

Life Cycle Carbon and Emissions Analysis

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Submitted to:

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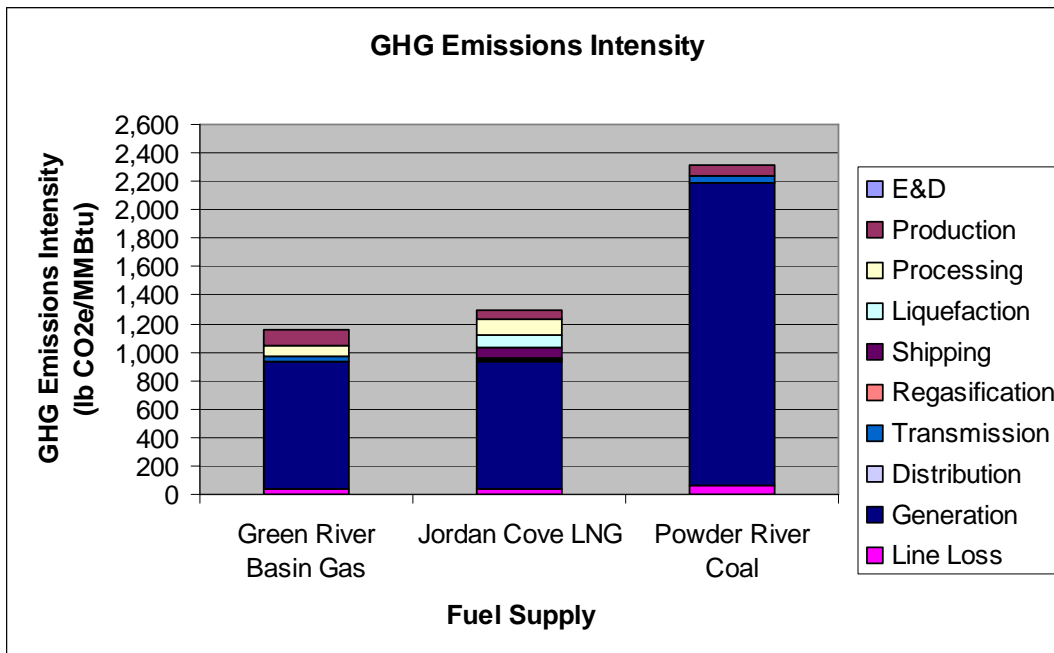
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1 Executive Summary

The purpose of this study was to compare the greenhouse gas (GHG) emissions intensity of fuels imported into Oregon for the purpose of electric power generation. All GHG emissions associated with the fuel, from origin to the burner tip, were estimated so that the emissions intensity of each supply chain could be compared directly. Three fuel supply chains were analyzed: natural gas from the Green River Basin (GRB) in Wyoming, liquefied natural gas (LNG) imported from Peru, Papua New Guinea, and Russia, and coal imported from the Powder River Basin (PRB) in Wyoming. For the purposes of this study, GHG emissions were estimated based on supplying fuel to two existing power plants in Oregon. The Coyote Springs power plant is fueled primarily by natural gas and the Boardman power plant is fueled primarily by sub-bituminous coal; both of these plants are located in Boardman, Oregon and are owned by Portland General Electric. GRB natural gas was assumed to be transported to Oregon via the Ruby Pipeline which is projected to be in operation by 2011. LNG was assumed to be imported from Peru, Papua New Guinea and Russia to the proposed Jordan Cove LNG import terminal. PRB coal is currently being imported to Oregon by the Burlington Northern Santa Fe railroad.

The total GHG emissions intensity for each supply chain was calculated per megawatt-hour of electricity generated. Exhibit 1.1 displays the supply chain emissions intensity for GRB gas, imported LNG, and PRB coal.

Exhibit 1.1: Fuel Supply Chain Greenhouse Gas Emissions Intensity



Emissions from fuel combustion during generation dominate the total supply chain emissions picture. The remaining portion of supply chain emissions is due to fugitives, venting, and combustion for energy to move the fuels through the chain.

2 Introduction

The life cycle GHG emissions intensity analysis of fuel supplies for power generation in Oregon required the breakdown of each supply chain into individual sectors. Emissions from major GHG emission sources were estimated in each sector and summed to determine the total emissions intensity per megawatt-hour for generating electricity from fossil fuels in Oregon.

The Green River Basin natural gas supply chain consists of six sectors: exploration and drilling, production, processing, transmission, distribution, and consumption. The current state of the North American natural gas industry is well defined by data from the US Energy Information Administration, and greenhouse gas emissions from the natural gas industry are estimated in the *Inventories of US Greenhouse Gas Emissions and Sinks: 1990 – 2006*. The US Inventory estimates methane emissions from oil and natural operations on a source level. The inventory also estimates non-energy CO₂ emissions that are associated with natural gas fugitives and venting (CO₂ is present in low concentrations in natural gas). Using activity data from the US Inventory as well as the Oil and Gas Journal's Worldwide Processing Survey, the upstream emissions intensity for exploration and drilling, production, and processing were estimated for the GRB. Emissions associated with transporting natural gas from the GRB to Oregon via the Ruby pipeline were calculated from the energy requirements to move the gas as well as fugitive and vented emissions along the pipeline. Gas is supplied to the Coyote Springs power plant by the Gas Transmission Northwest (GTN) pipeline. As the Ruby pipeline has an interconnect with the GTN pipeline downstream of the Coyote Springs power plant in Malin, OR, natural gas can be backed out of the GTN pipeline between Coyote Springs and Malin while still meeting demand further south. Natural gas is consumed in the Coyote Spring plant for electricity generation at a heat rate of 7,637 Btu/kWh.

Imported LNG into Jordan Cove shares the same six sectors as GRB natural gas with the addition of three extra steps: liquefaction and loading, shipping, and regasification and storage. The United States currently has eight active LNG import terminals along the East and Gulf coasts¹. The EIA tracks LNG imports delivered to these terminals, but does not have data on the activity upstream of the import terminals in the countries of origin. Downstream of the import terminals, LNG is regasified and enters the US transmission and distribution systems as any other supply of natural gas. Natural gas losses through fugitives, venting, and consumption upstream of the LNG import terminal were estimated to calculate the amount of natural gas that must be produced in each foreign country to satisfy the fuel requirements of the Coyote Springs power plant. For the purposes of this study, it was assumed that Peru, Papua New Guinea, and Russia would each export equal amounts of LNG to Jordan Cove. Sakhalin Island LNG is scheduled to start operations in late 2008, while Peru LNG is projected to start exporting

¹ These facilities include Everett, MA, Cove Point, MD, Lake Charles, LA, Freeport, and TX, Sabine, LA. Two terminals in the Gulf of Mexico and Offshore Boston can only receive special LNG tankers with regasification equipment on board.

LNG in 2010² and Liquid Nuigini LNG will start exporting in 2012³. Natural gas produced in these countries will be processed to remove heavier hydrocarbons and liquefied for oversea delivery to the Jordan Cove import terminal. Jordan Cove is expected to be operational by late 2012 and will have a natural gas transmission pipeline with interconnects to the Northwest pipeline near Roseburg, OR and the GTN pipeline at Malin, Or.

Coal from the Powder River Basin is delivered to Oregon through a different supply chain than that of natural gas. There are, however, some similarities between individual sectors for these different fuels. Coal mining is similar to natural gas production in that it involves the removal of the product from ground. Coal in the PRB is primarily surface mined using a truck and shovel method. The run-of-mine (ROM) coal is then processed in a coal preparation plant before it is transported by rail to Oregon. The Boardman power plant has coal delivered from the Buckskin mine near Gillette, Wyoming by the BNSF railroad. The Boardman plant is a 585 MW steam turbine plant that operates at a heat rate of 9,911 Btu/kWh.

² Peru LNG. Frequently Asked Questions.

<https://portal.perulng.com/irj/go/km/docs/documents/PLNG%20Website/English/Static%20Content/faqPopUp.html>

³ Liquid Nuigini Gas. Projects. <http://www.liquidniuginigas.com/project/>

3 Natural Gas Supply Chains

Natural gas is produced worldwide on its own and in conjunction with oil production. As domestically produced natural gas becomes more expensive, imported natural gas in the form of LNG becomes a viable option. Natural gas, regardless of the origin is produced and delivered to demand regions using similar methods. The natural gas supply chain consists of the six basic steps: exploration and drilling, production, processing, transmission, distribution, and consumption. Liquefying and delivering gas overseas requires the additional steps of liquefaction, shipping, and regasification.

Natural Gas Exploration and Drilling

Natural gas reserves are discovered through geological surveys and developed into new production through the drilling of exploratory wells. New wells that drill into a producing formation are completed and tied into gas sale pipelines. Major GHG emissions sources associated with exploration and drilling include diesel combustion in drilling rigs and natural gas venting and flaring during gas well completion. Driving factors that can have an effect on the magnitude of GHG emissions include average well depth, type of well (oil with associated gas or non-associated gas) and the fraction of gas wells requiring hydraulic fractures to stimulate production.

In 2006, it was estimated that over 9,000 exploratory and developmental wells were drilled in the Rocky Mountains region. Natural gas well drilling in the GRB was assumed to have the same emissions intensity as drilling operations in the Rocky Mountains region as a whole. The GRB contains approximately 281 fields with over 12 Tcf of natural gas reserves and is one of the largest formations in the United States⁴. The Rocky Mountains region contains a large number of unconventional wells that generate large well venting emissions associated with completion activities. In the LNG imports scenario, only wells drilled (oil and gas) for the purposes of producing gas to meet the demand requirements of the Coyote Springs power plant (after accounting for losses along the supply chain) are counted in the supply chain emissions. Emissions from exploration and drilling are small and account for less than one percent of supply chain emissions in both the PRB and imported LNG scenarios.

Natural Gas Production

Natural gas is produced from associated gas wells that produce both oil and gas, non-associated gas wells that produce gas only, and unconventional wells such as coal-bed methane wells. GHG emissions from natural gas production are driven by the amount of gas produced, the type of wells producing the gas, and the age and upkeep of producing wells. After the gas is produced from the well it must be delivered to gas processing facilities. Greenhouse gas emissions from gathering and boosting compressors were calculated based on the amount of horsepower required to deliver the gas through gathering pipelines to the processing plant and the fuel used by the compressors.

⁴ http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/maps/GGR_GAS.pdf

Rocky Mountains regional natural gas is produced through a mix of associated, non-associated, and unconventional wells; the average natural gas production rate from individual wells in the Rockies is only around 50 million cubic feet per year whereas natural gas wells from countries exporting LNG can have production rates much higher than those seen in the United States. The larger number of wells needed in the Rockies to produce enough gas to meet the fuel requirements of the Coyote Springs power plant as compared to imported gas will result in larger emissions. Each producing well or group of producing wells require ancillary equipment such as heaters, separators, glycol dehydrators, condensate tanks, compressors and meters in order to treat and deliver the gas to processing plants. This equipment is all prone to fugitive leaks and venting emissions during normal operations as well as in upset conditions. GHG emissions intensity from GRB production was 112 lb CO₂e/MWh as compared to 65 lb CO₂e/MMBtu for Jordan Cove LNG.

Natural Gas Processing

The carbon-dioxide (CO₂), methane (CH₄), and nitrous oxide (N₂O) emissions for the natural gas processing sector were estimated using the ICF Gas Processing GHG Model. The model calculates source specific CO₂, CH₄, and N₂O emissions from individual gas processing facilities in the United States. The configuration of each plant was estimated from details in the Worldwide Processing Survey from the Oil and Gas Journal. Both direct (combustion, fugitive and vented/flared) and indirect (imported electrical power) emissions are estimated for each U.S. processing plant. The emissions intensity of GRB gas processing was assumed to be equivalent to the Rocky Mountain gas processing emissions intensity.

Gas processing emission in LNG exporting countries was estimated from the ICF Gas Processing GHG Model. Data from the OGJ's Worldwide Processing survey was used to create an "average" gas processing plant in each country exporting LNG to Jordan Cove. The Worldwide Processing survey tracks individual processing plants in operation across the globe and contains data on the capacity, throughput, processes, and gas liquid production from each plant. The "average" gas processing plants developed for each country of interest are assumed to include Acid Gas Removal (AGR) units for the removal of CO₂ and hydrogen sulfide (H₂S) and dehydrators with molecular sieves for the extraction of water from the natural gas feed as these impurities will cause difficulties in gas liquefaction downstream of the processing plant. The gas processing plants also required fractionation for the removal of heavy hydrocarbons when the throughput was associated gas whereas, little fractionation was required for non-associated gas throughput. Indirect emissions associated with the purchase of electricity used in the fractionation process was not included as part of the natural gas supply chain. This electricity is used to extract natural gas liquids as a separate product and should not be attributed to the residue natural gas. Gas throughput and CO₂ content of the gas were adjusted in the representative plant to match the production characteristics of the producing country. Emissions intensity from gas processing was 75 lb CO₂e/MWh for GRB natural gas and 119 lb CO₂e/MWh for imported LNG.

Natural Gas Liquefaction and Loading

The volume of natural gas consumed by the liquefaction process was estimated by conducting an energy and material balance around the LNG liquefaction plant and

loading activities. Specifications from the Pluto LNG and Darwin LNG projects in Australia, as well as the ConocoPhillips Optimized Cascade process were utilized to construct a generic LNG liquefaction plant and loading model⁵. Liquefaction facilities located in cold temperature climates are able to achieve high fuel efficiencies. The GE Aerodrive turbines used to power the Darwin LNG Project show greatly improved heat rates and power output at low ambient temperatures⁶. For the purposes of this study it was assumed that LNG liquefaction in Sakhalin Island, Russia has 50% better fuel efficiency.

The fuel required for the loading activities is dependent on the natural gas consumed by the electric power generators and boil off compressors. The natural gas fired generators are used to run the loading pump used to deliver LNG from the storage tanks to the LNG carriers as well as satisfy the base electricity needs of the liquefaction plant. The loading pump horsepower was calculated by assuming a twelve hour loading time to fill an average ship capacity of 135,000 m³ of LNG. These generators have a higher fuel requirement during loading operations however they are assumed to be functional throughout the year. For the purposes of the study, the generators were assumed to have a duty of 25% capacity during non-loading operation.

Older LNG liquefaction plants with small boil-off gas compression systems vent or flare excess natural gas during loading operations. The new LNG liquefaction and storage plants in Peru, Papua New Guinea, and Russia were assumed to have boil-off compressors sized to meet not only the daily boil-off rate but also having an additional compressor designed to handle gas from the ship vapor return lines during loading activities. The amount of natural gas required to fuel the boil-off compressor is based on the horsepower requirement of the compressor, and is assumed to operate throughout the year. The ship vapor recovery compressor is assumed to have a similar horsepower requirement as the boil-off, operating only during loading.

Total natural gas consumption as fuel for liquefaction and loading was estimated to be around eight percent of the amount of gas liquefied and delivered to the U.S. This represents an emissions intensity of 81 lb CO₂e/MWh for imported LNG.

LNG Shipping

LNG is transported in specialized cryogenic tankers that keep the LNG insulated to minimize boil-off during the voyage. LNG tankers can be fueled in a number of ways: boil-off fired steam plants, dual fired boil-off gas and diesel, and diesel only with boil-off gas reliquefaction. All LNG shipping was assumed to use a dual fired engine that consumes boil-off gas for 80 – 90 percent of its fuel requirements and makes up the rest with diesel. The average tanker size was assumed to be 135,000 m³, while Jordan Cove is projected to be capable of unloading ships as large as 217,000 m³. Voyage duration was estimated using a service speed of 19.5 knots to cover the approximate distance between the port of origin and destination terminal. The shipping distance between the

⁵ ConocoPhillips. "ConocoPhillips Optimized Cascade Process." March. 2006.

http://lnglicensing.conocophillips.com/lng_tech_licensing/cascade_process/index.htm

ConocoPhillips. "Darwin LNG – Environment." March 2006. www.darwinlng.com/Environment/Index.htm

Pluto LNG. "Emissions, Discharges, and Wastes." <http://standupfortheburrup.de/downloads/05emissionsdischargesandwaste.pdf>

⁶ GE. "GE Aero Energy." January 2008. www.gepower.com/prod_serv/products/aero_turbines/en/downloads/1m2500plus.pdf

point of origin and the Jordan Cove import terminal was estimated to be 4,479 miles, 5,991 miles, and 3,875 miles for Peru, Papua New Guinea, and Russia respectively. LNG boil-off along the voyage was estimated using a 0.15 percent of cargo capacity per day boil-off rate for the laden voyage. The LNG tanker was assumed to keep a small heel of LNG in its tanks to maintain cryogenic temperatures on the unladen voyage. Maintaining cryogenic temperatures is necessary to avoid lengthy cool-down periods before reloading the ship with LNG for its next delivery. This heel was estimated to be 200 percent of the boil-off fuel required for the laden voyage. Emissions intensity for LNG shipped to Jordan Cove was estimated at 70 lb CO₂e/MWh.

LNG Storage and Regasification

After delivery to the United States, imported LNG is offloaded from the ship and stored in large cryogenic tanks before regasification. Jordan Cove is designed to store around 320,000 m³ of LNG with a gas design sendout capacity of 1 Bcf per day, however, the actual sendout rate is anticipated to be approximately 800 MMcf per day. Before regasification, LNG is pumped up to transmission pressure for injection into the pipeline. LNG received by Jordan Cove was assumed to be regasified using a combination of submerged combustion vaporizers (SCV) and exhaust heat from a cogeneration facility. SCVs are a mature technology with a high thermal efficiency resulting in less gas consumption than alternative vaporization methods. It was assumed that 80% of LNG send-out from the Jordan Cove terminal was vaporized using SCVs. The SCV was calculated to require around 1.5 percent of the gas send-out as fuel for vaporization; this calculation matches well with SCV vendor literature⁷. The remaining 20% of sendout is vaporized through recovery of waste heat from a cogeneration facility. LNG vaporization from cogen waste heat is not as efficient as an SCV and will have a higher GHG emissions intensity per unit of LNG vaporized. The increase in emissions intensity due to using this less efficient method of vaporization is small but, in the case of Jordan Cove, also produces around 40 Mw of power. The benefits of this local source of power generation from the Jordan Cove cogen plant are not quantified as part of this study. Electric power from this facility will increase reliability of the local electric grid as well as delivering power to close-by markets with relatively small losses as compared to power that is generated and transmitted over long distances. Emissions intensity for all regasification operations at Jordan Cove were estimated as 14 lb CO₂e/MWh.

Natural Gas Transmission

Emissions from the transport of natural gas in North America occur chiefly from gas engine exhaust at compressor stations located along the natural gas pipelines. To calculate emissions, the amount of fuel used by the compressor was needed. The fuel consumption was calculated from the horsepower and efficiency of the compressor. Centrifugal compressor horsepower was obtained from the *Inventory of US Greenhouse Gas Emissions and Sinks: 1990 - 2006*, while the value for compressor efficiency was obtained from the *Standard Handbook of Petroleum and Natural Gas Engineering*. Emissions factors from the API Compendium were then applied to the calculated fuel

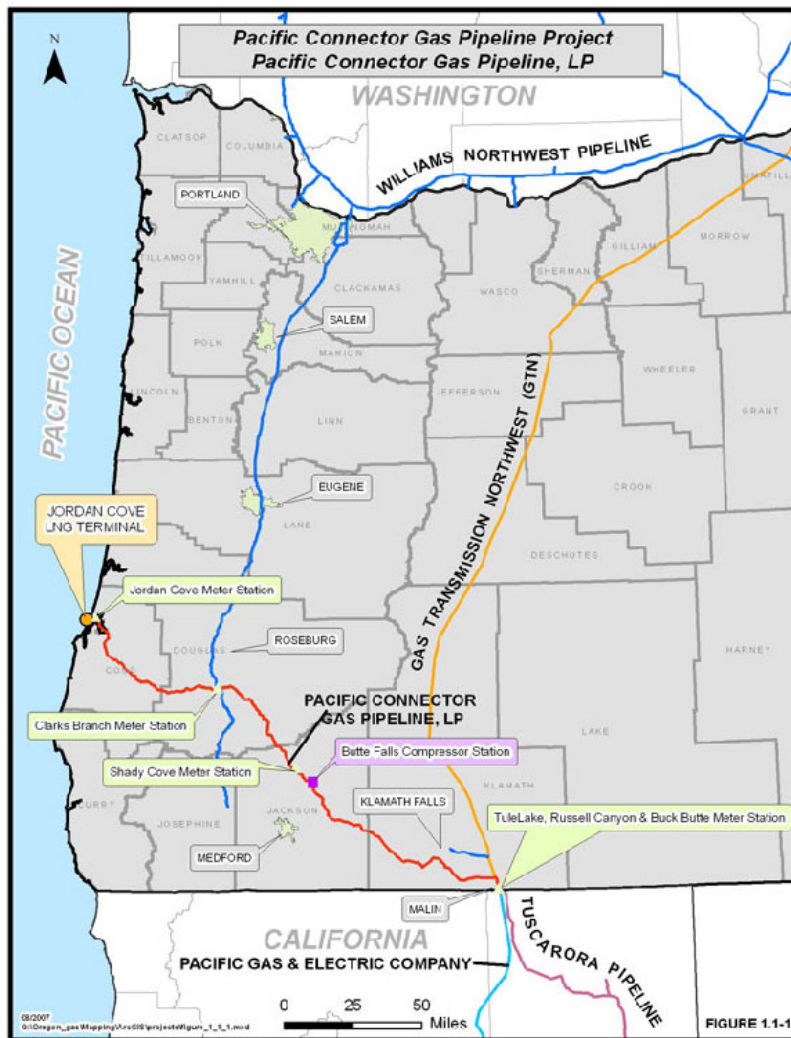
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[http://www.selasfluid.com/international/web/le/us/likeextllsfus.nsf/0/DF177ED5545D2251852572B10066C7A2/\\$file/LNG%20Brochure.pdf](http://www.selasfluid.com/international/web/le/us/likeextllsfus.nsf/0/DF177ED5545D2251852572B10066C7A2/$file/LNG%20Brochure.pdf)

use, thus determining combustion emissions from transmission compressors. Fugitive and venting emissions also occur during natural gas transmission. The intensity of fugitive and venting emissions along the pipelines from the GRB to the Coyote Springs power plant was assumed to be the same as the national average.

Exhibit 3.1 shows the major transmission pipelines in Oregon including the proposed Pacific Connector pipeline. The Ruby pipeline from the GRB (not shown) spans 680 miles and connects with other major pipelines in Malin, OR. Because the GTN pipeline flows from north to south, gas from the GRB will not actually be delivered to the Coyote Springs. Instead, natural gas will be taken off of the GTN line to supply Coyote Springs and the additional gas supplied by the Ruby pipeline will be used to meet demand downstream. The gas taken off of the GTN pipeline for Coyote Springs will no longer travel south to Malin and therefore emissions associated with moving gas through that stretch will be deducted from the GRB transmission emissions intensity. The transmission emissions intensity for gas from the GRB was estimated as 39 lb CO₂e/MWh.

Exhibit 3.1: Major Natural Gas Transmission Pipelines in Oregon



Source: Pacific Connector Gas Pipeline Project

LNG imports entering the domestic transmission system from Jordan Cove will use the Pacific Connector pipeline. The gas from Jordan Cove will free-flow without additional compression down the Pacific Connector pipeline to Malin, OR at the anticipated 800 MMscf per day sendout rate. As in the GRB supply scenario, gas supply to the Coyote Springs plant would be taken off of the GTN pipeline. Emissions associated with moving the plant fuel to Malin, OR will be deducted from the LNG import transmission emissions intensity. The net emissions intensity of gas transmission from Jordan Cove was estimated to be 17 lb CO₂e/MWh.

Natural Gas Distribution

Natural gas consumed by residential and commercial customers is usually delivered via low pressure distribution systems. Natural gas fired power plants require a high pressure natural gas source to fuel their large generators. It was assumed in this analysis that natural gas delivered to the Coyote Springs power plant was taken directly off of the transmission pipeline and therefore no emissions from gas distribution would be part of the supply chain.

Natural Gas Consumption - Coyote Springs Power Plant

Natural gas delivered to the Coyote Springs power plant is combusted to generate electricity. In 2007, nearly 11 trillion Btu were delivered to Coyote Springs and used to generate 1.4 million MWh of electricity. The overall heat rate of the plant was 7,637 Btu/kWh; the heat rate represents the overall generation efficiency of the plant. Any operations within the plant that have an energy requirement will factor into the overall heat rate. The emissions intensity of generate power at the Coyote Springs power plant was estimated as 894 lb CO₂e/MWh. This is by far the largest source of GHG emissions in both the GRB gas and Jordan Cove LNG supply chains.

Transmission Line Loss

After generation, electric power must be transmitted to demand areas using high-voltage overhead lines. In Oregon the preponderance of natural gas fired power generation facilities are located east of the Cascade Mountains, adjacent to the GTN pipeline yet the majority of electric demand is located west of the Cascade Mountains. High voltage lines are used to reduce resistive losses of electric power along the journey from plant to consumer. For the purposes of this study it was assumed that 3% of the power generated at the Coyote Springs plant was lost over 150 miles of 500 kV line between Boardman, OR and Portland, OR. To make up for these losses, more power must be generated at Coyote Springs than is required by consumers. Additional generation will result in GHG emissions along the entire supply chain; these emissions from all supply chain sectors are accounted for separately under the transmission line loss heading. The total emissions intensity from the additional generation load to make up for line losses was estimated as 34 lb CO₂e/MWh delivered for GRB gas and 38 lb CO₂e/MWh delivered for Jordan Cove LNG.

4 Coal Supply Chain

The Powder River Basin in Wyoming is one of the largest coal producing areas in the United States. Much of the coal in the PRB is close enough to the surface such that surface mining operations can easily remove the coal. The Boardman power plant is the only coal-fired plant in Oregon and is typically supplied by the Buckskin coal mine near Gillette, Wyoming. Coal from the Buckskin mine is sub-bituminous with a heat content of 8,368 Btu/lb and 5.5 wt percent ash content⁸. The Buckskin mine is a shovel and truck style surface mine that is capable of producing 20 million short tons of coal per year. The fuel demand at the Boardman plant is only 2.5 million short tons per year, so the Buckskin mine is capable of supplying 100 percent of the required fuel for the plant. Steps in the coal supply chain include mining, coal preparation, loading, transportation, and consumption.

Powder River Basin Coal Mining

Typical coal seam depth in the PRB is around 120 feet below the surface; removal of the overburden layer must occur before the coal itself can be extracted. Surface mines often use explosives to blast overburden and aid in exposing the coal seam. GHG emissions from explosive use at the Buckskin mine are assumed to be negligible⁹. The shovel and trucks used to remove the overburden and coal are diesel fueled and contribute the majority of emissions from mining. The excavators used in the Buckskin mine were assumed to be a 3,000 hp machine with a 44 cubic yard shovel capacity; the specs of the Liebherr R 996 Litronic¹⁰ excavator were used to approximate the excavators at the Buckskin mine. The trucks used in the Buckskin mine were approximated using the specifications of the 400 ton capacity Liebherr T 282 B¹¹ mining truck. Exhibit 4.1 details the parameters used to develop the emissions associated with mining coal from the Buckskin mine.

Exhibit 4.1 Buckskin Coal Mine Parameters

Coal seam depth	120	feet
Overburden removed	25,000,000	cubic yards per year
Coal production capacity	20,000	tons per year
Coal storage capacity	61,500	tons
Coal storage recharge rate	3,000	tons per hour
Coal loading rate	6,000	tons per hour
Coal heat content	8,368	Btu per pound
Coal ash content	5.50%	by weight
Coal required by Boardman Plant	7,061	tons per day

⁸ BNSF. Powder River Basin Mine Guide. <http://www.bnsf.com/markets/coal/mineguide/buckskin.html>

⁹ ICF's IPM coal module indicates that less than \$1 is spent on explosives per short ton of coal produced from truck and shovel surface mines.

¹⁰ Liebherr. Technical Description R 996 Litronic.

<http://www.liebherr.com/catXmedia/me/Documents/d62a49e0-e1b9-47f0-b16e-8483b4895c7f.pdf>

¹¹ Liebherr. Technical Description T 282 B. <http://www.liebherr.com/catXmedia/me/Documents/4d7c384c-6b38-48db-ace0-bf1b95b65013.pdf>

Other emission sources at the coal mine include water pumps and methane venting. Water pumps are necessary to remove water from the low areas of the mine so that the machines can work freely. The water pumping duty has been estimated as double the average rainfall amount in Gillette, WY; this accounts for rainfall as well as water that is contained in the seam itself. The coal-bed methane wells in the PRB that produce large amounts of water tap into coal seams that are much deeper underground than the seam on which the Buckskin mine operates. There is very little water removal in surface mining operations in the PRB. Methane gas is released into the atmosphere as the coal is broken up and removed from the earth. The majority of the methane is released during mining, but methane continues to vent from the coal throughout the supply chain. Total emissions intensity for mining coal from the Buckskin mine was estimated to be 67 lb CO₂e/MWh.

Coal Preparation Plant

Run-of-mine coal is delivered by truck to the coal preparation plant. Preparation plants are typically used to remove impurities in the coal and crush it to a manageable size for transportation. Coal from the PRB does not require as much preparation as coal from other areas, such as Appalachia, and is generally only crushed and screened. In this analysis, the ROM coal is assumed to be crushed into three to six inch chunks in a rotary breaker. The breaker modeled has a capacity of 1,500 tons/hour with a 12 foot diameter table and is 22 feet in length. The electricity requirements to operate this rotary breaker are small and the resulting GHG emissions are negligible.

Coal Loading

After coal passes through the preparation plant, it is loaded into railcars for transportation to the Boardman power plant. Emissions from loading have been approximated by calculating the energy requirements for lifting coal 40 feet by conveyor belt to load railcars from above. These energy requirements are also very small and the resultant GHG emissions are negligible.

Coal Transportation

The loaded railcars are transported to the Boardman power plant by the BNSF railroad. The route to the Boardman plant runs from Gillette, WY through Sandpoint, Idaho then into Boardman, OR¹². The laden voyage is approximately 1,000 miles and the diesel consumption of the locomotive is estimated as the 423 ton-miles/gallon fleet average¹³. This fuel efficiency measurement is calculated by the cargo weight, but the life cycle analysis must include fuel consumed along the total roundtrip from Buckskin to Boardman and back. Therefore, the weight of the un-laden railcars returned to the Buckskin mine were assumed to be 20 percent of the laden weight and the return

¹² BNSF. BNSF Coal Network. http://www.bnsf.com/markets/coal/pdf/coal_energy.pdf

¹³ Association of American Railroads. Freight Railroads and Greenhouse Gas Emissions. http://www.aar.org/GetFile.asp?File_ID=466

distance was again 1,000 miles. The emissions intensity for transporting coal to the Boardman power plant was estimated to be 45 lb CO₂e/MWh.

Coal Consumption – Boardman Power Plant

Coal delivered to the Boardman power plant is pulverized and combusted to generate electricity. In 2007, over 43 trillion Btu were delivered to Coyote Springs and used to generate 4.3 million MWh of electricity. The Boardman plant uses a steam turbine generator with an overall heat rate of 9,911 Btu/kWh; the heat rate represents the overall generation efficiency of the plant. Any operations within the plant that have an energy requirement such as the pulverization of the coal will factor into the overall heat rate. One emissions source not factored into the heat rate are emissions associated with disposal of the ash generated by burning coal. This ash is hauled away and disposed in an on-site landfill. The emissions intensity of generated power at the Boardman power plant was estimated as 2,128 lb CO₂e/MWh. This is by far the largest source of GHG emissions in PRB coal supply chain.

Transmission Line Loss

As the Boardman power plant is in close proximity to the Coyote Springs plant, the same assumptions were used for transmission line losses. Three percent of the power generated at the Boardman plant was assumed to be lost over 150 miles of 500 kV line between Boardman, OR and Portland, OR. The total emissions intensity from the additional generation load to make up for line losses was estimated as 67 lb CO₂e/MWh for PRB coal.

5 Results

Greenhouse gas emissions from generating electricity in Oregon’s power plants are dependent on a number of factors. Natural gas supplied to Oregon will have different emissions intensity depending on the origin of the gas. Imported LNG has a higher GHG emissions intensity due to the additional, energy-intensive liquefaction and shipping processes necessary to deliver the gas overseas. Exhibit 5.1 shows the supply chain emissions intensity of both GRB gas and Jordan Cove LNG.

Exhibit 5.1 Natural Gas Supply Chain Emissions Intensity

	GHG Emissions Intensity (lb CO ₂ e/MWh Delivered)	
	Green River Basin Gas	Jordan Cove LNG
Exploration and Drilling	2.77	0.61
Production	111.91	65.60
Processing	75.30	118.79
Liquefaction	0.00	80.54
Shipping	0.00	70.11
Regasification	0.00	13.87
Transmission	39.19	17.44
Distribution	0.00	0.00

Emissions from electrical power generation at Coyote Springs have been omitted from Exhibit 5.1 as they are equivalent for both the GRB natural gas and Jordan Cove LNG. Emissions from the additional liquefaction, shipping, and regasification nearly double the total emissions intensity of the supply chain steps before consumption.

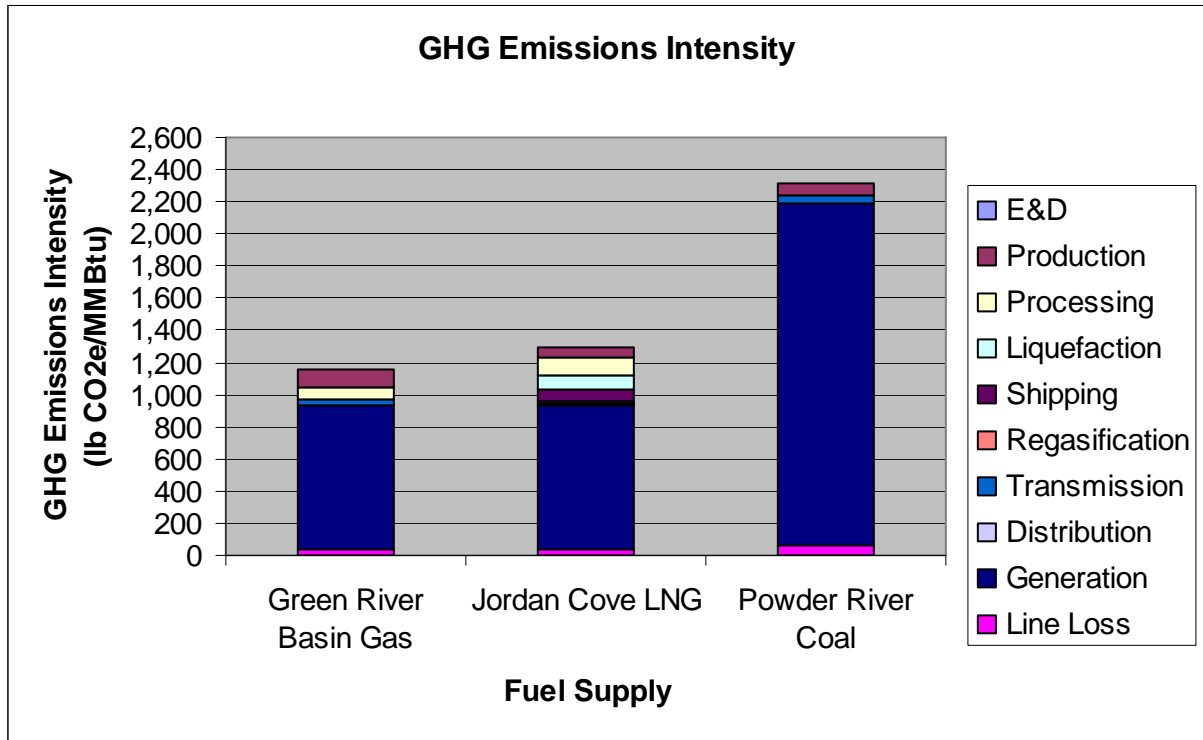
Emissions intensity of supplying coal to the Boardman plant are shown in Exhibit 5.2. Emissions intensity of electric power generation is omitted from Exhibit 5.2 so that the details of the other step may be shown. Note that the emissions intensity at the Boardman plant and Coyote Springs plant are not equivalent. The coal supply chain emissions intensity up to electricity generation is approximately half that of PRB natural gas. The production and transportation of coal has similar emissions intensity to the equivalent steps in the natural gas supply chains. Coal, however, does not require energy intensive processing steps as required to remove impurities and extract gas liquids from natural gas.

Exhibit 5.2: Coal Supply Chain Emissions Intensity

	GHG Emissions Intensity (lb CO₂e/MWh Delivered)		
	Green River Basin Gas	Jordan Cove LNG	Powder River Coal
Exploration and Drilling	2.77	0.61	0.00
Production	111.91	65.60	67.35
Processing	75.30	118.79	0.01
Liquefaction	0.00	80.54	0.00
Shipping	0.00	70.11	0.00
Regasification	0.00	13.87	0.00
Transmission	39.19	17.44	45.25
Distribution	0.00	0.00	0.00

When the emissions from electric power generation step in the supply chain are factored in, the overall emissions intensity of coal is nearly double that of both GRB gas and Jordan Cove LNG. The steam turbine generator at the Boardman plant is much less efficient than the combined cycle Coyote Springs generator resulting in greater energy input to generate the same amount of electricity. Exhibit 5.3 shows the generation component of the supply chain; emissions intensity of the Boardman plant is 2,128 lb CO₂e/MWh versus the 894 lb CO₂e/MWh of the Coyote Springs plant.

Exhibit 5.3: Total Fuel Supply Chain Emissions Intensity



From a greenhouse gas emissions standpoint, supplying fuel for Oregon’s existing electric power generation infrastructure needs is best served by domestically produced natural gas. Liquefied natural gas imported into the proposed Jordan Cove LNG terminal has a slightly higher greenhouse gas emissions footprint, but is still significantly lower than the footprint created from burning PRB coal for electric power generation.