Response to

Governor Kulongoski's

Request for LNG and Natural Gas Review

Oregon Department of Energy

May 7, 2008

Table of Contents

Executive Summary

Introduction

On February 14, 2008, Governor Kulongoski wrote the Federal Energy Regulatory Commission, insisting that the Commission's review of liquefied natural gas facilities (LNG) in Oregon stop until the Commission conducts a comprehensive review of all alternatives to supplying natural gas in the region. Governor Kulongoski also directed the Oregon Department of Energy to do the following: 1) conduct an evaluation of the need for natural gas; 2) conduct a evaluation of alternatives to providing natural gas to the region; and 3) review the life cycle carbon costs and emissions of liquefied natural gas, compared to coal and to non-LNG sources of natural gas.

Findings

1. Natural Gas Demand

1. Oregon uses natural gas in electricity production and for industrial uses. Many Oregon homes use natural gas as their primary home heating source.
2. Oregon imports 100 percent of its natural gas, mainly from Canada and the Rocky Mountain states.
3. Natural gas consumption in Oregon and the U.S. will likely rise over the next 20 years, while Canadian exports are expected to decrease.
4. A new pipeline from the Rocky Mountains or one LNG terminal could more than meet Oregon's increasing natural gas needs.

2. Alternatives for Natural Gas Supply to Oregon

1. A number of LNG terminals and natural gas pipelines have been proposed for Oregon. Each of the proposed LNG terminals and proposed pipelines has various environmental and socio-economic impacts on Oregon.
2. Not all of the proposed LNG or pipeline projects will serve Oregon loads to the same extent, although each could present additional indirect benefits. The Jordan Cove LNG terminal, and the Bronco and Ruby Pipelines would not serve most major Oregon markets. They would provide natural gas to California, freeing up natural gas from Canada and elsewhere which currently serves California. This gas could then serve Oregon.
3. Natural gas production from the Rocky Mountains is currently increasing and would likely be less expensive than LNG, given competition from Asian countries for Pacific Basin LNG.
4. An Oregon LNG terminal could result in lower pipeline costs to an Oregon utility if LNG prices were comparable to Rocky Mountain natural gas. However, it is unlikely that LNG terminals in Oregon would result in lower prices because of LNG market dynamics. Pacific Basin LNG is not currently competitive from a price standpoint with U.S. and Canadian-produced natural gas.

5. There is significant unused LNG terminal capacity on the Gulf and East coasts, raising further questions about the need for LNG terminals in Oregon.

3. Life-Cycle Greenhouse Gas Emissions

1. For electricity generation and direct use, LNG has more greenhouse gas emissions (GHG) than North American piped natural gas because of the fuel used in shipping, liquefying and regasifying gas.
2. Much of the future growth in LNG production is forecast to come from the Middle East. Transshipments from the Middle East to Oregon would be over 10,000 nautical miles, resulting in significant life cycle greenhouse gas emissions.
3. It is likely that natural gas emissions from re-gasification at LNG terminals in Oregon will be included in regional or U.S. greenhouse gas cap-and-trade regimes. This could make it more difficult for Oregon to meet its statutory greenhouse gas reduction targets. It is also possible that LNG liquefaction and transport emissions will be included in future international agreements.

Discussion

1. Natural Gas Demand

Demand for natural gas is on the rise. U.S. natural gas consumption is expected to increase by 0.3 percent per year through 2030 if no additional actions are taken to reduce greenhouse gas emissions. Natural gas consumption in Oregon is likely to rise as population increases, despite downward pressure on natural gas consumption in Oregon due to energy efficiency measures, increased carbon costs under certain climate change legislation, high natural gas prices, and in the event of a national economic recession. If federal climate change legislation is enacted, the rise in natural gas demand could be steeper due to fuel switching away from coal until and if, carbon capture and storage becomes feasible. Overall, natural gas consumption in Oregon and the U.S. will likely rise over the next 20 years.

As a whole, North American natural gas production is expected to be flat or decline over the next several years. Eighty-one percent of U.S. natural gas consumption is currently served by domestic supplies and 86 percent of imports come from Canada. The U.S. Department of Energy’s Energy Information Administration (EIA) expects a drop off in Canadian production, but a slight increase in U.S. production between Alaska and the current activity in the Rocky Mountain states.

EIA projects that demand for natural gas will rise until carbon capture and storage (CCS) becomes feasible and coal-fired power plants again become dominant. The Northwest Gas Association projects that Northwest natural gas demand will grow by 1.9 percent annually through 2012.

2. *Alternatives for Natural Gas Supply to Oregon*

- ***Proposed LNG Facilities and Proposed Pipelines***

There are currently three proposals to build LNG terminals in Oregon with many things in common and some key differences. Each is sited on a riparian area near a sensitive salmon population and requires dredging to accommodate LNG tankers. These tankers will pass near population centers. All terminal proposals have similar storage facility design. Each terminal also requires the construction of a pipeline to carry the gas to market.

In addition, five pipelines—Ruby, Bronco, Sunstone, Blue Bridge and Palomar—are also being proposed in and/or through Oregon. Some of these pipelines would be in direct competition to serve the same natural gas demand as the LNG terminals. As an alternative to an LNG terminal, some of these new pipelines would run between the Opal Hub in Wyoming and Oregon. Two of the pipeline proposals, Ruby and Bronco, terminate in southern Oregon and one, Sunstone, ends in northern Oregon.

Most of the pipeline proposals are recent, further information about exact routing and potential impacts must be developed before a complete evaluation can be made. However, for the reasons given below, it appears likely that the pipelines proposed from the Rocky Mountains could provide natural gas to the same markets more economically than the LNG terminals proposed in Oregon and with less life-cycle CO2 impacts.

- ***The Cost of LNG Compared to North American Natural Gas***

The LNG market is global with demand dominated by Europe, Japan, and South Korea, and supply coming from the Middle East, Nigeria, and Trinidad and Tobago. The heavy importers have little domestic natural gas production and have been willing to outbid the U.S. when they have needed LNG. Due to high transportation costs, there are two connected LNG markets – one in the Atlantic Basin and one in the Pacific Basin.

Atlantic Basin LNG prices in the U.S. are generally 8-to-9 percent higher than prices for North American natural gas. LNG contracts have traditionally been long in duration to provide certainty to market participants, but there is an emerging spot market.

Pacific Basin prices are generally higher due to high demand and distant supplies, and it is not clear that supplies in the Pacific Basin will rise to meet demand due to cancelled and deferred projects. A recent LNG contract between Indonesia and Japan priced LNG at over twice the price of North American natural gas, making Pacific Basin LNG prohibitively expensive in the near term.

As long as the price of oil is as high as it is (currently about $120 a barrel), it is in the interests of Asian countries which have no natural gas to pay much higher prices for LNG than the United States in order to replace oil with natural gas. The world price of oil would need to collapse to less than $60 a barrel for the Pacific Basin LNG price to approach the price of North American natural gas. That is not likely to happen in the near future. If anything, with increasing demand for oil from China, India and other countries, the upward pressure on the price of oil will likely continue.

There is an excess of U.S. terminals importing LNG from the Atlantic Basin. There are currently five LNG terminals in the U.S. on the East and Gulf Coasts, each of which operates at a low utilization percentage. Three more are under construction on the Gulf Coast. In the Atlantic Basin, FERC has approved 21 other LNG terminals, with another 40 in the planning stages or before FERC.

In the Pacific Basin, one LNG terminal is coming online in Northern Baja, Mexico for export to the United States. The Baja terminal is primarily for delivery to Southern California. That terminal is as large as one of the LNG terminals proposed in Oregon. By 2010 the Baja terminal could be expanded to be nearly as large as all three LNG terminals proposed in Oregon. There are currently no terminals under construction in the western United States.

3. LNG and Greenhouse Gas Emissions

In 2007, Carnegie Mellon University researchers modeled the life-cycle emissions of natural gas, LNG, and coal combusted in conventional power plants. LNG has higher life-cycle greenhouse gas (GHG) emissions than natural gas because natural gas is burned to liquefy the LNG, and natural gas and fuel oil are burned to ship the LNG and return empty tankers to port. The midpoint of the University's estimate placed LNG emissions 28 percent above those of natural gas and 30 percent below coal life-cycle emissions. However, LNG was equivalent to coal in greenhouse gas emissions when shipped over long distances (e.g. between the Atlantic and Pacific basins).

The Carnegie Mellon researchers also modeled life-cycle greenhouse gas emissions for the fuels after advanced technologies were deployed. The technology with the largest impact on greenhouse gas emissions was carbon capture and storage (CCS), a technology that is expected to be feasible by 2020. Coal performed well under the CCS scenario because it has relatively few upstream emissions while LNG performed poorly because of its high upstream emissions. With CCS factored in, LNG was modeled to have about twice the emissions of natural gas and 40 percent more than coal.

The Oregon Department of Energy took the Carnegie Mellon study along with numbers from other sources and adapted them to the situation in the Pacific Northwest. Comparing *pre-combustion* numbers for natural gas and its substitutes, LNG has about twice the greenhouse gas emissions of natural gas. The life-cycle greenhouse gas emissions for LNG, when *combusted* in conventional power plants, were forecast to be 6-to-12 percent greater than natural gas, but 39-to-48 percent less than coal.

When *combusted* in a plant with CCS where 90 percent of combustion emissions were captured, LNG life-cycle greenhouse gas emissions were projected to be 39-to-79 percent greater than natural gas and about the same or up to 20 percent worse than domestically produced coal.[1]

For electricity generation, LNG will have fewer greenhouse gas emissions than coal until CCS becomes feasible and it will have more than North American piped-natural gas. Assuming upstream emissions accounting, the additional emissions of LNG over natural gas could affect Oregon's chances of meeting its statutory greenhouse gas reduction goals.

Conclusion

Natural gas use in Oregon is likely to rise over the next twenty years. New sources of natural gas will be needed to meet this demand. However, natural gas supplied by LNG terminals proposed in Oregon are likely to cost more than natural gas produced in North America, including gas delivered by new pipelines proposed from the Rocky Mountains to serve the West Coast. In addition, the life cycle CO2 costs of LNG would likely be substantially higher than natural gas produced in North America.

[1] This includes factoring in coal train shipments.

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I. Natural Gas Demand

According to the U.S. Department of Energy's Energy Information Administration (EIA), in 2006 the U.S. consumed 21.86 trillion cubic feet (Tcf) of natural gas, which was down two percent from 2005. The drop in U.S. gas usage was attributable to reductions in usage in the residential, commercial, and industrial sectors which more than offset an increase in usage for electricity generation.

Background

Three LNG terminals are proposed for Oregon: Bradwood Landing LNG near Wauna, Jordan Cove in Coos Bay, and Oregon LNG in Warrenton. Each of these proposals has at least one affiliated pipeline. Additionally, five other natural gas pipelines have been proposed.

LNG, natural gas that is cooled to a liquid for transportation, is used mainly for price stability, contingencies and peak consumption. It is difficult to express all the complexities involved in characterizing an international commodity facing the global conditions of financing, supply, and political and market forces.

However, the Wall Street Journal recently reported: "Today, a tanker of liquefied natural gas, or LNG, pulling into port in Japan can command close to $20 per million BTUs, roughly double the price of the U.S. benchmark. As a result, the U.S. is having trouble attracting the imports it needs to supplement homegrown production. For the moment at least, the import slowdown means the U.S. has a glut of LNG import terminals…"[2]

Equally complex are social needs and the environmental effects of energy consumption.

"The global appetite for natural gas has profound implications for a U.S. economy already tipping toward recession and struggling against inflation pressures. The fuel heats half of U.S. homes, generates 20% of the country's electricity and is used to make everything from fertilizer to plastic bags."[3]

"In a twist, the effort to build alternative-energy projects like solar arrays and wind farms also boosts construction of gas-fired plants. Because wind is unpredictable, it's often necessary to build back-up generators…"[4]

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[2] "Surge in Natural-Gas Price Stoked by New Global Trade", *Wall Street Journal*, 18 April 2008, p.1
[3] Ibid.
[4] Ibid.

On August 8, 2005, President Bush signed the Federal Energy Policy Act of 2005 into law. It contains a provision that FERC has exclusive jurisdiction to approve or deny an application for the siting, construction, expansion or operation of an LNG import facility.

As a result, the Oregon Energy Facility Siting Council was pre-empted and lost the authority to review LNG terminals through the state siting process. However, Governor Kulongoski directed state agencies to participate in FERC's review of any LNG import terminals in Oregon. He designated the Oregon Department of Energy as the lead agency in working with FERC on proposed projects, including the coordination of state agency response on any application.

Oregon has a set of standards to review energy facilities, which protect natural resources, ensure public health and safety and protect against adverse environmental impacts. The standards ask three fundamental questions:

- Does the applicant have the appropriate abilities to build this energy facility?
- Is the site suitable?
- Would the facility have adverse impacts on the environment and the community?

The standards include:

- General Standard of Review
    - consultation with other agencies on noise, wetlands, water rights
- Organizational Expertise of the Applicant
- Structural Standard
- Soil Protection
- Land Use
- Protected Areas
- Facility and Site Retirement and Financial Assurance Requirements
- Fish and Wildlife Habitat
- Threatened and Endangered Species
- Scenic and Aesthetic Values
- Historic, Cultural and Archaeological Resources
- Recreation
- Public Services
- Waste Minimization
- Carbon Dioxide Emissions
- Need Standard for Non-generating Facilities

Use and Demand for Natural Gas

In 2006, Oregon consumed 0.22 Tcf of natural gas, which was a decrease of four percent from 2005. The Oregon decline can be attributed to decreased use of natural gas for electricity generation due to the favorable hydropower conditions in 2006. Of the 0.22 Tcf of natural gas that Oregon consumed in 2006, 18 percent was used by residential customers, 13 percent saw commercial use, 31 percent was utilized by industrial users, and 34 percent was used for electricity generation. Oregon received 0.77 Tcf of natural gas from interstate and international pipelines of which 0.53 Tcf (69 percent) was shipped through to California.

The EIA says that through the year 2030, U.S. consumption of natural gas will rise by 0.3 percent per year. However, there is a Congressional effort underway to reduce greenhouse gas emissions. Senate Bill 2191, the Lieberman-Warner proposal, is called America's Climate Security Act. If the bill becomes law, the EIA projects that GHG emissions reductions will be driven by carbon capture and storage (CCS) at coal-fired power plants and that natural gas consumption will initially rise and then sink back to near current levels. If CCS does not become commercially viable by 2030 and no other carbon mitigation measure emerges, the EIA predicts that there would be significant fuel switching to natural gas for electricity generation which would drive up consumption. Oregon would not be immune from such fuel switching.

Over 40 percent of the electricity consumed in Oregon comes from coal-fired generation. As climate change legislation is enacted, it is likely that financial conditions will encourage the switch from coal to natural gas since natural gas has much lower life-cycle GHG emissions. It is unlikely that Oregon will be able to replace all of the coal-fired power it uses with renewables in the short-term, so natural gas consumption is likely to rise.

Natural gas is also a good option for firming renewable power. Wind power, solar power, and hydropower all rely on beneficial weather conditions for electricity production. There is currently no grid scalable method to store electricity so there needs to be backup generation in case the wind is not blowing or the sun is not shining. Natural gas-fired power plants are good at firming renewable energy because they can be stopped and started as necessary – an ability coal-fired plants lack. Additionally, gas-fired power plants can be quickly built in Oregon with about a 36-month timeframe to design, site, and construct such a plant. As renewable energy becomes a larger part of the Oregon energy portfolio, more gas-fired generation will likely be built to fill in the gaps. This could increase demand for natural gas in Oregon.

Natural gas demand in Oregon could also rise for other reasons. Studies predict that climate change will alter the runoff regime of the Columbia River. These changes will likely cause the Federal Columbia River Power System to produce less summer power in the future. Some of this lost summer generation could be made up with gas-fired electricity, driving up consumption of natural gas. Legal issues around the operation of the dams could also diminish hydropower generation and increase reliance on natural gas.

Oregon is also anticipating demographic changes. The Oregon Office of Economic Analysis projects that the state's population will increase by over 50,000 people per year and that there will be over four million Oregonians by 2012. The increase in population will likely increase gas consumption for residential use and electricity generation.

Factors that could drive down natural gas demand in the state include higher natural gas prices, energy efficiency measures, higher fuel costs due to greenhouse gas emission caps, national economic recession, and increased reliance on renewable sources of energy. Oregon has been at the forefront of energy efficiency measures. This could also cause a drop in consumption for residential natural gas and for gas-fired electricity.

If the U.S. economy falls into a recession, energy usage could decline as the economy falters. This could cause a drop in natural gas consumption in the state. Oregon's Renewable Portfolio

Standard (RPS) set targets for renewable energy acquisition by large Oregon utilities, which may displace fossil fuel-fired electricity supply.

High prices due to decreased supply could also cause a reduction in natural gas consumption in Oregon. If LNG prices continue to be high and Canadian gas fields decline at a greater rate than anticipated, domestic natural gas prices will rise. Higher gas prices could reduce consumption of natural gas in Oregon.

It is likely that Oregon and the nation will consume more natural gas over the next 20 years. The EIA projects that demand for natural gas will rise until CCS becomes feasible and coal-fired power plants again become dominant. Demand for natural gas is on the rise. U.S. natural gas consumption is expected to increase by 0.3 percent per year through 2030 if no additional actions are taken to reduce greenhouse gas emissions. The Northwest Gas Association projects that Northwest natural gas demand will grow by 1.9 percent annually through 2012.

Stability of Natural Gas Supply

Natural gas supply disruptions commonly affect the U.S. In 2005, Hurricanes Katrina and Rita affected the Gulf Coast. Hurricane Katrina destroyed 44 natural gas platforms in the Gulf of Mexico and damaged 20 others, while Hurricane Rita destroyed 69 platforms and damaged 32 others. In addition, up to 75 percent of the natural gas processing capacity in the region was shut in (closed down) when threatened by Hurricane Rita. The storms temporarily shut in about five percent of U.S. production, some of which is not yet back online. Supply disruptions also have occurred when pipelines have exploded and when major processing plants have caught fire. The cost of natural gas can fluctuate wildly when there is a supply disruption. This cost can be contained if there is adequate regional storage of natural gas.

The average U.S. LNG terminal has storage for 8.8 Bcf of natural gas. When full, the average terminal would provide storage for about 14 days of average Oregon natural gas consumption and nine days of peak consumption assuming none of the gas was shipped out of state.

Oregon currently has storage for 16 Bcf of useable gas in geologic formations in Mist (NW Natural facility). Washington state has storage for 18.6 Bcf in Lewis County. This represents a 27-day average and 18-day peak Oregon usage in storage in Oregon and a 31-day average and a 21-day peak Oregon usage in storage in Washington. Another expansion of Mist is possible, but dependent upon good geology.

In the event of a supply disruption Oregon’s storage capacity could be critical. Since Oregon produces so little natural gas in relation to its consumption, a regional problem that left the Northwest isolated from supply could put significant stress on the state’s energy resources.

Regions also use local storage to overcome supply problems during times of high demand. A region can consume more natural gas than its incoming pipeline capacity if it has gas stored so that it can be put in intrastate pipelines for local use. Stored natural gas can also be used to smooth out seasonal price spikes. The storage offered by an LNG plant in Oregon could benefit the state due to cost savings during high demand periods and provide resiliency in an emergency.

II. Alternatives for Natural Gas Supply to Oregon

Natural Gas Supply Options in General

Supply of natural gas in the U.S. is served by a vast interconnected network of over 300,000 miles of interstate and international pipelines so gas can generally move easily from supply to demand. The result is only small regional differences in price caused by pipeline charges and regional chokepoints. Oregon is served primarily by Canadian natural gas that is shipped via pipelines from Washington. Oregon also receives natural gas from the Rocky Mountain states via the Northwest Pipeline that accesses the Opal Hub in Wyoming. The North American web of pipelines works to displace gas to other areas when supply is increased in a region. If, for example, LNG was offloaded in Oregon, North American supply would increase and imported gas from Canada or Wyoming would be displaced to other regions.

Oregon production of natural gas is minimal. In 2006, Oregon produced 621 million cubic feet (MMcf) of natural gas, or about 0.27 percent of its consumption. According to the EIA in 2006 the U.S. produced 19.34 Tcf of natural gas. This was up two percent from the year before despite a continuing large loss in capacity from the Gulf of Mexico due to Hurricanes Katrina and Rita. However, U.S. production has been flat since the late-1990s despite a boom in leasing and drilling activities over the last seven years.

Canada is our primary trading partner for natural gas. In 2006, Canada exported 3.6 Tcf of natural gas to the United States which represented about 19 percent of U.S. consumption and 86 percent of total U.S. natural gas imports that year. According to EIA's Annual Energy Outlook 2007, both Canadian natural gas production and exports are expected to decline in the coming years. Net exports to the United States are forecasted to decline to 1.2 Tcf in 2030, or 22 percent of net U.S. natural gas imports. This will primarily be due to a decrease in production in Canada.[5]

Gas usage in Canada is also expected to rise. The Athabasca oil sands in Alberta are an enormous deposit of hydrocarbons that can be conditioned into heavy crude oil when heated and processed. Canada uses natural gas for this process and their consumption is expected to rapidly increase as oil prices stay high. Coupled with reduced production, this will create upward price pressure on natural gas imported from Canada. The EIA says that the loss from declining Canadian production will be made up by LNG imports.

Even with the reduced supply from Canada, there is already enough LNG import capacity to serve projected U.S. consumption through 2025 (see Figure 1). The EIA projects the U.S. will require 8 Bcf/d capacity for national LNG imports by 2025.[6] EIA projects that by the end of 2008, the U.S. will have 11.1 Bcf/d import capacity. In addition, the Costa Azul plant in Baja, California, Mexico will have 1-2.7 Bcf/d capacity by 2010. This is more import capacity than is

[5] Under Chapter 6, Article 605 of NAFTA, Canada may not introduce barriers that would reduce the proportion of Canadian produced natural gas sent to the United States.

[6] EIA has repeatedly revised its LNG import numbers downward as LNG supply has not materialized and domestic demand has been met by North American supply. For example, from 2002 to 2006 it revised its 2020 projection downward by 7.4 percent. High costs, technological challenges, and geopolitical concerns have also put a damper on the LNG trade.

projected as necessary.

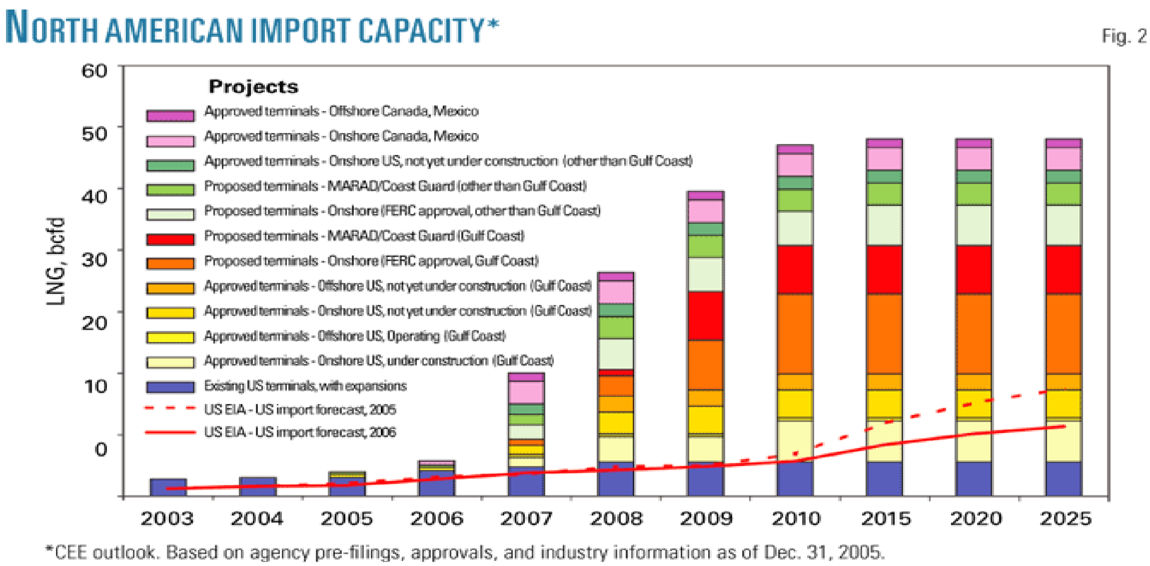

Figure 1: *This University of Texas Center for Energy Economics graph shows current and projected build out of LNG terminals. By the end of 2008, capacity to import 11 Bcf/d into the U.S. will be constructed.*

There are other future sources for natural gas besides LNG. The EIA projections estimate that domestic energy needs will be met, in part, by an increase in output from Alaska gas fields. The EIA estimates that Alaskan production will increase at a rate of 7.5 percent per year through 2030. There are currently plans to build a pipeline to provide this supply to the Lower 48 states. The pipeline would not be completed until 2018 at the earliest and high steel prices could make such a pipeline less likely to be built.

Natural gas production is also rising in Wyoming, Utah, and Colorado, which has spawned several pipeline proposals to transport this gas to Oregon. Companies are also aggressively building pipelines to carry some of this increased production to markets in the Midwest.

Two major pipelines import Oregon's 600+ MMcf/d average natural gas consumption (see Figure 2). Williams' Northwest Pipeline (NWP) can bring up to 429 MMcf/d of natural gas to Oregon from the Rocky Mountains and about 1,000 MMcf/d from Canada. The NWP brings natural gas to Portland from British Columbia and enters the U.S. near Sumas, Washington, roughly following Interstate 5. Gas from the Rockies comes into Oregon near Ontario.

TransCanada's Gas Transmission Northwest (GTN) pipeline can bring 2,826 MMcf/d of Canadian natural gas into Oregon. About 85 percent of the GTN imports are passed through to California. The natural gas in the GTN pipeline is from Alberta. It enters the U.S. near Kingsgate, Idaho, and moves through eastern Oregon, leaving the state near Malin, before traveling on to California and Nevada. A lateral line transports natural gas from Klamath Falls to Medford. On the average day in 2006, NWP brought 332 MMcf/d into Oregon while GTN brought in 1,735 MMcf/d.

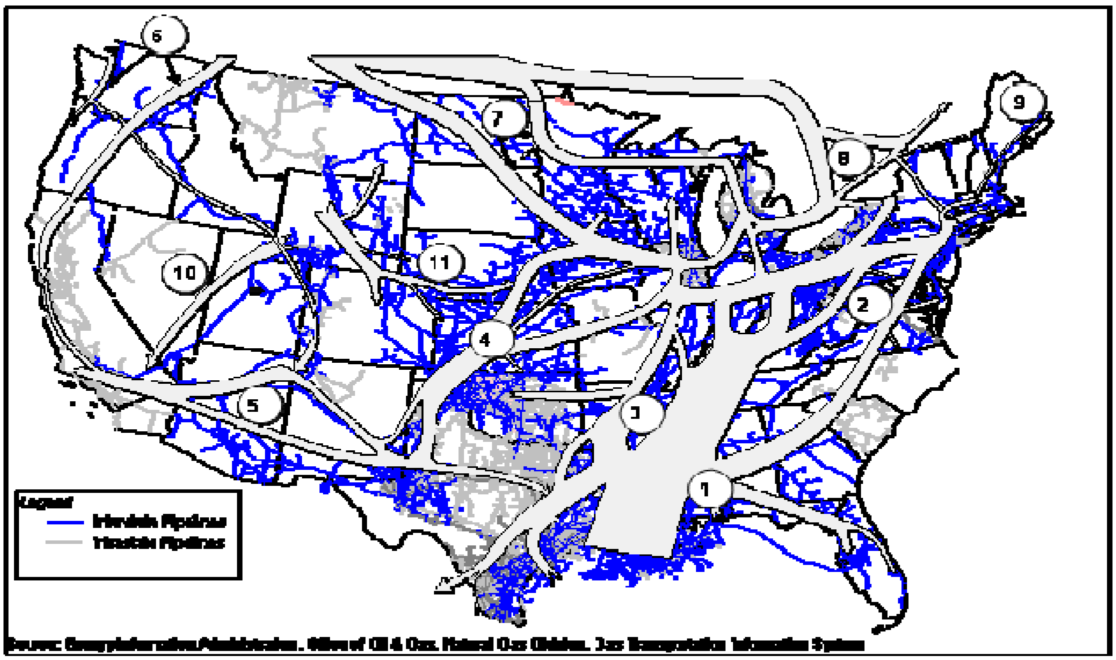

Figure 2: *Arrow width illustrates the amount of interstate pipeline capacity. The pipeline into California is unidirectional and cannot currently import natural gas into Oregon from California.*

In January 2007, Oregon used over 900 MMcf/d of natural gas, less than half of which could come directly from U.S. supplies. The rest came from Canada or out of regional storage. If Canadian gas fields declined rapidly or if there was a supply disruption from Canada, Oregon could be isolated from much of its supply of natural gas.

A supply disruption would probably not occur if a single pipeline importing gas from Canada failed. Gas is imported into the Northwest from Canada in Western Washington and in Idaho. The Williams Northwest Pipeline failed twice in Washington in 2005 and there was no significant supply disruption in Oregon as a result because GTN was able to take up any slack. Since then, Williams has replaced that entire section of the Northwest Pipeline and resumed normal operations. There are also redundant pipelines in Canada that serve the Northwest in much the same manner.

Oregon depends on Canadian natural gas for most of its supply. An LNG terminal in Oregon or an additional gas pipeline from the Rocky Mountain region could improve Oregon's outlook in the case of an emergency or a Canadian supply problem. The new LNG terminal in Baja, California in Mexico will also serve the broader West Coast market, which could free up more Canadian and Rocky Mountain gas for Oregon. Natural gas may also come from Alaska by pipeline in 10 years, at the earliest.

LNG Terminals Proposed in Oregon

There are currently three proposals to build LNG terminals in Oregon. The Bradwood Landing LNG proposal would build a 1.3 Bcf/d terminal 38 miles up the Columbia River near Wauna, the Jordan Cove proposal would build a 1 billion cubic feet per day (Bcf/d) terminal in Coos Bay; and the Oregon LNG proposal would build a 1.5 Bcf/d terminal in Warrenton. Each of these proposals also has at least one affiliated pipeline.

In a filing with FERC, the Williams Pipeline Company, which operates the existing pipeline from the Rocky Mountain natural gas production centers, said that its Northwest Pipeline (NWP) does not have the capacity to absorb the output of an LNG terminal in Oregon. Since each terminal has a proposed daily output capacity much greater than Oregon's daily consumption and since NWP does not have capacity to accept the gas, any LNG terminal will need to be coupled with a new pipeline feeding into TransCanada's Gas Transmission Northwest (GTN) pipeline. Each proposed LNG terminal should be considered along with the pipeline that will be needed to carry the natural gas to market.

Since LNG contains a large amount of energy in a small confined place, safety is a critical concern. The safety of LNG in storage on land is well established and a 2004 report by Sandia National Labs concluded that the accidental release of LNG from a tanker was not a major safety issue.[7] However, the report found that an intentional release (e.g. by a terrorist attack) could cause serious injury up to a mile away under the right conditions with a danger zone of one-third mile being the most likely. The report also found that the danger could be mitigated by such measures as ship escorts and ship exclusion zones – measures that would be implemented by the Coast Guard[8] for any of the LNG terminals in Oregon. However, safety is still a major concern for communities near the tanker haul and the terminal.

The three proposed LNG terminal sites have many things in common. Each is sited on a riparian area near a sensitive salmon population and requires significant dredging to accommodate the large LNG tankers. All of the terminal proposals route LNG tankers near population centers and have similar designs for their storage facilities. Each terminal also requires the construction of a pipeline to carry the gas to market. There are also key differences between each of the projects.

Bradwood Landing was the first proposed LNG terminal in Oregon and includes 1.3 Bcf/d peak output and 320,000 cubic meters of storage. At peak capacity about 125 LNG tankers a year would travel under the Astoria Bridge and 38 miles up the Columbia River to the terminal. The tankers would pass near Astoria and would likely pass other ships on their way up the river.

Bradwood Landing also requires dredging of 700,000 cubic yards over a 58-acre area in the migration corridor and rearing grounds of 13 endangered or threatened runs of salmon and steelhead. Its plan for re-gasification may also cause thermal loading impacts in the lower Columbia to the detriment of salmon.

Rather than undergoing treatment, wastewater would infiltrate into the porous ground directly or run into unlined settling ponds which would drain to Hunt Creek or into the Columbia River. The United States Coast Guard has made particular navigation requests that would improve operation of the lower Columbia River and improve the Coast Guard's ability to respond to incidents on the water.

The Bradwood Landing proposal also requires new pipelines. There would be a 34-mile pipeline to hook into the Mist storage facility, the gas-fired electricity generation in Port Westward, and ultimately into the interstate facilities of NWP. The short pipeline could result in reduced transmission costs which could offset some of the costs of Pacific Basin LNG.

The **Jordan Cove** terminal is proposed for Coos County and features a 1 Bcf/d terminal with 320,000 square meters of storage (the equivalent of about 14.9 Bcf of storage). The developers predict that at peak capacity it would bring 80 LNG tankers to the state each year. It would be located on the North Spit and the tanker slip would also accommodate container ships for a

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[7] Hightower, Mike, et al., Sandia National Laboratories, *Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water*, Pub. No. SAND2004-6258 (unlimited release December 2004).

[8] On April 23, 2008, the Bush Administration said it strongly opposed H.R. 2830, the Coast Guard Authorization Act of 2008, in part because it required the Coast Guard to provide security around LNG terminals and vessels. The Bush Administration said this "provides an unwarranted and unnecessary subsidy to the owners of private infrastructure... and would divert finite Coast Guard assets…".

potential adjacent development. The facility plan also calls for the construction of a 37 MW cogeneration facility that could provide transmission support in the coastal area around Coos Bay and North Bend. The proposed terminal is more than a mile from major population centers, but tankers would travel within a mile of Coos Bay and Empire. The Southern Oregon Regional Airport would be less than a mile from the terminal.

The terminal requires dredging of six million cubic yards of material from a 74-acre area; and it is on the migration corridor for the Coos River salmon that has been part of the Oregon Coastal Salmon Restoration Initiative.

The project also includes the 230-mile Pacific Connector Gas Pipeline, which would cross the Coast Range and Cascade Range. According to the PCGP resource report, the pipeline would cross both the Coast Range and the Cascade Range largely through sensitive late-successional reserve[9] areas in National Forests. Most wastewater at the terminal would be discharged into the tanker slip while oily wastewater would be separated and sent to the Port of Coos Bay's wastewater pipeline.

The imported gas would not serve most Oregon population centers. The gas would enter the Northwest Pipeline (NWP) at a place where there is not enough built capacity to serve northwest Oregon. The PCGP would terminate in Malin, which would not serve most of Oregon since the pipeline is normally unidirectional. The gas would not normally reach the Mist storage facility and the storage at the terminal could not easily reach most Oregon markets in the event of an emergency. Another pipeline would need to be built following the NWP rights-of-way north so that this natural gas could reach most Oregon markets on a regular basis. Such a pipeline has not been proposed.

Jordan Cove could affect the GTN pipeline. The Pacific Connector Gas Pipeline would hook into GTN at its terminus on the California border and might utilize NWP for some deliveries to markets south of Eugene. By displacing Canadian natural gas that has been traditionally imported over GTN, the PCGP could drive up per unit transportation costs because the fixed costs of the pipeline would be spread over fewer delivered units. This could cause delivered prices of Canadian natural gas to go up in Oregon. Displaced Canadian gas would likely be sent to the Midwest or to Alberta rather than significantly lowering prices in Oregon due to reduced demand from California, but prices may go down enough to offset the effect of the higher transportation costs.

Oregon LNG, which proposes a 1.5 Bcf/d terminal in Warrenton with 480,000 cubic meters of storage (the equivalent of about 22.3 Bcf of storage), is the latest project. At about eight miles, it has a shorter inland tanker haul than Bradwood Landing. The developer intends to use ambient

[9] "[Late-successional] reserves are large blocks of land which include both younger and late-successional forest types. They encompass the majority of both the existing ecologically significant late-successional and old-growth forests. The objective of LSRs is to protect and enhance conditions of late-successional and old-growth forest ecosystems. Thinning of younger forests within the LSRs is allowed in order to foster old-growth development. Large scale commercial harvesting of trees is not permitted in LSRs." Testimony to Congress of Henri Bisson of the U.S. Bureau of Land Management *available at* http://www.blm.gov/nhp/news/legislative/pages/2001/te011002.htm. Late-successional trees are from 80 to 200 years old. Construction of a pipeline through a LSR would require a 100-foot wide clearcut of these older trees.

air vaporizers about 70 percent of the time so it would produce less CO_2 than a terminal that used natural gas vaporizers.

Oregon LNG would also feature a larger slip so that new, more efficient LNG supertankers could dock there. However, to accommodate this large slip the Oregon LNG terminal requires dredging of 1,275,000 cubic yards over an 83-acre area in the Columbia River Estuary, which is the rearing ground for 13 endangered or threatened runs of salmon and steelhead. Also, wastewater would not be treated and would flow into adjacent wetlands which drain into the Columbia River.

At peak capacity approximately 100 LNG tankers would visit the terminal each year. The terminal would be within a mile of Warrenton and the exclusion zone for the tankers appears to intersect Hammond. The project is also tied to a 121-mile pipeline over the coast range and crossing the Willamette Valley, 36 miles of which is on existing rights-of-way. Some of the properties to be crossed include high value crop lands like vineyards. The pipeline would feed the Mist storage facility. There is an additional nine-mile connector pipeline in the plans, plus another pipeline would need to be built over the Cascades to bring the gas to GTN and the California market.

In summary, the Bradwood Landing LNG terminal has the shortest pipeline and the least dredge area and volume, however, it has the longest inland tanker haul. The Oregon LNG proposal requires a long pipeline (Oregon Pipeline) and the greatest dredging area, but it would have the shortest tanker haul in Oregon. Jordan Cove (Pacific Connector Gas Pipeline) would have the longest pipeline. It would not directly serve most major Oregon markets. However, it could make available in Oregon natural gas that is currently going to California.

Proposed New Pipelines from the Rocky Mountains

The Williams Northwest Pipeline (NWP) from the Rocky Mountain production centers is apparently operating at full capacity on peak days. A new pipeline from the Rocky Mountains could benefit Oregon in many of the same ways that a new LNG terminal could. There are proposals to build various new pipelines between the Opal Hub in Wyoming and Oregon. Two of the pipeline proposals terminate in southern Oregon and one ends in northern Oregon.

Pipelines from the Rocky Mountains would provide gas which is currently priced at less than half the cost of Pacific Basin LNG. However, there would be transport costs of natural gas for longer distances to Oregon than from LNG facilities located in Oregon, which could offset the price difference to some degree.

The **Palomar Pipeline** is being proposed by TransCanada and NW Natural. It has been proposed in two stages. As initially proposed (**Palomar East**) the pipeline would run from Maupin to Molalla, about 100 miles including through portions of the Mount Hood National Forest. As an interstate pipeline, it would be sited under FERC jurisdiction. The Palomar East pipeline would provide the NW Natural system and Oregon consumers with benefits in terms of added capacity and options for North American gas, whether or not any of the LNG terminals were built.

The Palomar Pipeline is not formally associated with an LNG terminal. The pipeline proposal has been extended from Molalla through NW Natural's storage facility at Mist, (**Palomar West**), where it could be extended to serve either the Bradwood or the Oregon LNG terminals. If extended the Palomar pipeline could transport gas from either LNG terminal to the Oregon market in Molalla and to the California market by hooking into GTN east of Maupin. Palomar would then also travel through the Clatsop State Forest and the Willamette Valley.

The **Ruby Pipeline** and the **Bronco Pipeline** have been proposed to terminate in southern Oregon primarily to serve the California market. These Ruby and Bronco pipeline projects would bring gas from the Opal Hub in Wyoming to southern Oregon and to serve the California market. These pipelines would hook into the GTN pipeline in Malin, Oregon. They would hook into the north-south interstate pipeline downstream of most of Oregon's demand on a unidirectional pipeline that connects to California and Nevada. The gas would not have a way to make it to most Oregon markets.

However, these new pipelines would provide two possible benefits to Oregon. They could potentially reduce costs to Oregon customers because there would be more competition in the California market with the Canadian gas that flows through Oregon. Also, if a long-term disruption occurred that stopped Canadian gas imports, the GTN pipeline could be re-pressurized to transport gas to the Oregon market from the Malin facility. However, since they would not directly supply the Oregon market under normal circumstances, neither of these pipelines would be a substitute for Bradwood Landing or Oregon LNG, but could substitute for Jordan Cove. The Ruby pipeline appears to have the shorter route through Oregon of the two, although the Bronco pipeline route has not been finalized..

There is also a third pipeline proposed from Wyoming to Oregon. Williams and TransCanada, the owners of the existing interstate pipelines serving Oregon, are proposing the **Sunstone Pipeline** to parallel the existing Northwest Pipeline. Williams and Puget Sound Energy are proposing to extend the new pipeline to the I-5 corridor as the **Blue Bridge Pipeline**. Sunstone would bring 1.2 Bcf/d of natural gas to Oregon – over twice the current daily consumption in the state. These new pipelines would parallel the existing Northwest Pipeline with Sunstone running from Opal to Stanfield, and Blue Bridge going from Stanfield to the I-5 corridor. The pipelines would mostly follow existing rights-of-way and would connect into the existing pipeline infrastructure of NWP and GTN.

These pipelines would provide enough natural gas to serve the Oregon and Washington markets if there were a supply disruption from Canada. They would also serve as a redundant supply to the aging NWP infrastructure. The footprint of the pipelines would also be less than other proposals since they would parallel an existing pipeline; they would largely be able to use existing construction easements; and they would be about 100 miles shorter than the other proposed pipelines. The route could also reduce costs since existing utility corridors would be used. These attributes could reduce environmental and socio-economic issues. Finally, they would feed into rather than compete with the GTN pipeline and could eventually replace the section of NWP from Wyoming to Oregon.

Building a pipeline can be disruptive to landowners and the environment. Pipeline companies typically choose a least-cost route for a pipeline and then attempt to negotiate an easement with landowners. If no agreement is reached, the company can use the power of eminent domain to condemn easements on target properties. Each easement is usually about 100- feet wide for construction and then narrows down to 10-to-60 feet after the pipeline is installed. The review of the impacts of individual pipeline routes is beyond the scope of this report.

The Federal Energy Regulatory Commission (FERC) does not require a pipeline company to supply a bond to cover abandonment costs. If a pipeline company goes bankrupt or abandons a route, it is not clear that FERC will require that reclamation of pipeline easements for completed projects or for work-in-progress will take place.

Cost and Availability of LNG Compared to North American Natural Gas

LNG is purified natural gas super-cooled to -260°F. At this temperature, the gas liquefies and is reduced in volume by more than 600 times. This allows for economic transshipment of LNG between countries and regions. In 2006, Algeria, Egypt, Nigeria, and Trinidad and Tobago exported LNG to the U.S. Other countries with proven reserves that could ship LNG to the U.S. in the future include Australia, Indonesia, Iran, Peru and Russia. The market for LNG is international with large shipments going to Spain, France, Belgium, Japan, South Korea, and Taiwan.

Japan, the largest LNG importer in the world, relies on LNG imports for 97 percent of its natural gas supplies. The spot LNG market is susceptible to large market swings when countries with little natural gas production are forced to switch to natural gas for electricity generation. For example, recent market disruptions have occurred when Spain had an especially cold winter and when some Japanese nuclear capacity was taken offline after a series of earthquakes.

The U.S. has not relied heavily on LNG to meet its energy needs because LNG is not competitive from a price standpoint with U.S. and Canadian-produced natural gas. U.S. LNG imports declined in 2005 and 2006 as other countries outbid the U.S. for LNG supplies. The U.S. Department of Energy's Energy Information Administration (EIA[10]) anticipates that world LNG prices will decline as more liquefaction capacity comes online and that the U.S. will begin to import more LNG. According to preliminary numbers, the U.S. imported over 750 billion cubic feet (Bcf) of LNG in 2007 – a record amount for the country. In early 2008, EIA estimated that LNG imports would grow by over a third in 2008. However, when first quarter 2008 imports were lower due to high prices, EIA revised its estimate down and predicted that LNG imports in 2008 will be 12 percent lower than 2007.

The EIA says that the U.S. has fallen behind the rest of the world in LNG imports partially because of a lack of long term contracts with suppliers. LNG contracts have traditionally been long in duration, but there is now an emerging spot market. Countries with little domestic natural gas production must rely on LNG and have been willing to pay higher prices in long term contracts and on the spot market.

Countries that rely on LNG and have limited storage capabilities have been especially willing to pay more for a firm supply of LNG during peak demands. Prices from 2001-2006 for LNG delivered to the U.S. were nine percent higher than domestically produced natural gas and eight percent higher than natural gas imported by pipeline. Spot prices and prices for LNG delivered to Asia were up to two times higher than U.S. wellhead natural gas prices.

[10] http://www.eia.doe.gov/

The LNG market developed as a long term market for the benefit of both exporters and importers. The long term nature of the LNG trade would enrich an importer if domestic prices rose during the life of the contract and the importer had access to the less expensive contracted gas. Long term contracts also benefited exporting countries because the exporters, which are predominantly emerging countries, could count on firm funds to make needed infrastructure improvements. However, some countries (notably Indonesia) were willing to divert shipments to higher priced markets in violation of their contracts when prices rose precipitously or domestic demand increased. Newer contracts are for shorter durations and have buyout clauses so that shipments can be diverted without violating contracts if prices rise drastically. This evidence points to a rising spot market for LNG with larger price swings and more competition for each shipment. This could continue to drive prices higher.

LNG imports into the U.S. tend to cluster in the spring and summer months when there is less international demand. The U.S. has large storage facilities in geologic formations and depleted gas fields. This allows U.S. gas suppliers to purchase LNG during off-peak months, store the gas, and deliver it to customers during high demand times. LNG suppliers send shipments to the U.S. during the summer months when other countries cannot accommodate the gas. As other countries develop storage mechanisms and increase the use of air conditioning, summer prices may rise and this seasonal arbitrage may become less practical due to higher prices. These higher prices could depress U.S. imports further.

An LNG terminal in Oregon may have low utilization rates because of LNG market dynamics. The existing U.S. LNG terminals are on the East Coast and the Gulf Coast, and historical U.S. imports have consequently come almost entirely from the Atlantic Basin. This should change as the U.S. will receive indirect Pacific Basin LNG imports from the new Costa Azul terminal in Baja Mexico. It could also change if an LNG terminal opened on the West Coast of the U.S. However, there is already considerable demand in the Pacific market with competition between Japan and South Korea and with large markets emerging in China and India. This may yield Pacific LNG prices that are higher than Northwest prices from Canada or the U.S. Rockies.

LNG marketers are taking advantage of arbitrage opportunities and shipping Atlantic Basin LNG to higher priced Pacific Basin markets despite high transportation costs. Asian contracts are generally tied to the price of oil which also tends to make Pacific Basin prices higher. As the price of oil continues to rise well above $100 a barrel, the demand of Asian countries to increase the substitution of natural gas for oil will continue to drive the price of Pacific Basin LNG higher. Also, some nations that had been expected to export large quantities of LNG into the Pacific Basin market are diverting the gas for domestic use.

Indonesia has reduced exports each year since 2004 to serve domestic demand and has warned that LNG exports will decrease again this year. Indonesia recently struck a contract with Japan that will reduce exports to Japan by half and raise the price of LNG to over twice the price of North American natural gas. This makes prices for Pacific Basin LNG prohibitive for the Oregon market. Also, Russia has deferred an LNG terminal and a pipeline to China in order to divert the gas for domestic use. These dynamics point to continued prohibitively high gas prices in the Pacific Basin.

There is already significant unused LNG terminal capacity in the U.S. There are currently five LNG terminals in the U.S. and three are under construction. The operating terminals are located in Cove Point, Maryland; Elba Island, Georgia; Everett, Massachusetts; Gulf Gateway, Louisiana; and Lake Charles, Louisiana. Currently, U.S. LNG terminals operate at a fraction of their maximum utilization rate. In 2006, the Lake Charles facility operated at 25 percent utilization; the Everett terminal operated at 66 percent capacity; the Elba Island Terminal operated at 33 percent capacity; and the Cove Point terminal operated at 32 percent utilization. In 2006, the Gulf Gateway terminal only received one partial shipment of LNG.

Later this year, Sempra Energy plans to open a 1 Bcf/d terminal in Costa Azul, Baja California, Mexico – a portion of which will serve the U.S. market. The terminal will likely be expanded to handle 2.7 Bcf/d by 2010. There are also three LNG terminals under construction on the Gulf Coast that will have a combined capacity of 5.6 Bcf/d. These terminals will be completed in 2008 and 2009. FERC has approved 16 other LNG terminals on the Gulf Coast, each with a capacity from 0.8 to 3.0 Bcf/d and 40 more are either in the planning stages or before FERC. LNG will be imported to the U.S. through these terminals if it is economical to do so.

Canadian authorities have also approved four LNG terminals (totaling three Bcf/d) with one on the Pacific Basin in British Columbia (Kitimat LNG). However, this plant is likely to serve the oil sands of Alberta rather than the U.S. market. Of the three others, two are in Quebec and one in New Brunswick.

LNG economics are dominated by transshipment distance which results in two loosely connected markets – one in the Atlantic Basin and one in the Pacific Basin. Due to high demand in Asia and insufficient supply, Pacific Basin LNG prices are generally higher than Atlantic Basin prices and much higher than North American natural gas prices. Prices will likely stay high in the Pacific Basin since supply has not materialized; exporters are cutting back on exports to meet their own domestic demand. Oregon is not likely to see a price benefit from a nearby LNG terminal unless Pacific Basin gas prices drop to Atlantic Basin prices, which is unlikely in the foreseeable future.

As long as the price of oil is as high as it is (currently about $120 a barrel), Asian countries which have little or no natural gas to pay much higher prices for LNG than the United States in order to replace oil with natural gas. The world price of oil would need to collapse to less than $60 a barrel for the Pacific Basin LNG price to approach the price of North American natural gas. That is not likely to happen in the near future. If anything, with increasing demand for oil from China, India and other countries, the upward pressure on the price of oil will likely continue.

In contrast, the recent pipelines proposed from the Rocky Mountains would provide more supplies of North American natural gas to Oregon and other West Coast markets at a price that is currently half that of Pacific Basin LNG. Given the world price of oil and its dominant impact on Pacific Basin LNG, it is likely that Rocky Mountain natural gas will continue to cost substantially less for Oregon consumers than Pacific Basin LNG.

III. LNG and Life-Cycle Greenhouse Gas Emissions

The life-cycle carbon emissions of LNG, when *combusted* in a conventional electricity plant, fall somewhere between those of natural gas produced in North America and shipped via pipeline, and those of coal.

Life-cycle[11] carbon emissions of LNG, North American natural gas, coal, and synthetic gas produced from coal (syngas) were modeled in a study conducted by researchers at Carnegie Mellon University.[12] The model produced a large range of possible life-cycle emissions for LNG. This is attributable to the varying amount of gas burned in transport ships during transshipments of LNG, which are dramatically different for various shipment distances.

The model showed that LNG life-cycle emissions for current plants were higher than those of natural gas due to energy expended during the liquefaction process and during transport. The midpoint of their estimate placed LNG emissions 28 percent above those of natural gas and 30 percent below coal life-cycle emissions. LNG was equivalent to coal in GHG emissions when shipped over long distances. The midpoints of the ranges of life-cycle emissions from current plants were 1250 pounds of carbon dioxide equivalent[13] per megawatt hour of electricity produced (lb CO_2e/MWh) for natural gas, 1600 lb CO_2e/MWh for LNG and 2270 lb CO_2e/MWh for coal.

The Carnegie Mellon researchers also modeled life-cycle greenhouse gas (GHG) emissions for the different fuels after advanced technologies were deployed. The technology with the largest impact on GHG emissions was carbon capture and storage (CCS). CCS involves removing a portion of the CO_2 from combustion emissions and injecting it into geologic formations so that it does not enter the atmosphere. It is expected that CCS will be technologically and economically feasible in the next 20 years. Coal performed well under the CCS scenario because it has relatively few upstream emissions while LNG and syngas performed poorly because of their high upstream emissions. In fact, with CCS, LNG was modeled to have about twice the emissions of natural gas and 40 percent more than coal. The midpoints of the ranges of life-cycle emissions from advanced technology plants with CCS were about 250 lb CO_2e/MWh for natural gas, 475 lb CO_2e/MWh for LNG and 350 lb CO_2e/MWh for coal.

[11] The Carnegie Mellon University study only included the life-cycle emissions of each fuel in the study and did not consider the one-time emissions from construction, commissioning, and decommissioning of each power plant or the one-time emissions for the raw materials used to construct each plant.
[12] Jaramillo, P.; Griffin, W.; Matthews, H., Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electric Generation. *Environmental Science and Technology* 2007, Vol. 41, No. 17, 6290.
[13] Carbon dioxide equivalent is the standard unit for greenhouse gas emissions. Different GHGs have different global warming potentials in that some GHGs stay in the atmosphere longer or block more of the radiant energy.

There are also other life-cycle analyses of GHG emissions from these fuels. The U.S. Department of Energy National Energy Technology Laboratory did a study comparing the GHG emissions of LNG and coal for producing hydrogen. This study found slightly different results. However, when extrapolated to include combustion for electricity generation, the results are similar. LNG was between natural gas and coal (though closer to natural gas than in the Carnegie Mellon study) when combusted in a conventional plant and roughly equivalent to coal when combusted in a plant with CCS. There are also two industry studies by the Gasification Technologies Council and PACE Global Energy Services that reach similar results.

Much of the future growth in LNG production is forecast to come from the Middle East. Transshipments from the Middle East to Oregon would be over 10,000 nautical miles in distance and would drive up life-cycle GHG emissions from LNG to near the top of the predicted range.

There is also an argument that a portion of the carbon emissions from LNG can be ignored when calculating the life-cycle carbon emissions of LNG. Some LNG exporting countries (notably Nigeria) do not have a large enough domestic natural gas market or distribution infrastructure to absorb the amount of natural gas that is produced as a byproduct of oil production. Historically, some of these countries treated the gas as waste and either flared it or vented it to the atmosphere. As the market for LNG has grown, some of these countries have captured the excess gas and shipped it abroad as LNG. This has allowed the LNG market to capture energy from gas that was previously wasted but still resulted in GHG emissions.

Some amount of LNG usage could be seen as a net reduction in GHG emissions since the carbon from the gas would have ended up in the atmosphere anyway and it is now being put to productive use. However, it is speculative to reduce the carbon premium of LNG over natural gas due to the construction of an LNG terminal in Oregon.

Another issue is the viability of (CCS), which has only been deployed in limited circumstances. It is difficult to assess when CCS will become a commercial technology. However, one successful deployment of carbon capture is in the production of synthetic gas from coal (syngas) and it is possible that future syngas plants would have upstream carbon capture technologies.[14] Combustion at an electricity generation plant should not necessarily be taken into account. Natural gas can be used to produce electricity or it can be used at home to light a stove or water heater. In Oregon, only 34 percent of natural gas is used to produce electricity. Thus, when comparing natural gas, LNG, and possible syngas, the best measure to use is *pre-combustion* pounds of CO_2 per MMBtu. Since coal is generally not burned at home, pounds of CO_2 per MWh of electricity generation is the best means of comparison when it is included.

[14] "Upstream carbon capture" refers to technologies that trap CO_2 during the production of the syngas rather than at the point that it is combusted. Large amounts of CO_2 are produced as a byproduct of syngas production and syngas has very high GHG emissions if this CO_2 is not captured.

The Oregon Department of Energy analyzed the numbers from other studies and adapted them to the situation in the Pacific Northwest. Factors considered included the projected transshipment distances for LNG, improvements in liquefaction technologies, the possibility of ambient air regasifiers at the LNG terminal, and the efficiencies of generation plants that actually exist in Oregon. Comparing *pre-combustion* numbers for natural gas and its substitutes, LNG has about twice the GHG emissions of natural gas while syngas with no upstream CCS would likely be 4.5-to-7 times worse than LNG. Syngas could be reduced to roughly the same *pre-combustion* range as LNG if upstream CCS were included.

When *combusted* in conventional power plants, the life-cycle GHG emissions for LNG were forecast to be 6-to-12 percent greater than natural gas, 39-to-48 percent less than coal, and about the same as syngas with upstream CCS. When *combusted* in a plant with CCS where 90 percent of combustion emissions were captured (such a facility does not yet exist), LNG life-cycle GHG emissions were projected to be 39-to-79 percent greater than natural gas and about the same up to 20 percent worse than domestically produced coal. This is due to LNG's high upstream emissions in liquefaction and shipment.

For electricity generation, LNG will have fewer GHG emissions than coal until CCS becomes feasible. LNG will have more GHG emissions than North American piped-natural gas. On a *pre-combustion* basis, LNG has about twice the GHG emissions of natural gas and it is roughly equivalent to domestically produced syngas with upstream CCS.

The incremental life-cycle GHG emissions of LNG could hurt Oregon's chances to meet its GHG reduction goals. Oregon has aggressive GHG reduction targets in statute. Oregon plans to arrest the growth of GHG emissions by 2010 and to achieve greenhouse gas emissions 10 percent below 1990 levels by 2020. Oregon's final target is to achieve greenhouse gas emissions 75 percent below 1990 levels by 2050.

When life-cycle GHG emissions are considered and LNG is compared to natural gas, it is possible that widespread use of LNG could affect Oregon's chances of meeting its targets. It is likely that natural gas emissions from re-gasification at LNG terminals in Oregon will be included in regional or U.S. GHG cap-and-trade regimes. It is possible that LNG liquefaction and transport emissions will be included in future international agreements. This could drive up the costs of compliance for an LNG importer due to LNG's higher life-cycle emissions. It could also disproportionately decrease available no-cost allowances for other Oregon businesses if the state distributed allowances to the LNG importer.

Conclusion

Either the Bronco or Ruby pipeline could serve as an alternative to the Jordan Cove LNG facility, which would primarily serve the California market. The Sunstone and Blue Bridge pipelines could serve as an alternative to the Bradwood and Oregon LNG facilities which would serve Northwest as well as California markets. They would provide additional natural gas to the Oregon and Washington markets both on an everyday basis and in the event of an emergency. They could also substitute for declining Canadian supply.

All the pipelines have the additional advantage of supplying domestic natural gas with far less greenhouse gas emissions than natural gas supplied as LNG. Assuming Canadian and Rocky Mountain natural gas supplies do not dwindle at rates much faster than projected and Alaskan natural gas reaches the Lower 48 states in a timely manner, a pipeline from the Rocky Mountains to northern Oregon could serve Oregon's increasing natural gas needs with fewer CO_2 impacts than the Bradwood or Oregon LNG facilities. Either the Ruby or Bronco pipeline could provide natural gas to the California market with fewer CO_2 impacts than the Jordan Cove LNG facility.

It is also likely that Rocky Mountain and Alaskan piped-natural gas, along with natural gas supplied from existing Gulf Coast LNG terminals, would be able to provide natural gas at less than the market price of natural gas available to an LNG terminal in Oregon, given the market price of Pacific Basin LNG set by Asian consumption and demand.

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