The Northwest Gas Landscape – Looking Forward

The Power & Natural Gas Planning Taskforce
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Acknowledgments

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Executive Summary

The Northwest depends on natural gas for producing electricity, heating homes and businesses, and powering industrial processes. Unlike some fuels, gas is difficult to store on-site. Both electric and natural gas utilities rely on the gas infrastructure system, a combination of pipelines and central storage facilities, to deliver gas the moment it is needed.

The size of the infrastructure system, and the type of arrangements utilities need to ensure a reliable gas supply, are dependent on regional supply and demand trends. This report discusses these trends, what new infrastructure options may be available, potential new gas users in the Northwest, and how these factors impact utility gas supply planning.

For the purpose of this report, “utility” refers both to natural gas distribution utilities and electric utilities that generate electricity using natural gas. Additionally, the Northwest market area is defined as British Columbia, Idaho, Oregon and Washington. Some gas used in the Northwest flows from Alberta and the U.S. Rockies; although these areas are not discussed in this report, they do impact Northwest gas supplies. Lastly, a “large” new user as discussed in this report is defined as consuming more than 150,000 dekatherms of gas per day (Dth/day).

Key report takeaways

- Large new gas users could have more control over future infrastructure expansions than existing users, including utilities. Utilities may have to adapt their preferred gas supply and infrastructure strategies based on the location and timing of infrastructure projects chosen by large new gas users.

- Utilities need reliable pipeline transportation from a robust gas supply. As new users enter the region, and existing users change their gas consumption patterns, what is considered to be a robust supply may change. This could cause utilities to change their preferred gas supply portfolio and/or transportation product (firm or non-firm) needed to ensure reliable delivery of gas to the point of consumption.
Pipeline Transportation Options

To transport natural gas from a supply source (a storage facility, production well or hub) to the point of consumption, utilities rely on a network of gas pipelines. The pipeline company does not own the gas – it provides the means to transport it. Utilities and other gas users must make arrangements with gas suppliers to purchase the gas, and then contract with the pipelines to deliver it. Generally speaking, there are two arrangements for transporting gas on the pipeline system: firm transportation and non-firm transportation.

- **Firm transportation** is effectively a standing reservation on the gas pipeline on a primary path that can be called upon any day of the year. Barring force majeure, customers with firm transportation can rely on the pipeline for gas transportation on the primary path year round. The primary path is defined in the firm transportation agreement by a specific receipt point and a specific delivery point.

- **Non-firm transportation** in this report refers to all other transport options, including interruptible, that are not firm. This category also includes firm transportation when a customer chooses to use the contract on other than the primary path, sometimes referred to as secondary firm.

The reliability of non-firm varies by pipeline and pipeline path. Some pipelines have space available and likely can transport non-firm year round. Other pipelines are “fully subscribed” and only transport non-firm when firm customers are not using their capacity. On all pipelines during high demand days non-firm users may find themselves unable to transport gas from their preferred source or unable to transport at all.

Utilities consider a number of factors when making arrangements for transportation. Typically, users who purchase firm transportation use the pipeline more frequently and/or rely on the pipeline for gas transportation during high demand days. Users of non-firm often don’t need guaranteed pipeline transportation during high demand days; some are willing to take the risk that capacity may not be available some of the time.

As the Northwest’s natural gas and energy landscape changes, utilities may switch between firm and non-firm transportation to ensure reliable and balanced delivery of their gas supply.
Other Considerations not Central to the Report

This report focuses on how an increase in gas demand, either from existing or new users, could change the gas landscape and/or impact utilities. A number of other potential changes to the Northwest energy world that may affect gas dynamics in upcoming years are not covered in detail in this report. These changes include:

- **Increased participation in energy imbalance markets (EIM).** This would, in theory, allow electric utilities to more efficiently use their electric generation. In the Northwest one utility is currently participating in an EIM, with a second utility expected to start participating soon. Many other utilities have shown interest in joining an existing EIM or creating a Northwest-centric EIM.

  An EIM may change how gas power plants operate. These changes could be yearly, seasonal, daily, hourly, sub-hourly, or all of the above. A study conducted by Pacific Northwest National Laboratories found that both combined-cycle combustion turbines (CCCTs) and gas-peakig units would run more often in the Northwest Power Pool under an EIM, increasing total gas use.¹ For some utility systems an EIM could increase the use of CCCTs while decreasing the use of peaking units. This could decrease annual gas use since CCCTs run more efficiently.

- **Proposed federal and/or state carbon regulations.** These regulations are expected to shift the electric generation system away from coal and toward more gas and renewables. Although this trend is already ongoing, these policies may cement and accelerate the shift. This could lead to increased demand on the gas system and potentially change how gas power plants operate as they ramp up-and-down to integrate variable energy resources.

Lastly, this report is not a joint planning document. Each individual utility will make its own choices regarding participation in infrastructure expansions, what type of pipeline service to purchase, and other gas delivery system opportunities.

Northwest Gas Supply and Demand

*This section summarizes the Northwest supply and demand forecast found in the Northwest Gas Association’s 2015 Outlook.*

Continuing a trend that started as the economy climbed out of the Great Recession, demand growth in the region has been largely flat. The existing system of natural gas pipelines and storage facilities has reliably served the requirements of the region for decades and is sufficient to meet today’s needs, though recent cold weather events have approached system limits. Additional infrastructure is likely to be required within the forecast horizon (2024 is the last year in the Outlook – individual utilities may see the need for new infrastructure at an earlier date) to serve new demand for natural gas, particularly on a design day (the highest expected gas demand).

The Pacific Northwest’s 48,000-mile network of transmission and distribution pipelines serves almost 3,500,000 natural gas customers. The pipelines that transport natural gas from production areas in Alberta, British Columbia, and the US Rockies can deliver more than 4,000,000 dekatherms per day (Dth/day) of gas to the region. Combined with underground and peak storage facilities, the region’s natural gas infrastructure is currently capable of delivering more than 6,500,000 Dth/day of gas at peak capacity.

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2 The full Outlook report can be found at [www.nwga.org](http://www.nwga.org).
3 As noted earlier, the region in this report is British Columbia, Idaho, Oregon and Washington.
Because natural gas utilities are obligated to provide service regardless of the circumstance, they design their systems to accommodate extreme but still plausible weather conditions called “peak” or “design” days. The figure below aggregates the projected design day demand in the region and compares it with the current infrastructure’s ability to deliver supply. Under the expected case, design day demand could stress the system, approaching or exceeding the region’s infrastructure capacity within the forecast horizon. Note that the expected case does not include large new gas projects in the Northwest.

![Figure 3 – Regional design day supply/demand (2015 NWGA Outlook)](image)

While the probability is small, design days occurring on every system across the entire region on the same day can happen. In fact, the winter of 2013-14 was one example of very cold weather (though not design day weather) impacting the entire region simultaneously. Figure 4 shows how in February 2014 the region, and nation, experienced simultaneously cold temperatures. During this event some of the region’s pipelines ran at maximum capacity.

![Figure 4 – Widespread cold temperatures in 2014](image)
Potential New Infrastructure / Supply Options

Reductions in projected demand, a slow economic recovery and the new reality of a vast North American supply of natural gas all combined to change the nature of gas projects now being considered by the region. The focus of concern has shifted from having an adequate gas supply to having enough infrastructure to transport gas to market. Due to the surplus of gas and accompanying fall in prices, the region has seen an increase in potential new industrial gas projects as well as a shift from gas import to export projects.

As the region looks for ways to serve growing demand, a number of projects to either build new pipelines or expand existing ones are in the works. The next page provides a map depicting a number of projects that have been proposed to serve incremental demand in the region and provides descriptions of each project. For a comprehensive list of proposed Northwest infrastructure projects, please see Appendix A.

New pipeline projects

New infrastructure projects are by their nature both large and expensive, but benefit from economies of scale. Generally, a project is not likely until there is sufficient new demand to trigger one or more parties to come forward and select a preferred project. Project developers will only commence construction if they are assured of cost recovery, therefore new infrastructure will only be built if the customers are willing to enter into long-term contracts for firm transportation. Once a new large volume customer (anchor tenant) selects its preferred infrastructure project and signs a contract, other loads will follow and the project will be built accordingly. Notably, when new gas infrastructure projects are built the participating customers, typically new users and existing users who seek to benefit from the project, are the ones that pay for the project.
The map and text below shows and describes select potential Northwest infrastructure projects:

1 – Washington Expansion Project – In response to a request for an incremental 750,000 Dth/day of capacity, Williams Northwest Pipeline (NWP) is planning to construct the Washington Expansion Project. The project consists of 140 miles of 36-inch diameter loop to be constructed in 10 different segments in or near NWP’s existing right-of-way along the I-5 corridor between Sumas, WA, and Woodland, WA. Additional compression at five existing compressor stations will also be added. In conjunction with this project, NWP is also proposing an incremental scalable expansion from Sumas to markets in the I-5 corridor as far south as Molalla, OR. This phase of the project is not contingent upon the aforementioned expansion and could go in service as early as the fall of 2018.

2 – Trail West/N-MAX – NWP is working with the current Trail West pipeline project sponsors – NW Natural and TransCanada Gas Transmission Northwest – to develop Trail West in conjunction with an expansion of the existing NWP system (N-MAX). The Trail West project
would consist of a 106-mile, 30-inch diameter pipeline that would run from Gas Transmission Northwest’s mainline in central Oregon to a NW Natural/NWP hub near Molalla – enhancing delivery capacity to the I-5 Corridor. Trail West’s initial design capacity is 450,000 Dth/day, expandable to 750,000 Dth/day. It would be linked to the proposed N-MAX project on the NWP system to deliver gas to other markets north along the I-5 corridor.

3 – Spectra System Enhancements/FortisBC KORP

Spectra System Enhancements—Spectra Energy continues to evaluate expansion of its T-South system to provide incremental delivery options for growing Western Canada gas supply to markets in the Pacific Northwest. All expansions on T-South would require pipeline looping and compression and can be brought into service between 2018 and 2020. T-South expansion options include the following from Station 2 to:

- Sumas delivering gas to the BC Lower Mainland and Northwest Markets
- Kingsvale delivering up to 450,000 Dth/day gas to Fortis Energy’s Southern Crossing system
- Summit Lake delivering gas to PNG’s pipeline system

FortisBC Kingsvale—Oliver Reinforcement Project (KORP) – Expanding Fortis Energy’s existing bi-directional Southern Crossing system (connecting Spectra’s T-South system at Kingsvale, BC, to TransCanada’s system at Yahk, BC) would facilitate access to an additional 300,000 – 400,000 Dth/day of Alberta Energy Company (AECO) priced gas supply for westbound delivery to markets in the Lower Mainland of BC and the I-5 corridor where several new large industrial projects are proposed. The expansion of the Southern Crossing system will require a 100-mile pipeline-looping project on the Kingsvale to Oliver, BC, segment, as well as an expansion of Spectra’s T-South system from Kingsvale to Huntingdon to meet the incremental flow.

4 – Pacific Connector Gas Pipeline Project – The Pacific Connector Gas Pipeline Project is a 232-mile 36-inch diameter pipeline extending from Malin to Coos Bay, Oregon. Williams and Veresen, Inc. are proposing the project to serve the Jordan Cove Liquefied Natural Gas (LNG) export terminal, as well as potential regional markets between Malin and Coos Bay. It includes 41,000 horsepower of compression to be installed near Malin yielding a total project design capacity of just over 1,000,000 Dth/day. The project will provide access to supplies from Western Canada and the U.S. Rockies via interconnections with Gas Transmission Northwest and the Ruby Pipeline. Williams will operate the project, which is a 50/50 joint venture with Veresen, Inc.
Natural gas storage facilities

Gas storage can largely be broken down into two categories: underground storage and liquefied natural gas (LNG) storage. Underground storage facilities have more capacity and can be used more frequently. Gas stored underground is used both on high demand days and to balance pipeline operations. The maximum withdrawal rate of underground storage projects is typically directly related to storage capacity utilization. As facilities deplete inventory, the amount of gas that can be withdrawn per day decreases. As such, there may be less underground storage withdrawal capability later in the winter.

The Northwest has two large underground storage facilities (Mist, in Oregon, and Jackson Prairie, in Washington). Currently there are no plans for new underground storage facilities, as underground storage development requires specific geological formations and conditions, but it may be possible to expand existing facilities.

LNG storage is quickly depleted and typically reserved for extreme high demand days and/or peak shaving. These facilities are smaller than underground storage projects and typically serve more of a local market than the greater region. The exception is Plymouth LNG in Washington, which serves multiple users across the region. Once depleted, LNG storage projects take a long time to refill.

The region today has seven LNG storage facilities and one liquid propane gas storage facility (similar in characteristics and use to LNG storage). The region may be gaining a new storage project via a combined-use (LNG for transportation and peak-shaving) project in Tacoma, WA. This project is in the development phase and could be online in late 2018. One challenge to new LNG storage projects is the rigorous permitting process.

Recall agreements

Recall agreements allow a utility to obtain gas supplies controlled by third parties (e.g., industrial users, power plants) for a limited number of days, usually in the winter. These third parties typically have the ability to switch from natural gas to a backup fuel (often oil) for a short period of time. The alternate fuel tanks of the third parties could be thought of as the storage medium. When the recall agreement is triggered, it is up to the third party to either shut down or switch to those alternative fuels, freeing up their natural gas for other users. Since these agreements are typically just for gas and not for transportation, the party using the recall agreement also needs to have a way to transport the gas to the point of consumption.

For a variety of reasons, these recall agreements most closely resemble LNG peak-shaving plants. First, there is usually a strict limitation on days when recall capacity is available. Second, the gas is typically made available adjacent to or within the utility's service territory, mirroring that of a market-area storage plant.
Prospective suppliers of this service expect it to be called upon only during the harshest weather, when alternate fuel costs are highest and re-supply is uncertain, and so they must include the possible cost of plant shutdowns and product loss, and include such factors in pricing the service. For that reason, it can be difficult to find third parties who are willing to consider providing such a service.

**Demand-side management**

Demand side management programs can reduce the need to build new gas infrastructure by slowing or reducing gas demand. These programs include energy efficiency measures, like insulating water heaters, which reduce total gas demand. Some utilities also employ demand-response programs that can reduce gas demand during peak hours. Gas and electric utilities in the Northwest have and continue to invest heavily in these programs, and their effect can partially be seen in declining demand forecasts for both gas and electricity.

**Biogas**

Biogas refers to the methane produced from biomass sources including wastewater treatment plants, animal manure, landfills, woody biomass, or crop residuals. If the biogas is purified to the standards of the pipeline industry, it is commonly referred to as bio-methane or renewable natural gas. The American Gas Foundation (AGF) conducted a study regarding the technical potential for producing bio-methane and predicted that it could meet 4 to 10 percent of natural gas use in the United States.\(^4\)

At present, the supply of bio-methane is extremely small. Its future growth may depend more on its use as a vehicle fuel (due to federal renewable credits known as RINs for biofuels used as motor fuels) than for heating or to make electricity.

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\(^4\) "The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality." AGF, September 2011.
Potential New Gas Users

There are many potential new gas users on the drawing board for the Northwest, adding up to more than 5,000,000 Dth/day of demand on peak. Although many of these new commercial ventures may not get built, if a combination of smaller projects or a single larger project were to be built in the Northwest, it could trigger a gas infrastructure expansion. These new ventures will likely be in the driver’s seat for how and when the gas system is expanded. Utilities may have to change their gas supply, transportation, and preferred new infrastructure strategies as a result.

New users may trigger an infrastructure build if they require firm transportation on the pipeline system and are willing to make long-term commitments. The gas system is built to ensure that firm transportation holders always have access to their contracted pipeline capacity, but non-firm holders are made no guarantees. If a new user needs fully reliable gas service they will likely require firm transportation (or on-site fuel backup). If there is enough firm demand for transportation above what is available from the existing pipeline system, a new infrastructure build may be triggered.

The chart below provides an overview of four types of potential new Northwest end-users. Note that the peak usage represents an estimate – actual projects may fall outside of the range. The values represent one new user per type and are not cumulative. For a point of comparison, the 2015 NWGA Outlook sees regional design day demand in its expected case to grow by around 30,000 Dth per year.\(^5\) Appendix B provides a detailed list of potential new users.

<table>
<thead>
<tr>
<th></th>
<th>Peak usage (thousand Dth/day)</th>
<th>Needs firm gas transportation?</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial(^6)</td>
<td>50 to 320+</td>
<td>Most likely if above 150,000 Dth/day</td>
</tr>
<tr>
<td>Power plant(^7)</td>
<td>25 to 100</td>
<td>Most likely, unless has oil backup</td>
</tr>
<tr>
<td>LNG export</td>
<td>200 to 1,000+</td>
<td>Potentially, or could help shave peaks</td>
</tr>
<tr>
<td>LNG for transport</td>
<td>50 to 100</td>
<td>Potentially, or could help shave peaks</td>
</tr>
</tbody>
</table>

Table 1 – Sample individual new user characteristics

Some projects may not have the need for firm transportation. For example, some power plants, particularly peaking units, may choose to use non-firm along with oil backup rather than firm transportation. Some industrial projects may find non-firm transportation a preferable alternative to firm. However, a large enough project (roughly over 150,000 Dth/day of demand) would likely need new infrastructure regardless of their preferred gas transportation type simply due to high utilization of the existing pipeline systems.

\(^5\) 2014/15 to 2023/24 average yearly growth.
\(^6\) Methanol plants are included this category.
\(^7\) Based on a plant ranging from roughly 100 to 600 megawatts in size.
The remainder of this section will describe potential new user types, why they may locate in the Northwest, and some of their general characteristics.

**Industrial**

Due largely to increased production, natural gas prices in North America have fallen considerably in the past decade while prices in other markets, particularly Asia, have remained high. These lower prices and widening price differentials have resulted in greater interest in using natural gas for industrial projects and exporting natural gas. Often gas can be used to power industrial equipment and/or be used as a feedstock in producing value-added products.

Industrial projects range in size. Potential industrial projects in the Northwest include fertilizer facilities and methanol plants, among other developments. The methanol plants being considered would consume from 160,000 to 320,000+ Dth/day each. The methanol, which is used among other applications to manufacture plastics, would then be exported. Fertilizer facilities and other industrial projects would likely be smaller users of gas.

![Graph showing gas price spread between US and Japan](image)

**Electric power plants**

At the end of 2020, two large Northwest coal units, Boardman and Centralia 1, will be retired, and at the end of 2025, Centralia 2 will be retired. At the same time, the region may see growing demand for electric energy, capacity and flexibility. Due to these retirements and potentially increasing electric demand, the region may see new gas-fired electric power plants built to maintain system adequacy.

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8 World Bank Commodity Price Data (The Pink Sheet), nominal U.S. dollars, June 2015. Note that LNG prices in Japan have been falling recently.
Gas power plants range in size and efficiency. In the past decade, gas power plants from roughly 150 to 650 MW have been built in the Northwest with varying levels of efficiency. To determine how much gas is burned in a power plant the formula below can be used.

\[
gas \text{ use} (Dth) = \text{hours run} \times \text{unit size (MW running)} \times \left(\frac{\text{heat rate (Btu/kWh)}}{1,000}\right)
\]

For example, a 440 MW CCCT with a heat rate of 7,000 Btu/kWh\(^9\) would consume around 75,000 Dth/day of gas per day running at 100 percent.

**Liquefied natural gas for export**

As noted above, natural gas prices in North America have fallen in the past decade. However, gas prices in other parts of the world have remained relatively high. Companies are interested in transporting inexpensive North American natural gas from the Northwest to higher-priced markets.

There are a wide range of sizes for LNG export projects. Smaller projects may consume around 200,000 Dth/day of gas whereas a large project can use more than 1,000,000 Dth/day. Some projects may have the potential to help the region meet demand during high-use days by either allowing diversion of the incoming gas supply or by vaporizing stored gas. However, this capability is dependent on the design of the infrastructure and contracts that support the export project.

**Liquefied natural gas as a transportation fuel**

There has been interest, particularly with marine vessels, to use LNG as a transportation fuel in the Northwest. Similar to export projects, LNG for transport projects would require a liquefier and storage. On high demand days, LNG projects could potentially help the region meet demand, but similar to an export project, this capability is dependent on the infrastructure and contracts that support the LNG project.

**Existing projects firming their supply**

Some existing Northwest gas users currently utilize non-firm transportation. If these users were to switch to firm transportation it could reduce the amount of non-contracted (or unsold) pipeline space available for other non-firm users and/or provide demand to expand the existing gas system.

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\(^9\) Heat rates are typically expressed in how many British thermal units (Btu) are needed to generate one kilowatt hour of electricity. By dividing the heat rate by 1,000 we can convert to how many dekatherms are needed to generate one megawatt hour of electricity.
Utilities Need Gas Transport from a Robust Supply

During high demand days it is critical that utilities have reliable access to gas supply. This reliable access to gas supply is both a factor of the supply basin and the transportation system connecting the supply basin to the end market. The gas supply basins feeding the Northwest have resources in excess of the region’s needs. Pipeline transportation to connect these basins to end markets has historically been provided on both a firm and non-firm basis. Due to the low level of firm contracts, utilities were able to rely on non-firm transportation services during peak demand days.

As gas consumption patterns change and new users locate to the Northwest, more firm transportation capacity has been contracted on the pipelines and subsequently less non-firm capacity is available to meet peak day demands. In effect, the remaining non-firm capacity could become insufficient to meet peak day demands. If this were to occur utilities may have to make alternate plans to secure a reliable gas supply.

Example – Sumas gas hub

Sumas is one of the Northwest’s key gas supply hubs and has traditionally had a fairly significant supply of gas flowing into it from Station 2 via the Spectra Pipeline on a non-firm basis (see Figure 7). Effective November 2015, however, all available year-round capacity on Spectra has been contracted on a firm basis intending to service incremental industrial demand. The result is less non-firm capacity available for the market to rely on to meet its needs.

If utilities determine they can no longer reliably access gas at Sumas, alternate gas supply plans may have to be made, including purchasing firm transportation (if available), seeking an alternate supply source from a different area or participating in an infrastructure build.

Figure 7 – Station 2 to Sumas
As noted above, there is potential that certain utility loads and end-users, including new loads, may seek to participate in an infrastructure build, likely a pipeline expansion, to ensure reliable gas availability at Sumas. An infrastructure build will occur if there is enough demand to ensure cost recovery for the developer. This demand could come from a single large user or a combination of users. The issue will be one of timing as it may take four years or longer from contract execution to expanded capacity being available to serve portions of the traditional Northwest market.

Utilities will continue to monitor all supply sources and pipeline flows. Each utility has a different set of criteria for what they consider to be an economical and robust supply, and each utility will make their own decision regarding what arrangements they need to ensure an adequate gas supply for their customers and power plants. If a supply source becomes unable to provide enough gas to serve the market, utilities will have to rethink their gas supply strategies, including their gas transportation options.
Appendix A – Potential New Gas Infrastructure Projects in the Northwest

The list below contains examples of gas infrastructure projects that could be built in the Northwest to provide better access to gas supply. Note that the bulk of these projects are potential and many may not materialize. All design day gas use values should be viewed as estimates. Lastly, this list should not be considered all-inclusive.

<table>
<thead>
<tr>
<th>Potential Northwest gas infrastructure expansion projects</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Type</strong></td>
</tr>
<tr>
<td>-----------</td>
</tr>
<tr>
<td>New pipeline</td>
</tr>
<tr>
<td>New pipeline</td>
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<tr>
<td>New pipeline</td>
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<tr>
<td>New pipeline</td>
</tr>
<tr>
<td>New pipeline</td>
</tr>
<tr>
<td>Pipeline expansion</td>
</tr>
<tr>
<td>Pipeline expansion</td>
</tr>
<tr>
<td>Pipeline expansion</td>
</tr>
<tr>
<td>Pipeline expansion</td>
</tr>
<tr>
<td>Underground storage</td>
</tr>
</tbody>
</table>
Appendix B – Potential New Gas Users in the Northwest

The list below contains examples of gas projects that could locate in the Northwest and/or firm their existing fuel supply. Note that the bulk of these developments are potential and many may not materialize. All design day gas use values should be viewed as estimates. Lastly, this list should not be considered all-inclusive.

<table>
<thead>
<tr>
<th>Type</th>
<th>Project name</th>
<th>Likely pipeline</th>
<th>Est. max use (Thousand Dth/day)</th>
<th>Earliest online</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Electric Power</td>
<td>I-5 Corridor gas unit</td>
<td>Williams NWP</td>
<td>50 to 100</td>
<td>2019</td>
<td></td>
</tr>
<tr>
<td>Electric Power</td>
<td>Carty Generating Station</td>
<td>TransCanada GTN</td>
<td>75</td>
<td>2016</td>
<td>Under construction</td>
</tr>
<tr>
<td>Electric Power</td>
<td>Wind Chaser</td>
<td>TransCanada GTN</td>
<td>85</td>
<td>2019</td>
<td></td>
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<tr>
<td>Industrial</td>
<td>Fertilizer project</td>
<td>Williams NWP - east</td>
<td>70 to 80</td>
<td>2017</td>
<td></td>
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<tr>
<td>Industrial</td>
<td>Kalama Methanol</td>
<td>New pipeline or expansion</td>
<td>160 to 320</td>
<td>2018</td>
<td></td>
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<td>Industrial</td>
<td>Other industrial - BC</td>
<td>Spectra</td>
<td>50 to 100</td>
<td>2019</td>
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<td>Industrial</td>
<td>Other industrial - US</td>
<td>Williams NWP</td>
<td>50 to 100</td>
<td>2019</td>
<td></td>
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<td>Industrial</td>
<td>Port Westward Methanol</td>
<td>New pipeline or expansion</td>
<td>160 to 320</td>
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<td>Industrial</td>
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<td>Pacific Connector (new)</td>
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<td>Kitimat LNG</td>
<td>Pacific Trail Pipeline (new)</td>
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<td>Oregon Pipeline (new)</td>
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<td>Fortis BC &amp; Spectra</td>
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<td>2019</td>
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<td>LNG for transport</td>
<td>Tacoma LNG</td>
<td>Puget Sound Energy &amp; Williams NWP</td>
<td>20</td>
<td>2018</td>
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