	**74.6**
2023	3.7	2.3	22.0	18.0	0.3	28.8	**75.1**
2024	3.7	2.3	22.0	17.9	0.3	29.2	**75.4**
2025	3.7	2.3	22.0	18.0	0.3	29.7	**76.1**
2026	3.7	2.4	22.1	18.0	0.3	30.2	**76.6**
2027	3.7	2.4	22.1	18.0	0.4	30.6	**77.1**
2028	3.7	2.4	22.0	17.9	0.4	31.0	**77.4**
2029	3.8	2.4	22.1	17.9	0.4	31.5	**78.1**
2030	3.8	2.4	22.1	17.9	0.4	31.9	**78.6**
2031	3.8	2.5	22.1	17.9	0.4	32.4	**79.0**
2032	3.8	2.5	22.0	17.8	0.5	32.7	**79.3**
2033	3.8	2.5	22.1	17.9	0.5	33.3	**80.0**
2034	3.8	2.5	22.1	17.9	0.5	33.7	**80.5**
2035	3.8	2.5	22.1	17.9	0.5	34.2	**81.0**
2036	3.9	2.6	22.2	17.9	0.5	34.6	**81.6**
2037	3.9	2.6	22.1	17.9	0.5	35.0	**81.9**
2038	3.9	2.6	22.2	17.9	0.5	35.3	**82.3**
2039	3.9	2.6	22.2	17.9	0.6	35.5	**82.7**
2040	3.9	2.6	22.3	17.9	0.6	35.7	**83.0**
2041	3.9	2.7	22.3	18.0	0.6	36.0	**83.4**
2042	3.9	2.7	22.3	18.0	0.6	36.2	**83.7**
2043	3.9	2.7	22.4	18.1	0.6	36.5	**84.1**
2044	3.9	2.7	22.3	18.0	0.6	36.6	**84.2**
2045	3.9	2.7	22.4	18.1	0.7	36.9	**84.6**

NAVIGANT

U.S. Natural Gas Consumption by End Use (Bcfd) – *Jordan Cove Export Case*							
Year	Lease & Plant Fuel	Pipeline & Distribu-tion Use	Res/ Comm	Industrial	Vehicle Fuel	Electric Power	Total Consump-tion
2012	3.2	2.1	21.8	18.4	0.1	20.9	**66.6**
2013	3.3	2.2	21.9	18.4	0.1	22.4	**68.2**
2014	3.3	2.2	21.9	18.3	0.1	23.5	**69.3**
2015	3.3	2.1	21.9	18.3	0.1	24.4	**70.1**
2016	3.3	2.1	21.9	18.1	0.2	25.0	**70.5**
2017	3.3	2.3	21.9	18.1	0.2	25.7	**71.5**
2018	3.3	2.3	21.9	18.0	0.2	26.3	**72.1**
2019	3.4	2.3	22.0	18.0	0.2	26.9	**72.8**
2020	3.7	2.3	21.9	18.0	0.2	27.3	**73.4**
2021	3.7	2.4	22.0	18.0	0.2	27.9	**74.2**
2022	3.7	2.4	22.0	18.0	0.2	28.4	**74.7**
2023	3.7	2.4	22.0	18.0	0.3	28.8	**75.2**
2024	3.7	2.4	22.0	17.9	0.3	29.2	**75.5**
2025	3.7	2.4	22.0	18.0	0.3	29.7	**76.2**
2026	3.7	2.5	22.0	18.0	0.3	30.2	**76.7**
2027	3.7	2.5	22.1	18.0	0.4	30.6	**77.2**
2028	3.7	2.5	22.0	17.9	0.4	31.0	**77.5**
2029	3.8	2.5	22.1	17.9	0.4	31.5	**78.1**
2030	3.8	2.5	22.1	17.9	0.4	31.9	**78.6**
2031	3.8	2.5	22.1	17.9	0.4	32.4	**79.1**
2032	3.8	2.6	22.0	17.8	0.5	32.7	**79.4**
2033	3.8	2.6	22.1	17.9	0.5	33.3	**80.1**
2034	3.8	2.6	22.1	17.9	0.5	33.7	**80.6**
2035	3.8	2.6	22.1	17.9	0.5	34.2	**81.1**
2036	3.9	2.7	22.2	17.9	0.5	34.6	**81.7**
2037	3.9	2.7	22.1	17.9	0.5	34.9	**82.0**
2038	3.9	2.7	22.1	17.9	0.5	35.3	**82.4**
2039	3.9	2.7	22.2	17.9	0.6	35.5	**82.7**
2040	3.9	2.7	22.2	17.9	0.6	35.7	**83.0**
2041	3.9	2.7	22.3	18.0	0.6	36.0	**83.5**
2042	3.9	2.8	22.3	18.0	0.6	36.2	**83.7**
2043	3.9	2.8	22.4	18.0	0.6	36.5	**84.2**
2044	3.9	2.8	22.3	18.0	0.6	36.6	**84.2**
2045	3.9	2.8	22.4	18.1	0.7	36.9	**84.6**

U.S. Natural Gas Consumption by End Use (Bcfd) – *Aggregate Export Case*							
Year	Lease & Plant Fuel	Pipeline & Distribu-tion Use	Res/ Comm	Industrial	Vehicle Fuel	Electric Power	Total Consump-tion
2012	3.2	2.1	21.8	18.4	0.1	20.9	**66.6**
2013	3.3	2.2	21.9	18.4	0.1	22.4	**68.2**
2014	3.3	2.2	21.9	18.3	0.1	23.5	**69.4**
2015	3.3	2.1	21.9	18.3	0.1	24.4	**70.1**
2016	3.3	2.1	21.9	18.1	0.2	25.0	**70.6**
2017	3.4	2.5	21.9	18.0	0.2	25.7	**71.7**
2018	3.4	2.6	21.9	17.9	0.2	26.3	**72.3**
2019	3.5	2.7	21.9	17.9	0.2	26.8	**73.1**
2020	3.8	2.7	21.9	17.9	0.2	27.3	**73.7**
2021	3.8	2.8	21.9	17.9	0.2	27.8	**74.5**
2022	3.8	2.8	22.0	17.9	0.2	28.3	**75.1**
2023	3.8	2.8	22.0	17.9	0.3	28.8	**75.6**
2024	3.8	2.8	21.9	17.9	0.3	29.2	**75.9**
2025	3.9	2.8	22.0	17.9	0.3	29.7	**76.6**
2026	3.9	2.8	22.0	17.9	0.3	30.1	**77.1**
2027	3.9	2.9	22.0	17.9	0.4	30.6	**77.6**
2028	3.9	2.9	22.0	17.8	0.4	31.0	**77.9**
2029	3.9	2.9	22.1	17.9	0.4	31.5	**78.6**
2030	3.9	2.9	22.1	17.9	0.4	31.9	**79.1**
2031	3.9	2.9	22.1	17.9	0.4	32.3	**79.5**
2032	3.9	2.9	22.0	17.8	0.5	32.7	**79.8**
2033	4.0	3.0	22.1	17.8	0.5	33.2	**80.5**
2034	4.0	3.0	22.1	17.8	0.5	33.7	**81.0**
2035	4.0	3.0	22.1	17.8	0.5	34.1	**81.5**
2036	4.0	3.0	22.2	17.8	0.5	34.6	**82.1**
2037	4.0	3.0	22.1	17.8	0.5	34.9	**82.4**
2038	4.0	3.0	22.1	17.8	0.5	35.2	**82.8**
2039	4.0	3.0	22.1	17.8	0.6	35.5	**83.1**
2040	4.0	3.0	22.2	17.8	0.6	35.7	**83.4**
2041	4.0	3.1	22.3	17.9	0.6	36.0	**83.8**
2042	4.0	3.1	22.3	17.9	0.6	36.1	**84.1**
2043	4.1	3.1	22.3	18.0	0.6	36.4	**84.5**
2044	4.1	3.1	22.3	18.0	0.6	36.5	**84.5**
2045	4.1	3.1	22.3	18.0	0.7	36.8	**85.0**

U.S. Natural Gas Consumption by End Use (Bcfd) – *GHG Demand Case*							
Year	Lease & Plant Fuel	Pipeline & Distribu-tion Use	Res/ Comm	Industrial	Vehicle Fuel	Electric Power	Total Consump-tion
2012	3.2	2.1	21.8	18.4	0.1	20.8	**66.6**
2013	3.3	2.2	21.9	18.4	0.1	22.3	**68.2**
2014	3.3	2.2	21.9	18.3	0.1	23.5	**69.3**
2015	3.3	2.1	21.9	18.3	0.1	24.7	**70.4**
2016	3.3	2.1	21.8	18.0	0.2	25.6	**71.1**
2017	3.4	2.5	21.9	17.9	0.2	26.6	**72.5**
2018	3.5	2.6	21.9	17.8	0.2	27.5	**73.5**
2019	3.5	2.7	21.9	17.8	0.2	28.3	**74.4**
2020	3.5	2.8	21.9	17.7	0.2	29.1	**75.1**
2021	3.5	2.8	21.9	17.8	0.2	29.9	**76.2**
2022	3.5	2.8	21.9	17.8	0.2	30.7	**77.0**
2023	3.5	2.9	22.0	17.7	0.3	31.5	**77.9**
2024	3.6	2.9	21.9	17.7	0.3	32.2	**78.5**
2025	3.6	2.9	22.0	17.7	0.3	33.1	**79.6**
2026	3.6	2.9	22.0	17.7	0.3	33.9	**80.4**
2027	3.6	3.0	22.0	17.7	0.4	34.7	**81.3**
2028	3.7	3.0	21.9	17.6	0.4	35.3	**81.9**
2029	3.7	3.0	22.0	17.6	0.4	36.1	**82.8**
2030	3.7	3.0	22.0	17.6	0.4	36.8	**83.6**
2031	3.8	3.0	22.0	17.6	0.4	37.5	**84.4**
2032	3.8	3.0	21.9	17.5	0.5	38.1	**84.9**
2033	3.8	3.1	22.0	17.5	0.5	38.8	**85.8**
2034	3.9	3.1	22.0	17.5	0.5	39.5	**86.4**
2035	3.9	3.1	22.0	17.5	0.5	40.1	**87.1**
2036	3.9	3.1	22.1	17.4	0.5	40.4	**87.5**
2037	4.0	3.1	22.0	17.4	0.5	40.7	**87.8**
2038	4.0	3.1	22.1	17.4	0.5	41.0	**88.1**
2039	4.0	3.1	22.1	17.4	0.6	41.2	**88.5**
2040	4.1	3.2	22.2	17.4	0.6	41.3	**88.7**
2041	4.1	3.2	22.2	17.5	0.6	41.6	**89.2**
2042	4.1	3.2	22.2	17.5	0.6	41.7	**89.3**
2043	4.1	3.2	22.3	17.5	0.6	42.0	**89.7**
2044	4.1	3.2	22.2	17.4	0.6	42.0	**89.5**
2045	4.1	3.2	22.3	17.4	0.7	42.3	**89.9**

Appendix E: Henry Hub Price Forecast Comparison Table

Henry Hub Price Forecast Comparison (Real$/MMBtu)				
Year	*Navigant Base*	*Jordan Cove Export*	*Aggregate Export*	*GHG Demand*
2012	$4.12	$4.12	$4.12	$4.12
2013	$4.53	$4.52	$4.52	$4.52
2014	$4.21	$4.17	$4.13	$4.14
2015	$4.31	$4.21	$4.08	$4.19
2016	$4.68	$4.59	$4.45	$4.82
2017	$4.84	$4.91	$5.12	$5.57
2018	$4.93	$5.02	$5.42	$5.92
2019	$4.92	$5.01	$5.50	$6.07
2020	$4.98	$5.06	$5.60	$6.23
2021	$5.02	$5.08	$5.57	$6.26
2022	$5.10	$5.15	$5.59	$6.34
2023	$5.20	$5.25	$5.66	$6.47
2024	$5.34	$5.39	$5.78	$6.66
2025	$5.51	$5.55	$5.92	$6.88
2026	$5.65	$5.70	$6.04	$7.07
2027	$5.80	$5.84	$6.17	$7.27
2028	$5.96	$5.99	$6.31	$7.51
2029	$6.14	$6.17	$6.48	$7.77
2030	$6.31	$6.34	$6.64	$8.02
2031	$6.47	$6.50	$6.79	$8.18
2032	$6.67	$6.70	$6.99	$8.40
2033	$6.87	$6.90	$7.19	$8.71
2034	$7.07	$7.10	$7.40	$9.02
2035	$7.31	$7.35	$7.66	$9.33
2036	$7.51	$7.55	$7.90	$9.54
2037	$7.62	$7.66	$8.00	$9.62
2038	$7.72	$7.77	$8.11	$9.72
2039	$7.80	$7.84	$8.19	$9.81
2040	$8.28	$7.90	$8.28	$9.87
2041	$7.98	$8.01	$8.39	$10.00
2042	$8.05	$8.08	$8.43	$10.07
2043	$8.17	$8.19	$8.50	$10.21
2044	$8.14	$8.16	$8.46	$10.16
2045	$8.28	$8.30	$8.55	$10.31

APPENDIX C.1

Navigant Whitepaper

NAVIGANT

WHITEPAPER: ANALYSIS OF THE EIA EXPORT REPORT 'EFFECT OF INCREASED NATURAL GAS EXPORTS ON DOMESTIC ENERGY MARKETS' DATED JANUARY 19, 2012

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Disclaimer: This report was prepared by Navigant Consulting, Inc. for the benefit of Jordan Cove Energy Project, LP. This work product involves forecasts of future natural gas demand, supply, and prices. Navigant Consulting applied appropriate professional diligence in its preparation, using what it believes to be reasonable assumptions. However, since the report necessarily involves unknowns, no warranty is made, express or implied.

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EIA Report Overview

On January 19, 2012, the Energy Information Administration (EIA) of the U.S. Department of Energy released a report ("Effect of Increased Natural Gas Exports on Domestic Energy Markets", or "Report") presenting estimated impacts of liquefied natural gas export scenarios on certain aspects of the domestic energy markets. EIA performed the analysis pursuant to a request by the Office of Fossil Energy of the Department of Energy, which is responsible for evaluating applications to export liquefied natural gas. The main findings of the Report included the following:

- Increased natural gas exports lead to increased natural gas prices.
- The source of the gas volumes needed for the increased exports would be about two-thirds from increased natural gas production, with most of the balance provided by decreased natural gas consumption.
- Most of the increased production would be from shale gas sources, and most of the decreased consumption results from coal-for-gas fuel switching in electric generation.

EIA's approach was to start with four "baseline" cases taken from the 2011 Annual Energy Outlook ("AEO2011"), which was released in April 2011; the four baseline cases are the AEO2011 Reference case, and the Low Shale EUR[1], High Shale EUR, and High Economic Growth cases. Against these four baseline cases, EIA performed four alternative export scenarios, as follows:

Name	Export Level	Ramp-Up
Low/Slow	6 Bcfd	+1 Bcfd per year (or 6 years)
Low/Rapid	6 Bcfd	+3 Bcfd per year (or 2 years)
High/Slow	12 Bcfd	+1 Bcfd per year (or 12 years)
High/Rapid	12 Bcfd	+3 Bcfd per year (or 4 years)

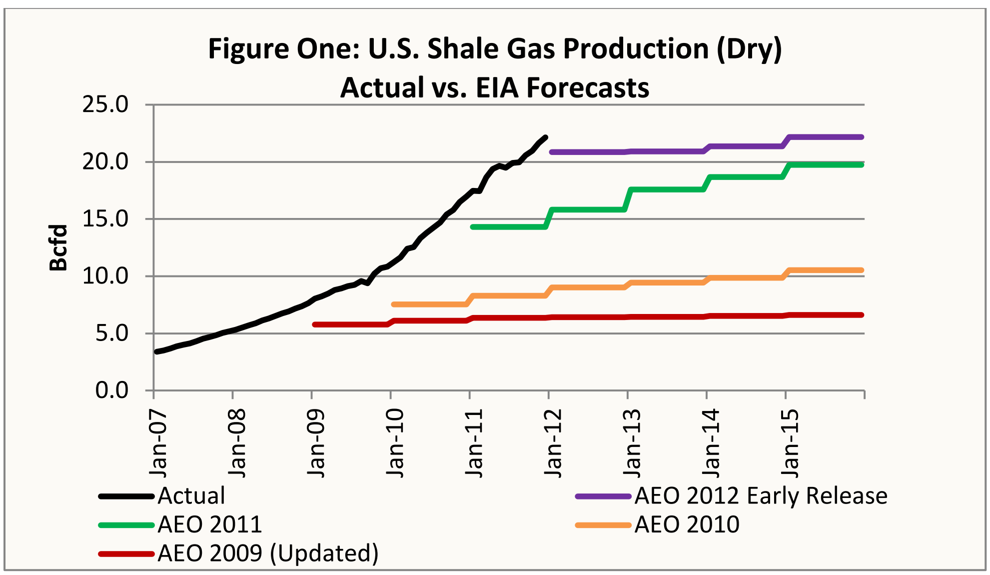
Thus, the Report analyzed 16 different case-scenario combinations, with emphasis on presenting production, consumption, producer revenue and consumer expenditure metrics for the four export scenarios under the Reference case baseline, and also natural gas pricing estimates under all 16 case-scenario combinations. Media reporting has already focused on price impacts estimated under "extreme" market assumptions, i.e. high exports and low supplies, that are by their nature highly unlikely, perhaps "extremely unlikely." The Report also included data tables showing average values of a host of variables over the first and second ten-year periods of the analysis, as well as over the entire twenty-year period of the analysis. Annual data from the analysis is available on the EIA website.[2]

[1] Estimated ultimate recovery.

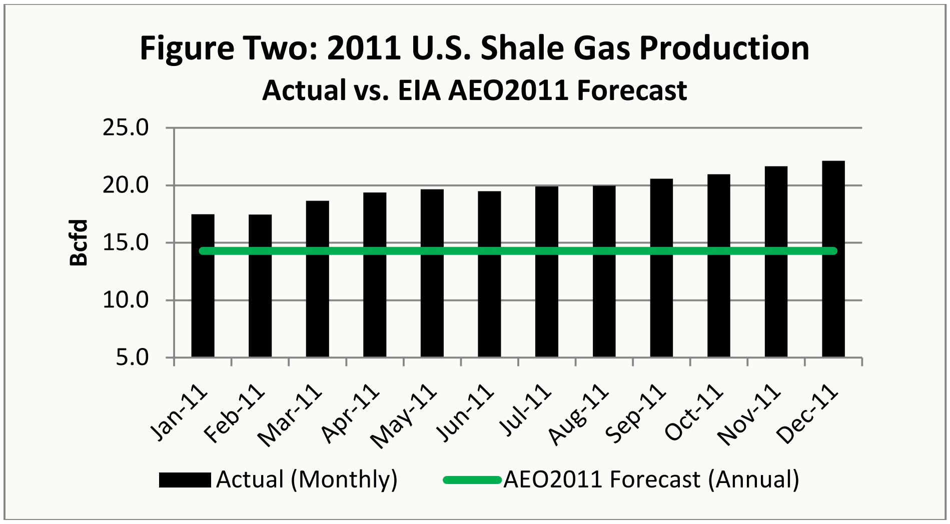
[2] http://www.eia.gov/analysis/requests/fe/

The Shale Gas Supply Forecasts Used in the Report Are Well Below Existing Levels and Do Not Capture Current Development Trends

As background, it is instructive to note that EIA's Annual Energy Outlook projections historically have systematically understated upcoming shale gas production. As can be seen in Figure One below, the first year of each of the last three shale production forecasts was far surpassed by the actual production for that year (AEO2009, AEO2010, and AEO2011). The speed of development of shale gas resources is so great that many forecasts simply have not caught up with the realities in the field. Even with the very large jump shown for the AEO2011 shale production forecast for 2011, an increase of over 70% from the AEO2010 figure, it was still significantly below actual 2011 shale gas production levels, by more than 25% for the annual average level and by 35% for the year-end production level. The clear trend in the data shows that the same result will occur for AEO2012, where the forecast production level for 2012 was already surpassed by the year-end 2011 production level. Figure Two following shows this surge in more detail.

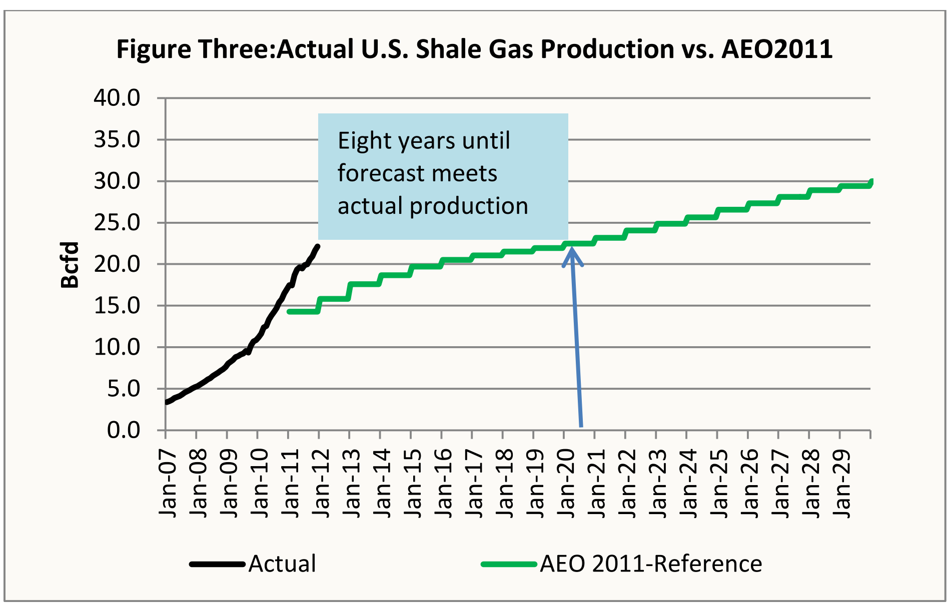


Source: EIA; Lippman/Navigant



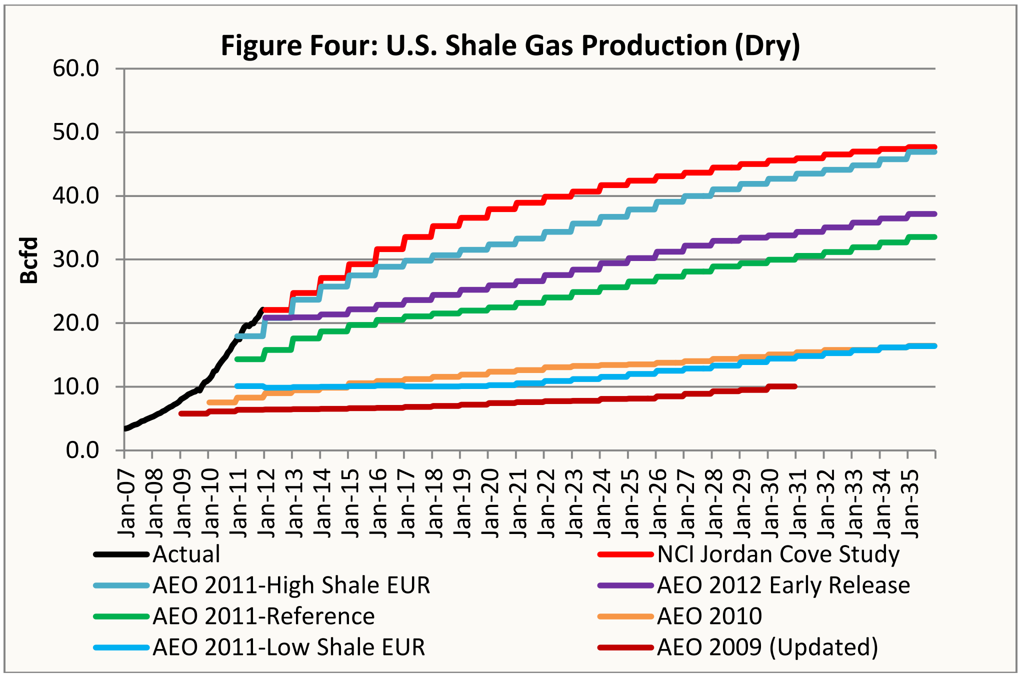
Source: EIA; Lippman/Navigant

The lagging of a forecast behind actual production figures can easily become a long-term issue unless recalibrated. As seen in Figure Three, the AEO2011 Reference case shale gas production forecast that was already eclipsed by a substantial amount by actual production levels in 2011 will be below those current production levels for another eight years; not until 2020 will that Reference case meet today's production levels. While the AEO2012 Early Release Reference case is a step in the right direction (it will match today's production levels in only three more years), the EIA's Report is based on the AEO2011 forecast, and as such appears to assume a significantly underestimated natural gas supply.



Source: EIA; Lippman/Navigant

As noted above, the shale gas production forecasts used in the AEO Reference cases have been low with respect to historical and current production levels. As can be seen following, however, even in the EIA's AEO2011 High Shale EUR case used in the Report, the production forecast appears low. The 2011 forecast production level was eclipsed by actual shale gas production levels in the U.S. in March of 2011, and was about 19% below actual levels at the end of the year.



Source: EIA; Lippman/Navigant

Further, the High Shale case is lower than Navigant's shale gas production forecast used in the market study supporting Jordan Cove's export application, which Navigant believes to be conservative. As outlined in our Jordan Cove Report, Navigant believes its forecast to be conservative as a result of our fundamental basis of projection that requires empirical production data before a resource is included, meaning that forecasts for production from even very large potential plays will be small or zero if the particular play does not have a history of production. This is certainly the case for the Utica Shale, a resource that underlies the prolific Marcellus Shale on the East Coast, but is currently largely undeveloped; while Navigant did not assume any production from the U.S. portion of the Utica Shale in its Jordan Cove Report, it is arguable that it could be producing many multiples of the .5 Bcfd that Navigant estimates for the Canadian portion of the play by the end of the Report's study period.

Given the relationship to both existing production levels and Navigant's forecast, the AEO2011 High Shale EUR forecast can likely be considered low, even as a reference-level case. That conclusion, in turn, helps illuminate the fact that the AEO2011 Low Shale EUR forecast is clearly out of line with current developments, as it already reflects only 50% of actual production, and holds that level for over ten years. Any reliance by the media on the Low Shale case, particularly in combination with a scenario of ultra-high exports, certainly appears misplaced.

Compounding the issue of understated shale production forecasts is the fact that now with the publication of the AEO2012 Early Release, the AEO2011 data underlying the Report is even more dated. Compared to AEO2011, AEO2012 shows a shale gas production forecast increase that averages about 3.5 Bcfd greater than the AEO2011 forecast. This increase in reference case shale gas production beyond that assumed in the Report is actually equivalent to 58% of EIA's assumed low export case incremental volume of 6 Bcfd, or 29% of the assumed high incremental export volume of 12 Bcfd. Using the EIA's updated AEO 2012 forecasts of gas production together with its stated assumptions on export volumes would have led to smaller than the stated price increases.[3]

[3] The understatement of forecast shale volumes due to the dated forecast has an even greater effect on the High Shale EUR case, where the AEO2011 shale production figure for 2025 is 1.42 times that in the Reference case. Using that same factor would give a High Shale EUR increment of 5 Bcfd, based on the 3.5 Bcfd increment in the newly released AEO2012 Reference case. Thus, the effect of the increase in Reference case shale gas production figures on the High Shale EUR figure (i.e. 5 Bcfd) could account for about 83% of EIA's low incremental export volume, or about 42% of the assumed high incremental export volume, in that case.

Media Coverage is Highlighting the Least Representative Scenarios and Metrics

An article on the Report in Platt's Gas Daily noted a 54% gas price increase in 2018 "under the most extreme export volume and gas market assumptions". The article could have clarified that the "extreme" assumptions, while not mutually exclusive, resulted from mixing a baseline case and an export scenario that, by their very nature, do not represent a realistic real-world scenario, but an extremely unlikely combination of assumptions. The 54% gas price increase is a one-year metric that resulted when the Low Shale EUR baseline case is combined with the high export/rapid ramp-up scenario. The fact that one would not expect higher exports in a low shale case was actually alluded to in the Report by EIA, which stated on page 4 that "for purposes of this study, the scenarios of additional exports posted by DOE/FE in their request do not vary across the different baseline cases that are considered. In reality, given available prices in export markets, lower or higher U.S. natural gas prices would tend to make any given volume of additional exports more or less likely." Thus, beyond the fact that the Low Shale EUR forecast itself is already contradicted by actuality, by being 50% below already existing production levels as discussed in the prior section, the combination of the Low Shale EUR forecast with high exports, resulting in the 54% price increase in a given year, is not a realistic outcome on which to focus attention.

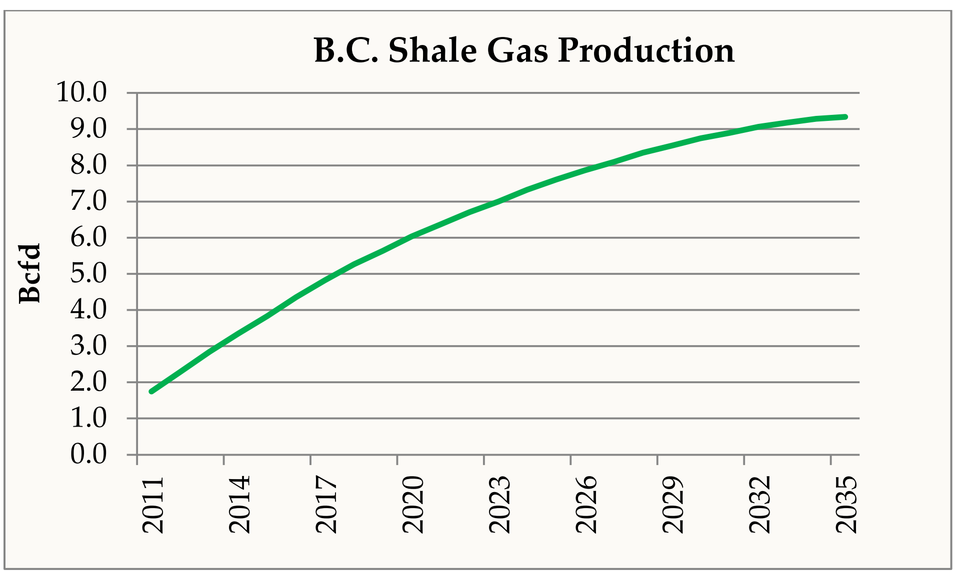
The least unrealistic baseline case-scenario combination from among those offered in the Report would use the High Shale EUR baseline case, which comes closer to a realistic reference case, despite still lagging actual production, as discussed in the prior section. With respect to exports, Navigant's market study supporting Jordan Cove's export application assumes 5.9 Bcfd of U.S. LNG export capacity in the long-term under its "aggregate export" case, designed to be a high end figure comprised of both licensed and generic projects; Navigant thus views the EIA low export case as closer to a reasonable export figure, though still at the high end. In any event, the High Shale baseline together with the low/slow export scenario, while still reflecting assumptions Navigant believes to be low on the production side and high on the export side, generates a maximum-year price increase 74% lower than the quoted 54% figure.

One more point about the media commentary on results concerns the use of maximum, single-year price impacts, as opposed to more generalized measures of sustained impacts, such as changes in price averages over years. As can be seen from the EIA's charts and tables, the average price increases are always a fraction of whatever the maximum-year increase is and illustrated below with respect to the Low Shale EUR scenario.

Export Scenario	Low Shale EUR Case, Percent Price Change	
	Maximum Year	Average, 2015 - 2035
Low/Slow	20%	9%
Low/Rapid	30%	11%
High/Slow	29%	18%
High/Rapid	54%	20%

Canadian Shale Gas Will be a Major Source for Jordan Cove, While the Report Assumes Gulf Coast LNG Export Activity

The location of the Jordan Cove project in the Pacific Northwest is relevant in several ways to an assessment of the Report with respect to Jordan Cove. First, a significant part of the gas feedstock for Jordan Cove will be from Canadian resources, with Navigant's estimates of sourcing being initially 70% from the Western Canadian Sedimentary Basin, shifting down to 35% by 2045, with 50% from the WCSB overall for the full term of the project. As shown below, Navigant estimates future Canadian shale gas supplies from British Columbia will increase from about 4 Bcfd to over 9 Bcfd over the Report's study period - more than adequate to be the primary gas supply source for the Jordan Cove LNG export project. It should also be noted that with the changing dynamics of the U.S. market, stemming from the ample supplies from currently developed and developing U.S. shale plays, the additional demand created by potential LNG exports from the U.S. West Coast is being looked upon increasingly favorably as an important new market for Western Canadian production. U.S. LNG exports would help support gas development in Canada that otherwise could stall or be "stranded" due to the lack of effective access to the US market resulting from less expensive and abundant U.S. domestic gas in other regions.



Source: Navigant

An important aspect of the Report to note is that the Report only focused on LNG exports that would be shipped out of the West South Central Census Division, effectively from LNG export projects in Texas or Louisiana on the Gulf Coast. Due to the strong regional supply and infrastructure in the area, the expectation is that the supply impact of the LNG projects analyzed in the Report would be isolated to Gulf supplies. To the extent Jordan Cove draws on U.S. gas supplies, the supply would in all likelihood be met entirely from supply in the large and growing Rockies supply basin, not from any Gulf area supply. Thus, the Report does not have real pertinence to the Jordan Cove LNG export project because it is based on an analysis and scenarios for LNG export and supply that are tied to a wholly distinct region of the country from a supply and infrastructure standpoint.

It should also be noted that in assuming Gulf Coast exports, the Report specifically did not model any East Coast export facility, the location of which would be suited to the ample supplies coming out of the Marcellus Shale. Had the Report included some assumed LNG export out of the East Coast, the results would likely have yielded lower price impacts due to the size of the Marcellus basin as the most likely supply source for East Coast LNG exports should they develop. This certainly was Navigant's findings in the work done for the Dominion Cove Point LNG export project.

LNG Exports Will Facilitate a Less Volatile U.S. Gas Market

Certain beneficial attributes of providing for increased gas demand by virtue of LNG exports are not clearly susceptible to quantification, and were not dealt with by the Report. An unappreciated but very important aspect of the North American gas market is that reliable demand is a key to underpinning reliable supply and a sustainable gas market. Demand and supply are two parts of a single dynamic. Domestically produced natural gas and then manufactured LNG for export can be an integral part of a healthy natural gas market that achieves a closer balance of supply and demand. In today's market, with a surplus of supply compared to demand, additional baseload LNG export demand offers the ability to sustain the ongoing development of gas supply that fosters a sustainable industry at prices that are more stable and less volatile.

Before the advent of significant shale gas production, the natural gas industry's history reflected periodic periods of 'boom and bust' cycles, partially due to the uncertain nature of the process of exploration and development of natural gas. Driven by uncertainty and risk around the process of exploration process of finding and developing gas supply to meet demand, both for the short and long terms the industry was prone to cycles of over and under supply that often caused prices to rise and fall dramatically. This in itself caused other, second-tier ramifications impacting the investment cycle for supply, causing supply to be frequently out of phase with demand. Due to the uncertainty of the exploration process (and at times the availability of capital to fund such discovery), gas supply suffered from periods where it was 'out of phase' with demand for natural gas by gas fired electric generating facilities and other users on the demand side. These factors contribute to natural gas price volatility. The price volatility itself affected investment decisions, amplifying the feedback loop of uncertainty. In the end, price volatility has been a major cause of limits on the more robust expansion of natural gas as a fuel supply source, despite its advantages over other energy forms as an environmentally clean, abundant and affordable energy resource.

The shale gas resource has a generally lower-risk profile even when compared to conventional gas supply that reinforces its future growth potential. Despite advances in technology, finding and producing conventional gas still involves a significant degree of geologic risk, with the possibility that a well will be a dry hole or will produce at very low volumes that do not allow the well to be economical. In unconventional shale gas, exploration risk is significantly reduced. Resource plays have become much more certain to be produced in commercial quantities. The reliability of discovery and production has led shale gas development to be likened more to a manufacturing process rather than an exploration process with its attendant risk. This ability to control the production of gas by managing the drilling and production process potentially allows supplies to be produced in concert with market demand requirements and economic circumstances.

The dependability of shale gas production as a result of its abundance as well as its reduced exploration risk has the potential to improve the phase alignment between supply and demand, which will in turn tend to lower price volatility. The vast shale gas resource will support a much larger demand level than has heretofore been seen in North America, and at prices that are less volatile due to its production process characteristics. LNG exports, including those from the Jordan Cove LNG export project, therefore should be seen as instrumental in providing the increased demand to spur exploration and development of shale gas assets in North America for the long-term benefit of this country and others.

APPENDIX D.1

List of Landowners for the JCEP LNG Terminal Project

(Privileged and Confidential)