# Review of Pipeline Utility Corridor Capacity and Distribution for Petroleum Fuels, Natural Gas and Biofuels in Southwest Washington

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**Submitted to:**
State of Washington
Energy Facility Site Evaluation Council
Olympia, Washington

**Submitted by:**
ICF International

# Introduction

This report has been conducted at the request of the Washington State Energy Facility Site Evaluation Council (EFSEC) with direction and funding as stipulated by the Washington State Legislature. The EFSEC retained ICF International, based in Fairfax, Virginia with a regional office in Bellevue, Washington to perform the analysis.

This study seeks to understand the current capacity and capability of the petroleum, biofuels and natural gas infrastructure in southwest Washington to supply oil products and natural gas into the region, and to identify the need for new capacity or corridors to supply the region. The study has been initiated as a result of concerns expressed by businesses and constituents in the study region stemming from increasing patterns of higher prices and supply disruptions in the region.

In order to develop the analysis, considerable time was spent gathering information from stakeholders in the market as well as public information that would enable an informed review from multiple perspectives of the oil and natural gas markets impacting southwest Washington. It is very clear that while this study was initiated and funded by the state of Washington, the issues impacting Washington citizens are also affecting the state of Oregon, in particular the citizens in the greater Portland/Willamette Valley region.

Consequently, this report is focused on a “Study Area” that includes southwest Washington (Vancouver region) and northwest Oregon (Portland/Willamette Valley region). The study results and recommendations should be applicable to the entire study region, and in fact the issues are as vital, if not more so, to the state of Oregon due to their greater population in the study area.

The report covers natural gas as a wholly separate issue from petroleum and biofuel supply. This distinction is logically given that there is a dedicated and entirely separate infrastructure for natural gas, and minimal overlap in the marketplace between natural gas and petroleum customers.

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# Executive Summary

This project was initiated by the Washington legislature based on growing concerns from constituents in southwest Washington regarding high gasoline and diesel prices and increased price volatility. The Washington State Energy Facility Site Evaluation Council (EFSEC) was tasked by the legislature to investigate the issue, and ICF was subsequently retained to complete the assessment. While gasoline and diesel prices in southwest Washington stimulated the desire to complete this study, the actual assessment was expanded to include an integral market region in northwest Oregon (the Portland/Willamette Valley area). The study was also expanded to cover natural gas and biofuels, which are important energy sources for the study region. The study assessed the infrastructure, supply and demand, and pricing patterns for petroleum products, biofuels, and natural gas to determine the level of supply capability into the region, demand trends, and the future outlook. The study was based on internal ICF resources and expertise, along with extensive input from key stakeholders in the region.

The study was divided into two sections: 1) liquid products, including biofuels, and 2) natural gas. Key findings and recommendations from the study are discussed in these two groups in the following paragraphs.

**Petroleum and Biofuels**

**Background**

The supply of petroleum fuels into the study area is primarily sourced from refineries located north of Seattle on Puget Sound (near Anacortes and Bellingham), augmented by marine deliveries from California and imported cargoes. The refineries supply product into Portland and Vancouver fuel terminals via the Olympic pipeline as well as through marine deliveries. All marine deliveries move into the study area via the Columbia River, with Portland terminals located along the Willamette River.

The primary supply corridor into the study area is the Olympic pipeline, which has the capacity to deliver 300,000 barrels per day (TBD[1]) along the Interstate 5 corridor. About 130-132 TBD of this volume is shipped into the Portland/Vancouver market, and the balance to destinations in northern Washington. Olympic's capacity is limited, and the pipeline has been operating at capacity since it was fully operational in 1971.

The Portland/Vancouver terminals and infrastructure must be capable of meeting demands of about 200-210 TBD from the terminals along the river. The demands on the Portland/Vancouver terminals include about 45 TBD that must be supplied into the Tri-Cities area via barging, as well as an additional 45 TBD that moves into the Eugene area via the Kinder Morgan pipeline. The actual consumption of petroleum fuels in the Portland and Vancouver study area is about 117 TBD based on 2005 estimates.

[1] Thousands of barrels per day; One thousand barrels equals 42,000 gallons

With the pipeline delivery limited to 130-132 TBD, the refiners and other suppliers use marine deliveries from Puget Sound, California and foreign imports primarily from the Pacific Rim ("Pac Rim") to meet the study area's demand needs. These movements, in particular the marine deliveries from the Puget Sound refiners, represent additional supply corridors into the study area.

Ethanol and biodiesel have been small factors in supply prior to 2007, with ethanol usage of about 2 TBD in 2005 in Oregon, and minimal volumes in the Vancouver area. Oregon usage will increase considerably due to Oregon's recent mandate to move to E-10[2] statewide by mid-2008.

The Portland and Vancouver terminals act as a hub in receiving products and trans-shipping products from them to other destinations. The terminals in the region have had virtually no new tanks added in the past ten years. This fact, coupled with higher demands, additional requirements to transport and store more grades of products, and the propensity for disruptions in the fuel supply chain (refinery problems, pipeline outages, weather delay impacts on marine deliveries, etc) have created added price volatility and supply disruptions in the study area. The price volatility and supply disruptions have increased in recent years, and are likely to continue to impact the study area for several reasons:

1. Oregon's mandate to convert to E-10 statewide will further increase the strain on the pipeline and terminals to manage multiple product grades. (E-10 requires refiners to produce, ship and store a sub-octane grade of gasoline for blending at the terminals)
2. The added ethanol volume into the marketplace will be additional local supply of a gasoline component, but will also require dedicated tanks in terminals for storing ethanol. As existing tanks become dedicated to ethanol, fewer tanks will be available for holding base sub-octane gasoline and conventional gasolines.
3. Announced construction of a new pipeline from Utah refineries to Las Vegas is likely to decrease volumes shipped into eastern Washington in 2009 from Utah for supply in the Tri-Cities area. This will increase load on the Portland/Vancouver hub to supply more fuels to eastern Washington.
4. Growth in demands in the study area will over time require greater volumes of imported gasoline from Pac Rim sources to meet demand, unless capacity additions take place in the Puget Sound refiners. Strong growth in Asia may make it more and more expensive to attract these volumes to the U.S. market.

While the current capability to supply the study area (and all of western Washington) is adequate, over time the changes noted above will require increasing dependence on foreign imports of oil products without expansion of refining capacity. An expansion of the Olympic Pipeline would only serve to shift marine supply from the Puget Sound refiners to the expanded pipeline, and not solve the growing import dependence or the price volatility concern.

Oil product prices in the Portland/Vancouver area change in response to changes in NYMEX oil futures pricing, West Coast market factors, and the regional Portland hub issues noted above. The study results indicate that without steps to address these regional supply issues, the study area is likely to experience continued and increased price variations and supply disruptions. An even more significant concern would be the longer term increased dependence on imported products, which could elevate the overall price levels in the northwest market.

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[2] E-10 is gasoline containing 10% ethanol

**Recommendations**

Overall the study area has a very good access to petroleum fuel supply, with access to nearby refinery production, well developed pipeline and marine supply corridors, and a growing local biofuel supply. The recommendations are targeted to increase the utilization and capability of the existing infrastructure in the study area, streamline permitting for new infrastructure, including tankage, pipeline and refinery capacity, and increase the transparency of the petroleum supply in the marketplace. These recommendations should work to mitigate volatility and supply disruptions.

**Recommendations are:**

1. Increase the utilization of the existing terminals in the study area by reducing the number of individual products that must be shipped and stored. Washington should consider conversion to E-10 gasoline, similar to Oregon, in areas supplied by Olympic pipeline in the study area. This will simplify pipeline shipments and more effectively use terminal tanks in Portland and Vancouver. There will also be value in keeping similar grades of gasoline supply to the Umatilla, Oregon and Tri-Cities region of Washington. Washington and Oregon authorities should collaborate on this key issue, with input from the oil industry and other stakeholders on a priority basis.

2. Streamline the process and authorities for parties to develop and implement infrastructure projects, such as increasing tankage, expanding pipeline capacity, and expanding refinery capacity. Maintain the state pre-emption over energy facility siting, and improve the coordination of Federal, State, local and tribal interests which can delay necessary infrastructure projects. Recognizing the exposure the northwest region may have to increased oil product imports, consider repeal or restructuring of the Magnuson Act, which currently inhibits refinery expansion projects.

3. Initiate a weekly report summarizing refinery operation, fuel production, and pipeline movements in an aggregated manner (to preserve confidentiality). This increased transparency, which is already in place in California, will help energy officials in both Washington and Oregon as well as consumers and business to gain a better understanding of how and why physical supply and prices are changing.

4. Require Olympic pipeline to identify incremental pipeline capacity additions that could be made, including scoping cost and added capacity for each increment. Additional pipeline supply will provide more delivery flexibility into the study region, and complement any refinery expansion projects.

5. Implement an oversight and governance mechanism, with authorities and funding as necessary, to insure that these issues are addressed and progress is made to implement agreed recommendations.

These recommendations will not mitigate the fundamental volatility in oil prices, in particular on the west coast, but will help address the identified infrastructure constraints in the study area. It is very critical to achieving any of these recommendations that both Washington and Oregon recognize the existing problems and collaborate to drive results.

## Natural Gas

### Background

The Pacific Northwest has no significant production basins, and essentially all natural gas consumed in the Pacific Northwest is imported from other regions, most notably from western Canada (90% of imports) and to a lesser extent, the northern Rockies (10%). Two Interstate pipelines that serve the region – Northwest Pipeline and Gas Transmission Northwest (GTN) – have a combined Pacific Northwest regional import capacity of approximately 4,100 MMcf per day. Southwest Washington is served exclusively from Northwest Pipeline. Pipeline capacity into the Vancouver area market totals 1,200 MMcf per day: 550 MMcf from the east and 650 MMcf per day from the west/north. The market can be served by both directions simultaneously if necessary. Average 2007 annual load for the southwest Washington area is estimated to be about 125 MMcf per day.

Natural gas prices in the region are largely determined by the North American supply / demand balance with local market conditions playing a secondary role. Pacific Northwest gas price indexes at pipeline interconnects at the Canadian and California borders, currently trade at about $1 discount to prices at Henry Hub Louisiana, the national market price and NYMEX trading hub.

### Projection

Regional natural gas consumption in the area is projected to increase at a rate of 3 percent per year mostly driven by consumption in gas-fired electric generation. Seasonal and peak day consumption is projected to increase at a slower rate, 2 percent per year, since power generation will have a larger impact on the nonpeak summer months.

Gas supply is expected to remain abundant well beyond the forecast period of 2025. However by 2025, Western Canada production is expected to decline from 17 Bcf per day to less than 14 Bcf per day. In contrast, Rockies production grows from 8 to over 12 Bcf per day by 2025. Supply form either basin will always be available from if the prevailing market price is paid.

Northwest natural gas prices are projected to remain near current levels through 2015, although the price difference to Henry Hub will narrow to near parity. Better pipeline connections across the U.S. and liquefied natural gas (LNG) imports in the Gulf of Mexico are anticipated to reduce eastern U.S. prices. By 2025, Canadian gas prices are expected rise from current levels of more than a $1 below Henry Hub prices to less than 20 cents per MMBtu below Henry Hub.

Pipeline capacity is expected to be adequate for Canadian imports on both Northwest and GTN until at least 2020. Northwest Pipeline entering the Vancouver market from the east may consistently run full in the winter months by about 2012. This is mainly for economic reasons not necessity. The Southwest Washington market can also be served from the North with Canadian imports.

**Recommendations**

Pipeline capacity to serve Southwest Washington appears adequate until sometime late next decade. With projected price increases in Canadian gas supplies, the main focus of Washington gas consumers should be to evaluate other supply sources.

**1**. **Rockies Gas Supplies**. **Analyze Pipeline Projects that Transport Rockies Gas West – Contract for Capacity if Economically Viable.** Northwest Pipeline capacity cannot be easily expanded to bring additional Rockies gas to the study area, but any proposed projects that bring Rockies gas to California should be examined. Gas in California could move to the Pacific Northwest largely with existing infrastructure.

**2**. **LNG Imports**. **Analyze Cost and Price impacts of Direct Pacific Northwest LNG Imports – Contract for Capacity if Economically Viable.** LNG imports could be an economic source of gas. In addition, any import terminal sited in the Pacific Northwest will reduce, or possibly even eliminate, the need for additional import pipeline capacity that may be required in the foreseeable future

**3.** **Arctic Gas. Support Arctic Gas Development. -** Arctic gas development will directly reduce western Canadian gas prices and thus purchased gas costs for Southwest Washington consumers.

**4.** **Natural gas Storage**. **Analyze Cost and Benefits of Additional Storage beyond Current Expansion Plans -** Additional natural gas storage will increase the ability to store higher volumes of less expensive Rockies supplies. Storage expansions are a direct substitute for incremental pipeline capacity and should be considered for peak day delivery coverage as the market grows.

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# 1 Petroleum & Biofuels Analysis & Conclusions

## Background

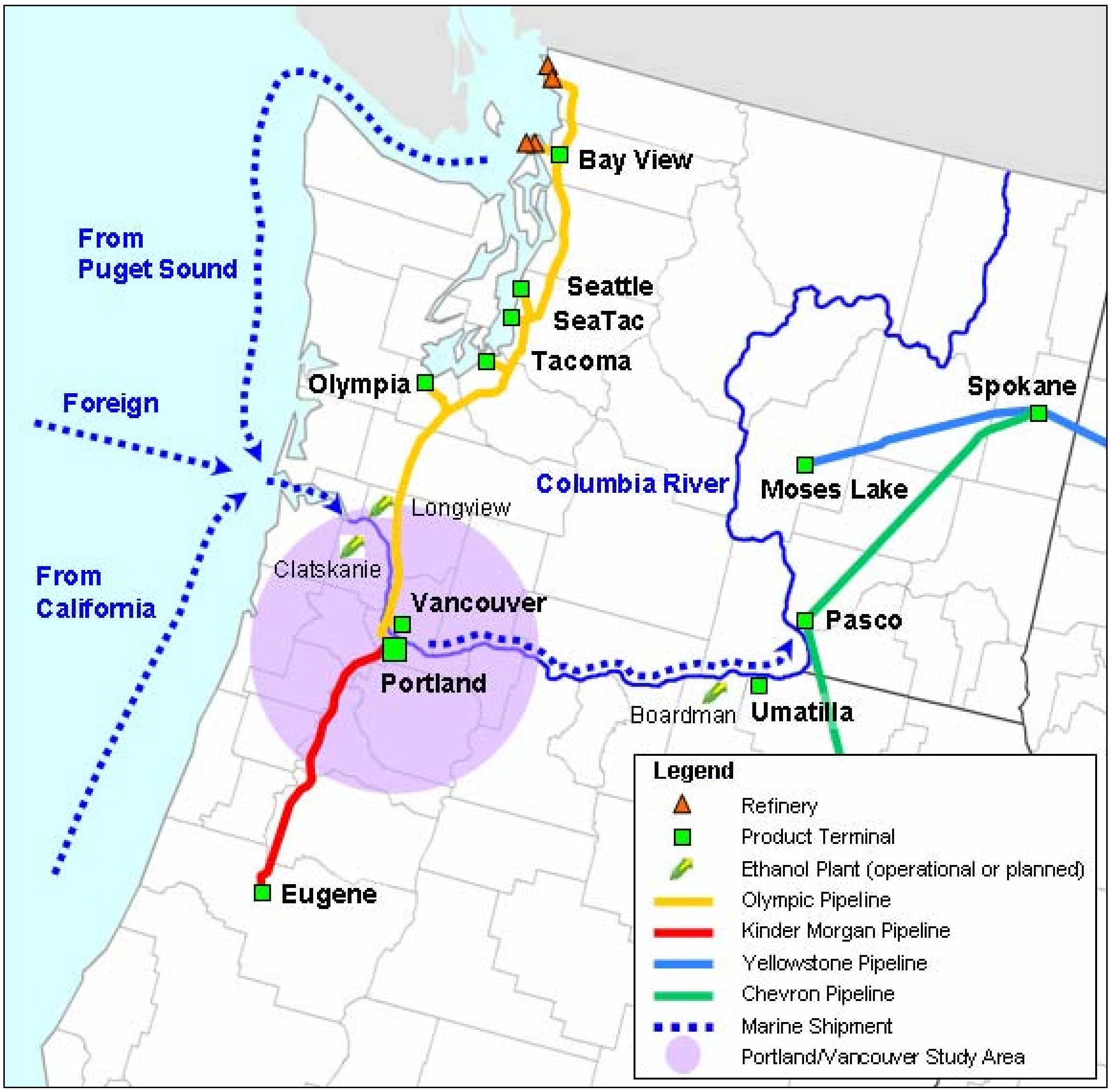
The supply of petroleum products into the southwest Washington and northwest Oregon region (“study area”) is highly dependent upon delivery of fuels from the Olympic pipeline. Additional supply enters the regional market through waterborne imports from foreign or domestic locations into the Portland, Oregon and Vancouver, Washington areas The overall demand for petroleum products has increased in the region due to population and economic growth, with increasing dependence upon imported products due to capacity constraints on the Olympic pipeline. The Olympic pipeline is sourced from Puget Sound refineries and has not been expanded since its full completion in 1971.

The study area is part of a West Coast petroleum product marketplace that has many infrastructure constraints. The West Coast market has become increasingly constrained due to very strong growth in demand for gasoline and diesel in California, Arizona and Nevada, minimal expansions of refinery capacity in the past 10-15 years, and more stringent product specifications for fuels, especially in California. Moreover, the West Coast is a great distance from the major U.S. refining centers in the Gulf Coast, which means that the ability to replenish supply in the event of refinery disruptions takes a long time and is very expensive. Consequently, the region has higher prices for oil products than the rest of the United States, greater price volatility, and a higher propensity for supply disruptions.

The Northwest petroleum market consists of four refineries north of Seattle (BP, ConocoPhillips, Shell and Tesoro) as well as a smaller U.S. Oil refinery located in Tacoma on Puget Sound. The four major refineries supply petroleum products into the Seattle/Tacoma market via Olympic pipeline continuing south to Olympia, Vancouver and Portland.  The refineries also move product by ocean-going barges into the study area, and also produce and ship California quality product by barge into San Francisco and Los Angeles markets.

The study area, shown below in Exhibit 1.1, is positioned between the Northwest and California refining centers. It is supplied by product from Olympic pipeline as well as marine shipments from Puget Sound, California and imported markets. Product also leaves this region via a separate pipeline into the Eugene, Oregon market and also by river barges supplying the Umatilla, Oregon and Pasco/Tri-Cities, Washington markets.

**Exhibit 1.1: Study Area**




Source: ICF International

The study area, as part of the overall West Coast market, is subject to price volatility when West Coast supply disruptions occur. All four Northwest refiners have sister refineries in California, and have capability (to varying degrees) to supply product into California either on an ongoing basis or in response to California disruptions. Some product also moves into the study area from California, as well as from foreign sources. The physical linkage of the study area to the

California market through cargo movements means that the Northwest will see volatility when the California market is disrupted.

However, the study area market is also exposed to its own volatility stemming from its role as a hub for pipeline and marine movements both into and out of the Portland/Vancouver area. Pipeline outages or delays due to refiner problems, as well as marine delivery delays due to severe weather at the Columbia River bar, can trigger disruptions in supply and price in the study area over and above the usual West Coast volatility.

The impact of the price and supply disruptions on businesses and consumers in the region was a significant impetus for this study. The price volatility makes it difficult for a business to manage fuel costs, which an increasingly larger share of budgets for commercial businesses, state and local government entities, school districts, and so on.

The analysis in this report examines the fundamental supply and demand of product in the study area and the issues that appear to be primary factors causing price volatility, including pipeline capacity.

# Analysis: Supply & Demand

## Approach & Overview

In order to analyze the market in the study area, it is essential to get an understanding of the overall flow of petroleum products into and out of the market. This requires the development of a significant amount of information on the infrastructure, pricing and the supply and demand trends in the market. The study developed information from a number of public sources as well as discussions with stakeholders with operations in the study area. The areas of information included:

- Infrastructure: Pipelines, Terminals, Marine transportation, Refineries
    - Stakeholder interviews
    - OPIS[3] terminal directory
    - U.S. Energy Information Administration (EIA) database
    - Company websites

- Supply and Demand: Volumes shipped into and from the study area
    - Stakeholder interviews
    - EIA data on petroleum demands, imports and movements
    - Army Corps of Engineers data on waterway movements of petroleum products

- Pricing and Costs
    - Stakeholder interviews
    - OPIS and Platt's[4] data on petroleum product prices
    - Published pipeline tariffs for product transportation

- Product Quality Issues & Biofuels
    - Stakeholder interviews
    - Oregon & Washington state Energy resources and/or legislative records
    - Company websites

The overall level of information received was sufficient to perform this initial study. However, the study would have benefited from more specific data from the stakeholders. The stakeholders primarily provided verbal input to the study team and were reluctant to provide hard statistics for confidentiality reasons.

The study team used the aggregated information collected from the multiple sources noted above to develop an overview of the market in the study area. This information and initial

[3] Oil Price Information Service, a company which publishes oil industry information, such as terminal locations and capacity, pricing information, etc. OPIS reports primarily domestic prices, and OPIS price is used as a basis for oil transactions

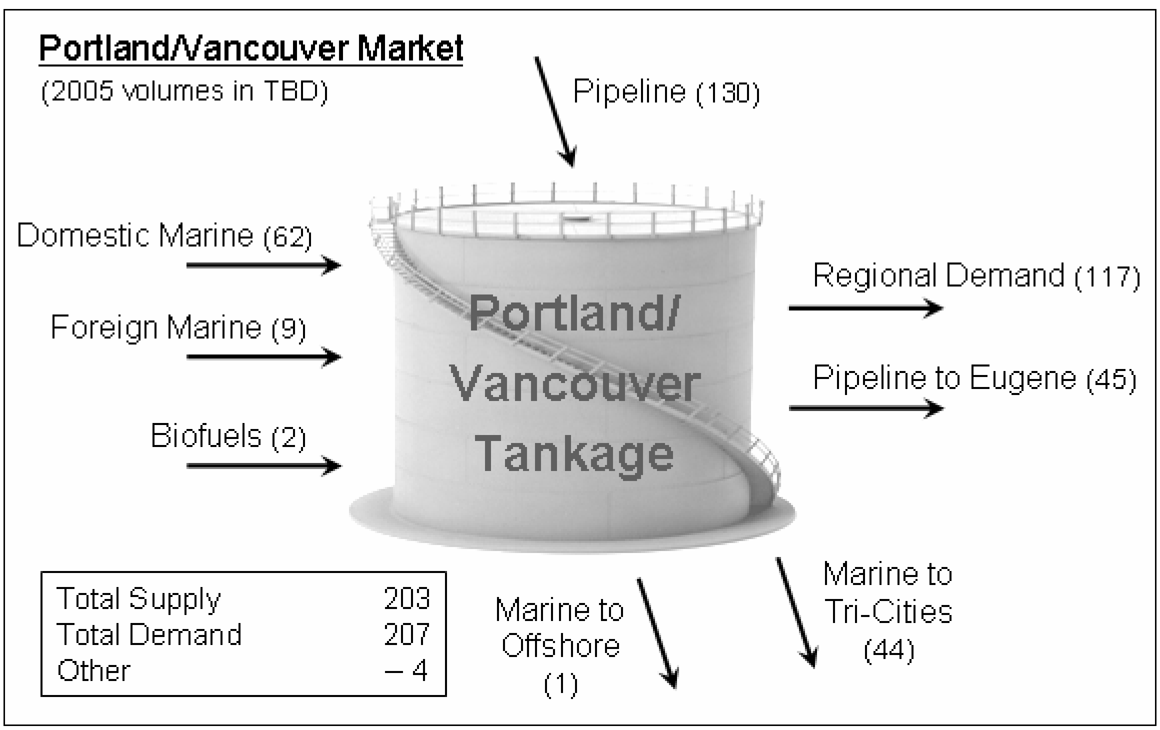
[4] Platts is another oil industry price reporting service who covers both domestic and international prices; Platts price quotes are used as the basis for oil transactions.

conclusions was presented to a number of stakeholders on October 10th in Vancouver[5] to receive comments and feedback so that the final report would have as much input as possible. Based on that feedback and continued analysis, this final report has been completed.

The overall flow of petroleum fuels in the study area is shown in Exhibit 1.2. The fuel supplied through the Portland/Vancouver hub includes gasoline, jet fuel and diesel fuel that are provided via Olympic pipeline and marine transportation into the terminals in the Portland and Vancouver area. Marine deliveries arrive from Puget Sound refiners, California refiners, and imported cargoes. Some of the terminals also receive ethanol supply from local or remote sources. The total volume of fuel moving into the region is about 200,000 barrels per day, or 8,400,000 gallons per day.

Product moves out of the terminals in several modes. First, the most significant volume is lifted by truck to supply local gasoline stations, commercial businesses, and so on. Second, volumes moves by a pipeline owned and operated by Kinder Morgan into terminals in the Eugene region. Third, volume moves out by river barges to the Tri-Cities area in Washington and Umatilla, Oregon to supply those markets. On rare occasions volumes moves from the study area to other regions (exported or to California). The Portland and Vancouver region depends significantly on the efficient operation of the entire infrastructure shown in Exhibit 1.2 to maintain normal market conditions.

**Exhibit 1.2: Portland/Vancouver Market Supply & Demand Overview**




Source: ICF analysis as cited throughout the report. “Other” could include inventory adjustments, inventory changes and/or data anomalies from various sources utilized.

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[5] All stakeholders were invited to this meeting; about 20 stakeholders attended from a cross-section of the oil industry as well as state energy representatives. All stakeholders received an electronic copy of the presentation.

This section of the report will now review the supply and demand components of the infrastructure.

## Supply Components

### Terminals

The volumes of each product move into the study area terminals by pipeline and marine movements. The terminals in the study area are primarily located in Portland on the Willamette River, with two terminals located in Vancouver (See Exhibit 1.3). The largest terminals are owned and operated by Kinder Morgan and NuStar. These terminals are used by oil companies, trading companies and distributors to manage supply and distribution. The major pipeline shipping companies (BP, ConocoPhillips, Shell and Tesoro) own terminals, as well as Chevron. The total storage capacity in these terminals has been essentially unchanged since 1997. There have been ownership changes and some adjustments up and down in reported tankage, but the overall capacity has been stable through 2006. In 2007, the NuStar terminal in Portland has added two 100MB capacity tanks, which increases tankage in the region (although it is an increase of less than 2%).

**Exhibit 1.3: Portland/Vancouver Market Petroleum Fuel Terminals**

| Portland | MB Storage | Petroleum Terminals |
|---|---|---|
| Kinder Morgan | 1400 | 2 |
| NuStar | 1039 | 1 |
| ConocoPhillips | 749 | 1 |
| Chevron | 714 | 1 |
| Shell | 447 | 1 |
| BP | 434 | 1 |
| McCall | 130 | 1 |
| | | |
| **Vancouver** | | |
| NuStar | 304 | 1 |
| Tesoro | 281 | 1 |
| **Total** | **5498** | **10** |

Sources: OPIS 2007 Terminal Directory, company websites

Most of the terminals have the capability to receive product from Olympic pipeline and marine deliveries, and load product out via trucks, Kinder Morgan pipeline, and marine vessels.[6] The scheduling of receipts into a terminal and deliveries from the terminal requires a very carefully developed plan to insure that adequate inventory is available in the terminal tanks for each

[6] Confirmation of modes of receipt and delivery could not be verified for all facilities.

grade of product in order to meet scheduled deliveries (also called “liftings”). An example terminal schedule for one product is shown on Exhibit 1.4 below. The schedule shows a terminal which has deliveries from both pipeline and barge receipts, as well as truck, pipeline and barge loadings. The intent is to demonstrate that the staging of receipts and deliveries typically has little room for error. Delays in receipts can easily create outage situations; delays in deliveries can cause tanks to become full and require changes in receipt schedules to avoid tank inventory being non-containable.

**Exhibit 1.4: Example Petroleum Terminal Rundown Volumes are in MB, thousand barrels**

| Day | Inventory (80 MAX) | Receipts | | | Liftings | | | | Net In/(Out) | Inventory (80 MAX) |
|---|---|---|---|---|---|---|---|---|---|---|
| | Open | Pipeline | Barge | Total | Rack | Pipeline | Barge | Total | | Close |
| 1 | 30 | | | 0 | 3 | | | 3 | (3) | 27 |
| 2 | 27 | 50 | | 50 | 3 | | | 3 | 47 | 74 |
| 3 | 74 | | | 0 | 3 | | 15 | 18 | (18) | 56 |
| 4 | 56 | | | 0 | 3 | 30 | | 33 | (33) | 23 |
| 5 | 23 | | | 0 | 3 | | | 3 | (3) | 20 |
| 6 | 20 | | 25 | 25 | 3 | | | 3 | 22 | 42 |
| 7 | 42 | | | 0 | 3 | | | 3 | (3) | 39 |
| 8 | 39 | | | 0 | 3 | | 15 | 18 | (18) | 21 |
| 9 | 21 | 50 | | 50 | 3 | | | 3 | 47 | 68 |
| 10 | 68 | | | 0 | 3 | | | 3 | (3) | 65 |
| 11 | 65 | | | 0 | 3 | | | 3 | (3) | 62 |
| 12 | 62 | | | 0 | 3 | | | 3 | (3) | 59 |
| 13 | 59 | | | 0 | 3 | | 15 | 18 | (18) | 41 |
| 14 | 41 | | | 0 | 3 | | | 3 | (3) | 38 |
| 15 | 38 | | | 0 | 3 | 30 | | 33 | (33) | 5 |
| 16 | 5 | 50 | | 50 | 3 | | | 3 | 47 | 52 |
| 17 | 52 | | | 0 | 3 | | | 3 | (3) | 49 |
| 18 | 49 | | | 0 | 3 | | 15 | 18 | (18) | 31 |
| 19 | 31 | | | 0 | 3 | | | 3 | (3) | 28 |
| 20 | 28 | | | 0 | 3 | | | 3 | (3) | 25 |
| 21 | 25 | | | 0 | 3 | | | 3 | (3) | 22 |
| 22 | 22 | | | 0 | 3 | | | 3 | (3) | 19 |
| 23 | 19 | 50 | | 50 | 3 | | 15 | 18 | 32 | 51 |
| 24 | 51 | | | 0 | 3 | | | 3 | (3) | 48 |
| 25 | 48 | | | 0 | 3 | | | 3 | (3) | 45 |
| 26 | 45 | | 25 | 25 | 3 | 30 | | 33 | (8) | 37 |
| 27 | 37 | | | 0 | 3 | | | 3 | (3) | 34 |
| 28 | 34 | | | 0 | 3 | | 15 | 18 | (18) | 16 |
| 29 | 16 | | | 0 | 3 | | | 3 | (3) | 13 |
| 30 | 13 | 50 | | 50 | 3 | | | 3 | 47 | 60 |

Source: Example presented by ICF for illustrative purposes.

The actual coordination of operations is more complicated due to the multiple grades of product that are required to be handled. As an example, the terminals as well as the pipeline must carry and store a number of different grades of product. The products include premium and regular grades of gasoline, with both conventional gasoline (87 and 92 octane) as well as sub-octane grades of each gasoline for ethanol blending by several companies. Gasoline must also be carried and stored for shipment upriver to the Tri-Cities region. This gasoline requires a different vapor pressure than gasoline in the Portland/Vancouver area and must be segregated in different tanks in the study area. Distillate grades include two different jet fuels, low sulfur diesel (LSD), ultra low sulfur diesel (ULSD), off-road low sulfur diesel, and high sulfur heating oil.

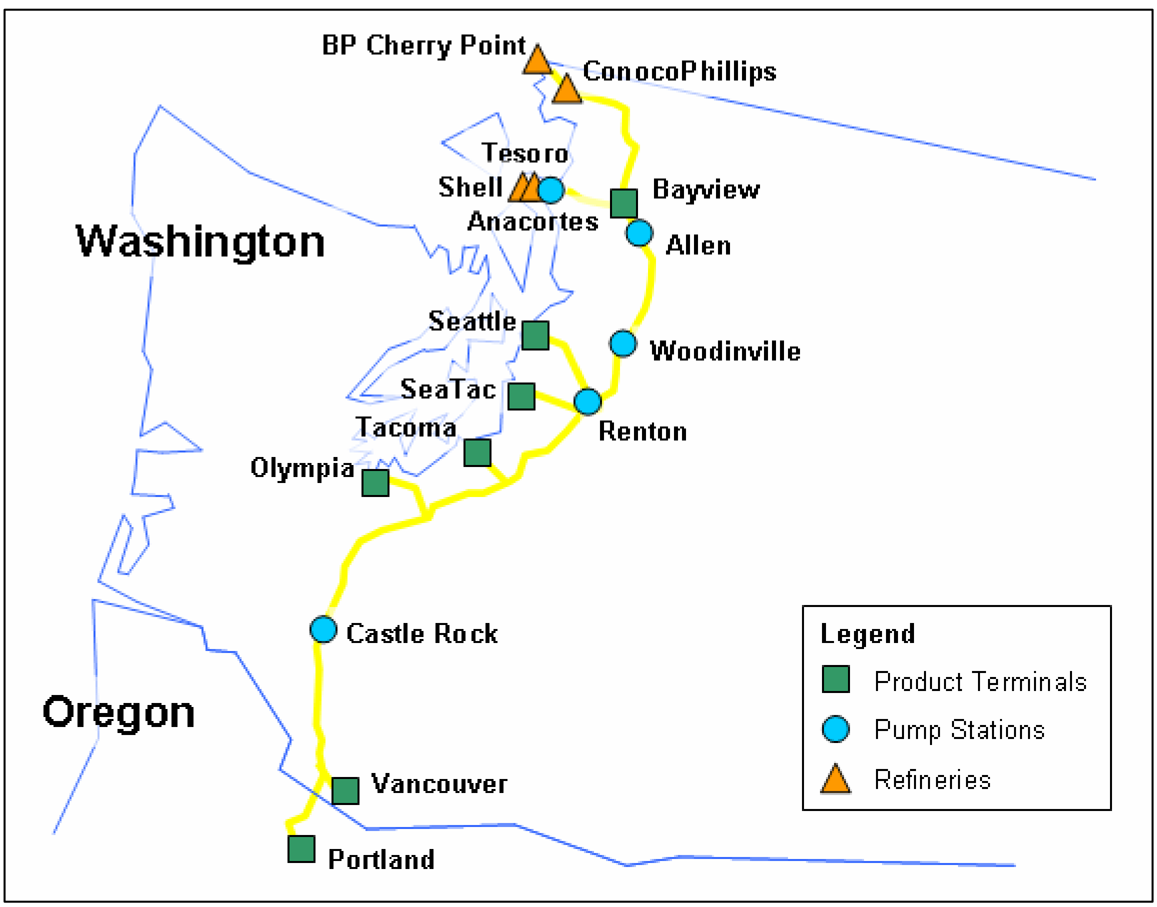
The addition of the sub-octane grades and the ULSD product are changes from 1997. Sub-octane shipments will increase with Oregon’s imminent conversion to 100% E-10, which will require more terminals to alter tankage from conventional gasoline to sub-octane as well as store ethanol. The overall tankage in the study area will not change, but the individual number of tank inventory management requirements (as in Exhibit 1.4) will increase. The conversion to E-10 may also require separation of gasoline for Umatilla from the Tri-Cities gasoline. Both would have different vapor pressure gasoline than Portland, but Umatilla terminals would require sub-octane.

The current logistics management is significantly more difficult and prone to disruption than in 1997, and will be more challenging in the future. The dichotomy in Oregon and Washington state gasoline requirements is aggravating the issue.

### Olympic Pipeline

Olympic pipeline is the primary petroleum product artery supply fuel into the study area. Olympic is an interstate common carrier pipeline[7] which transports gasoline, diesel and jet fuel from the four refineries in Northwest Washington to the study area. The pipeline (See Exhibit 1.5) flows roughly parallel to Interstate-5 and supplies the Seattle, Tacoma, Olympia, Vancouver and Portland markets.

**Exhibit 1.5: Olympic Pipeline Diagram**




Source: Olympic Pipeline Company

[7] Common carrier pipelines

The pipeline is owned by Enbridge Pipeline Company (65%) and BP Pipeline (35%), and has a capacity of about 300,000 barrels per day (300 TBD) in total to all product terminals. The pipeline has three segments which deliver to the Seattle/Tacoma, Olympia, and Portland/Vancouver markets. The volume that has been delivered on segment 3 to Vancouver/Portland has averaged about 130-132 TBD in recent years (the largest volume delivered is to the Seattle/Tacoma region). The pipeline has been operated at capacity for many years, and has not been expanded since it was fully completed in 1971. This throughput level of 300 TBD has only recently (summer 2007) been fully achievable after a temporary, but extended period where the pipeline was required to operate at restricted pressure following major repair work in 2000/2001. The restriction reduced the overall capacity by roughly 10 TBD.

The pipeline operation involves shipping batches of product from the refineries in a sequenced order of movement. Since gasoline, diesel and jet fuel are all transported in the same pipeline, the timing of movements and deliveries must be carefully executed to avoid contamination (for example, ULSD can easily be contaminated if small quantities of higher sulfur diesel are mixed). The ability of the pipeline to operate at its rated capacity is highly dependent on 1) the pipeline components (pumping stations, etc) operating reliably, and minimal outages for leak repair or other maintenance (which is clearly required periodically) and 2) the refineries supplying the pipeline must have product available to meet their required shipment schedule into the pipeline. When refinery operational problems occur, especially unplanned ones which impact their ability to meet Olympic's schedule, the pipeline either must reduce rates or work with other refiners to accelerate their shipments.

Operation of the pipeline over the past five years has resulted in average total deliveries into the study area of 130-132 TBD, based on information provided by Olympic. The pipeline is averaging somewhat higher than that in 2007 with the restriction on operational pressure removed. At a current maximum daily pumping capacity, the pipeline should be able to deliver about 135 TBD annually into the study area, allowing for historical levels of maintenance work as well as the impact of refinery problems. The transit time on the pipeline can vary from 36 to 48 hours depending on the source location (Anacortes or Ferndale) and the product shipped (gasoline can be pumped at a higher rate than distillates).

Since the pipeline is a separate business from the refineries, and a common carrier pipeline with interstate movements, it is regulated by the Federal Energy Regulatory Commission (FERC). FERC regulates the tariff, or fee, that shippers pay to move product to various destinations on the pipeline. The tariff for moving product from the Northwest Washington refineries to the study area is about 2.5 to 3.0 cents per gallon (cpg).

The shippers on the pipeline must nominate volumes desired to be shipped on each pipeline cycle. Due to the pipeline's operation at capacity, the nominations are always for more volume than the pipeline can ship. Therefore, Olympic pro-rates the volume allowed for each shipper based on their nominations each month. Shippers are familiar with this process and coordinate their marine movements with the pipeline schedule to control product inventory levels in the refineries.

**Marine Movements**

Olympic pipeline has provided about 130-132 TBD into the Portland/Vancouver region. Overall demands in the study area are about 200 TBD. The shortfall in supply to the region is made up by marine movements into the area. The marine movements are sourced from several areas:

- Puget Sound Refiners: The Puget Sound refiners ship about 290 TBD (total of all segments) on Olympic pipeline, but produce approximately 430 TBD gasoline, diesel and jet fuel.[8] Some of difference is used to supply local Northwest Washington demand, but the large majority of the 140 TBD difference is moved via marine vessels. Some of the volume difference moves into the Portland/Vancouver market. Refiners have term contracts with some of the major marine transport companies in the region (Crowley, Sause Brothers, and Seacoast) for ocean going barge equipment to move the product.

  The marine volumes moved from Puget Sound into the study area are typically at costs ranging from near the Olympic tariff to several cents per gallon above the tariff. In general, the marine movements are more expensive than the pipeline tariff, but not a significantly greater cost.[9]

  The refiners also move a significant volume into the California market to support their demands in the California region (which includes Arizona and Nevada). The volumes involved usually include the more difficult to produce California gasoline and ULSD grades (e.g. CARBOB gasoline). The California grade product is more expensive to produce than conventional gasoline used in Washington, but also has a higher value in California.

  The refiners also will export some gasoline and distillates when economic. Estimated volumes in 2005 were about 10 TBD.[10]

- California Refiners: Volume can move into the Portland/Vancouver market from California. Chevron, who does not have a refinery in Washington, supplies the study area by ocean going marine equipment from its California refineries, for example.

- Imported Product: Product, primarily gasoline, also moves into the Portland/Vancouver market from foreign sources. The volume is typically sourced from Korean or other Far East refiners and is driven by economics. Higher prices in the study area make it economic for trading companies to buy product in the Far East and sell into the Portland market.

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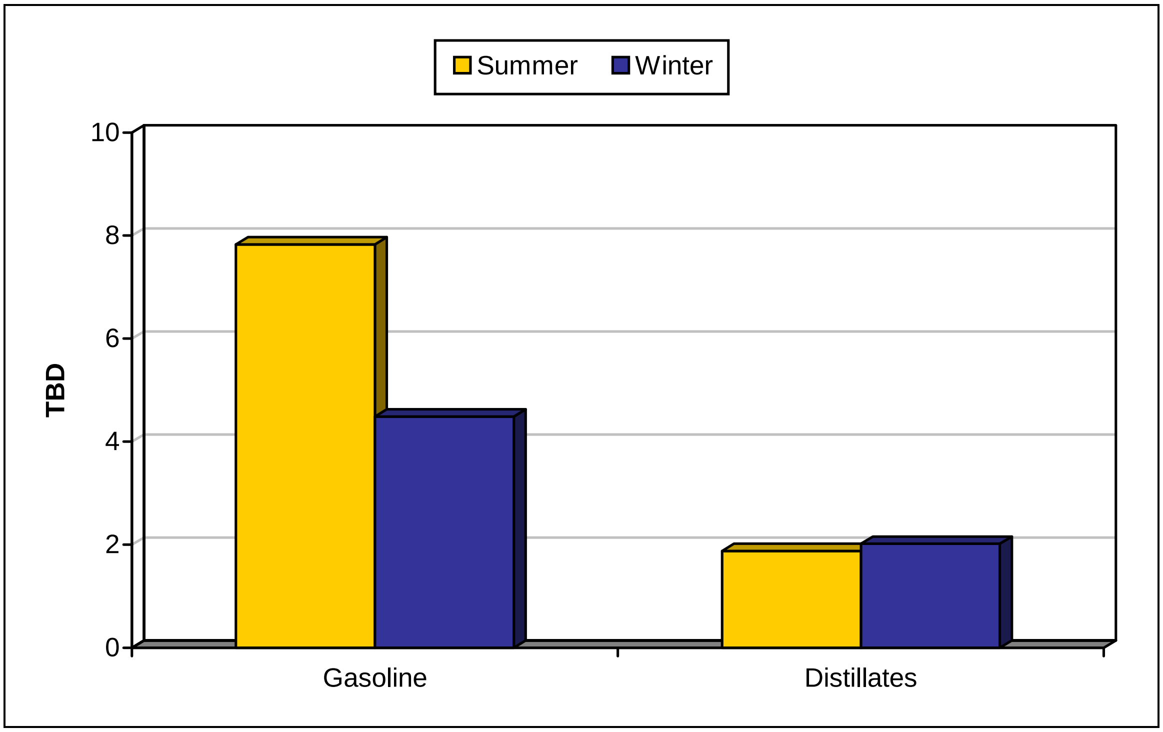
[8] ICF estimate based on refinery capacity, configuration and utilization assuming 92% utilization and 80% clean product yield (gasoline, jet, diesel)

[9] Information provided by some chartering companies as well as shippers; No parties were willing to provide specific contract terms/

[10] Army Corp of Engineers Waterway report, 2005

Exhibit 1.6 shows the seasonality of imported product over the past 7 years into the study area. Almost twice as much gasoline is imported in the summer months (April through September) than the balance of the year. Additionally, virtually all of the imported product is sourced from trading companies such as Vitol, Glencore, Mieco, etc, who arrange cargo movements to take advantage of price arbitrages between markets.

**Exhibit 1.6: Imported Product Seasonality, 2000-2007**




Source: EIA

The marine deliveries into the study area deliver product into local terminals along the Willamette River after transiting the Columbia River bar and moving upstream. Without weather disruption, the transit time from a Puget Sound refinery is 36-42 hours[11]. Weather can wreak havoc on the schedule however. Delays of several days can occur at the Columbia River bar as severe weather can make it unsafe for vessels to transit the bar. This disrupts the terminal schedules as noted above. Also, the relatively shallow draft of the Willamette River in the terminal area makes it necessary for vessels which require a deeper draft to "lighter"[12] their cargoes offshore onto shallow draft barges. This primarily impacts foreign cargoes.

Total marine volumes into the study have averaged about 75 TBD in recent years, and were 71 TBD in 2005, the latest year with complete data from the Army Corps of Engineers. This included about 62 TBD of domestic movements (both from Puget Sound and California) and 9 TBD of foreign imports.

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[11] Total round trip time, including refinery loading hours, transit to Portland/Vancouver, discharge, return transit to the refinery dock is about 5 days with good weather

[12] Lighter means to connect hoses from one vessel to another to transfer product

Finally, input from marine and terminal stakeholders in the study area indicated that, in general, the dock facilities at area terminals were not congested, and capacity existed from a berthing perspective for additional receipts of marine supply.

### Puget Sound Refiners

As noted earlier, the Puget Sound refiners are the source of product shipments into Olympic pipeline, as well as marine deliveries to waterborne destinations. While the refiners did not provide specific production and distribution statistics for this report due to confidentiality and anti-trust concerns, ICF estimated their production volume to identify the potential additional product that could potentially be shipped on the pipeline. ICF's rough estimate of this volume is identified in Exhibit 1.7 below:

**Exhibit 1.7: Estimate Puget Sound Refiner Distribution**

| | TBD | Comment |
|---|---|---|
| Total Gasoline, Jet and Distillate Production | 430 | Based on reported crude capacity, 92% utilization, and 80% yield of clean products |
| Volume shipped on Olympic | (290) | Assuming volumes at near capacity |
| Local Northwest Washington Demand | (40) | Estimated far northwest Washington demand |
| Marine Deliveries from the Refiners | (100) | By difference; estimated destinations as shown below |
| Foreign Exports | 10 | Army Corps of Engineers Records |
| Volumes to Port/Van | 50 | Estimate based on Army Corps total volume Into Portland/Vancouver (60-70 TBD) |
| Volumes to California | 40 | By difference |

Source: ICF estimates as noted; Army Corps of Engineer data; Olympic throughput volumes; assumptions are for BP, ConocoPhillips, Shell and Tesoro refineries in aggregate

While this is clearly an estimation since actual data is not available, it does provide an order of magnitude of the possible additional volumes "available" to ship on Olympic pipeline if in fact the pipeline had additional capacity. The volumes exported and shipped to California are unlikely to be redeployed into Olympic. This is because those products are being shipped to other markets due to 1) higher realizations and/or 2) capability to meet more stringent California quality requirements. The volumes being shipped to the Portland/Vancouver market (roughly 50 TBD) would be the maximum added volumes that could be shipped on Olympic, barring any planned refinery expansion projects.

The other implication of this analysis is that as overall consumption of fuel in the Portland area, or demands into Eugene or the Tri-Cities area change, the incremental supply will need to be sourced from foreign imports. Currently this is certainly feasible, however as gasoline and diesel demands grow in the Far East, imports from Korea and the Far East may be less readily available, and higher prices may be necessary to attract imports.

While no significant northwest refiner expansion projects have been announced, the State of Washington (and Oregon) should recognize that longer term demand growth may be more economic and secure through refinery expansion projects than imports.

**Biofuels**

The primary biofuels used in the study area are ethanol and biodiesel.

**Ethanol** has been used by several refiner/marketers in the region who have been marketing E-10[13] gasoline for some time. There have been no ethanol plants operating in the immediate study area, however three new facilities are either completed or under construction in Oregon and Washington. These plants[14] will have the capacity to produce about 203 million gallons of ethanol per year, or about 14 TBD supply. The completion of the first of these facilities will trigger the initiation of a state-wide conversion to E-10 gasoline in Oregon, beginning in early 2008 (the city of Portland converted to E-10 in mid-2007).

Ethanol used to date in Oregon and the study area is believed to have been supplied via railcar from the Midwest. Railcar supply of ethanol has been the primary distribution method from the production centers in the Midwest[15]. Ethanol cannot be shipped in pipelines with gasoline, or blended with gasoline due to ethanol's affinity for water, which exists in small amounts in gasoline.

The ethanol supply chain involves lifting of product from ethanol manufacturing plants by either railcar for longer distance deliveries, or via truck to local deliveries. In either case, the ethanol is delivered ultimately into oil product terminals (for example the terminals in the study area) in segregated tankage. The ethanol is then blended into delivery trucks in a 10% blend with conventional gasoline for service station delivery. Refiners must alter the base production of conventional gasoline to change the octane level, vapor pressure and distillation quality of the gasoline so that the incorporation of ethanol in the blend will not impact the performance of gasoline[16] significantly.

Ethanol usage in the study area in 2005 was about 2 TBD[17] based on EIA data for Oregon ethanol consumption. Once the Oregon ethanol requirement changes to 10% statewide, this volume will increase to about 14 TBD.

**Biodiesel** is also transported from production sites to oil terminals by truck for blending. Biodiesel is more compatible with petroleum based fuels for pipeline supply, but biodiesel production sites are generally much lower in production volume than ethanol plants, and not located near existing oil pipeline infrastructure. In addition, the amount of biodiesel which can be blended in petroleum based diesel is typically low, with most biodiesel sold being blends of 2-20% (grades are identified as B2, B5, B10, etc based on percent biodiesel).

Biodiesel blends are currently supplied at several terminals in the study area. There is a small biodiesel plant in the Seattle area, and a large biodiesel plant in Hoaquim has recently become operational (August, 2007). The Hoaquim plant has a capacity at full production of 6 TBD. The study has not identified how this biodiesel is being marketed.

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[13] E-10 gasoline is a blend of 10% ethanol with conventional gasoline
[14] Pacific Ethanol in Boardman, Oregon started in August 2007 with 40 million gallons/year capacity; Cascade Grain will begin operations in spring 2008 in Clatskanie, Oregon will have a 108 million gallon/year capacity; Northwest Renewable Fuels in Longview, Washington will have 55 million gallons/year capacity.
[15] California is supplied completely by railcar to meet their demands of at least 60 TBD.
[16] Ethanol has a lower BTU content than petroleum based gasoline. Blends of E-10 will reduce mileage about 3%.
[17] http://www.eia.doe.gov/emeu/states/sep_fuel/html/fuel_use_ww_en.html

### Supply Summary

Current supply of products in the study area have amounted to about 200-205 TBD to meet demand needs[18]. Supply is primarily from Olympic pipeline. Marine deliveries are used to balance needs of the region, with smaller amounts of ethanol and biodiesel used for local needs. Supply availability will increase in the short term as Oregon increases ethanol usage substantially, and this will reduce marine deliveries of gasoline into the region to rebalance supply.

Puget Sound refinery fuel production is the prime source of supply for the study area via Olympic pipeline and marine deliveries. The refineries do not have surplus capacity to produce additional product into Olympic pipeline or by marine into the study area without either 1) refinery expansion projects or 2) reduction of marine deliveries into the California or export markets.

## Demand Components

The demands on the Portland/Vancouver hub are significant. The terminals in the Portland area must provide product for all local fuel consumption, including jet fuel into the Portland airport, as well as being a source point for volume moving on the Kinder Morgan pipeline into the Eugene area, and marine deliveries up the river into the Tri-Cities area as well as Umatilla, Oregon. The demands on the Portland/Vancouver hub drive the required supply into the study area, plus or minus a small amount for inventory variations. In order to actually understand the dynamics of the market in the hub area, it is important to be able to delineate the relative volumes moving into each of the distribution areas.

### Volume Upriver (Tri-Cities, Umatilla)

The volume of product moving upriver can be determined from the Army Corps of Engineers data. Volume records indicate that in 2005 about 44 TBD of product moved out of Portland/Vancouver terminals into Umatilla, Oregon and the Tri-Cities region. Earlier years had similar volumes. This demand placed on the study area terminals is important for several reasons:

1. Petroleum consumption in the Tri-Cities region is supplied from both the study area as well as Chevron pipeline moving petroleum product from refinery sources in Utah into Pasco. Product also moves on Yellowstone pipeline from Montana refineries into the Spokane and Moses Lake area. Based on EIA data, the total volume averaged about 32 TBD in 2005 in addition to the 44 TBD from the study area. The volumes moving on these pipelines can vary due to refinery supply issues in Montana and Salt Lake City. As these shipments increase or decrease, it can reduce or create added demand on the Portland area terminals to meet its commitments.

2. The quality of the gasoline supplied in the Tri-Cities market is different than the study area. Vapor pressure of gasoline has a higher limit in the Tri-Cities market, and must be segregated from gasoline supplies for the study area. This requires some terminal tanks

[18] Olympic Pipeline is about 130-135 TBD; Marine deliveries about 70 TBD; ethanol about 2 TBD

in the study area to be set aside for dedicated usage and cannot be used to supply study area consumption.

3. The movement of product upriver is primarily handled by barge tows operated by Tidewater Marine, who moves product for all parties into the Tri-Cities and Umatilla area. The barge requirements are dictated by inventory management at the terminals upriver. During periods when the locks on the Columbia River are closed for maintenance, the barge schedules must be altered to insure that inventory in terminals upriver is sufficiently high to cover the lock maintenance. This can create high demands on the Portland/Vancouver terminals during this period.

A future issue which is a concern is that Holly Corporation has announced plans[19] to construct a 62 TBD pipeline from the Salt Lake City region to Las Vegas. The intent is to provide petroleum products into a high growth market from the Utah region. This project is planned for completion at the end of 2008. This project may impact the delivery of fuels into the Tri-Cities region from the Chevron pipeline. To the degree this occurs, it will increase required shipments from the study region and place added demand on the Portland market.

Finally, there is periodic movement of product offshore ("downriver") from the Portland area terminals. This typically averages only 1-2 TBD per year, and appears to occur when terminal inventory is surplus in the region.

**Kinder Morgan Pipeline to Eugene**

Volume moves out of Portland/Vancouver area terminals into the Eugene region on the Kinder-Morgan pipeline. This pipeline, according to conversations with Kinder Morgan, handles approximately 45 TBD of product, and operates at or near capacity. Terminals in the study area which are sources for pipeline shipments into Kinder-Morgan must maintain adequate inventory in their Portland area tanks to meet their required shipment dates and volumes on the pipeline. The geographical area between Portland and Eugene is normally supplied by the most economic source for trucks to source product, however trucks may on occasion load at non-optimal sources if supply is tight.

**Local Portland/Vancouver Market Demand**

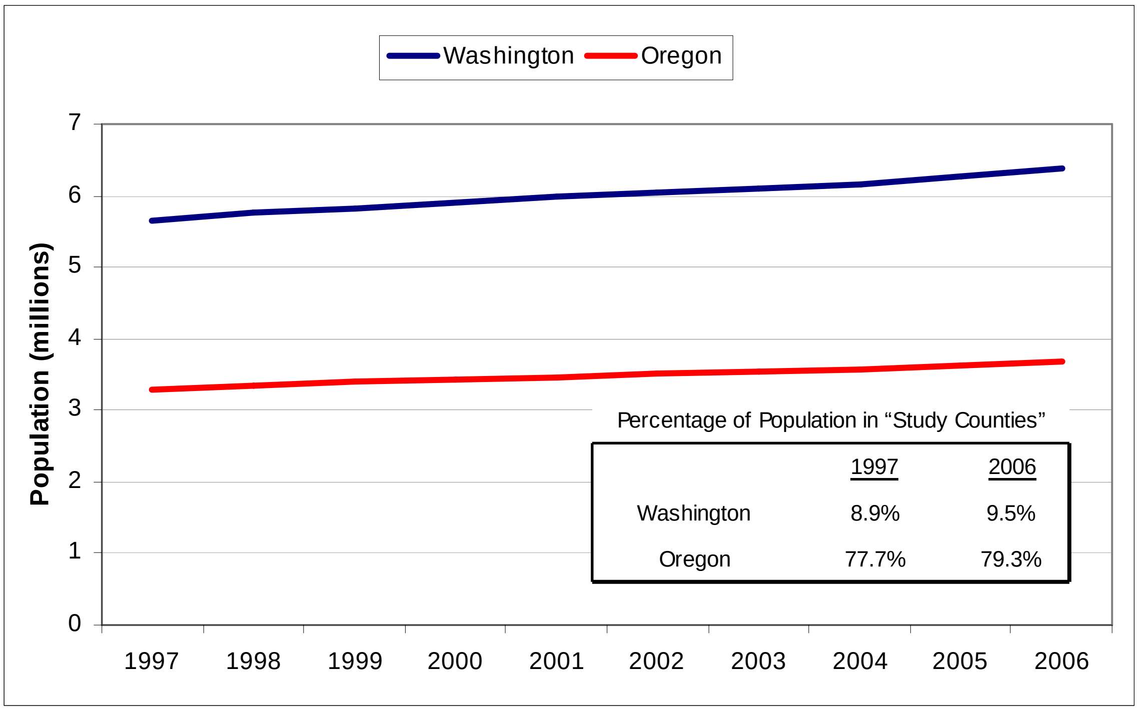
The largest demand volume is for consumption in the large Portland/Vancouver metropolitan area. This area is supplied directly by tanker trucks loaded from the ten terminals in the area, with the exception of a pipeline that solely is used to supply jet fuel into the Portland airport. The optimal method to determine the actual consumption in this market would be to gather information from the various terminals on actual volumes delivered, however none of the terminals preferred to disclose this information as it is would contain confidential information.

In lieu of this, ICF was able to estimate demands in the study area from analysis of EIA data on state-wide petroleum consumption for both Washington and Oregon. This analysis was done using historical demand levels from EIA back to 1997, and adjusted based on trends in population growth in all of the Oregon and Washington Counties which have product sourced

[19] http://www.hollycorp.com/press_release.cfm?id=274

via the Portland/Vancouver terminals and Kinder Morgan pipeline (essentially the I-5 corridor). The trend in state-wide population growth has been steady over the period, as shown in Exhibit 1.8. The exhibit also shows that the percentage of state population in the study area counties has increased, indicating those counties are growing somewhat faster than the state as a whole (presumably with higher energy requirements as well).

**Exhibit 1.8: Population Growth in Washington & Oregon, and Study Area Share**

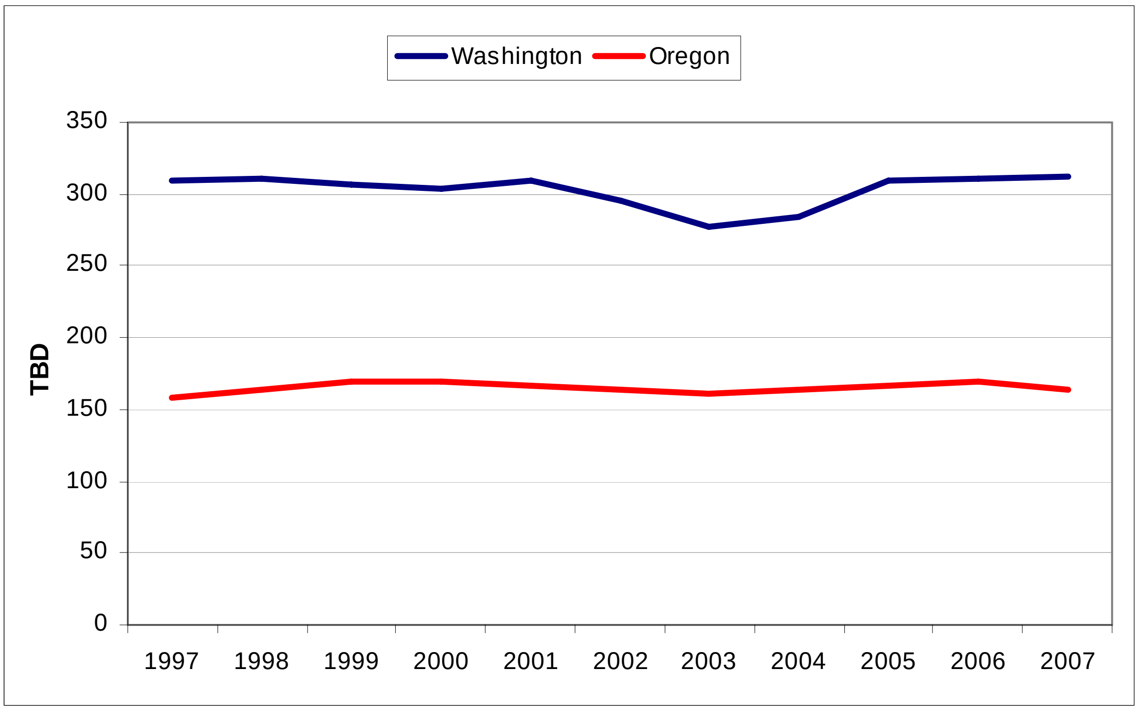



| | 1997 | 2006 |
|---|---|---|
| Washington | 8.9% | 9.5% |
| Oregon | 77.7% | 79.3% |

Sources: State of Washington Office of Financial Management, State of Oregon Office of Economic Analysis, Portland State University Population Research Center

Exhibit 1.9 shows the overall petroleum fuel growth in Washington and Oregon over the study period. This exhibit aggregates gasoline, jet fuel and diesel consumption. Note that overall it does not appear as if the total fuel consumption in Washington and Oregon has increased appreciably over the period. One significant reason stems from the reductions in consumption following the events of September 11, 2001 which primarily reduced the jet fuel demand for a sustained period.

**Exhibit 1.9: Total Petroleum Products Supplied in Washington & Oregon**




Source: EIA Prime Supplier Sales Volumes

Using the population forecasts for the study area counties and the EIA state-wide fuel consumption data, an estimate can be made of the year by year consumption for fuel in the study area. The results of this analysis are shown in Exhibit 1.10. This analysis shows that overall consumption increased from 1997 from about 153 TBD to 166 TBD in 2006; however, this increase was at a low in 2003 and has actually increased about 2-3% per year since 2003.

**Exhibit 1.10: Demand Estimate in Study Area**

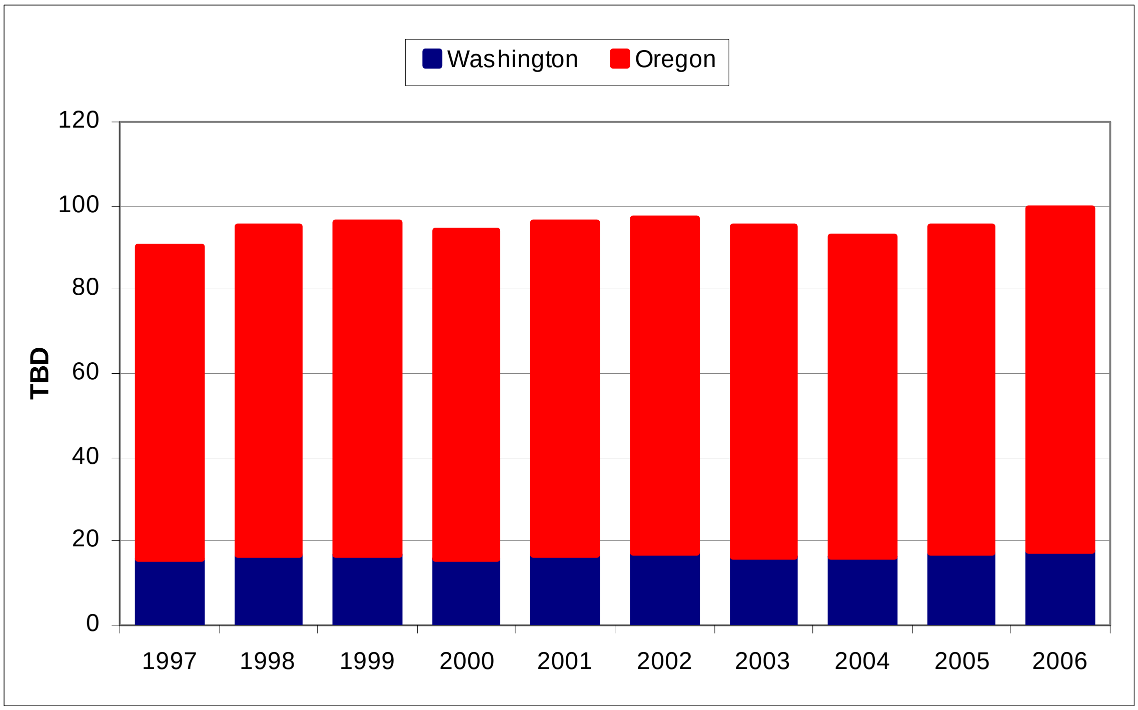
| **Demand Estimation (TBD)** | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **County** | **1997** | **1998** | **1999** | **2000** | **2001** | **2002** | **2003** | **2004** | **2005** | **2006** |
| Clark | 17 | 18 | 18 | 18 | 18 | 18 | 17 | 18 | 19 | 20 |
| Cowlitz | 5 | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 5 | 5 |
| Lewis | 4 | 4 | 4 | 4 | 4 | 3 | 3 | 3 | 4 | 4 |
| Pacific | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Skamania | 1 | 1 | 1 | 1 | 1 | 0 | 0 | 0 | 1 | 1 |
| **WA Counties** | **28** | **28** | **28** | **28** | **28** | **27** | **26** | **27** | **29** | **29** |
| Benton | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| Clackamas | 15 | 16 | 16 | 16 | 16 | 16 | 15 | 16 | 16 | 16 |
| Columbia | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Crook | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 3 |
| Deschutes | 5 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 7 | 7 |
| Gilliam | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Hood River | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Jefferson | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Lane | 15 | 15 | 15 | 15 | 15 | 15 | 14 | 15 | 15 | 15 |
| Lincoln | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Linn | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 |
| Marion | 13 | 13 | 14 | 14 | 13 | 13 | 13 | 13 | 13 | 14 |
| Multnomah | 29 | 30 | 31 | 31 | 30 | 30 | 29 | 29 | 30 | 30 |
| Polk | 3 | 3 | 4 | 4 | 3 | 3 | 3 | 3 | 3 | 4 |
| Wasco | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Washington | 19 | 20 | 21 | 21 | 21 | 21 | 20 | 21 | 21 | 22 |
| Wheeler | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Yamhill | 4 | 4 | 5 | 5 | 4 | 4 | 4 | 4 | 4 | 5 |
| **OR Counties** | **126** | **130** | **134** | **134** | **132** | **130** | **128** | **130** | **133** | **137** |
| **OR & WA Total** | **153** | **158** | **162** | **162** | **160** | **158** | **154** | **157** | **162** | **166** |

Sources: State of Washington Office of Financial Management, State of Oregon Office of Economic Analysis, Portland State University Population Research Center, EIA Prime Supplier Sales Volumes

The total volume of about 162 TBD in 2005 includes the 45 TBD that is the normal throughput on the Kinder Morgan pipeline to Eugene. Therefore, the net demand on the immediate Portland/Vancouver area terminals would be estimated at about 117 TBD in 2005.

The estimated gasoline consumption growth over this period is shown in Exhibit 1.11 below. It shows a somewhat similar pattern as the total fuel consumption line, with gasoline averaging about 60 percent of the total consumption in the study market.

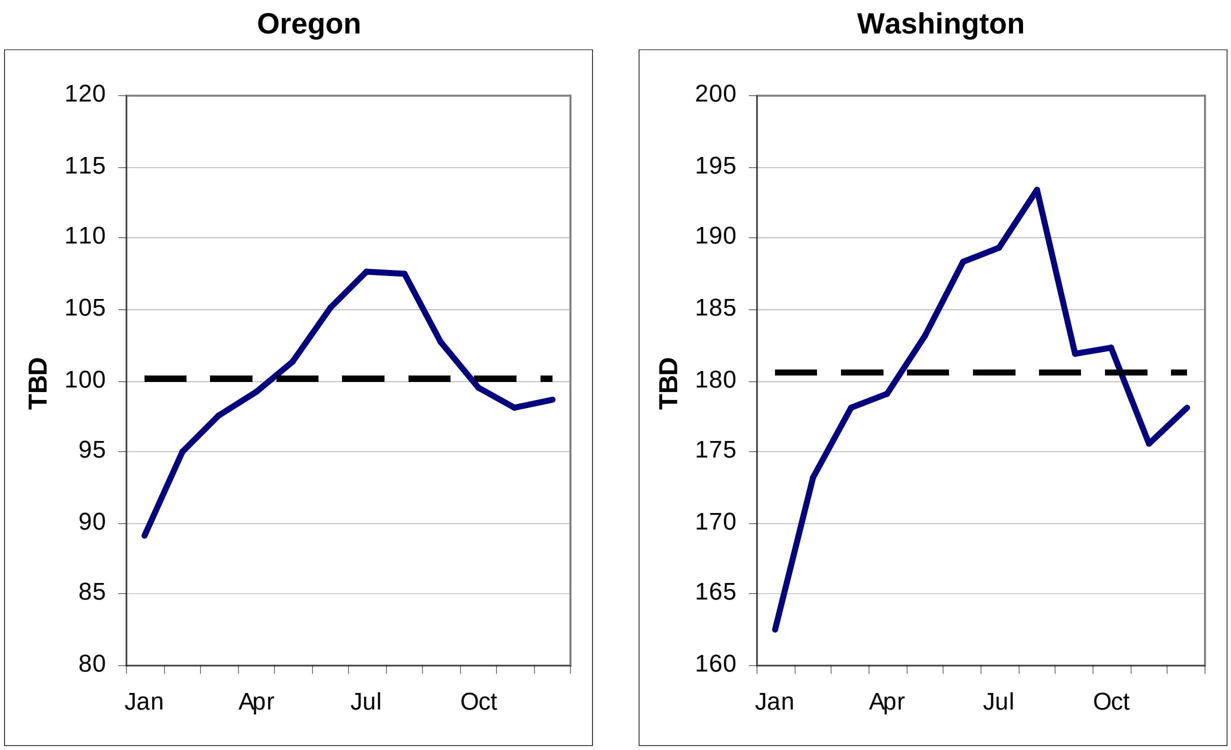
**Exhibit 1.11: Gasoline Consumption Estimate in Study Area**




Sources: State of Washington Office of Financial Management, State of Oregon Office of Economic Analysis, Portland State University Population Research Center, EIA Prime Supplier Sales Volumes

Gasoline consumption is important because in addition to the high volume, it also is more seasonal. Exhibit 1.12 below shows the seasonal trend of gasoline sales in Washington and Oregon based on average EIA data over the past 10 years. The charts indicate that both states will sustain summer consumptions at about 7% above the annual average consumption. This means for the study region that the average gasoline consumption in the summer can be about 7%, or about 7 TBD higher than the full year average. This means an increased requirement on the terminals in the Portland hub in summer months. (Diesel consumption were also examined and found to be significantly more ratable.)

**Exhibit 1.12: Gasoline Consumption Seasonality, 1997-2006**




Source: EIA Prime Supplier Sales Volumes

The other issue related to gasoline seasonality is that gasoline vapor pressure (RVP) must be adjusted at the refinery at several times during the year to raise or lower gasoline vapor pressure. Vapor pressure is adjusted by adding or reducing light material (butane) from gasoline. Butane is added in the winter up to EPA specifications so that gasoline ignites properly in cold weather; it is reduced in the spring so that engines do not vapor lock in the summer. When RVP is reduced, it is done by having the refineries produce very low RVP gasoline for a period. Since RVP is closely monitored by EPA, the scheduling personnel must operate tanks in the system on very low inventory to “flush” the tankage with lower RVP product during the conversion[20] and minimize the risk of an EPA citation.

[20] Vapor pressure does not blend linearly and it may require several cycles of pipeline delivery to flush the tanks in the system and convert to lower RVP without EPA violations.

The conversion to higher RVP in the fall is not as challenging, since it is not a penalty to have vapor pressure a bit under specification during the conversion.

### Demand Summary

Total demands on the Portland/Vancouver market hub amounted to about 207 TBD in 2005 based on estimated regional demands (study area plus Kinder Morgan pipeline volumes) of 162 TBD and marine deliveries of about 45 TBD total. Demands can be 10 TBD higher during summer months due to higher summer gasoline consumption.

## Supply and Demand Consensus and Implications

Exhibit 1.13 shows the combined supply and demand estimates for the Portland/Vancouver hub in 2005. The table shows a relatively good approximation despite the fact that in many cases specific information was not available. The difference could be related to small differences in assumptions for the counties supplied, or incomplete marine data from the Corps of Engineers, or several other areas. However, overall we believe the exhibit provides a reasonably accurate depiction of the overall supply and demand.

**Exhibit 1.13: Overall Petroleum Supply and Demand (TBD), 2005 Portland/Vancouver Hub**

| Supply | | Demand | |
|---|---|---|---|
| Olympic Pipeline | 130 | Portland Regional Terminals | 117 |
| Domestic Marine | 62 | Pipeline to Eugene | 45 |
| Foreign Marine | 9 | Marine to Tri-Cities | 44 |
| Ethanol Blending | 2 | Marine to Offshore | 1 |
| Total Supply | 203 | Total Demand | 207 |

Sources: State of Washington Office of Financial Management, State of Oregon Office of Economic Analysis, Portland State University Population Research Center, EIA Prime Supplier Sales Volumes, U.S. Army Corps of Engineers Navigation Data Center, Olympic Pipeline Company

The observations from development of the supply and demand information provided above, coupled with input from the numerous stakeholders who were interviewed for this report, result in the following conclusions:

1. The relative stable capacity level of the terminal tankage in the Portland/Vancouver market over the past ten years, coupled with higher demands and increasing diversity of the various grades of product that are required to be stored creates a much more difficult system to operate than in the past.

2. The normal activity of day to day pipeline management as well as marine transportation coordination and refinery processing involve frequent operational disruptions, ranging from refinery downtime to pipeline inspections to weather delays.

3. The impact of periodic operational disruptions on the trans-shipment process through the Portland and Vancouver terminals has created situations where the supply of products into the study region has been disrupted. These disruptions typically trigger changes in price or allocations of product to control inventory and to reflect potential replenishment costs. The disruptions can be particularly difficult during periods of RVP conversion in the spring, or lock closures impacting the timing of river-watery traffic.

4. Seasonal disruptions (higher summer gasoline demands, lock maintenance, for example) are more predictable, but still result in periods of more peak stress on the terminal system.

5. While pipeline supply into the region is roughly double marine deliveries, both modes of supply provide relatively smooth and timely (under two day transit time) deliveries into the terminals in the study area. Both methods of delivery can be prone to disruptions related to their specific delivery process (pipeline outages and weather delays), and refinery outages can impact both supply methods when refinery problems occur.

6. The state-wide change to 10% ethanol in all gasoline in Oregon will provide several new impacts on the Portland/Vancouver hub. First, higher volumes of locally produced ethanol will be more local fuel supply which will aide in reducing dependence on marine deliveries (it will in effect convert some marine deliveries of gasoline into terminals into truck deliveries of ethanol into terminals). Second, it will increase stress on hub terminals by requiring them to reserve tanks for ethanol usage and by requiring them to handle multiple grades of gasoline by adding a sub-octane grade of premium and regular to some terminals not currently handling a "BOB[21]" product. Third, the ethanol blending process incorporates a wholly different supply chain from the local ethanol plants into the terminals.

The companies operating the fuel business in the market work diligently to minimize disruptions. However, disruptions have occurred and will continue to occur due to the nature of the business and the need to manage an increasing number of product grades through the Portland/Vancouver hub.

The net result of the realities of the infrastructure and supply and demand issues discussed is that price volatility has become a major issue in the study area. As noted in the Background section, price volatility is a West Coast issue, however the analysis of the study area supply and demand factors indicates that the Portland/Vancouver market has the capability to create localized price anomalies over and above the West Coast.

The next section examines the pricing issues and impacts in the market.

[21] BOB refers to "Blendstock for Oxygenate Blending", a sub-octane product tailor blended at the refinery to meet octane and distillation specifications for merchantable gasoline after blending with 10% ethanol

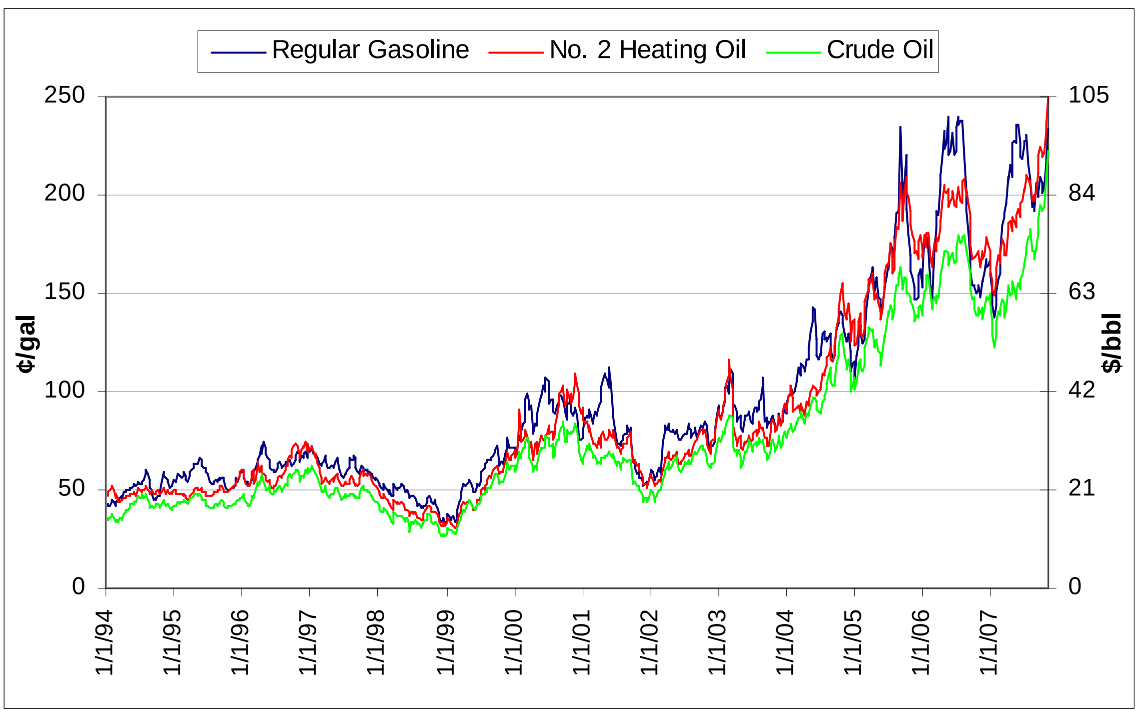
# Analysis: Price

## Global Pricing

Over the past few years global oil markets have shown a relentless drive to higher prices. These changes have been driven by a number of factors, but are primarily evidence of higher global demands for petroleum products as many developing countries, particularly in Asia, enjoy strong economic growth. At the same time, global crude oil production has seen geopolitical disruptions which impact supply in key producing nations, and refining capacity additions have lagged demand growth.

Exhibit 1.14 shows the trend in NYMEX futures prices for crude oil, unleaded gasoline and No. 2 distillate fuel since 1994. Relative stability in prices began changing in 1999-2000, with a definitive trend up beginning in 2004 and sustained thereafter. In addition, there is increased volatility in prices over the past several years, most notably directly following Katrina and Rita, and the following spring. While the NYMEX futures market indicates prices for physical delivery of gasoline and heating oil in New York Harbor, and crude oil in Cushing, Oklahoma, these prices are measures of the value of petroleum fuels worldwide. The prices are often used as the basis for petroleum fuel transactions, and are also used by hedgers, speculators, and investment firms.

**Exhibit 1.14: Overall Price Trend, NYMEX Petroleum 1994-2007**




Source: EIA

## West Coast and Portland/Vancouver Pricing Analysis

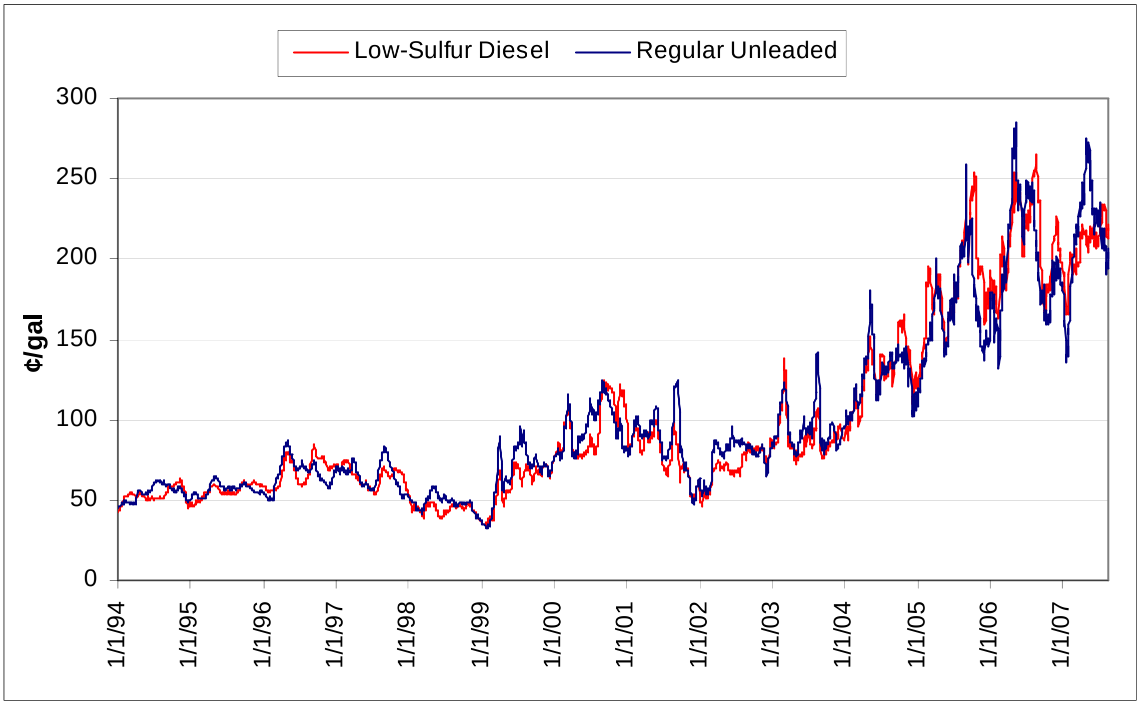
The petroleum market on the West Coast has experienced a similar increase in petroleum prices as other regions in the world. The West Coast market has, however experienced significantly greater volatility in product prices than the NYMEX futures. The primary reasons for this are that the West Coast demands, in particular California, Arizona and Nevada have increased significantly in the past 5-10 years, while refinery capacity expansion on the West Coast has been minimal. At the same time, changes in quality requirements for California gasoline have made it very difficult for many refineries outside California (and some within California) to make the California grade gasoline. Similar changes have occurred in the diesel fuel sulfur requirements, and as of June 2006 all diesel fuel in the U.S. for on-road usage must be 15 ppm[22].

These tighter restrictions have tended to make California gasoline a significant premium above the NYMEX price. The Ultra low Sulfur Diesel (ULSD) is also at a premium versus the NYMEX (which is a heating oil product with a sulfur level maximum of 2000 ppm). While the Portland and Seattle markets do not require the production of gasoline with California quality requirements, the Northwest market is linked to the California market, as noted in the Supply section of the study. Refiners in the Northwest either routinely or as needed will move product into California to help meet their demands in California. When refinery outages occur in California, replenishment from the Northwest is the most expeditious route (if suitable product quality can be met).

[22] Parts per million. 15 ppm equals a sulfur level of 0.0015 percent.

Exhibit 1.15 shows the trend in gasoline and low sulfur diesel price in the Portland market since 1994. Portland is a very vital trading location, with a number of transactions occurring “off the pipeline” as individual refiners or traders manage their inventory in the Portland/Vancouver hub. The exhibit shows an increasing level of price consistent with the NYMEX prices, but with more volatility, in particular since 2004. These prices track gasoline and low sulfur diesel (LSD), which was the primary diesel commodity through mid-2006. Note that prior to 2003 occasional price spikes occurred, but the spikes were of very limited duration and much lower in magnitude.

**Exhibit 1.15: Portland Spot Market Price Trends 1994-2007**



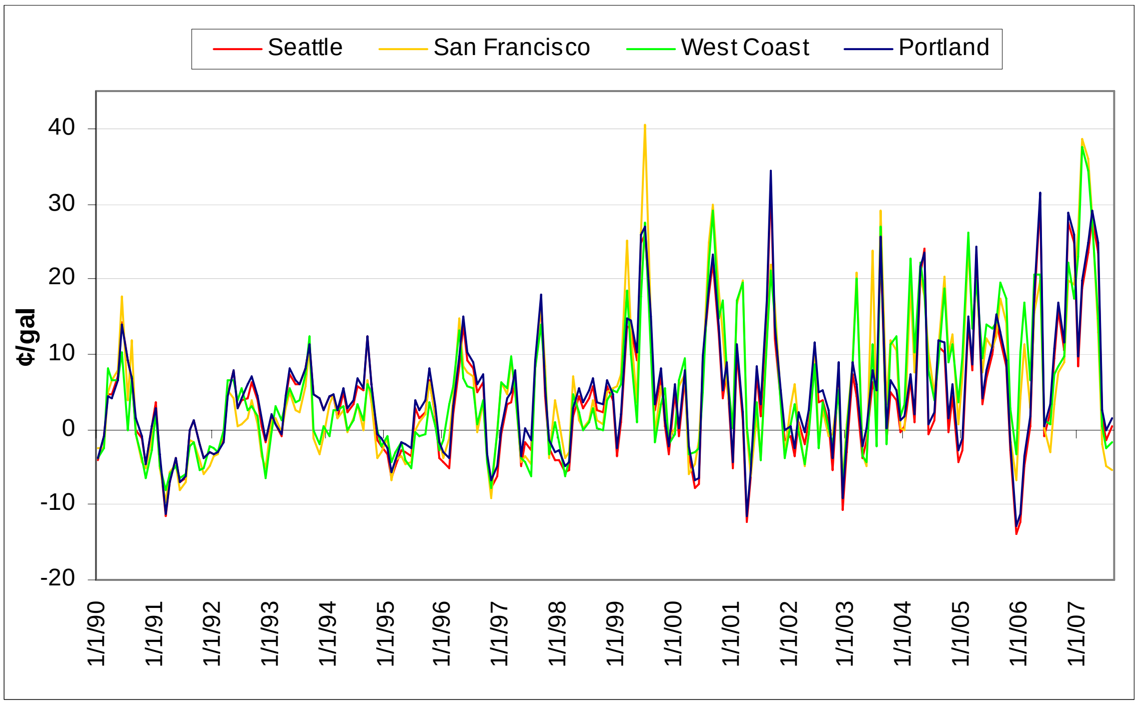

Source: Platts

The volatility in the market creates extreme havoc for distributors[23] and end users of petroleum products. First, the volatility is an indicator of supply shortages which means that a distributor may have difficulty meeting their customer needs. Assuming fuel can be secured, the cost of the fuel must be passed on to the consumer which means that the end user experiences higher costs than have been budgeted.

[23] A distributor is a company that purchases oil products from terminals under various contract terms to resell to businesses, homeowners, government entities, school districts, etc or through service stations.

As noted earlier, the Portland/Vancouver market mirrors the West Coast volatility. Exhibit 1.16 below shows the relative price spread between West Coast market areas versus the NYMEX gasoline price for conventional gasoline since 1990. The volatility versus the NYMEX began increasing in 1999, and has remained very volatile since then. The relative volatility of the Portland, Seattle, San Francisco and West Coast[24] price points all have similar volatility patterns over the period. In some cases the California price has the greatest spread, in others, Portland or Seattle. In summary, the Portland market on gasoline is similar to the other West Coast markets in terms of volatility.

**Exhibit 1.16: West Coast Spot Market Gasoline Price Spreads vs. NYMEX 1990-2007**



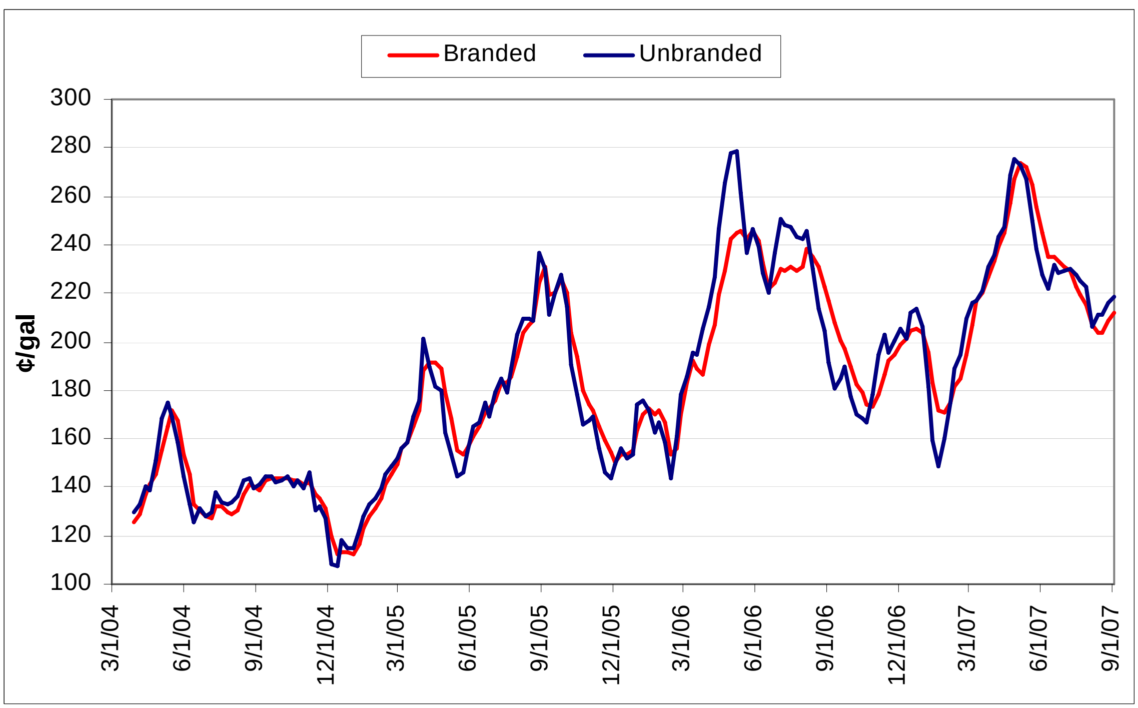

Sources: Platts, EIA

[24] The "West Coast" price point is for a waterborne cargo of unleaded gasoline valued for any West Coast location.

Exhibit 1.17 shows the impact of gasoline volatility from a slightly different perspective. This chart shows unleaded regular gasoline rack prices in the Portland market for branded and unbranded distributors. Rack prices are the prices distributors pay at a terminal for product. Branded distributors are buying gasoline from a major oil company and marketing the gasoline at a service station with the company brand; unbranded buyers buy gasoline without the branded companies' proprietary additives and can market the gasoline under independent brands. Branded buyers typically pay a higher price than unbranded buyers, but are given priority to supply in tight markets. Suppliers will raise unbranded prices above branded when supply is tight to preserve supply for branded buyers.

This exhibit shows that in times of tight supply (price spikes up), unbranded prices move above branded in the Portland market. The converse happens when prices spike up. The exhibit also clearly shows the seasonal spikes that occur in gasoline every spring in the Portland market (this also occurs in Seattle and California) as refiners and terminals draw down gasoline inventory to convert RVP (vapor pressure) to lower summer levels. This is also a period of the year where refiners often perform maintenance in this period in advance of higher summer gasoline demands. Delays in getting the refineries back in full operation can make the period more difficult.

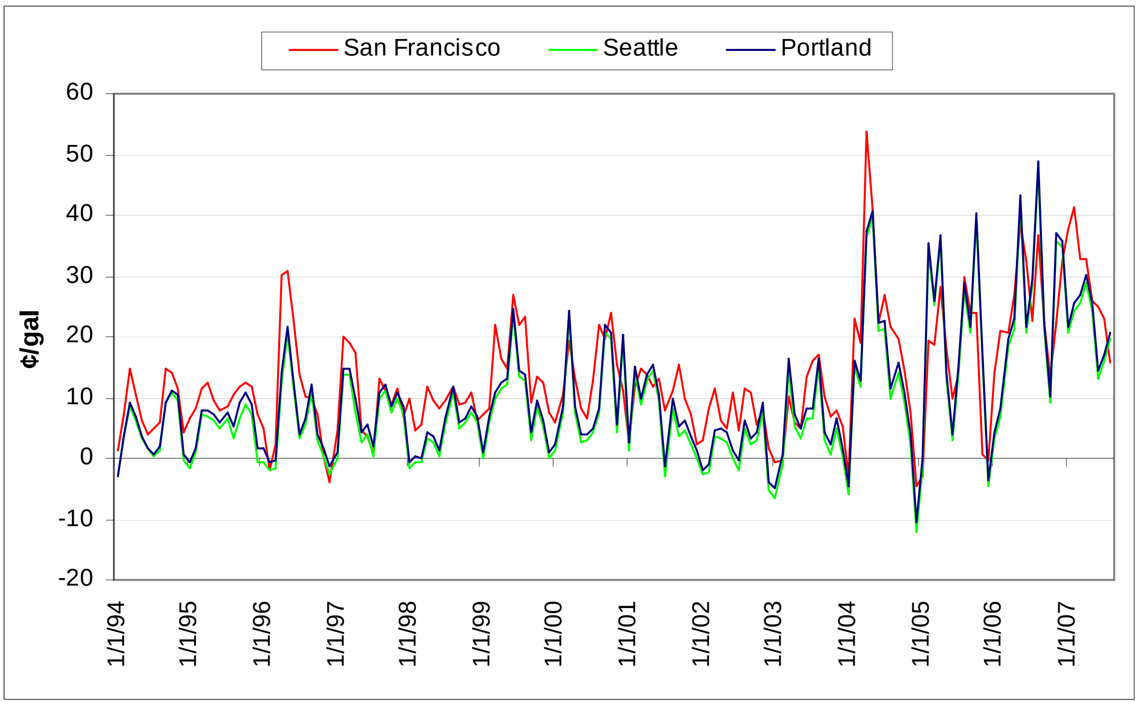
**Exhibit 1.17: Portland Branded and Unbranded Rack Prices**




Source: OPIS

Exhibit 1.18 shows a similar chart to Exhibit 3.3 for Low Sulfur Diesel price versus the NYMEX No. 2 fuel price. This chart shows a fairly consistent pattern of volatility through 2003, followed by a significant increase in volatility in all regions beginning in 2004. The initiation of the wider spread is believed to be related to a couple factors. First, a revived economy in 2004 resulted in significant growth in LSD demands in California in 2004; second, refinery capability to produce LSD did not increase and in fact may have been reduced as many refineries in the 2004-2006 period had their diesel production facilities shutdown to implement new process equipment that could manufacture diesel with lower sulfur for ULSD requirements. Again, the volatility exists in all markets on the West Coast.

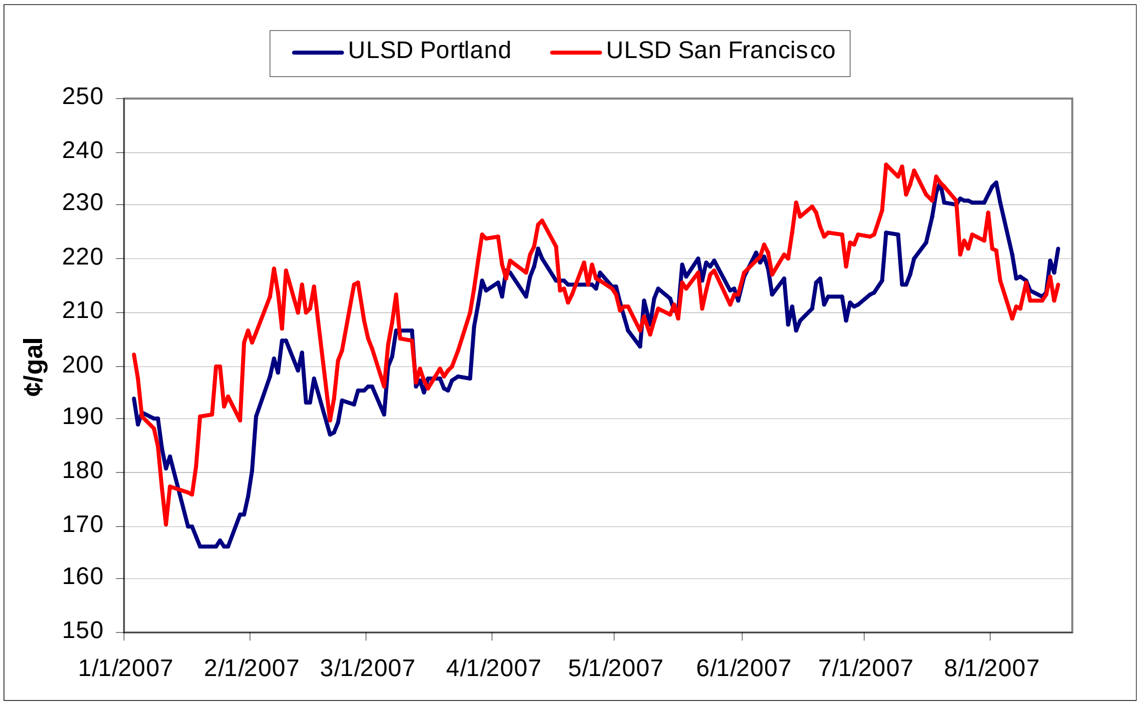
**Exhibit 1.18: West Coast Spot Market Low Sulfur Diesel Price Spreads vs. NYMEX 1994-2007**




Sources: Platts, EIA

Exhibit 1.18 shows high volatility versus the NYMEX, but it also shows some disparity between the San Francisco and Portland markets. Exhibit 1.19 shows a track of the ULSD prices between Portland and San Francisco in 2007. This exhibit shows that the variation has been as high as 30 cpg over this period, with San Francisco prices typically higher. Recent prices in October 2007 have seen the Portland market as much as 30 cpg above San Francisco.

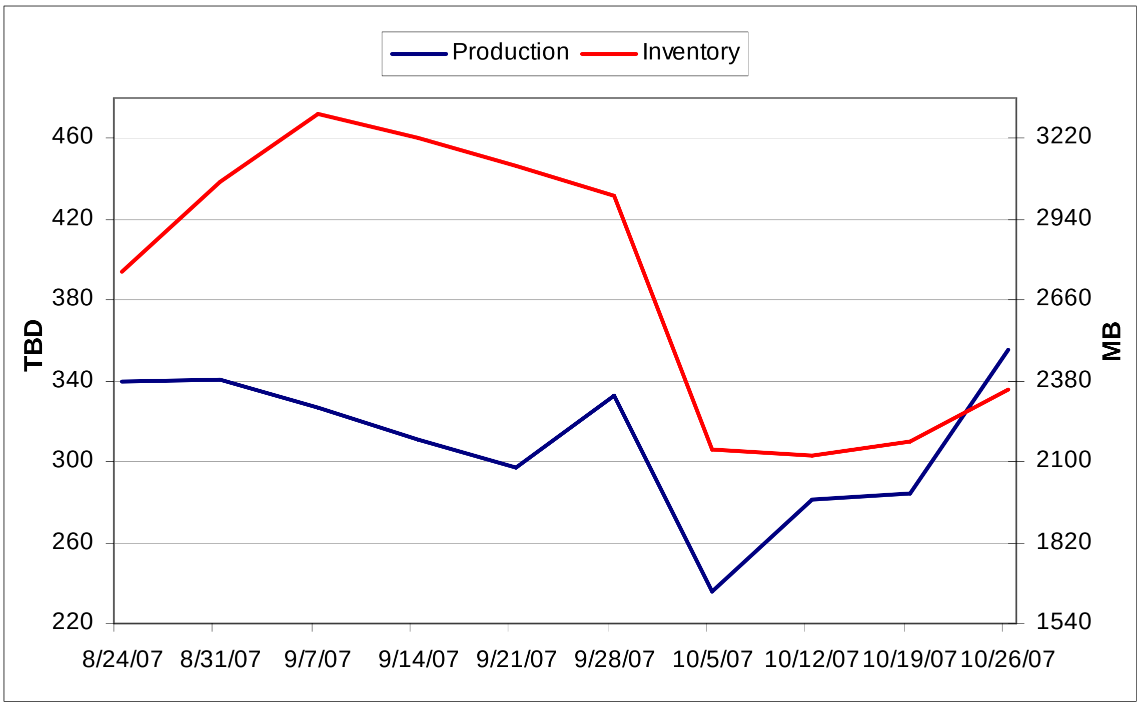
**Exhibit 1.19: West Coast Spot Market Ultra Low Sulfur Diesel Prices, 2007**




Source: Platts

It is not 100% clear on the precise reason for the high prices in the Portland (and Seattle) markets for ULSD in October, however examination of refinery production and inventory data in California[25] (See Exhibit 1.20) indicates a severe reduction in California ULSD production and inventory occurred in October. It is possible that some ULSD production was diverted from one or more Northwest refiners to California to mitigate the outage impact in California, thereby making ULSD inventory tighter in the Northwest. The wide spreads between the two markets returned to an essentially a minimal price differential by early November, but in the meantime distributors and consumers in the Portland and Seattle markets were impacted by very high pricing.

**Exhibit 1.20: California Refinery ULSD Production & Inventory September/October 2007**



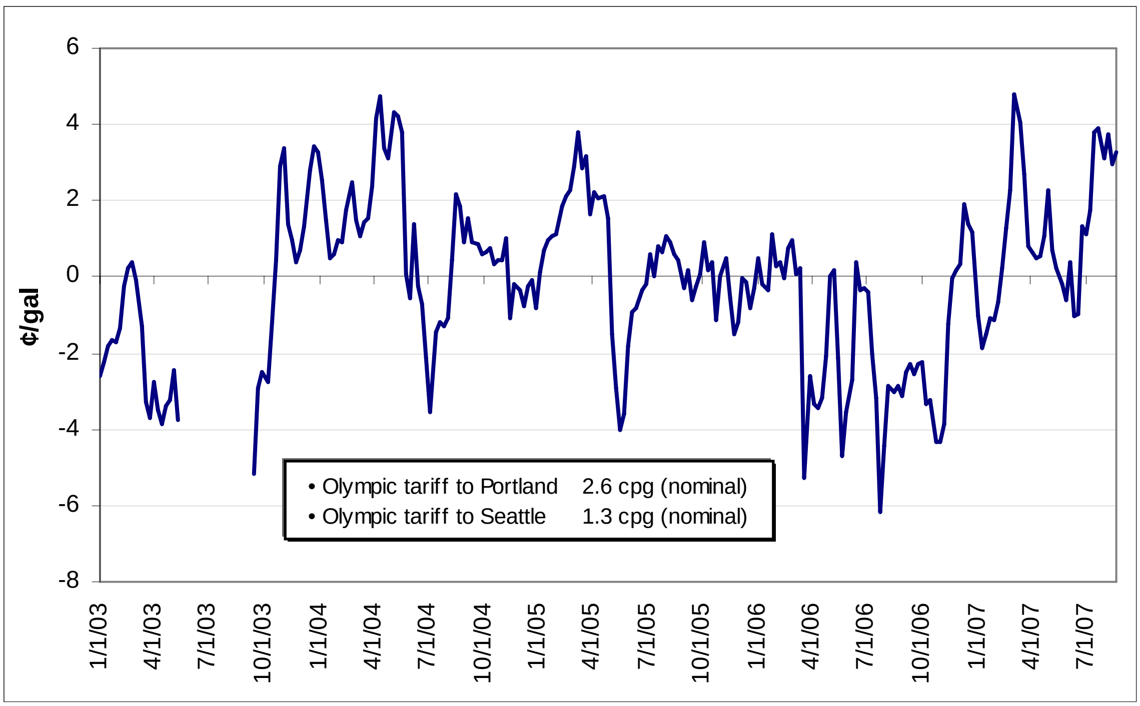

Source: California Energy Commission Weekly Refinery Production Reports

[25] California Energy Commission Weekly Refinery Production reports

Exhibit 1.21 and Exhibit 1.22 compare rack prices between the Portland market and the Seattle market, based on average rack prices as published by OPIS for unleaded and ULSD. The pipeline tariff from refiners to the Portland area is about 1.3 cpg higher than the tariff to Seattle. The charts indicate that there is a good deal of price volatility in unleaded rack prices between the markets, with the Portland area at times with a premium of up to 4 cpg and at other times at a discount of 4 cpg. The ULSD data is shown only from mid-2006, when ULSD was required for all on-road usage[26].

Overall, both charts indicate that over time the refiners selling gasoline or ULSD at the rack in Portland marginally recover the incremental pipeline tariff of about 1.3 cpg to ship product to the Portland market. With marine transportation costs typically a bit higher than the pipeline tariffs, the volume shipped via marine would likely not recover the higher transportation cost. This also provides an indication that the overall supply of product into the Portland/Vancouver area is not constrained versus Seattle. Despite the pipeline operating at capacity, the routine movement of marine supply from the Puget Sound refiners, California refiners and foreign imports keeps the Portland/Vancouver market prices competitive (over time) with Seattle.

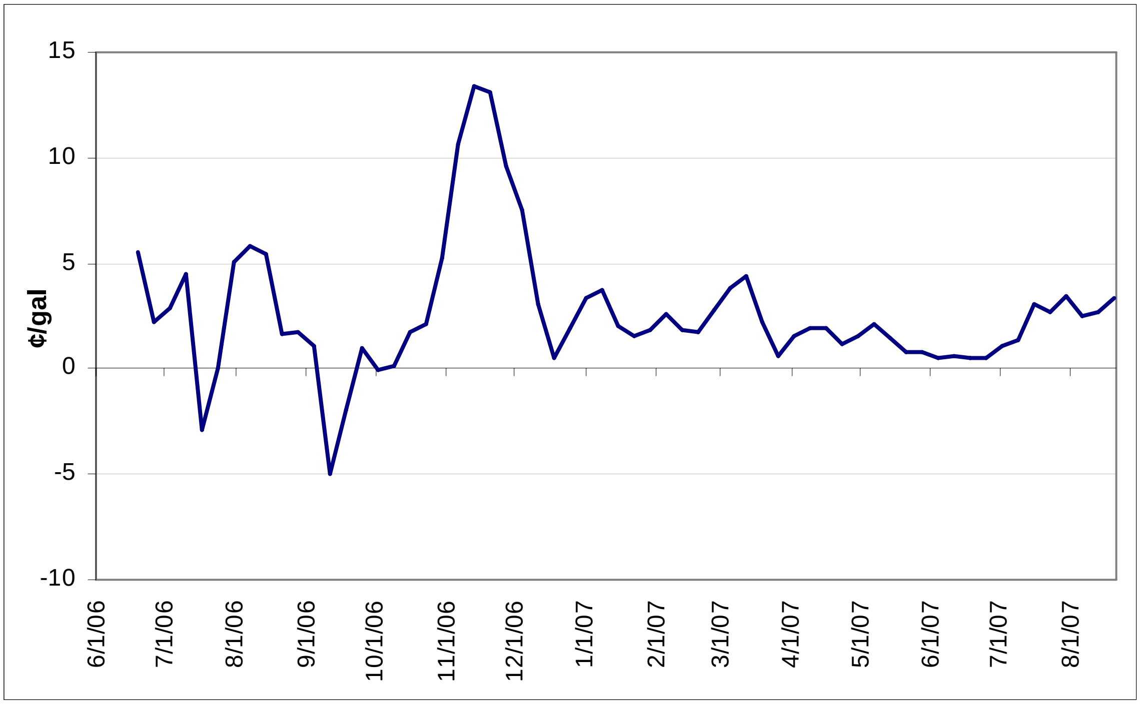
**Exhibit 1.21: Unleaded Gasoline OPIS Rack Price, Portland minus Seattle, CPG**




Sources: OPIS, Federal Energy Regulatory Commission (FERC), Washington Utilities and Transportation Commission (WUTC)

26 EIA reported data indicate that West Coast PADD 5 inventories of ULSD increased significantly at the expense of LSD in mid-2006.

**Exhibit 1.22: ULSD OPIS Rack Price, Portland minus Seattle, CPG**




Source: OPIS

## Pipeline Disruption Pricing Analysis

Additionally, ICF examined the recent history of Olympic pipeline outages to determine the impact of a pipeline outage on prices in the Portland/Vancouver market. The analysis focused on pipeline outages that occurred in segment 3 (the section delivering into the study area). For study purposes, only regular unleaded gasoline prices were reviewed, and only pipeline outages of three days or greater were considered. ICF reviewed Platts Portland pipeline spot unleaded prices over the five days prior to the outage initiation, and compared to average unleaded prices over the ten days following the outage. Since the prices overall are so volatile, we also compared the outage periods with the Portland unleaded premium over the NYMEX gasoline price in the same periods.

Exhibit 1.23 shows a table with the results of this analysis. The data basically show that there are clearly incidents where the absolute price as well as the spot price premium vs. NYMEX increased following a pipeline outage, but there were a similar number of situations where the price and the price spread declined after a pipeline outage. Given the overall price volatility in the global market, the change in absolute price is less indicative of the impact of a pipeline outage than the change in price versus the NYMEX. The fact that the differential to the NYMEX did not strengthen with regularity when the pipeline experienced a shutdown means that either 1) the shutdown was planned and suppliers had adequate time to insure adequate supply in the study area by alternative supply methods (increased barging, for example) or 2) adequate inventories were in place in the study area to cushion the outage. The reality may simply be that pipeline outages have a significant impact on price only when the terminal system is already lean on inventory and more urgent replenishment is required.

**Exhibit 1.23: Pipeline Disruption Pricing Analysis**

| | Portland RUL Spot Average (¢/gal) | | | Portland vs. NYMEX RUL Average (¢/gal) | | |
|---|---|---|---|---|---|---|
| Segment 3 Outage | 5 Trading Days Before Outage | 10 Trading Days Beginning on First Day of Outage | Change | 5 Trading Days Before Outage | 10 Trading Days Beginning on First Day of Outage | Change |
| May 7-11, 2007 | 266.5 | 261.9 | -4.6 | 38.8 | 31.0 | -7.8 |
| Mar 19-22, 2007 | 217.6 | 225.2 | +7.5 | 26.5 | 22.8 | -3.6 |
| Sep 19-23, 2006 | 173.8 | 175.0 | +1.2 | 12.3 | 21.5 | +9.2 |
| Jul 18-23, 2006 | 242.5 | 238.1 | -4.4 | 4.6 | 1.0 | -3.6 |
| Sep 26-29, 2005 | 219.4 | 208.5 | -10.9 | 13.5 | 12.8 | -0.7 |
| Aug 29-Sep 1, 2005 | 205.4 | 227.6 | +22.2 | 14.6 | 10.7 | -4.0 |
| Jul 26-28, 2005 | 181.8 | 197.7 | +16.0 | 12.5 | 21.1 | +8.6 |
| Jun 3-7, 2005 | 150.7 | 163.8 | +13.1 | 1.6 | 9.1 | +7.5 |
| Feb 25-28, 2005 | 147.5 | 155.3 | +7.9 | 19.4 | 10.7 | -8.6 |
| Oct 21-24, 2004 | 139.3 | 138.4 | -0.9 | 0.5 | 3.3 | +2.8 |
| Sep 21-23, 2004 | 140.0 | 140.0 | +0.1 | 15.4 | 6.0 | -9.4 |
| May 23-25, 2004 | 163.0 | 132.5 | -30.5 | 20.5 | -1.2 | -21.7 |
| May 12-16, 2004 | 173.3 | 163.2 | -10.1 | 41.6 | 21.4 | -20.3 |
| Feb 26-29, 2004 | 120.3 | 114.1 | -6.2 | 16.3 | 4.1 | -12.2 |
| Nov 7-11, 2003 | 96.0 | 91.4 | -4.6 | 15.7 | 4.5 | -11.2 |
| Sep 21-24, 2003 | 83.4 | 82.9 | -0.4 | 1.8 | -1.6 | -3.4 |
| Aug 13-15, 2003 | 121.1 | 137.3 | +16.3 | 25.8 | 34.4 | +8.6 |
| Jun 7-11, 2003 | 92.0 | 96.1 | +4.1 | 3.6 | 9.0 | +5.4 |
| Mar 24-27, 2003 | 103.6 | 90.5 | -13.1 | 9.7 | -0.5 | -10.2 |
| Average, 2003-2007 | | | +0.1 | | | -3.9 |
| Average, 2005-2007 | | | +5.3 | | | -0.3 |

Sources: Olympic Pipeline Company, Platts, EIA

## Pricing Summary

The examination of prices in the Portland/Vancouver market indicates clearly that the region experiences high volatility in price. The price of products in the study area mirrors the high volatility on the West Coast that stems from a tight supply demand balance, stringent product quality specifications, high growth in demands, and isolation from sources of timely product replenishment.

Gasoline price volatility in the study area appears to be impacted heavily by the conversion period to lower vapor pressure gasoline each spring (this also occurs in the California market). The higher prices in the spring and summer appear to stimulate higher foreign imports of product by traders into the Portland market during this period, which bolsters supply and mitigates price. The requirement to handle increasing grades of gasoline product through the existing terminal system contributes to the volatility due to the difficulty in managing inventory of more grades of product.

The conversion to ULSD for all on-road diesel sales in 2006 appears to still be somewhat in transition. The products' very low sulfur level may make it difficult for West Coast refiners to "catch up" production with demand following refinery production outages. The data from the recent price escalation in the Portland/Seattle market versus California makes it evident that the ULSD market is very thin on the West Coast and in the study area.

The analysis of pipeline outages versus price shows that the impact of pipeline outages does not necessarily mean prices will increase, or that premiums to NYMEX will increase. In many cases the suppliers either have adequate inventory or react through increased barging to manage supply during outages. When the base level of supply is thin, the pipeline outage can cause significant spikes.

Overall the impact of the pricing volatility in the study area to distributors and suppliers is significant. The pricing evaluation indicates that the specific incidents of volatility in the Portland/Vancouver area appear to stem primarily from increased stress on the infrastructure and the disruptions that occur in the petroleum supply chain. There is no compelling evidence that pipeline outages, or the fact that the pipeline operates at capacity, is the primary cause of Portland market volatility.

It is an important consideration that while NYMEX pricing can change based on geo-political events and speculation as well as supply and demand fundamentals, spot market pricing (differentials to NYMEX) is primarily driven by supply and demand fundamentals. While it is possible to manipulate physical supply to create shortages or surpluses and impact the spot market, in most cases the root cause of spot market spikes or declines stems from disruptions to the normal supply and demand patterns in an area (refinery outages, weather delays on barges, pipeline outages). This appears to be the situation which is occurring in the Portland/Vancouver market with increasing regularity.

## Future Outlook: Supply, Demand & Price

The overall supply and demand balance in the Portland/Vancouver market will be changing from the historical balance previously presented. The introduction of E-10 into the entire Oregon market over the course of the next year will be a significant change for the region. There are multiple implications of this change.

### Supply/Demand Balance

ICF estimated the impact of the ethanol transition on the Portland/Vancouver supply & demand for the 2010 and 2020 timeframe, assuming a nominal 1% growth in petroleum fuels demand over the period, and conversion of Oregon-based gasoline demand to 10% ethanol (See Exhibit 1.24). It was additionally assumed that no expansion of Olympic pipeline[27] would take place, nor any change in marine supply into the region from domestic sources. Foreign cargo imports were adjusted to balance supply and demand.

**Exhibit 1.24: Forecast Study Area Petroleum Fuels Supply & Demand Balance, TBD**

| | 2005 | 2010 | 2020 |
|---|---|---|---|
| **Supply** | | | |
| Olympic Pipeline | 130 | 135 | 135 |
| Domestic Marine | 62 | 65 | 65 |
| Foreign Marine | 9 | 7 | 24 |
| Ethanol Blending | 2 | 8 | 9 |
| Total Supply | 203 | 215 | 233 |
| **Demand** | | | |
| Portland Regional Terminals | 117 | 123 | 136 |
| Pipeline to Eugene | 45 | 45 | 45 |
| Marine to Tri-Cities | 44 | 46 | 51 |
| Marine to Offshore | 1 | 1 | 1 |
| Total Demand | 207 | 215 | 233 |

Sources: State of Washington Office of Financial Management, State of Oregon Office of Economic Analysis, Portland State University Population Research Center, EIA Prime Supplier Sales Volumes, U.S. Army Corps of Engineers Navigation Data Center, Olympic Pipeline Company

[27] Olympic volume assumes no pressure restrictions on the pipeline.

The chart indicates several important considerations:

1. The addition of ethanol at 10% of the gasoline demand in the region is an immediate added supply of fuels into the study area. The incremental 6 TBD supply by 2010 in effect backs out requirements for marine deliveries into the region.

2. Over time, as demands increase in the region and the pipeline supply remains constant, an increasing percentage of supply via marine delivery will occur. Marine deliveries will increase to almost 90 TBD by 2020, including an estimated 24 TBD of foreign supply. As noted earlier in the report, barring expansion of any Puget Sound refineries, the higher foreign import requirements may expose the northwest market to higher prices which may be needed to continue and expand imports from the fast growing Pac Rim region.

3. The required volume of marine deliveries may increase beyond the volumes shown in the exhibit as early as 2009 if the completion of the Holly pipeline to Las Vegas reduces volumes into Eastern Washington on the Chevron pipeline. Any reduction in the Chevron pipeline deliveries will further increase marine deliveries into, as well as out of, Portland/Vancouver areas terminals, and result in even higher imports.

## Logistics Management

There are other implications of the ethanol transition which are less easily depicted, but very significant to supply continuity in the study area. These include:

1. The conversion of all of Oregon's volume to E-10 may mean that refiners will have to supply a sub-octane grade to terminals in the region. While some refiners do that currently, the Oregon change may require all refiners to modify their refinery operation to allow more controlled blending of the finished E-10 gasoline blends at the terminals.

2. In addition, terminals in the region will need to insure adequate ethanol tankage is available, and that tankage can be dedicated to both conventional gasoline storage as well as the sub-octane grades of gasoline. This will increase the complexity of the inventory management in the study area since an additional product stream will need to be handled.

3. The ethanol supply chain itself must become operational and efficient as quickly as possible. The local production sources are extremely valuable, but the logistics coordination to move the ethanol from the production sites to the multiple terminals in the region (as well as Eugene and Umatilla markets) will likely require a transition period to become a smooth operation. This supply chain is completely outside the control of the petroleum operators, and can result in gasoline product outages if ethanol inventory in the terminals is not routinely replenished (even if the tanks are full of sub-octane supply).

4. The management of additional grades of product throughout the system will make the potential for disruptions greater than the current experience level.

The net future outlook therefore is some early reduction in marine volume requirements as ethanol is ramped up in Oregon, with greater propensity for supply disruptions. Over time, initial kinks in the ethanol supply chain should iron out, but the potential for disruptions and the subsequent price volatility will remain high. As demands grow and the Utah to Las Vegas pipeline pulls product out of the region, marine deliveries, primarily foreign imports, will become an increasing portion of the supply into the study region.

## Conclusions

The review of the Portland/Vancouver petroleum supply corridor can be summarized with the following statements:

### Positive Factors

- The primary supply corridors into the Portland/Vancouver market are stable and dependable sources of supply
    - Puget Sound refiners currently have ample capacity to supply the study area
    - Olympic pipeline supply currently handles about 65% of the Portland hub requirements
    - Marine supply from Puget Sound is less than a two day transit to the study area; California sourced marine supply is slightly longer

- Marine supply coupled with pipeline supply provides a substantial supply safety net for the region in the event of pipeline outages. This has been demonstrated during the extended pipeline outage in 1999/2000. Both methods of delivery are timely and managed by companies who know the region and the limitations of the infrastructure.

- Trading companies have found the Portland market as a favorable destination for cargoes of gasoline sourced from the Pac Rim, in particular Korea. The Portland/Vancouver region's conventional gasoline requirement has made it an easier product for Pac Rim refiners to produce than California quality gasoline. (this advantage may still be there with Oregon's E-10 mandate, as Pac Rim refiners may also be able to produce the sub-octane grade gasoline)

- Multiple terminals in the Portland/Vancouver area provide coverage options if an individual terminal runs out

- New tankage (200 MB) has been added in 2007 in Portland to increase area storage

### Concerns

- As noted earlier, the price of products in the study area mirrors the high volatility on the West Coast that stems from a tight supply demand balance, stringent product quality specifications, high growth in demands, and isolation from sources of timely product replenishment.

- In the Portland/Vancouver market, constant terminal storage capacity since 1997, increased demands, and additional product grades have made the day to day execution of operations within the region's infrastructure more complicated.

- Unexpected operational changes (barge weather delays, pipeline & refinery outages, off-spec product, etc) can rapidly disrupt ratable[28] supply and create product shortages that must be managed. The infrastructure issues noted in the prior bullet severely diminish the flexibility to resolve the normal operational disruptions that the petroleum supply chain must handle. Furthermore, disruptions in the California market may result in Northwest refiners or traders diverting product from the study area or the Puget Sound refineries into the California market to either mitigate supply problems or take advantage of higher prices in California. This would create a tighter market in the Northwest.

- Prices in the Portland/Vancouver area respond to changes in NYMEX pricing, West Coast market factors, and regional Portland hub issues. The increased volatility in Portland/Vancouver prices in recent years is not simply due to higher NYMEX volatility or overall West Coast disruptions. The local Portland market is becoming more prone to disruption and subsequent volatility due to the issues mentioned above.

- The local Portland market volatility is likely to worsen as tankage and operational flexibility is further reduced with Oregon's introduction of E-10. With demands in southwest Washington primarily for conventional gasoline, the pipeline, barges and terminal system will need to juggle more product grades in an already constrained infrastructure.

- The situation may worsen further in 2009 if supply to the Tri-Cities area from Utah refineries is reduced when the Holly pipeline to Las Vegas is projected to be operational. More volume to the Tri-Cities will be required out of Portland and Vancouver terminals to compensate for the reduced supply from Utah via Chevron pipeline.

- Longer term, sustained demand growth at only 1% annually will result in higher levels of foreign imports to meet demand growth unless refinery capacity additions are made. The availability of foreign imports from Pac Rim sources may require higher price levels in the future to attract volume away from the Chinese market.

This study was initiated on the premise that the southwest Washington petroleum fuels customers would have more reliable fuel supply with less pricing volatility if a major expansion of the Olympic pipeline was implemented. The analysis of the system has identified that while added pipeline capacity could certainly benefit in providing additional supply flexibility, the issues driving the price volatility in the study area market are more complex. The reality is that managing increased grades of products through a fixed terminal infrastructure with increasing demand levels and the ever-present potential for disruptions from weather or mechanical breakdowns is a more direct cause of price volatility than the Olympic pipeline capacity constraint. Continued exposure to outages and higher prices are the likely outcome without some intervention to mitigate the situation.

The recommendations will address potential opportunity areas to explore which can mitigate volatility in the study area.

[28] Ratable means that product receipts and deliveries take place on a routine cycle.

## Recommendations

There are a number of recommendations presented below which may work to mitigate the price volatility experienced by Washington and Oregon citizens in the study area. None of these recommendations provide an enduring solution to the fundamental volatility in oil markets that all consumers in the United States and, in particular the West Coast continue to see. However the recommendations will address, over time, some of the operational and infrastructure issues that create undue added volatility and supply disruptions in the Portland/Vancouver area.

Implementation of these recommendations will require collaboration between governments (Oregon and Washington), internal state government organizations, oil industry participants, and other stakeholders to achieve change. Collaboration in most cases requires concessions and trade-offs to achieve a greater good. These recommendations will require such concessions among the stakeholders. In addition, it should be noted that these recommendations represent ICF's best assessment based on the information and analysis to date. It is very possible that reaction to this report, further review and input from stakeholders and collaborative efforts may identify other ideas and solutions that should be considered. That would be a positive outcome.

Recommendations are discussed below.

1. **Improve the efficiency of the existing terminal infrastructure:** The state of Washington should work in collaboration with the state of Oregon and representatives of the oil industry, including Olympic pipeline, to identify actions which will reduce the number of product grades which are required to be shipped through the Portland hub. Steps to reduce the number of grades will improve the operation of the pipeline as well as improve the flexibility of the terminals in the study area to manage inventory. In order to achieve this goal, specific opportunities that could be explored include the following:

    a. The State of Washington should require all gasoline sold through in southwest Washington counties sourced from Portland and Vancouver terminals to contain 10% ethanol (E-10). This will result in a requirement to supply only sub-octane grades on Olympic pipeline segment 3 for Portland and Vancouver region customers, instead of both conventional and sub octane grades, which will be necessary due to Oregon's E-10 mandate. This will likely also require conversion of gasoline sales in the Olympia, Washington area (Olympic segment 2) to E-10 due to operational constraints on the Olympic system.

       This change will simplify shipments on Olympic, and provide a common gasoline product to all terminals, increasing the effective capacity of the existing terminals by eliminating the need for reserving tanks for as many individual grades.

       The terminals will still need to reserve tanks for different quality product to be shipped up river, however the need for a different vapor pressure in that market is a requirement for engine performance and a different quality supply to that market must be continued.

    b. The Oregon E-10 mandate will impact the supply of gasoline upriver. The Oregon terminals in the Umatilla area will be required to supply E-10 for Oregon customers. Supply to Washington customers from Umatilla, and from terminals in the Tri-Cities area do not require E-10. This may mean that Portland area terminals that supply upriver customers may need to reserve tankage for both sub-octane gasoline (for Oregon customers) and conventional gasoline grades for Washington customers.(Both of these grades would be at a different vapor pressure than required by Portland area customers).

This situation should be examined to determine if Umatilla area customers should be exempted from the Oregon E-10 mandate by Oregon authorities, or if Washington authorities should require ethanol usage at 10% for eastern Washington counties as well. The most effective immediate action would be for Oregon to delay the Umatilla area requirement until this issue could be evaluated. The fact that eastern Washington is also supplied from refineries in Montana and Utah means that the sub-octane delivery capability from those sources should be assessed before a decision is made on mandating E-10 in Eastern Washington.

These changes should be reviewed and comments solicited from the suppliers into the region (all Washington refiners and other suppliers at a minimum), Olympic and Kinder Morgan pipeline, marine companies and marketing organizations. The end result should be a more consistent alignment of product requirements in each region between Washington and Oregon.

The focus of these recommendations is solely to improve the ability of the existing terminal infrastructure to provide product to Washington and Oregon consumers with less potential for disruption, thereby mitigating volatility. The recommendations also have the advantage of not requiring lengthy construction periods to implement.

2. **Improve the processes for parties to invest in infrastructure:** The process to add energy infrastructure in Washington (as well as Oregon) should be reviewed and improved to allow proposed infrastructure projects to be evaluated and considered in a more streamlined manner. This recommendation stems from stakeholder comments that indicated that there are parties interested in leasing more tankage in the study area if it would be available, and also that some existing terminal owners are having difficulty getting permitting approved for tank modifications in Oregon required for the conversion to E-10. Interviews also indicated that additional land does exist at some terminals for adding more tanks.

   It is important that Washington identify the existing processes for permitting new facilities, and clarify siting authorities so that parties in Washington who are interested in adding petroleum infrastructure will have a clear and defined path for developing and implementing facility investments. This recommendation therefore suggests that a programmatic environmental document be developed under the Washington State Environmental Policy Act in collaboration with Federal NEPA[29] law to address energy infrastructure siting (this could be applicable for tankage, pipelines, refineries or gas and electric facilities as well). Applicants could tier off this programmatic document for site specific projects. This approach may expedite the time line for implementation of needed infrastructure and thereby improve the economics of these projects. Funding may be needed from the legislature to develop this.

   In addition, it is essential that state pre-emption over energy facility siting must be maintained. State pre-emption and coordination of local government authority is necessary

[29] National Environmental Policy Act

as a matter of public policy in order to address the needs of the state as a whole. This is particularly true as it becomes clear that more infrastructure is needed due to sustained growth in the state. Processes to improve the coordination of Federal, State, local and tribal interests should be established so that identified issues can be resolved promptly.

Oregon may wish to also examine their existing processes and procedures so that a consistent road map exists for petroleum infrastructure development. Again, collaboration between the states is a critical success factor in addressing the infrastructure issues.

In particular, the high dependence for petroleum supply on the northwest refiners should be recognized. As demand continues to grow in the region, and even with penetration of ethanol and biodiesel in the fuel mix, it will be necessary to expand refineries in the northwest to limit what will become a growing dependence on foreign product supply (with potentially higher prices to attract product from Pac Rim markets). The state should specifically initiate a dialogue with the refiners to identify the areas which could be streamlined to accelerate the refinery permitting process without jeopardizing required review processes or environmental concerns. One issue which will need to be addressed is the limitation imposed by the Magnuson Act on additional crude oil imports into the refineries on Puget Sound. This act can inhibit refinery expansion projects, and should be either repealed or restructured so that necessary infrastructure projects can be more viable. Resolving this issue and streamlining the permitting process could accelerate decisions to invest in the refineries.

3. **Improve transparency of petroleum supply**: The increased levels of price volatility and periodic supply disruptions in the study area have led to impacts on consumers and business in the study area (as well as in both states overall). The study has identified that there are frequently very real operational impacts that trigger the price escalations. However, this information is not readily visible to parties who depend on both supply and pricing stability. ICF recommends that there should be increased transparency to all parties of the oil industries' operations in the state of Washington. This could be accomplished through legislation of a weekly report similar to the reports compiled by the California Energy Commission that identify weekly refinery operational data on utilization and production for key products. These reports are aggregated to protect individual company information, and a similar process could be established for Washington. The data is, in most cases, already being compiled and reported weekly to the U.S. Energy Information Administration (EIA), and these existing reports may provide a means for parties to begin reporting also to the State of Washington.

   In addition, weekly reports of Olympic Pipelines' total volumes shipped overall and in segment 3 (to Portland/Vancouver) could be required, and incorporated in a weekly summation of refinery and pipeline activity in Washington. The Olympic report would need to provide volumes in total, and not volumes by shipper, specific terminal destination, or by specific product to protect confidentiality of shipper information. Olympics reports could also include identification of any pipeline shutdown events, as well as planned future downtime for repairs.

   The disclosure of this information will assist primarily in keeping Washington (and Oregon) consumers informed on the performance of the petroleum industry in the state, and assist in the identification of at least some of the reasons for price disturbances. However, the increased transparency could also create the potential for unnecessary supply disruption, and therefore not be viewed as a panacea for volatility. As an example, a report which identifies an upcoming Olympic maintenance outage would be helpful to shippers, since it warns them of an outage and provides them time to arrange barge supply if needed to maintain Portland & Vancouver inventory. Olympic does currently provide these notices to shippers.

However, distributors or end users may see an outage announcement and anticipate a supply disruption. To protect their customers, and in fear of rising prices, they may accelerate terminal loadings and in fact create a shortage which may not have occurred. The evidence from the analysis of price changes during Olympic downtime indicates that price may or may not go up during an outage. Nonetheless, the perception of a possible outage may drive abnormal behavior and in fact worsen the situation.

(It should be noted that while the refinery production data and pipeline movements have not been transparent, the Portland area prices are very actively traded and the refiners, suppliers and traders, as well as the distributors who buy product at the racks are very knowledgeable on the market price in the Portland area.)

4. **Identify Olympic Pipeline expansion increments:** An expansion of Olympic pipeline would provide additional delivery flexibility to the study area, but would not resolve volatility problems or provide more supply capability. The "surplus" product that the Puget Sound refiners currently move by marine vessels into the Portland/Vancouver area is estimated at about 50 TBD, and this is the likely maximum increase in Olympic capacity that would make sense (barring a refinery expansion). The downside of an expansion of this size is that most of the Portland and Vancouver market's supply will now be in one primary mode of delivery. Marine equipment that would no longer be required would be redeployed elsewhere, and would not be available in the event of a pipeline outage.

   Nonetheless, ICF believes it is important to identify pipeline expansion increments so that the potential cost and increase in throughput can be identified. This is a key first step and may identify some low cost expansions that may make sense simply to provide some operational flexibility for the pipeline.

   Consequently, ICF recommends that Olympic pipeline be requested to identify to the State of Washington (possibly EFSEC if so authorized) potential investment steps that would boost overall pipeline capacity and capacity on segment 3 into the study area. These estimates should be scoping quality estimates (not detailed engineering estimates) which identify the cost and deliverability impact of each increment. The goal is to determine if there are potential opportunities to expand the pipeline short of a large-scale investment.

   This information will also be useful if refiners begin to announce expansion plans, as it may define possible pipeline incremental capacity growth which would complement a refinery expansion.

5. **Oversight and governance:** These are initial recommendations stemming from this study. As noted earlier, additional ideas, or alterations of these recommendations may merit consideration. ICF recommends that the EFSEC, with appropriate funding, provide an ongoing oversight involvement with this initiative so that feedback can be gathered, state to state collaboration and discussions can take place, and industry involvement can be initiated to identify and implement these or other viable recommendations.

These recommendations, in summary, involve reducing the grades of fuel products stored and shipped, streamlining permitting processes and siting procedures for tanks, pipelines and refineries, implementing a reasonable transparency program, and identification of incremental pipeline capacity increase steps and costs. In addition, ongoing governance and monitoring will insure that actions are taken to evaluate and implement recommendations. These recommendations cannot be achieved without a strong collaborative relationship between Washington and Oregon state authorities, including energy officials, legislators, and the executive branch. Involvement of the oil industry, including refiners, marketers, pipelines and terminal and marine personnel will also be critical to the achievement of a more efficient petroleum product supply infrastructure in the Portland/Vancouver area, as well as throughout both states.

# 2 Natural Gas Analysis and Conclusions

## Background: Overview of the Southwest Washington Natural Gas Market

This section provides an overview of the Southwest Washington natural gas market and surrounding regions. It describes existing natural gas infrastructure such as pipeline and storage facilities in Washington and the surrounding states. It discusses recent consumption trends, sources of natural gas supply, and recent natural gas price trends. The section concludes by examining forecasted natural gas pipeline flow versus capacity to project future pipeline adequacy.

## Review of Pipeline and Storage Infrastructure

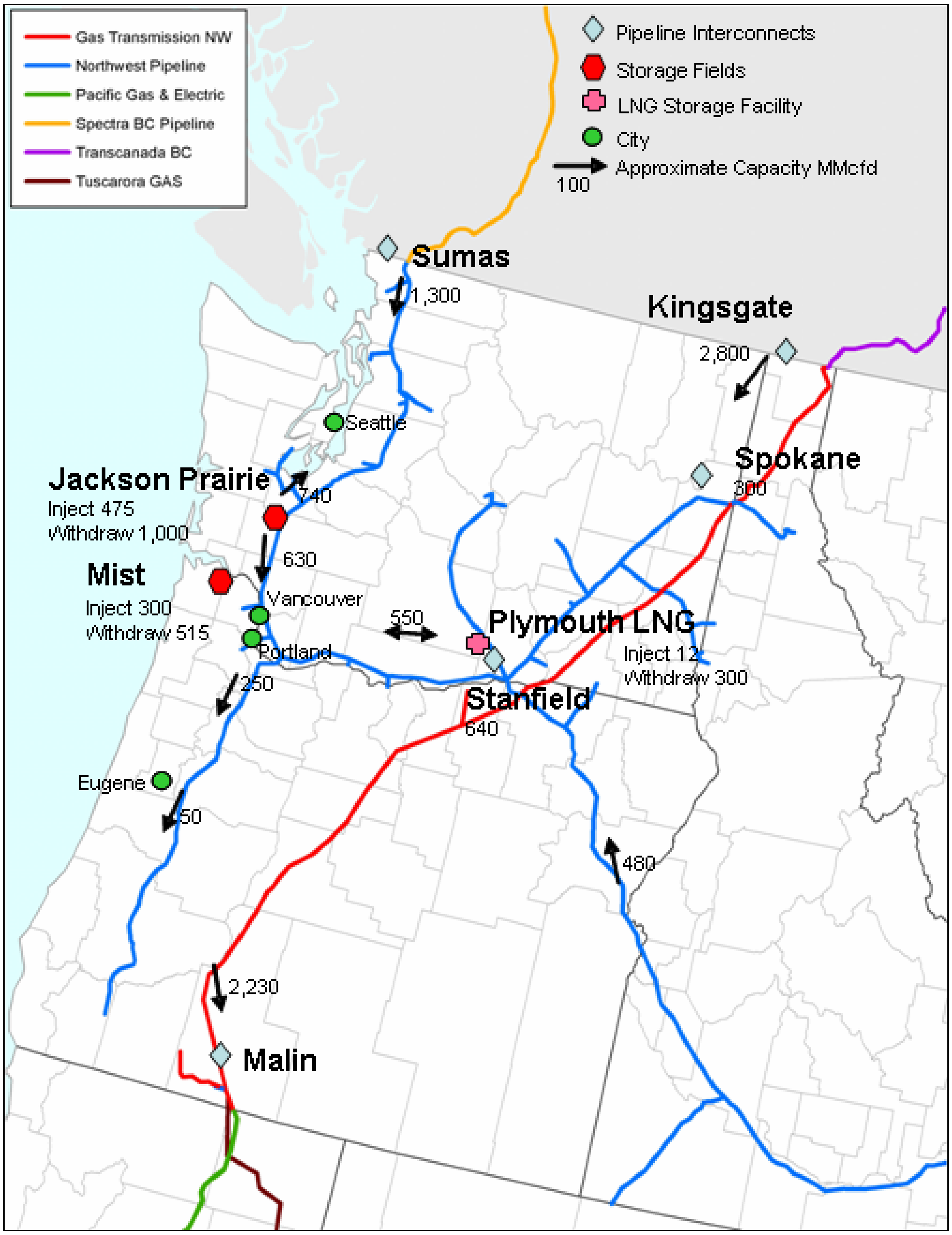
### Pipelines in the Pacific Northwest

The Pacific Northwest has essentially no natural gas production[30] Therefore, the Pacific Northwest natural gas market including Southwest Washington must import all of its natural gas. Historically the region has relied exclusively on supplies delivered from other areas via interstate pipelines. Two interstate pipelines transport gas into and through Washington and Oregon - Northwest Pipeline and Gas Transmission Northwest (See Exhibit 2.1). Approximately 4.1 Bcfd of pipeline transportation capacity enters the region (from Canada and Idaho) and 2.2 Bcfd of transportation capacity exits into California. The characteristics for each pipeline are summarized below.

Southwest Washington is served exclusively by Northwest Pipeline. The Northwest Pipeline Corporation is owned by The Williams Companies, Inc. Northwest Pipeline extends from the San Juan Basin in New Mexico to the Washington / Canadian border through the states of New Mexico, Colorado, Utah, Wyoming, Idaho, Oregon, and Washington. The total system consists of 4,120 miles of pipe, 42 compressor stations and 12.4 Bcf of working gas storage. It has a peak delivery of 3.4 Bcf per day and an average annual throughput of approximately 1.8 billion cubic feet.

[30] In 2005, Washington had no marketed production and Oregon had 454 MMcf or about 0.1 percent of the Pacific Northwest consumption for the year.

**Exhibit 2.1: Major Pipelines in the Pacific Northwest**




Source: ICF International

In the Pacific Northwest, Northwest Pipeline can receive approximately 1.3 Bcf per day from Westcoast Energy at Sumas Washington along the Canadian Border. Natural gas also enters the region through Northwest's line entering Oregon near Caldwell, Idaho with a capacity of approximately 480 MMcf per day. Northwest can also receive gas from Gas Transmission Northwest at Stanfield, Oregon at approximately 640 MMcf per day and Spokane, Washington at 300 MMcf per day.

The capacity of Northwest's Columbia line between Stanfield, Oregon and Vancouver, Washington which enters Southwest Washington from the East is approximately 550 MMcf per day. Northwest's capacity from the North into the Vancouver area is 630 MMcf per day. Southwest Washington can be served from both directions simultaneously. Total pipeline capacity into the Southwest Washington market is over 1.2 Bcf per day.

This capacity must also be used to serve gas consumers in the Portland Oregon area and communities to the south. The capacity of Northwest's line just south of Portland is 250 MMcf per day. This line serves localities in Eastern Oregon and reduces in size as it serves communities to the South.

Gas Transmission Northwest (GTN) is owned by TransCanada. Its pipeline is 612 miles and extends from Kingsgate, Idaho to Malin, Oregon at the Oregon / California border. This pipeline was built mainly to bring Canadian gas supplies to California. However, it offers an alternative method of bringing gas supplies into Washington and Oregon through its interconnect with Northwest pipeline at Stanfield, Oregon and Spokane, Washington. Southwest Washington consumers would most likely use the Stanfield interconnect to receive gas supplies from GTN.

GTN can receive approximately 2.8 Bcf per day from the Foothills pipeline at Kingsgate Idaho. GTN delivers gas to two pipelines at the California border - Tuscarora Transmission and Pacific Gas and Electric Company (PGE)[31]. The capacity to Tuscarora is 185 MMcf per day. The capacity to PGE is over 2.2 Bcf per day. The majority of GTN's pipeline capacity is dedicated to markets on PGE.

**Natural Gas Storage in the Pacific Northwest**

There are two conventional natural gas storage fields in the region - the Mist field and the Jackson Prarie field. Both are near Southwest Washington located in fields in Columbia County, Oregon and Lewis County, Washington respectively. There is also a liquified natural gas (LNG) storage facility near Plymouth Washington (see Exhibit 2.1).

The Mist Storage field is located just to the Northwest of the Portland / Vancouver area. It is operated by the area distribution company, Northwest Natural. It has a maximum capacity of nearly 16 Bcf and a maximum delivery of 515 MMcf per day. It is used predominately to serve Northwest Natural's sales to core heating load customers. However with expansions of the facility in recent years, Northwest Natural has contracted capacity to store third party gas. In 2005, Portland General Electric signed a 10-year contract to augment gas pipeline service to its Beaver Generating Plant in the area. Northwest Natural also offers both firm and interruptible storage services for transportation customers in its distribution system.

The Jackson Prairie field is owned in three equal shares by Northwest Pipeline, Puget Sound Energy, and Avista Utilities. It is an aquifer based facility and is used mainly to meet seasonal variations between winter and summer demand. The working gas capacity of the field is approximately 22 Bcf. The field has a current max delivery of 1 Bcf per day. It is in the process of being expanded. The working gas capacity is being expanded in annual stages. By 2010 the

[31] PGE is an intrastate pipeline and distribution company operating completely within California.

total working gas capacity will be approximately 25.4 Bcf. Maximum delivery will be increased to approximately 1.15 Bcf per day by 2008.

Northwest pipeline owns and operates a liquefied natural gas storage facility located in Plymouth, Washington about 12 miles to the west of the interconnect with GTN in Stanfield, Oregon. This facility provides standby service for Northwest Pipeline's customers during extreme peaks in demand. The facility has a total LNG storage capacity equivalent to 2.4 Bcf of gas, liquefaction capability of 12 MMcf per day and regasification capability of 300 MMcf per day. At these maximum fill and withdrawal rates, it takes a minimum of 200 days to completely fill the facility and only 8 days to empty it. The gas at the LNG plant is mainly owned be storage gas is owned by major Northwest Pipeline’s transportation customers.

# Analysis: Supply & Demand

## Historical Gas Consumption in Southwest Washington and the Pacific Northwest

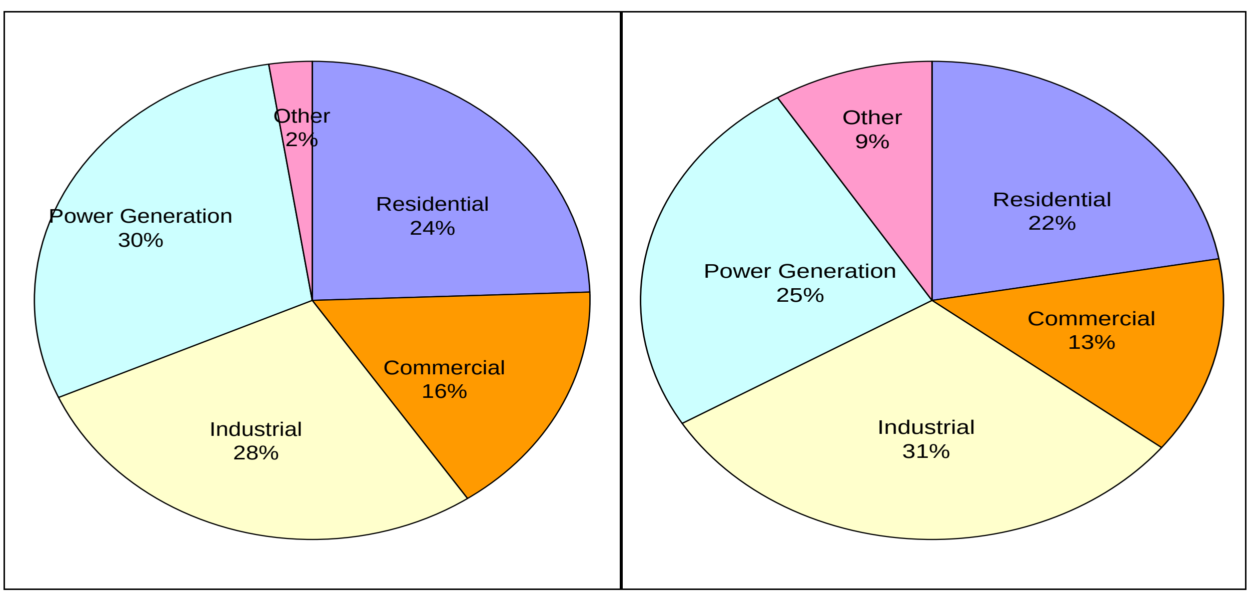
Combined natural gas consumption in Washington and Oregon for 2007 is projected to be 426 Bcf (Exhibit 2.2), averaging about 1.2 Bcf per day for the year, or roughly 1.9 percent of total U.S. consumption of 22.6 Tcf. Current 2007 gas consumption in Southwest Washington[32] is projected to be about 45 Bcf or an average of 125 MMcf per day.

The market shares of the various gas consuming sectors illustrate regional differences as compared to national averages. Pacific Northwest residential and commercial sector gas consumption accounts for 40 percent of the regional market, while the U.S. national average is only 35 percent. This is expected in northern regions as the bulk of consumption in these sectors is for heating load, therefore increased market share in the R/C sectors more significantly impacts seasonal consumption patterns. The Pacific Northwest is also weighted more towards power generation gas consumption relative to the national average, with 30 percent of the total gas market, about 124 Bcf, consumed in power generation. In contrast, only 25 percent of the total U.S. gas consumption is currently consumed in the power sector. The regions' relatively higher market power generation share will impact consumption volatility coinciding with swings in electricity sales in both the summer for air conditioning, and winter for electric space heating.

**Exhibit 2.2**: **Comparison of Pacific Northwest and National Natural Gas Consumption by Sector for 2007**

**Washington and Oregon**
**426 Bcf**

**Total U.S**
**22,591 Bcf**




Source: ICF International Estimates (Actuals through September)

[32] Includes: Cowlitz, Skamania, and Clark

Industrial consumers in the Pacific Northwest consume approximately 119 Bcf, accounting for 28 percent of the total gas consumed in the region.  This is very similar to the national average of 31 percent.  The other category includes pipeline fuel and lease and plant (gas used in processing and gathering in production fields).  There is essentially no gas production in the Pacific Northwest, so this category is insignificant.  About 10 Bcf per year is used for pipeline fuel to bring gas to local markets and to transport gas to the California border.

Sector market share in the Southwest Washington gas market is heavily influenced by the amount of gas consumed in Clark Public Utilities' River Road Generating Plant.  The River Road Plant can consume up to 42 MMcf per day. The power generation loads are highly variable. Residential, commercial, and small industrial loads consume an average of 100 MMcf per day. Peak winter loads for the nonpower sectors may reach 150 MMcfd in the winter while they are lower in the summer and shoulder months.

Annual Pacific Northwest regional gas consumption has fluctuated the last 12 years (Exhibit 2.3).  Expected 2007 gas consumption of 426 Bcf is approximately 15 percent larger (63 Bcf) than the 363 Bcf consumed in 1995.  However, the regional market is about 17 percent smaller (90 Bcf less) than levels seen in 2000.  Regional consumption was at or near 500 Bcf four out of the five years between 1998 and 2002.  This is an average reduction of 200 MMcf per day and has resulted in reduced regional pipeline utilization rates.  The majority of this fluctuation is due to changes in regional industrial demand.

**Exhibit 2.3: Historical Gas Consumption in the Pacific Northwest (Bcf per Year)**

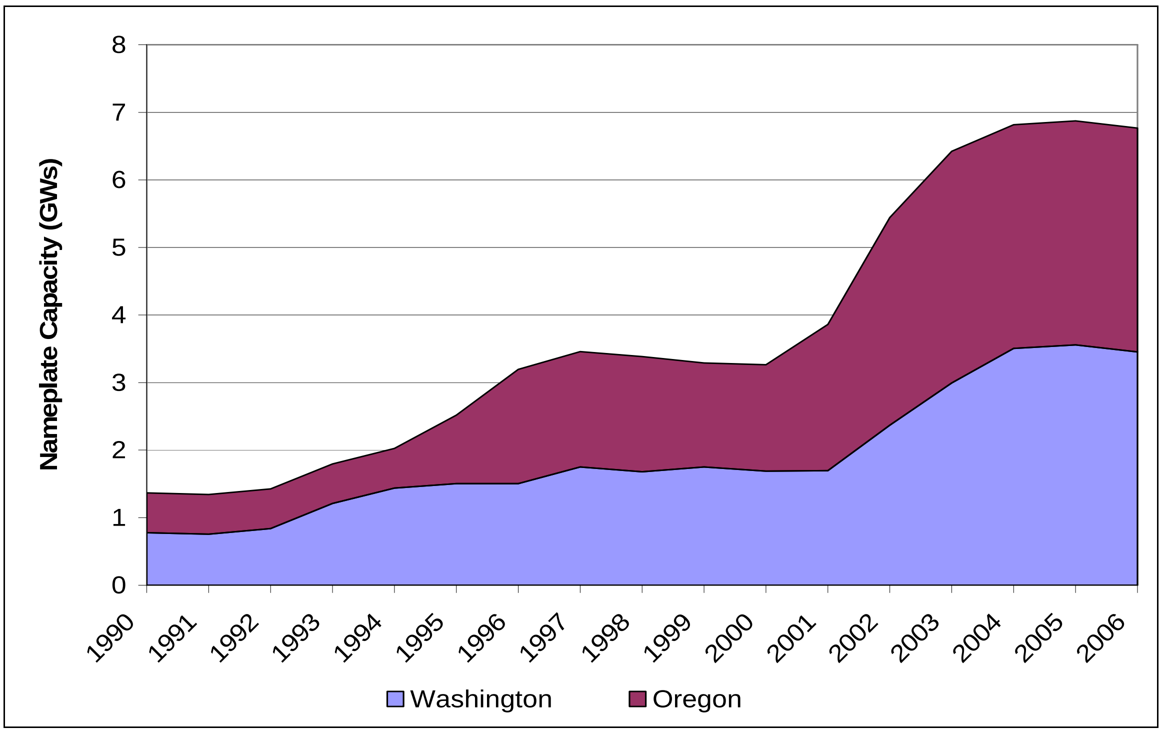
| Year | Residential | Commercial | Industrial | Power Generation | Other | Total |
|---|---|---|---|---|---|---|
| 1995 | 81 | 65 | 179 | 29 | 10 | 363 |
| 1996 | 96 | 74 | 202 | 21 | 10 | 403 |
| 1997 | 94 | 72 | 205 | 44 | 12 | 427 |
| 1998 | 105 | 78 | 245 | 74 | 12 | 514 |
| 1999 | 108 | 79 | 251 | 41 | 12 | 491 |
| 2000 | 104 | 76 | 247 | 78 | 11 | 516 |
| 2001 | 107 | 75 | 141 | 95 | 10 | 428 |
| 2002 | 107 | 74 | 145 | 161 | 10 | 497 |
| 2003 | 107 | 71 | 138 | 155 | 10 | 480 |
| 2004 | 106 | 70 | 143 | 136 | 11 | 466 |
| 2005 | 90 | 63 | 119 | 147 | 10 | 428 |
| 2006 | 98 | 66 | 119 | 128 | 10 | 422 |
| 2007 | 104 | 68 | 119 | 124 | 10 | 426 |
| Net Increase 1995 to 2007 | 23 | 3 | -59 | 95 | 0 | 63 |
| Annual Growth Rate 1995 to 2007 | 2.1% | 0.4% | -3.3% | 13.0% | 0.4% | 1.3% |
| Weather Adjusted | 1.5% | 0.1% | | | | |

Source: ICF International Historic Market Backcast

Industrial demand, which had been rising through 2000, has subsequently decreased in response to increases in natural gas prices.  A sharp crop can be seen from 2000 to 2001.  The California Energy crisis occurred in 2000. The Pacific Northwest's industrial gas consumers have reduced their gas use by more than half from over 250 Bcf in 1999 to about 120 Bcf in 2007. The market share of industrial gas consumption - 51 percent in 1999 - has decreased to 28 percent of the total region's gas use in 2007.

Unlike the industrial sector, gas use for power generation has shown robust growth. The market share of power sector gas use, which was 8 percent of total gas use in 1995, has increased to 30 percent in 2007. This is due to increased reliance on newly built gas-fired generating capacity, consistent with recent trends throughout North America. Since the early 1990s gas fired generation capacity in Washington and Oregon has increased by 5.5 GWs or by a factor of five (Exhibit 2.4).

**Exhibit 2.4: Pacific Northwest Net Gas-fired Generation Capacity (GWs)**



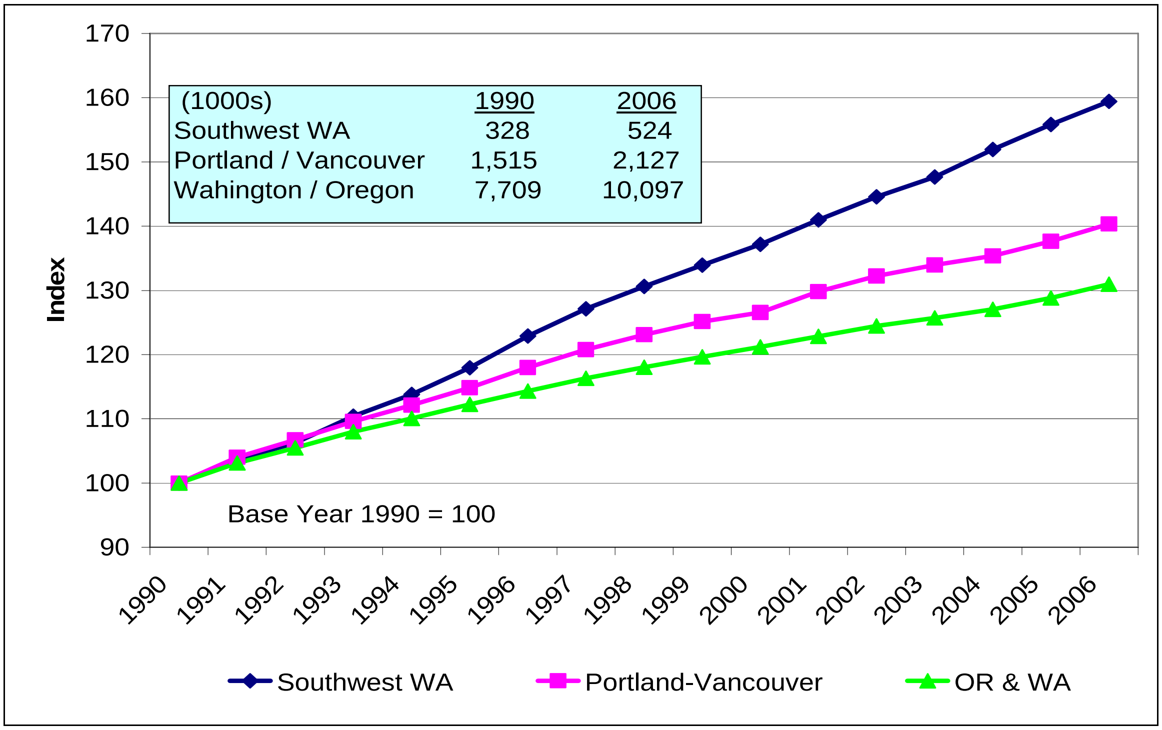

Source: Energy Information Administration

Even though the trend for gas use in regional power generation has been up, the sector has exhibited significant year-to-year fluctuations in consumption (see Exhibit 2.3 above). Gas use for power generation is not only influenced by total electricity sales but also generation from other sources. Hydro electricity accounts for over 70 percent of the total generation and generation name plate capacity in the Pacific Northwest. Hydro electricity is dependent on snow pack and rainfall amounts which can vary significantly year-to-year.

The Pacific Northwest's residential and commercial gas consuming sectors have also grown, although it is not readily apparent from historical consumption patterns. Since these sectors consume gas mainly for space and water heating, weather has a significant influence.

However, adjusting for weather[33], residential consumption has grown at 1.5% per year, almost equal to population growth. Efficiency trends have most likely been offset by increased square footage per household.  The population of southwest Washington has increased twice the rate of the region as a whole, driven by population increases in Clark County (Exhibit 2.5). Residential gas consumption has also most assuredly increased at a faster rate, although the specific data is not available from public sources.

**Exhibit 2.5**: **Southwest Washington, Portland / Vancouver, and Pacific Northwest Population Trends**




Source: U.S. Census Data and State Agencies

Commercial growth is relatively flat at 0.4 percent per year or 0.1 percent normal weather adjusted.  Efficiency gains have offset increased commercial space heating demand. Commercial load is more price sensitive than the residential sector.

[33] Adjusting for weather involves using multi variable regression analysis that separates the weather impacts and the time trends of gas consumption.

## Projected Gas Consumption

Projected gas consumption for the Pacific Northwest and the U.S. total is shown in Exhibit 2.6. This market projection assumes constant normal[34] weather and a GDP growth rate of 3.1 percent per year[35]. The Pacific Northwest is projected to grow at an annual average rate in excess of 3 percent through 2025. This is significantly higher than national averages of approximately 1.5 to 2 percent. However, total regional consumption is not projected to reach historical 2000 levels at about 500 Bcf per year until about 2013.

**Exhibit 2.6: Projected Natural Gas Consumption by Sector for the Pacific Northwest and Total U.S. (Bcf per year)**

| U.S. Total | 2007 | 2010 | 2015 | 2020 | 2025 | Change 2007 - 2015 | Annual Growth | Change 2007 - 2025 | Annual Growth |
|---|---|---|---|---|---|---|---|---|---|
| ***Residential*** | 4,996 | 5,169 | 5,402 | 5,630 | 5,901 | 406 | 1.0% | 905 | 0.9% |
| ***Commercial*** | 3,022 | 3,144 | 3,313 | 3,417 | 3,600 | 291 | 1.2% | 577 | 1.0% |
| ***Industrial*** | 6,955 | 7,069 | 7,241 | 7,496 | 7,927 | 287 | 0.5% | 972 | 0.7% |
| ***Power Generation*** | 5,586 | 6,688 | 8,398 | 9,453 | 9,457 | 2,812 | 5.2% | 3,871 | 3.0% |
| ***Other*** | 2,032 | 2,144 | 2,244 | 2,287 | 2,323 | 212 | 1.2% | 291 | 0.7% |
| ***Total*** | 22,591 | 24,213 | 26,598 | 28,284 | 29,208 | 4,007 | 2.1% | 6,617 | 1.4% |
| **Washington and Oregon** | | | | | | | | | |
| ***Residential*** | 104 | 117 | 133 | 148 | 164 | 29 | 3.1% | 60 | 2.6% |
| ***Commercial*** | 68 | 74 | 80 | 84 | 92 | 11 | 1.9% | 24 | 1.7% |
| ***Industrial*** | 119 | 117 | 112 | 117 | 124 | -8 | -0.9% | 5 | 0.2% |
| ***Power Generation*** | 124 | 151 | 224 | 305 | 349 | 100 | 7.7% | 225 | 5.9% |
| ***Other*** | 10 | 10 | 7 | 9 | 12 | -3 | -3.9% | 2 | 0.8% |
| ***Total*** | 426 | 470 | 555 | 663 | 741 | 129 | 3.4% | 315 | 3.1% |

Source: ICF International

The residential, commercial, and power generation sectors are all projected to contribute to regional gas consumption growth. Most of the increase, about three-quarters, is due to increased gas-fired generation. The combined space-heating sectors, residential and commercial, contribute the remaining one-fourth.

The relatively large projected growth of gas consumption in the power sector is the main reason for the higher than average growth in the Pacific Northwest market overall. The power sector's projected annual consumption growth rate to 2025 of 5.9 percent is almost double the national projected average of 3.0 percent. Gas-fired generation is projected to be a major contributor to regional incremental electricity sales. We do not project any significant increases in generation capacity from hydro or nuclear sources.

Most of the projected increases in generation capacity, about 55 percent, will be renewables. However, renewables often have relatively low load factors. Therefore, most of the increase in

[34] Normal weather is defined by the National Oceanic and Atmospheric Association (NOAA) as the average temperatures from 1971- 2000. Region averages are population weighted based on the 2000 Census.
[35] The GDP growth rate is consistent with long term (30 year) averages. GDP is the largest single long-term driver of gas consumption.

electricity generation must come from sources such as coal and natural gas. We project renewables to account for 15 percent of incremental electricity generation while coal and gas split the remaining 85 percent. Nuclear and hydro generation remain near current levels while oil generation is not predicted to be significant.

Gas use in the residential sector is projected to grow steadily at a rate of over 2.5 percent per year from 2007 to 2025. The total U.S. growth rate in this sector is projected to be only 1.0 percent per year. Thus the Pacific Northwest growth rate is higher than the national growth rate. This is mainly due to higher projected demographic trends. However, a portion of the increased growth rate, about 1.0 percent, is due to Pacific Northwest warmer weather in the base year 2007. Therefore, underlying consumption growth is closer to 1.5 percent per year, still significantly higher than the national average.

Commercial space heating also follows demographic trends. The Pacific Northwest commercial sector is projected to grow at 1.7 percent per year from 2007 to 2025, higher than the national average of 0.9 percent. By 2025, combined R/C regional annual gas consumption will rise to over 250 Bcf versus about 175 Bcf last year. Projected growth is driven by continued population growth that yields continued growth in residential construction and commercial floor space. Natural gas market share in new construction is expected to remain high for the region. Further, continued increases in the average square footage of living space per house also contribute to growth in residential sector gas use. Growth in R/C demand has a larger impact in winter gas consumption (See below).

Unlike recent trends and consistent with other projected trends throughout North America, we project that recent declines in industrial sector gas use in the Pacific Northwest are unlikely to continue. As has been the case in other regions throughout North America, the most inefficient and marginally economic uses of gas in the industrial sector have already been squeezed out of the market at the relatively high gas prices that have occurred during the past few years. Hence, we project a relatively flat level for industrial gas use. Growth in regional industrial output is projected to be offset by efficiency gains in gas use. This growth rate is smaller than the projected overall North American growth rate for the sector, which shows a modest growth in gas consumption. Other regions of North America have more energy intensive industries that are unable to completely offset growth in gas consumption with efficiency gains.

Projected gas consumption in smaller geographic areas, such as Southwest Washington, is more difficult to determine. However, we expect residential and commercial gas consumption to follow demographic trends. Clark County has higher than regional population growth, therefore gas consumption growth rates will be higher than the regional average if that trend continues. Incremental power generation gas consumption is obviously determined by specific power plant locations, especially any new construction. Portland General Electric has two plants just over the border in Oregon. The Beaver pant and the newly constructed Port Westward plant. Each can consume over 100 MMcf per day. While not specifically Southwest Washington consumption, both will impact gas pipeline utilization in the area.

**Projected Seasonal Gas Consumption**

Similar to many northern U.S. markets, the Pacific Northwest gas consumption peaks in the winter. Current gas use averages between 0.7 and 2.3 Bcfd with gas use in peak winter months over three times the use in shoulder and summer months. There is a secondary power generation peak in August and September as electricity sales are still robust and generation from hydro sources has declined for the season.

Although the Pacific Northwest market will grow overall, the pattern of seasonal gas consumption is unlikely to change significantly. The region will remain a winter peaking market even with additional gas use for electricity generation. However, winter peak month to summer low month consumption ratios will decline from 3.2 currently to 2.8 by 2025. Increased gas-fired electric generation is expected to affect the seasonal pattern by increasing summer gas consumption more, on a percentage basis, relative to percentage increases in winter consumption.

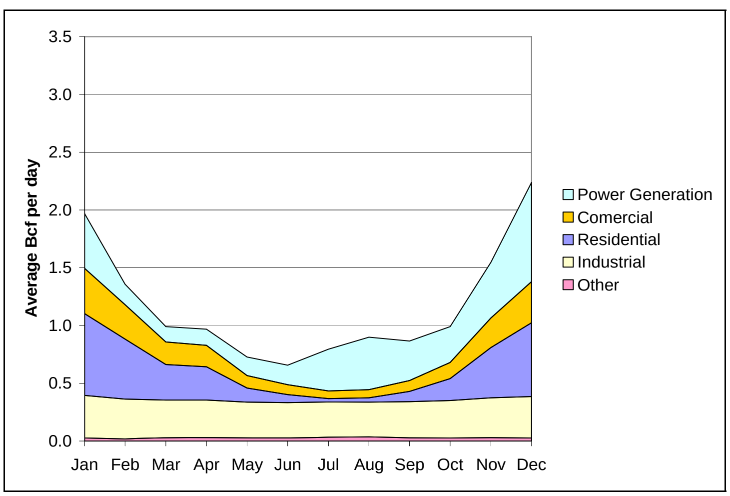
Overall peak average winter month gas consumption increases 17 percent over current levels by 2015 from 2.2 Bcf per day to 2.6 Bcf per day, and by 42 percent per day by 2025 to 3.2 Bcf per day. This is significantly less than the growth in annual consumption of 30 and 73 percent for 2015 and 2025 respectively. It is estimated that peak demand growth for the Pacific Northwest will grow at an annual average rate of 1.9 percent, lower than the annual consumption growth rate of 3 percent.

Relative to current levels, peak month R/C load consumption will be 6 percent higher in 2015 and 25 percent higher in 2025. This is similar to the overall growth in annual load. It is expected that peak day contract coverage for core heating load customers must also grow by at least this amount. In Southwest Washington, if population growth remains above regional averages, incremental peak contract coverage will need to be even higher.

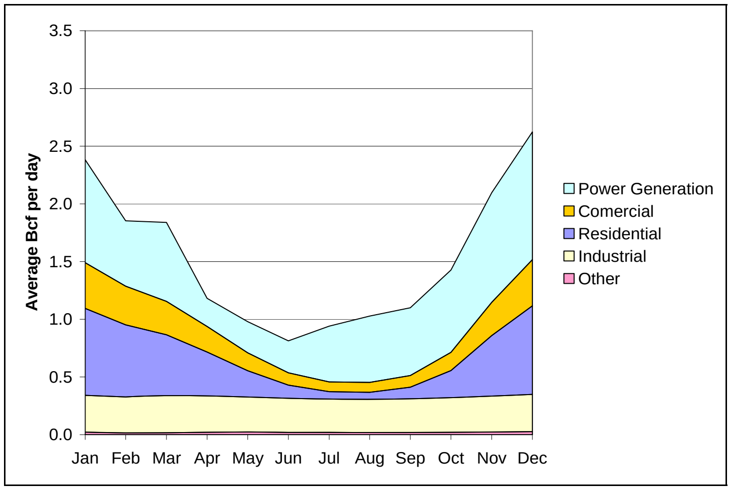
The underlying conclusion from all of the seasonal results is that gas in the region is likely to remain most valuable during the winter. This suggests that if regional storage capacity is added, it may be a substitute for some incremental pipeline capacity. Either incremental storage or incremental pipeline capacity can enhance market reliability.

**Exhibit 2.7: Projected Seasonal Gas Consumption for Washington and Oregon**

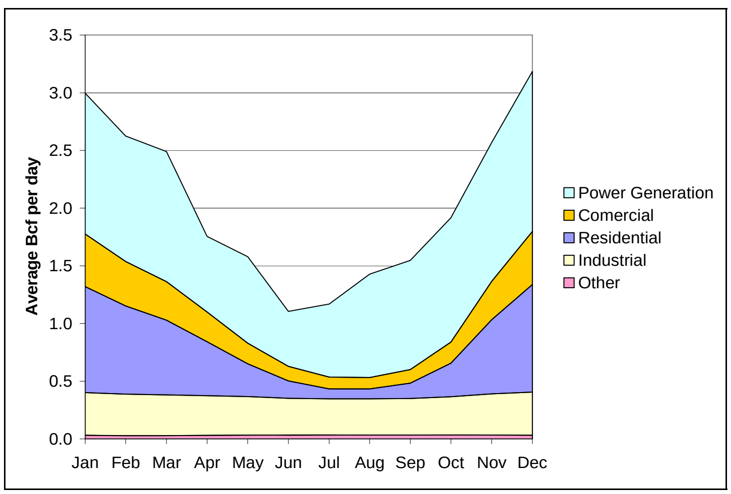
**2007**



**2015**




**2025**




Source: ICF International

## Historical Gas Supplies

Since the Pacific Northwest has no indigenous gas production, regional gas consumers rely on sources of supply from outside the state. Historically, the area has depended on gas from the Western Canadian Sedimentary Basin in Alberta and British Columbia and more recently also on Northern Rocky Mountain supplies in Wyoming, Colorado, and Utah. Canadian supplies enter the region via Northwest and GTN. Rocky Mountain supplies enter the Pacific Northwest exclusively through Northwest Pipelines.

Southwest Washington can receive Canadian gas from the north via Northwest Pipeline at the Sumas interconnect and via GTN interconnect at Stanfield Oregon. GTN receives Canadian gas at Kingsgate Idaho. Southwest Washington can receive Rockies gas directly via Northwest Pipeline.

Both regions serving the Pacific Northwest markets have substantial gas production. Current production in Western Canada and the Northern Rockies is 6.2 and 2.9 Tcf per year, respectively (Exhibit 2.8), collectively accounting for over 35 percent of total U.S. and Canadian natural gas production. From 1995 to 2001, production in Western Canada grew by 940 Bcf per year or an average of 2.5 Bcf per day. Since 2001, Western Canadian production has remained relatively steady, and fluctuated within 0.5 Bcf per day of current production levels of 17.1 Bcf per day.

Northern Rockies[36] production has shown steady and consistent growth, more than doubling from 3.6 Bcf per day in 1995 to 8.1 Bcf per day expected for 2007. For the last 12 years annual production growth rates have averaged 6.8 percent, making it the fastest growing supply region in North America. Northern Rockies production accounted for 12 percent of total U.S. production in 2007, up from 5 percent in 1995.

**Exhibit 2.8: Historical Production in the Northern Rockies, San Juan Basin, and Permian Basin (Bcf per Year)**

| | Western Canada | | Northern Rockies | |
|---|---|---|---|---|
| | Bcf per year | Average Bcfd | Bcf per year | Average Bcfd |
| 1995 | 5,314 | 14.6 | 1,331 | 3.6 |
| 1996 | 5,588 | 15.3 | 1,305 | 3.6 |
| 1997 | 5,861 | 16.1 | 1,293 | 3.5 |
| 1998 | 5,965 | 16.3 | 1,391 | 3.8 |
| 1999 | 6,112 | 16.7 | 1,486 | 4.1 |
| 2000 | 6,174 | 16.9 | 1,651 | 4.5 |
| 2001 | 6,254 | 17.1 | 1,860 | 5.1 |
| 2002 | 6,044 | 16.6 | 2,038 | 5.6 |
| 2003 | 6,157 | 16.9 | 2,175 | 6.0 |
| 2004 | 6,237 | 17.0 | 2,325 | 6.4 |
| 2005 | 6,315 | 17.3 | 2,523 | 6.9 |
| 2006 | 6,363 | 17.4 | 2,752 | 7.5 |
| 2007 | 6,237 | 17.1 | 2,943 | 8.1 |
| Net Increase 1995 to 2007 | 923 | 2.5 | 1,612 | 4.4 |
| Annual Growth Rate 1995 to 2007 | 1.3% | | 6.8% | |

Source: Energy and Environmental Analysis, Inc. Historic Market Backcast

[36] Northern Rockies includes Wyoming, northeast Utah, Montana, North Dakota, South Dakota, and Colorado except for the southwest portion near the New Mexican border. The values above exclude all production in the San Juan Basin in New Mexico and Colorado.

In the two supply areas serving the Pacific Northwest, there are significant reserves and undiscovered resources remaining to meet future market needs (Exhibit 2.9). As of the end of 2006, total reserves of the two regions combined were over 87 Tcf. This equates to 35 percent of the known reserves in the U.S. and Canada. The average reserve to production ratio is 11 years for the Northern Rockies and 9 years for Western Canada. This brackets the North American reserves to production average ratio of about 9.5 years. The Northern Rockies is a rapidly developing region and reserve discovery has outpaced production.

Undiscovered and undeveloped economic resource is estimated at over 270 Tcf for the two regions or just under 3 times the proven reserves. The Northern Rockies estimated undiscovered resource is about 3.5 times current reserves while Western Canada is 2.5 times. Western Canada is a comparatively more mature basin, and on a percentage basis there are less remaining prospects that can be developed.

**Exhibit 2.9: Natural Gas Resource, Reserves, and Production End of 2006 (Tcf)**[37]

| | *Cumulative Historical Production* | *Proven Reserves* | *(Plus) Estimated Remaining Resource* | *(Equals) Total Remaining Resource* | *Estimated Production in 2007* |
|---|---|---|---|---|---|
| ***Northern Rockies*** | 45.4 | 31.8 | 110.4 | 142.2 | 2.9 |
| ***Western Canada*** | 138.1 | 55.7 | 142.4 | 198.1 | 6.2 |
| ***Subtotal*** | 183.5 | 87.5 | 252.8 | 340.3 | 9.1 |
| **North America** | 1,117.3 | 245.6 | 1,455.4 | 1,701.0 | 25.5 |

Source: ICF International

In total, the two basins have a combined volume of discovered and undiscovered resources of over 340 Tcf or 37 years of remaining supply at current production rates of about 9 Tcf per year. It is very important to note that the estimated resource assumes current production technologies are applied. Additional resource will be available as technology advances and additional natural gas supply can be economically developed. Annual production rates are also projected to change (see below).

[37] Unless otherwise stated, values are dry gas at the end of 2005. Resource values represent technically recoverable resource with current technology. Estimates exclude the inaccessible portion of the resource in the Rockies and Gulf of Mexico. The Atlantic Coast Offshore waters and most of the Pacific Offshore waters are also inaccessible.

In 2007, the Pacific Northwest imported over 980 Bcf of natural gas or an average of about 2.7 Bcf per day. About 90 percent of the imports came from Canada and the remaining 10 percent came from the Northern Rockies (Exhibit 2.10). As a percentage of Pacific Northwest imports, Rockies supplies have been growing since 2000. Prior to 2000, Canadian gas also served markets in Idaho and Nevada via Northwest Pipeline. Physically, Rockies gas did not have a net annual flow into the region.[38] Today with the dramatic increase in Rockies production, gas always flows to the west on Northwest Pipeline at the Oregon / Idaho border.

GTN exports a large portion of the regional imports to the California and Nevada markets via PG&E and Tuscarora Pipeline at Malin Oregon. Historically between 50 and 65 percent of all gas imports into the region were exported. Regional gas consumption accounts for the remaining 35 to 50 percent. Consumption as a percentage of imports trended from about 35 percent in 1995 up to just under 50 percent in 2002 and has fluctuated above and below 45 percent since than.

**Exhibit 2.10: Historical Gas Pacific Northwest Gas Balance (Average Bcf per Day)**

| | Sources | | | Disposition | | | |
|---|---|---|---|---|---|---|---|
| Year | From Canada | From Rockies | Total Supply | WA /OR Consumption | CA / ID Exports | Total Uses | Balance[1] |
| 1995 | 2.87 | - | 2.87 | 0.99 | 1.83 | 2.82 | -0.05 |
| 1996 | 3.10 | - | 3.10 | 1.10 | 1.97 | 3.07 | -0.03 |
| 1997 | 3.45 | - | 3.45 | 1.17 | 2.24 | 3.41 | -0.04 |
| 1998 | 3.57 | - | 3.57 | 1.41 | 2.13 | 3.54 | -0.03 |
| 1999 | 3.31 | - | 3.31 | 1.34 | 1.93 | 3.27 | -0.04 |
| 2000 | 3.53 | 0.00 | 3.53 | 1.41 | 2.09 | 3.50 | -0.03 |
| 2001 | 3.07 | 0.12 | 3.19 | 1.17 | 1.97 | 3.14 | -0.05 |
| 2002 | 2.89 | 0.13 | 3.02 | 1.36 | 1.61 | 2.97 | -0.05 |
| 2003 | 2.61 | 0.15 | 2.76 | 1.32 | 1.41 | 2.73 | -0.03 |
| 2004 | 2.62 | 0.15 | 2.77 | 1.28 | 1.46 | 2.74 | -0.04 |
| 2005 | 2.59 | 0.17 | 2.76 | 1.17 | 1.56 | 2.73 | -0.03 |
| 2006 | 2.58 | 0.29 | 2.87 | 1.15 | 1.66 | 2.82 | -0.05 |
| 2007 | 2.69 | 0.31 | 3.00 | 1.17 | 1.77 | 2.94 | -0.06 |

[1] Balance includes system losses and beginning to ending year storage level variations.

Source: ICF International Historic Market Backcast

## Projected Gas Supplies

The major source of gas supply for the Pacific Northwest is the Western Canadian Sedimentary Basin and it is anticipated that it will continue to be for the foreseeable future. The Northern Rockies is a growing source of gas supply for the region and is likely to increase. Washington and Oregon currently have no access to LNG imports. However, in the future, LNG imports may contractually be available to the region indirectly through backhauls from proposed

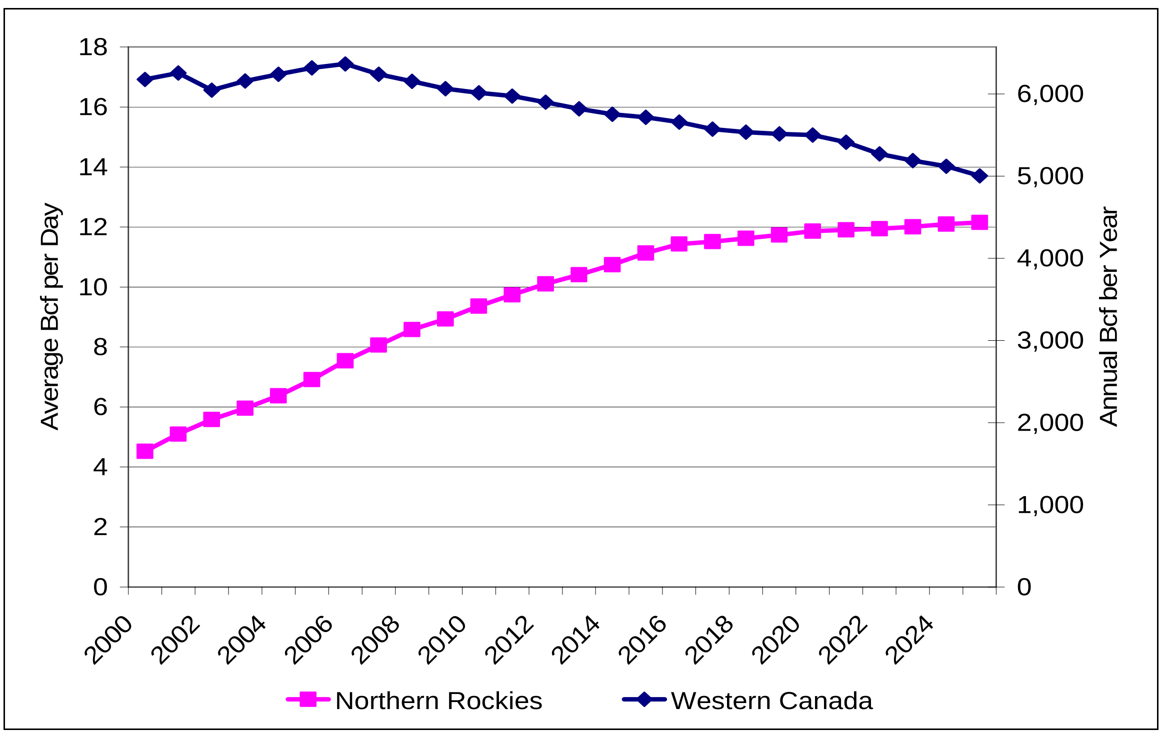
[38] Contractually, Pacific Northwest consumers may have purchased Rockies gas even in years where there are no net physical imports into the region.

terminals in Baja, Mexico or Southern California or directly from proposed terminals in Oregon (discussed below). Since there is no local production, all gas supplies must be imported into the state via interstate pipelines or LNG terminals.

Although Western Canada is classified as a “mature” production area, there are significant remaining recoverable resources, over 31 years at current production rates of approximately 6 Tcf per year.  E & P technology advances will increase this volume even more.  As with many mature basins, the production rate is projected to decline as incremental production from new wells does not offset reductions from existing.  Current Western Canadian production of approximately 17 Bcf per day is forecasted to decline to under 14 Bcf per day by 2025.  The basin production decline may be offset by Arctic gas development, such as the Mackenzie Delta Pipeline and the Alaska pipeline projects (discussed below).

In contrast, the Northern Rocky Mountain producing area is projected to be one of the fastest growing production areas in North America.  It currently accounts for 11 percent of North American gas production.  However, the region holds 13 percent of the known reserves.  A significant amount of gas resource in the Rocky Mountains is unconventional, including coalbed methane and very low permeability formations.  Recent production increases are projected to continue into the foreseeable future.  Production in the Northern Rockies is projected to increase from current levels of an average of 8.1 Bcfd (2.9 Tcf per year) to 12.2 Bcfd (4.4 Tcf per year) in 2025.

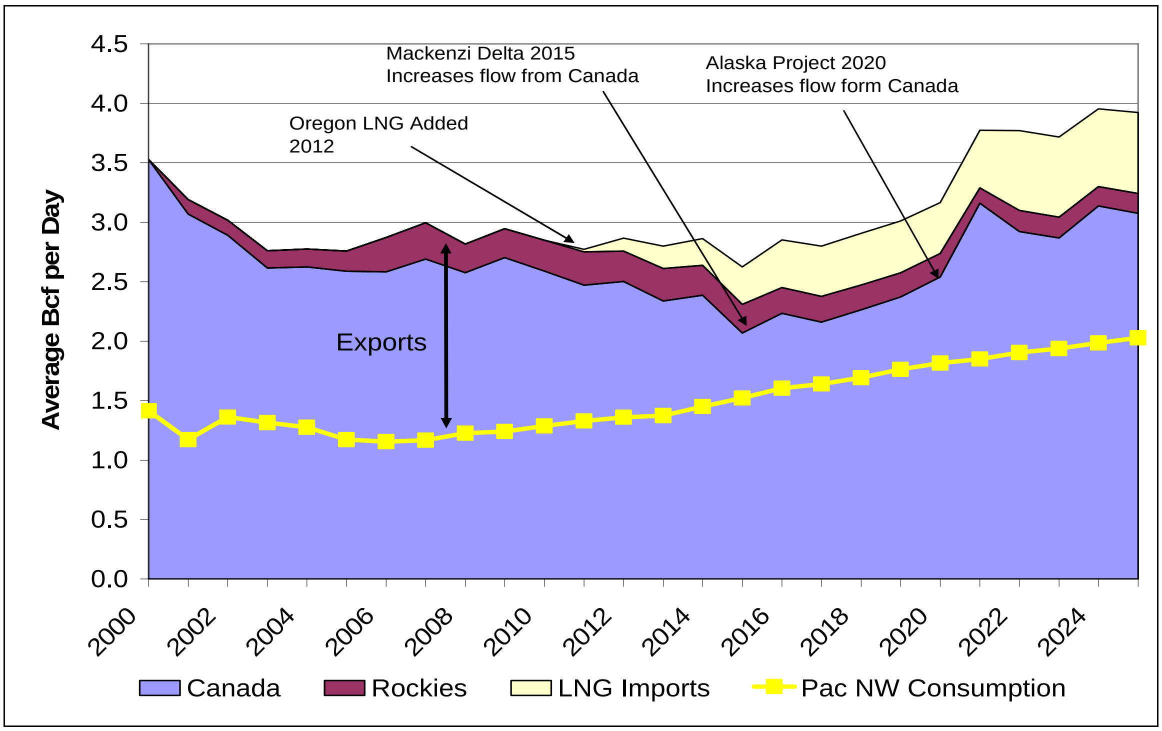
**Exhibit 2.11: Projected Production in Western Canada and the Northern Rockies**




Source: ICF International

Exhibit 2.12 shows projected Pacific Northwest supplies by source versus Pacific Northwest consumption for the ICF Base Case through 2025. Major sources are Canadian gas, Rockies gas, and direct LNG imports (projected for the future). Key supply assumptions are noted on the graph and are discussed below. Total consumption for Washington and Oregon is also shown. System losses and year end storage variances are relatively minor; therefore the difference between consumption and total gas supplies equals exports to California.

**Exhibit 2.12: Projected Pacific Northwest Gas Supply Sources versus Consumption – ICF Base Projection**




Source: ICF International

Canadian gas imports into the Pacific Northwest are projected to trend downwards through 2015. Annual average import rates decline from current levels at approximately 50 MMcf per day per year. Western Canada production is projected to decrease while at the same time Canadian gas consumption increases leaving less gas available for export to the U.S. Gas use for oil sand development is a key driver that increases Western Canadian gas consumption.

Canadian imports are projected to decrease even though Pacific Northwest consumption increases steadily. The net result is that there will be less physical gas exports from Canada available to California. Contractually, Canadian exports may continue at higher levels than projected above. If this is the case, Pacific Northwest consumers may have to purchase

Rockies gas and / or LNG imports in California and “back haul”[39] them to Washington and Oregon.

The downward trend of Canadian imports should continue unless Arctic pipeline projects are developed. The ICF Base Case assumes that a 1.5 Bcf per Day Mackenzie Delta project is built in late 2015 and a 4 Bcf per day Alaska Project is built in late 2020, expanded to 6 Bcf per day in 2023. Both the Mackenzie Delta and Alaska pipeline projects seem justified given the projected decline of Western Canadian production. Both would heavily utilize existing pipeline infrastructure from Alberta to the U.S. However, both projects face significant political obstacles even if the economics are highly favorable. The timing of the projects is highly speculative and may slightly before to significantly after the dates assumed in the ICF Base Case.

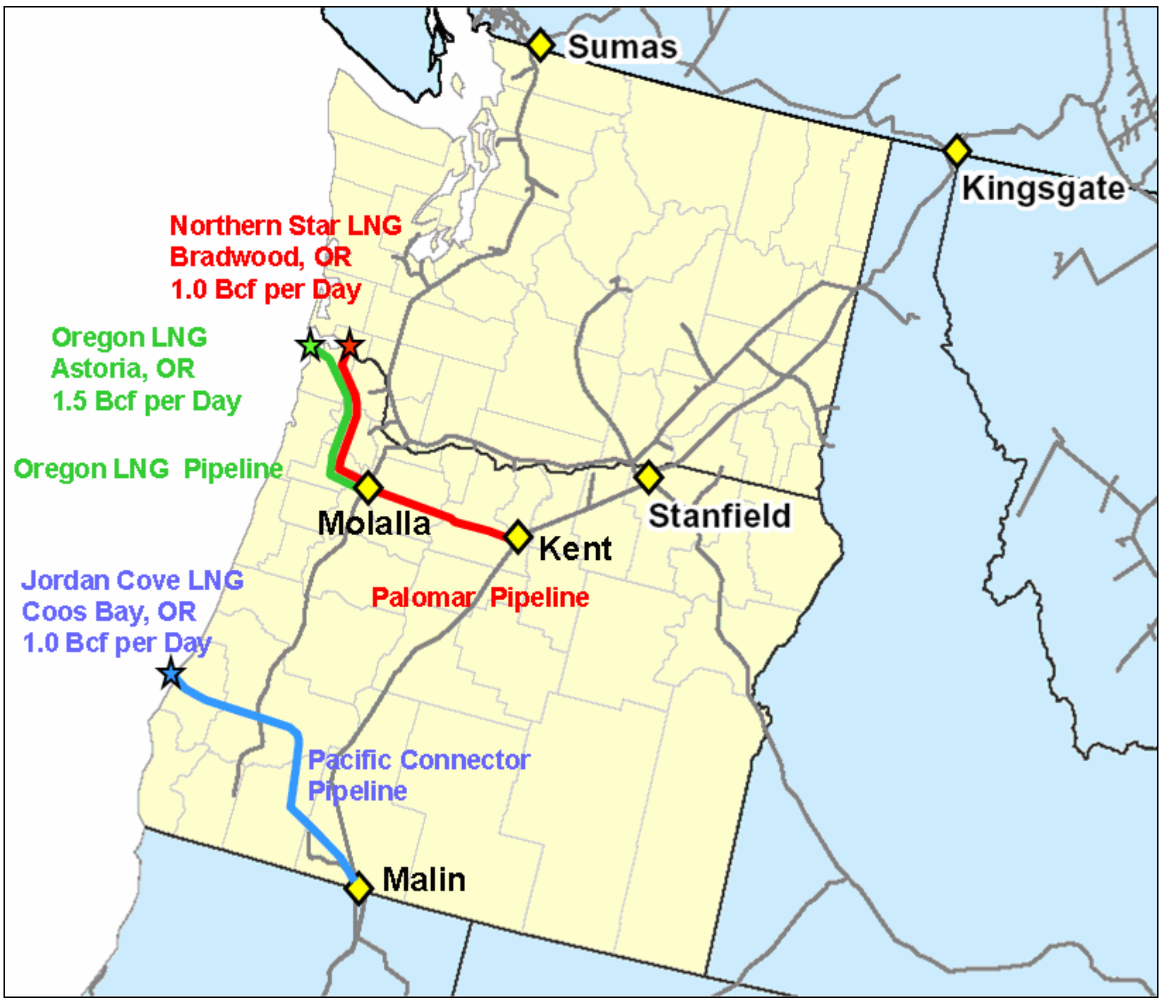
Supply scenario analysis may be helpful in determining more specific impacts and consequences of major supply assumptions for the region. However, that was beyond the scope of the current study.

Rockies imports into the Pacific Northwest will continue near current levels with annual averages between 200 to 300 MMcf per day. Although there will be significant growth in Rockies production, direct imports into the region are limited due to Northwest Pipeline capacity. A portion of pipeline flow from Wyoming to the Northwest is consumed in Idaho and Northern Nevada. Minor growth in consumption in these markets will also limit Rockies imports into the Pacific Northwest. There are no planned expansions of Northwest Pipeline at this time. Other routes to move Rockies gas supply to the West are deemed more economical.

[39] A backhaul is a contractual arrangement where gas supplies are purchased downstream of physical flow. The pipeline makes deliveries through displacement; delivering gas upstream to the purchaser of the backhaul supplies and delivering only net supplies (gross deliveries less the backhaul) downstream.

The ICF Base Case assumes that one new LNG terminal begins direct imports starting in late 2012. There are currently three proposed LNG terminals for the Pacific Northwest (Exhibit 2.13). Two on the coast near the Washington / Oregon State border at Bradwood and Astoria, Oregon. The Jordan Cove location is further south near Coos Bay, Oregon. The proposed terminals range in size from 1 to 1.5 Bcf per day in maximum delivery capacity. All three terminals have an anticipated in-service date after 2011.

**Exhibit 2.13: Projected Pacific Northwest Gas Supply Sources versus Consumption – ICF Base Projection**




Source: ICF International

Each of the proposed terminals has an associated pipeline project. Local load in the Pacific Northwest is too variable and not large enough to be economic for a LNG terminal. To site a terminal at a size that would be economic, at least 1 Bcf per day to start with, access to Northern Californian markets would be necessary. The proposed Jordan Cove terminal would access California Markets through a direct pipeline, the Pacific Connector. The other two proposed projects, would build new pipeline capacity to either Northwest or GTN.

The ICF Base Case assumes that the Jordan Cove terminal is built along with the Pacific Connector pipeline for exports to California. However, if one of the other terminals is built, regional impacts will be similar. The terminal begins operations in late 2012. Imports increase throughout the forecast reaching an annual average of over 600 MMcfd by 2023.

There is no guarantee that any LNG terminal will be built in the Pacific Northwest. None of the terminals are under construction. All have significant permitting and legal steps yet to take. In addition, international LNG supply must be procured in advance of any LNG terminal opening. If a Pacific Northwest LNG terminal is not built, the bulk of the impact would most likely reduce physical exports to California.

# Analysis: Price

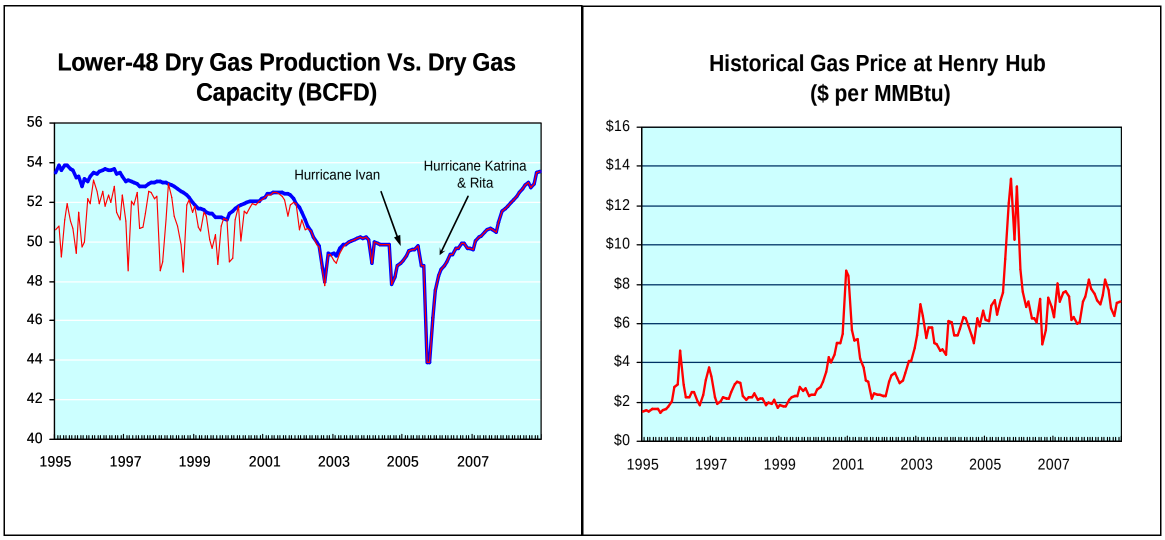
## North American Historical Gas Price Trends

The North American natural gas market has undergone a fundamental shift that started at the beginning of this decade.  From the years 2000 through 2007, gas prices at most trading locations throughout North America have averaged in excess of $5 per MMBtu.  Since 2005, most have averaged in excess of $6.50 per MMBtu.  Price volatility has increased, unlike prices in the 1990s that were fairly constant at between $2 and $3 per MMBtu.  This leads to the conclusion that the North American natural gas market is fundamentally different than the market in the 1990s.

In this new era, the supply and demand balance for natural gas is much tighter than it was in the 1990s.  Throughout most of the 1990s, a gas bubble existed in the North American natural gas market.  During the period, productive capacity for natural gas exceeded gas production, or the amount of gas necessary to satisfy gas consumption at prevailing market prices.  The gas bubble that existed during the 1990s was created during the regulated market environment that existed for natural gas during the 1970s and early 1980s.  By and large, the bubble was created during the oil boom that occurred in the U.S. in response to two different oil price shocks that had occurred in the 1970s.

Exhibit 2.14 shows that the trends for U.S. gas production and productive capacity[40] have diverged in recent years, and the result has been the bursting of the gas bubble that kept prices relatively low and constant throughout the 1990s. After 2000, gas producers in the U.S. have produced at capacity. In this environment, there is little shut-in gas supply and little gas-on-gas competition between producers willing to bid the price down towards variable cost to sell their excess supply. The result has been much higher gas prices. Also, the lack of excess productive capacity has contributed to the levels of price volatility that have been recently observed. The market has a less flexible gas supply ready to satisfy gas demand during cold winter and hot summer weather.

**Exhibit 2.14: Recent Historical Trends for Productive Capacity, Production, and Gas Prices**




Source: ICF International, Platts Gas Daily

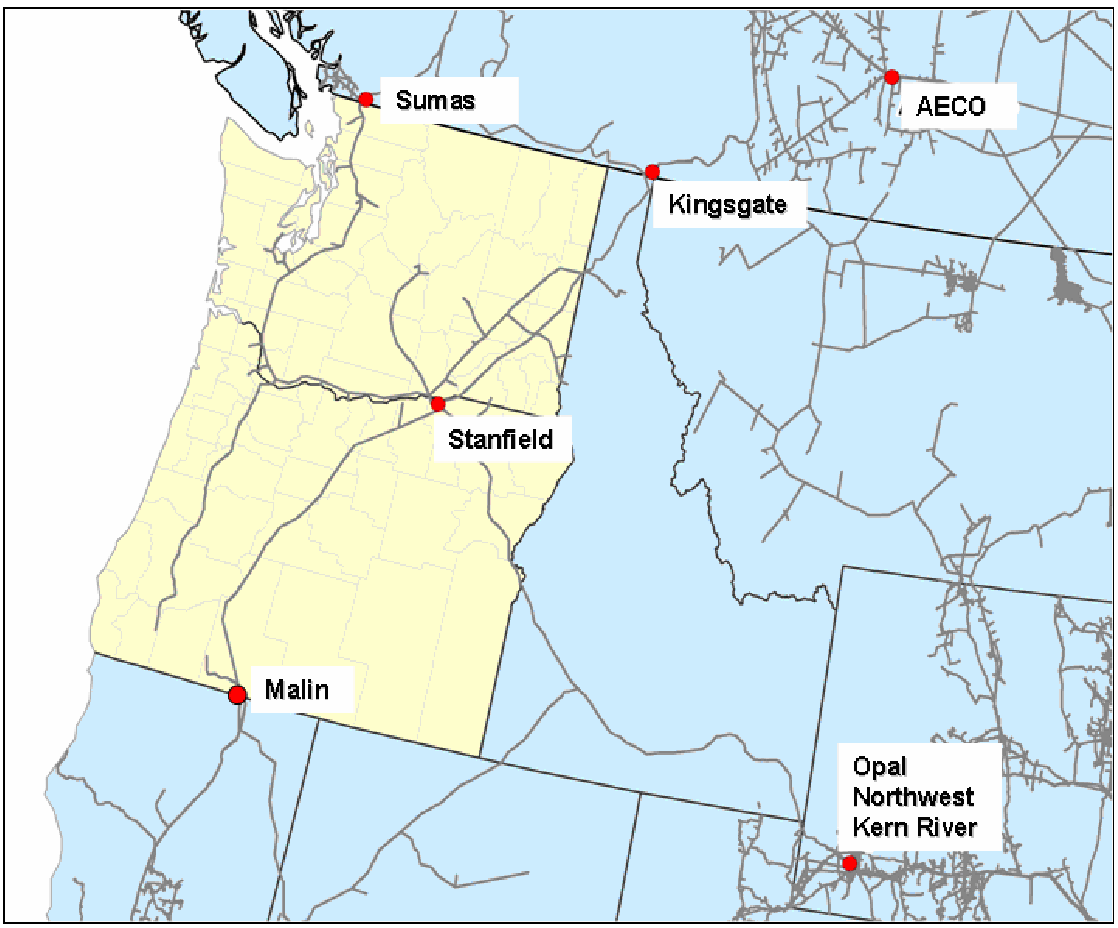
[40] Productive capacity is the maximum amount of gas that can be produced on a daily basis. Prior to about 2000, gas wells were often turned on and off to meet swings in consumption.

## Gas Pricing Points Near Southwest Washington

Most natural gas transactions throughout the U.S. and Canada occur at a relatively small number of pricing points often referred to as market centers. Southwest Washington itself currently has no specific liquid natural gas pricing point. Therefore, Washington gas purchases must be indexed to nearby area pricing point upstream or downstream, such as Sumas at the Canadian Border or Malin Oregon at the border of California. The most widely referenced pricing points in the area are shown in Exhibit 2.15. The majority of gas transactions occur at the following locations:

- Northwest, Canadian Border (Sumas)
- GTN, Kingsgate
- Stanfield, Oregon
- PG&E Malin
- TCPL Alberta, AECO-C
- Opal Wyoming
    - Northwest Wyoming Pool
    - Kern River, Opal Plant

**Exhibit 2.15**: **Regional Pricing Points**




Source: Platts Gas Daily

Northwest, Canadian Border (Sumas)

The Sumas price index tracks transactions into Northwest Pipeline from BC pipeline (Westcoast Energy) at the Sumas Washington / Huntington, British Columbia interconnection at the U.S. / Canadian border. Transactions are reported in $U.S. per MMBtu.

GTN, Kingsgate

The Kingsgate price index tracks transactions into Gas Transmission Northwest from Foothills Pipeline at the U.S. / Canadian border in Boundary County Idaho. Prior to August 1, 2004 the index was known as PG&E Gas Transmission Northwest. Transactions are reported in $U.S. per MMBtu.

Stanfield, Oregon

The price index includes all transactions from GTN at the Stanfield compressor station in Umatilla County Oregon on the Oregon Washington Border.

PG&E, Malin

The price index includes all transactions into Pacific Gas and Electric's Lines 400 and 401 from Gas Transmission Northwest (formally PG&E Gas Transmission, Northwest) at the Oregon/ California Border at Malin, Oregon.

TCPL Alberta, AECO-C

The index includes deliveries into TransCanada's Alberta System at the AECO-C, Nova Inventory Transfer (NIT) Hub in southeastern Alberta. AECO-C is the principle storage facility and hub on TCPL Alberta. Prior to August 2004, the index was known as NOVA. The price is reported in $Canadian per gigajoule.

Northwest, Wyoming Pool

The Northwest, Wyoming Pool is one of several pipeline indexes that report transactions in the Opal, Wyoming area. This index includes transactions that deliver gas into Northwest Pipeline from the Green River, Wyoming compressor station to the Kemmerer, Wyoming station. Included are deliveries at any of the following gas processing plants: Opal, Painter, Anschutz, Muddy Creek, Granger, Shute Creek, and Whitney Canyon.

Kern River, Opal Plant

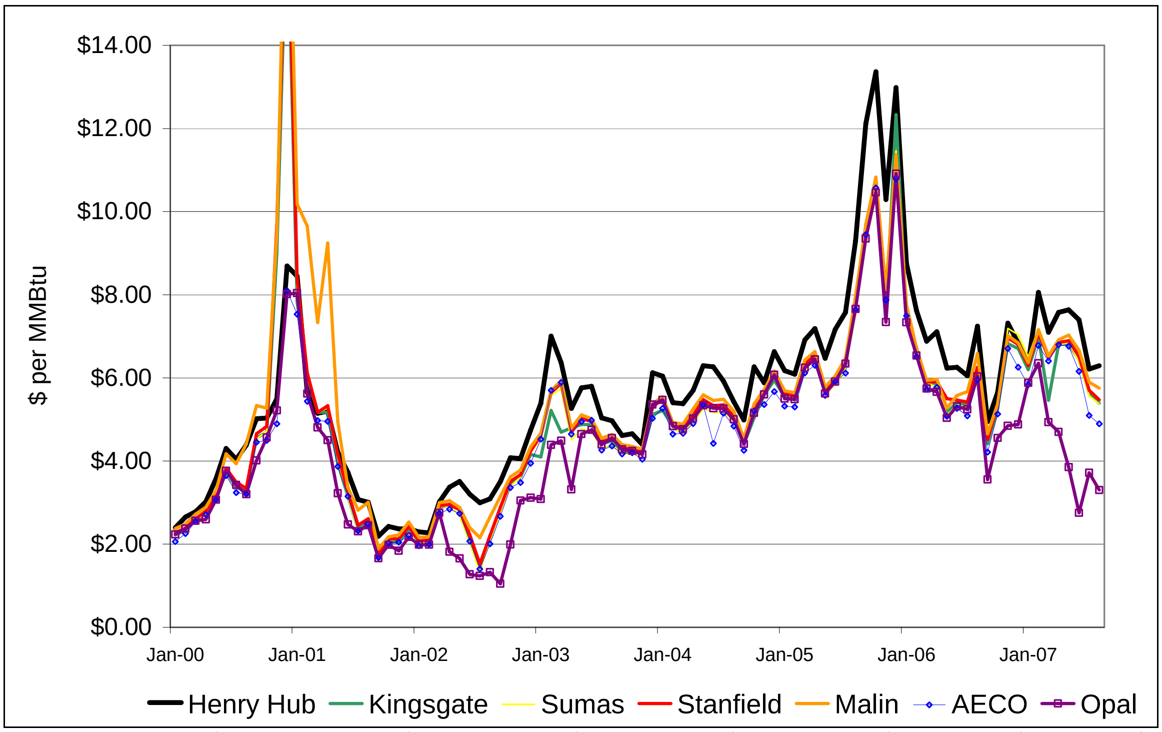
The Kern River, Opal Plant price index tracks transactions into Kern River at the Opal, Wyoming processing plant and the Muddy Creek compressor station in southwestern Wyoming where Kern River connects with Northwestern, Questar, and Colorado Interstate Gas pipelines. Gas traded at the Opal plant that is not nominated into a specific pipeline is included in the price index.

## Pacific Northwest Historical Gas Prices and Basis

Natural gas prices in the Pacific Northwest will follow national trends. The North American supply / demand balance is the major driver of Pacific Northwest Natural gas prices and will continue to be in the future.  Specific regional market conditions play a secondary albeit and important role in determining gas prices.  Natural gas will always be available in all markets throughout North America, as long as purchasers of gas are willing to pay the market price.

The North American natural gas pipeline grid covers all of the lower-48 states and the southern portions of Canada.  Open access pipeline rules allow natural gas to freely flow to where it is needed.  High price differentials between locations usually do not exist when there is unused pipeline capacity.  Therefore natural gas prices, including prices in the Pacific Northwest, will rise and fall in tandem throughout the market (Exhibit 2.16).

**Exhibit 2.16**: **Historical Monthly Natural Gas Prices for Henry Hub and Indexes near the Pacific Northwest ($'s per MMBtu)**




| | Henry Hub | Kingsgate | Sumas | Stanfield | Malin | AECO | Opal |
|---|---|---|---|---|---|---|---|
| Average 2000-2007 | $5.63 | $5.04 | $5.07 | $5.16 | $5.44 | $4.78 | $4.46 |
| Average 2005-2007 | $7.60 | $6.58 | $6.62 | $6.67 | $6.76 | $6.40 | $5.86 |

Source: Platts Gas Daily

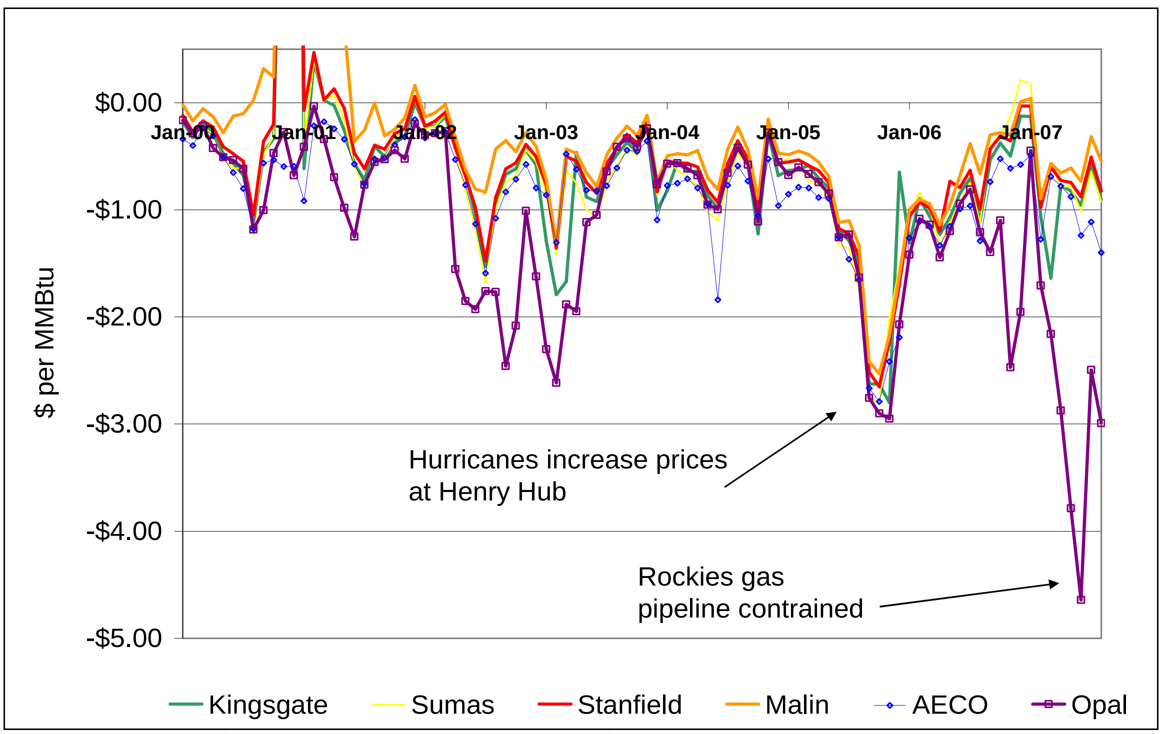
Pipeline bottlenecks can and do cause certain areas to disconnect from the rest of the larger North American market.  This is occurring now in the Northern Rockies as production development has outpaced new pipeline construction.  The result is significantly lower prices. However, these price disconnects are temporary.  Reconnection with the rest of the market will return with the construction of new spare pipeline capacity in and out of the region in question.

Pacific Northwest gas price indices (Kingsgate, Sumas, Stanfield, and Malin) have averaged within 40 cents per MMBtu of each other since 2000 and within 18 cents since 2005.  Canadian imports via Northwest Pipeline at Sumas exhibit a 3 to 4 cent premium over GTN Kingsgate imports. Since 2005, GTN gas deliveries at Malin Oregon have averaged 18 cents over GTN Canadian receipts. Stanfield prices trend in the middle, closer to Canadian border prices.

Supply basin gas prices almost always trend lower than the price index for the consumption market that they serve. Otherwise, there would not be an economic incentive to incur the transportation costs to move the gas to the market. Since 2005, Western Canada AECO prices have averaged 18 cents and 22 cents per MMBtu lower than Kingsgate and Sumas impost prices respectively. Rockies gas at Opal has averaged 70 cents per MMBtu less than Stanfield prices since 2005.

Regional price differentials are most often compared to Henry Hub, Louisiana; the location specified in the NYMEX Futures contract. Any geographic price differences are referred to as a "basis". When a basis reference point is not specified, the reference point is assumed to be Henry Hub. The basis for all of the Pacific Northwest price indexes plus AECO and Opal are shown in Exhibit 2.17. Basis to Henry is not only impacted by market conditions in the Pacific Northwest, but also to market conditions in Louisiana. For example, basis widened to the Pacific Northwest after Hurricanes hit the Gulf Coast. This was mainly due to high prices in the Gulf as opposed to low prices out West.

**Exhibit 2.17**: **Historical Monthly Natural Gas Basis from Henry Hub for Indexes near the Pacific Northwest ($'s per MMBtu)**




| | | | | | | |
|---|---|---|---|---|---|---|
| Average 2000-2007 | ($0.59) | ($0.56) | ($0.47) | ($0.19) | ($0.85) | ($1.17) |
| Average 2005-2007 | ($1.02) | ($0.97) | ($0.93) | ($0.84) | ($1.19) | ($1.74) |

Source: Platts Gas Daily

Pacific Northwest basis from Henry Hub has averaged near minus 50 cents per MMbtu since 2000 and near minus $1 per MMBtu since 2005. Since 2003, most of the indices have fluctuated within that minus 50 cent to minus $1 range except for the hurricane periods. Malin has had a slightly smaller basis. Malin basis was strong positive during the California Energy crisis in 2000.

In the supply regions, Opal basis has averaged in excess of minus $1 and recently has even approached minus $5 per MMBtu. The very large Opal basis is expected to disappear as significant pipeline capacity is built out of the Rockies in 2008[41]. However, the Opal basis could easily widened again in the future if incremental pipeline capacity falls behind production development. AECO prices trend higher than Opal prices thus shrinking the basis. AECO basis has average between minus 85 cents and $1.19 per MMBtu.

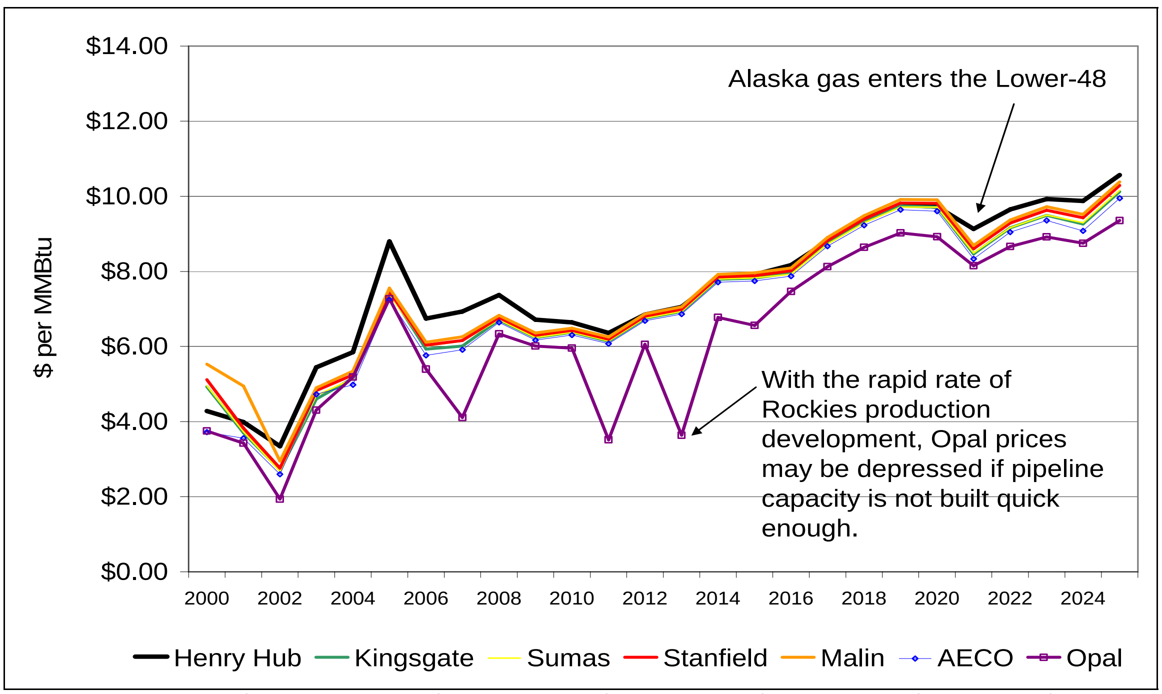
[41] The first phase of the 1.8 Bcf per day Rockies Express is expected to be on line early in 2008.

## Future Outlook: Supply, Demand and Price

## Projected Natural Gas Prices and Basis

Price projections for Pacific Northwest indexes plus AECO, Opal and Henry Hub are shown in Exhibit 2.18. This price projection assumes normal weather[42] for all forecast years and should be thought of as the underlying projected natural gas trend. Generally, colder winters and hotter summers will increase natural gas prices while warmer winters and cooler summers will decrease prices.

**Exhibit 2.18: Projected Annual Natural Gas Prices for Henry Hub and Indexes near the Pacific Northwest 2000-2025 ($'s per MMBtu)**




| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Average 2000-2007 | $5.63 | $5.04 | $5.07 | $5.16 | $5.44 | $4.78 | $4.46 |
| Average 2005-2007 | $7.60 | $6.58 | $6.62 | $6.67 | $6.76 | $6.40 | $5.86 |
| Average 2008-2010 | $6.91 | $6.44 | $6.44 | $6.50 | $6.56 | $6.37 | $6.10 |
| Average 2011-2015 | $7.20 | $7.09 | $7.09 | $7.15 | $7.21 | $7.02 | $5.31 |
| Average 2016-2020 | $9.17 | $9.10 | $9.07 | $9.17 | $9.26 | $9.00 | $8.44 |
| Average 2021-2025 | $9.83 | $9.30 | $9.32 | $9.45 | $9.54 | $9.15 | $8.77 |

Source: ICF International

[42] The projection also assumes normal hydro (snow pack and rainfall) conditions. Which is important in determining the amount of hydroelectric generation. Hydro electric generation is a substitute for gas-fired electric generation.

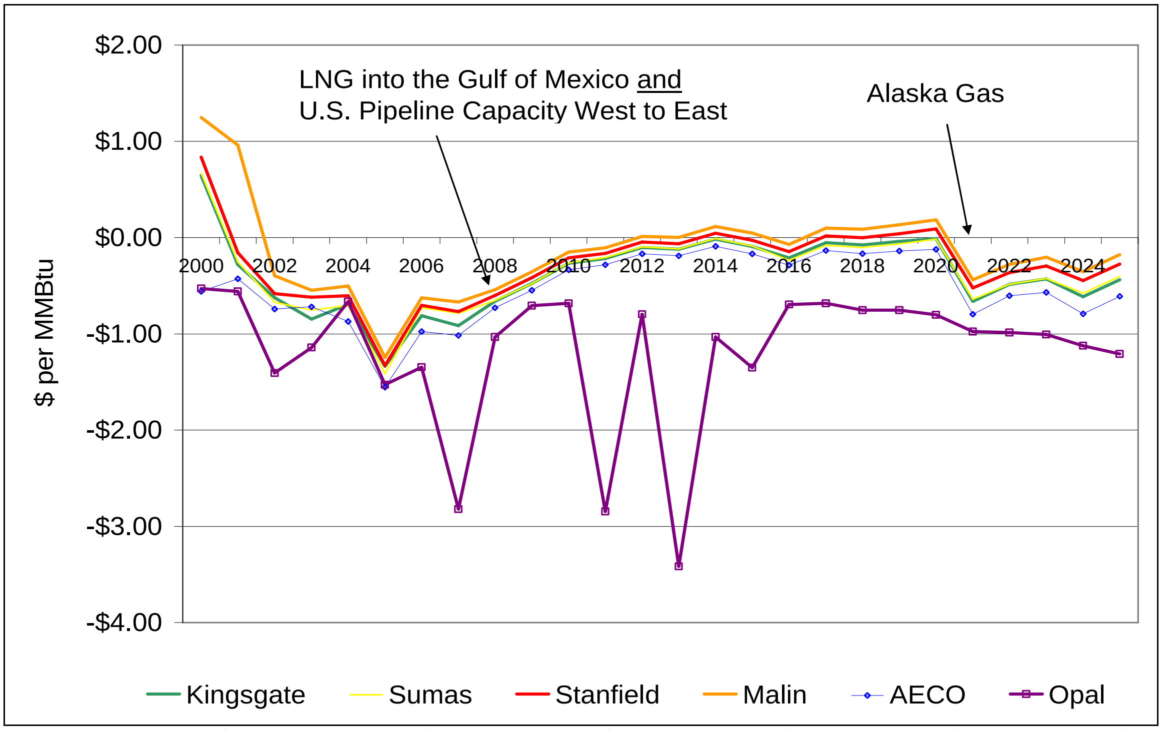
Henry Hub prices, the benchmark for the U.S. national price, are projected to decline from current levels near $7 per MMBtu to about $6.50 per MMBtu by 2011. Pipeline capacity, already under construction, from West to East lowers Eastern U.S. and Canadian prices. Large imports of LNG into the Gulf of Mexico also reduce Henry Hub prices. In 2012, after the first initial "wave" of LNG imports into the U.S., prices are projected to rise steadily, mainly due to inflation. If the Alaska pipeline project is built and injects large gas supplies into the market in a very short period of time, gas prices could temporarily decline about $1 per MMBtu.

Western natural gas prices are projected to follow national trends. Pacific Northwest prices (Kingsgate, Sumas, Stanfield, and Malin) remain near current levels of about $6.50 per MMBtu through about 2011 and than rise slowly. Unlike Henry Hub prices, national incremental pipeline capacity to the East puts moderate upward pressure on prices in the West. However, since the market is highly connected, LNG imports anywhere in North America will put downward pressure on Pacific Northwest prices.

In 2008, Opal prices are expected to rise significantly, by almost $4 per MMBtu, from 2007 levels as new pipeline capacity is built to the east. Since the Northern Rockies are expected to continue to have rapid production development, incremental pipeline capacity may not be built exactly when needed. If the region again becomes pipeline constrained, temporary price depressions will occur. AECO prices are expected to follow similar trends as the Pacific Northwest price indices, remaining near current levels through 2011 and rising thereafter. Arctic supply development will have a relatively large impact on Western Canadian gas prices, dropping prices well in excess of $1 per MMBtu.

Projected basis to Henry Hub is shown in Exhibit 2.19. Pacific Northwest basis is expected to shrink from current levels. Prices are expected to be closer to parity with Henry Hub by 2015. Projected pipeline capacity increases connectivity between East and West North America gas markets and reduces the West to East price differential. As mentioned above, significant imports of LNG into the Gulf of Mexico, reduces Henry Hub prices relative to other markets.

**Exhibit 2.19: Projected Annual Natural Gas Basis from Henry Hub for Indexes near the Pacific Northwest 2000 – 2025 ($'s per MMBtu)**




| | | | | | | |
|---|---|---|---|---|---|---|
| Average 2000-2007 | ($0.59) | ($0.56) | ($0.47) | ($0.19) | ($0.85) | ($1.17) |
| Average 2005-2007 | ($1.02) | ($0.97) | ($0.93) | ($0.84) | ($1.19) | ($1.74) |
| Average 2008-2010 | ($0.47) | ($0.47) | ($0.41) | ($0.35) | ($0.54) | ($0.81) |
| Average 2011-2015 | ($0.11) | ($0.10) | ($0.05) | $0.01 | ($0.18) | ($1.89) |
| Average 2016-2020 | ($0.08) | ($0.10) | 0.00 | $0.09 | ($0.17) | ($0.74) |
| Average 2021-2025 | ($0.53) | ($0.51) | ($0.38) | ($0.29) | ($0.68) | ($1.06) |

Source: ICF International

## Projected Natural Gas Costs to Southwest Washington

Long-term gas costs delivered to Southwest Washington[43] relative to Henry Hub by supply source and route are shown in Exhibit 2.20. The table takes projected supply basin basis from the current ICF Base Case projection, and adds estimated full pipeline tariff rates and fuel charges. For illustrative purposes, current tariff rates are used even though they may have changed in the historic period. Any negotiated pipeline transportation discounts would reduce this value.

**Exhibit 2.20: Net Cost from Different Areas to Southwest Washington Consumers (2004$ per MMBtu)[44]**

| | Historic 2000-2007 | 2008-2010 | 2011-2015 | 2016-2020 | 2021-2025 |
|---|---|---|---|---|---|
| **Rockies Gas via Northwest Pipeline** | | | | | |
| Opal Basis | ($1.17) | ($0.81) | ($1.89) | ($0.74) | ($1.06) |
| Transport Cost | $0.38 | $0.38 | $0.38 | $0.38 | $0.38 |
| Fuel Cost (1.73%) | $0.08 | $0.11 | $0.09 | $0.15 | $0.15 |
| Total | ($0.71) | ($0.32) | ($1.42) | ($0.21) | ($0.53) |
| **AECO Gas via Foothills, Westcoast and Northwest** | | | | | |
| AECO Basis | ($0.85) | ($0.54) | ($0.18) | ($0.17) | ($0.68) |
| Transport Cost | $0.85 | $0.85 | $0.85 | $0.85 | $0.85 |
| Fuel Cost (3.23%) | $0.15 | $0.21 | $0.23 | $0.29 | $0.30 |
| Total | $0.15 | $0.52 | $0.90 | $0.97 | $0.47 |
| **AECO Gas via Foothills, GTN, and Northwest** | | | | | |
| AECO Basis | ($0.85) | ($0.54) | ($0.18) | ($0.17) | ($0.68) |
| Transport Cost | $0.78 | $0.78 | $0.78 | $0.78 | $0.78 |
| Fuel Cost (4.11%) | $0.20 | $0.26 | $0.29 | $0.37 | $0.38 |
| Total | $0.13 | $0.50 | $0.89 | $0.98 | $0.48 |

Source: ICF International, Public Tariff Information

With full cost firm contracts, Rockies supplies are projected to significantly be the least expensive gas supply for Southwest Washington. Rockies supplies to Southwest Washington are projected to be delivered at an average cost usually between 20 cents and 50 cents per MMBtu below Henry Hub spot prices. Periodically larger discounts relative to Henry Hub may occur if the production basin becomes pipeline constrained.

Unfortunately, Northwest Pipeline is fully subscribed and incremental capacity cannot be added at existing rates. Most of beneficiaries of the relatively low cost gas will go to existing contract holders on Northwest Pipeline. For incremental Rockies gas to move West, completely new

[43] Costs reflect purchases by LDCs or a large end user buying gas directly off of the pipeline. Costs do not include distribution charges.
[44] Full firm transportation rates at 100 percent load factor.

pipelines would need to be built or Kern River Pipeline to Southern California would need to be expanded.

Canadian gas from AECO to Southwest Washington via either Sumas or Kingsgate, would be significantly higher than Rockies gas. Projected delivered gas costs to Southwest Washington average between 50 cents to $1 above Henry Hub prices. This is higher than recent cost trends of less than 15 cents per MMBtu relative to Henry Hub. The increase is due to both a narrowing of the AECO to Henry Hub basis and an increase in fuel costs. Fuel costs increase with higher absolute gas prices.

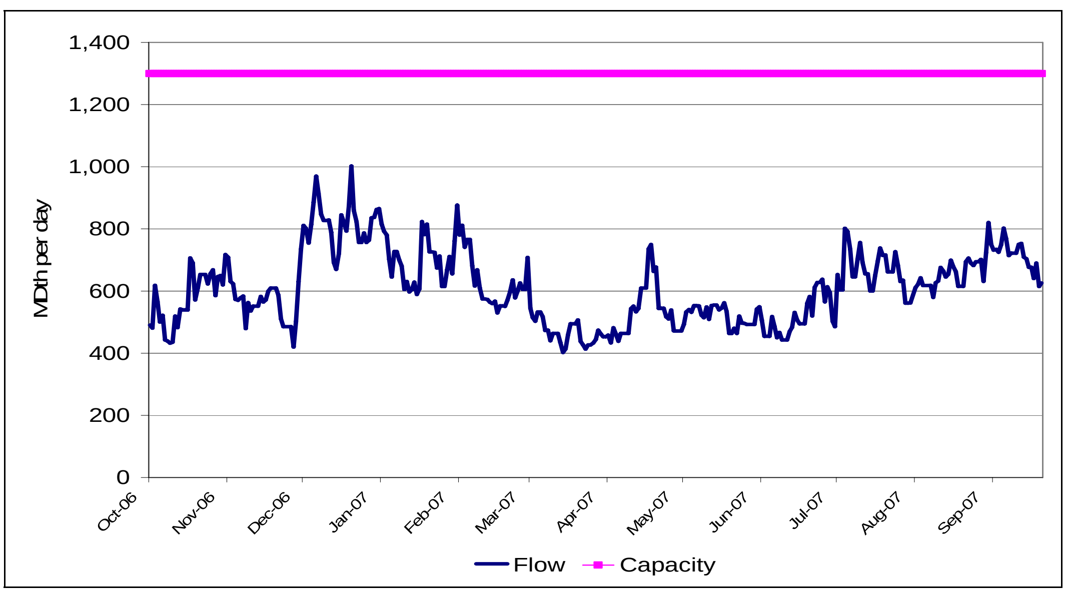
## Projected Natural Gas Pipeline Capacity, Flow, and Adequacy to Southwest Washington

This section examines historical, current, and projected natural gas pipeline utilization in the Pacific Northwest with concentrations in the Southwest Washington area. Pipeline flows for gas imports into the region such as Northwest Pipeline at Sumas, GTN at Kingsgate, and Northwest Pipeline are examined first. Projected utilization and adequacy for Northwest Pipeline in Southwest Washington near the Vancouver area follows.

### Pipeline Imports Sumas via Northwest, Kingsgate via GTN, and Rockies via Northwest.

Daily Canadian imports at Sumas on Northwest Pipeline from October 2006 through October 2007 are shown in Exhibit 2.21. Capacity at the border is approximately 1,300 MDth per day. Within this one-year time period, there was always excess pipeline capacity available. Receipts ranged from 400 to 1,000 MDth per day and averaged just over 600 MDth per day. Therefore a minimum of 300 MDth per day of pipeline capacity went unused. There are no significant pipeline constraints on the Canadian side of the border. The full spare pipeline capacity on Northwest would have been available if the market needed it.

**Exhibit 2.21: Current Capacity and Daily Receipts, Northwest Pipeline Sumas Station (MDth per Day)**

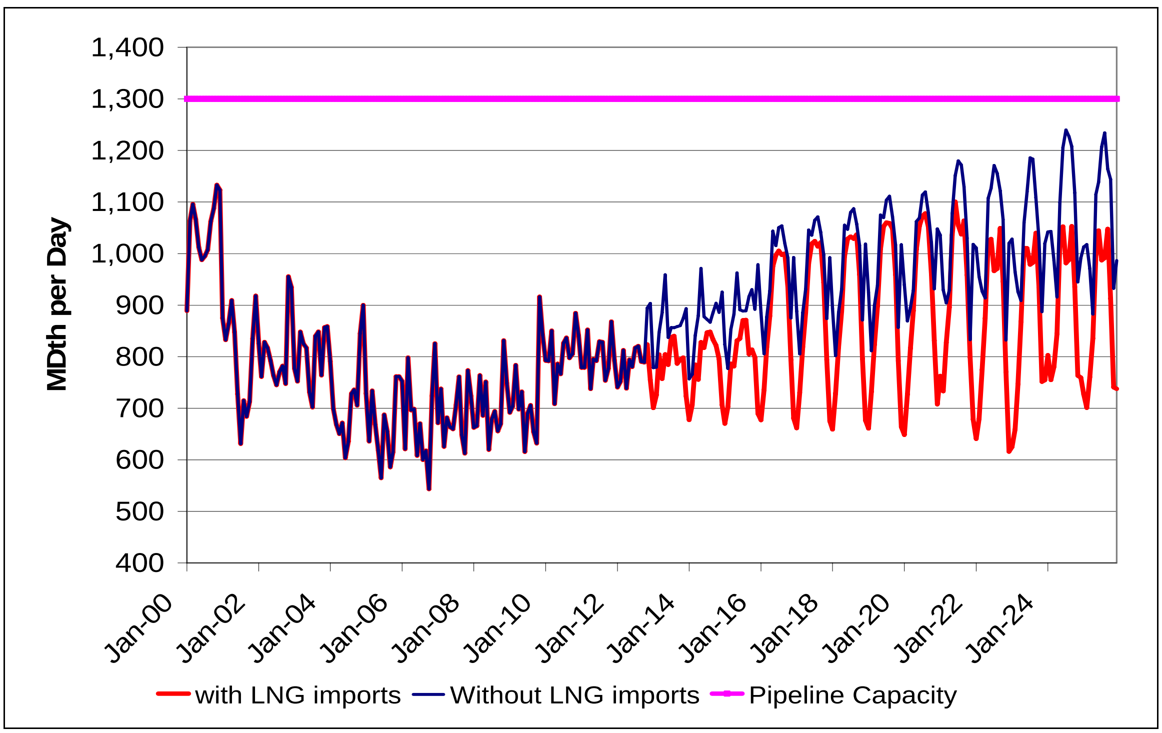



Source: ICF International

Spare physical pipeline capacity at Sumas, Washington is highly important to Southwest Washington gas consumers. Northwest pipeline capacity between the Seattle area to Oregon is rarely, if ever, constrained flowing south. The segment of pipeline typically flows north in the winter. Therefore, any spare capacity at Sumas is available to serve Southwest Washington markets. Imports at Sumas are exclusively Canadian gas.

Monthly projected Sumas receipts through 2025 are shown in Exhibit 2.22. The ICF Base Case assumes that an LNG import terminal begins operation on the Oregon Coast in late 2012. Exhibit 2.22 also shows projections for Sumas receipts if no LNG import terminal is sited in the Pacific Northwest. Exhibit 2.22 only shows monthly projected fluctuations which gives an indication of the seasonality of flow. However, daily fluctuations will be greater than shown and that must be considered when judging pipeline adequacy.

**Exhibit 2.22: Projected Monthly Pipeline Average Flow versus Capacity - Sumas Station (MDth per Day)**



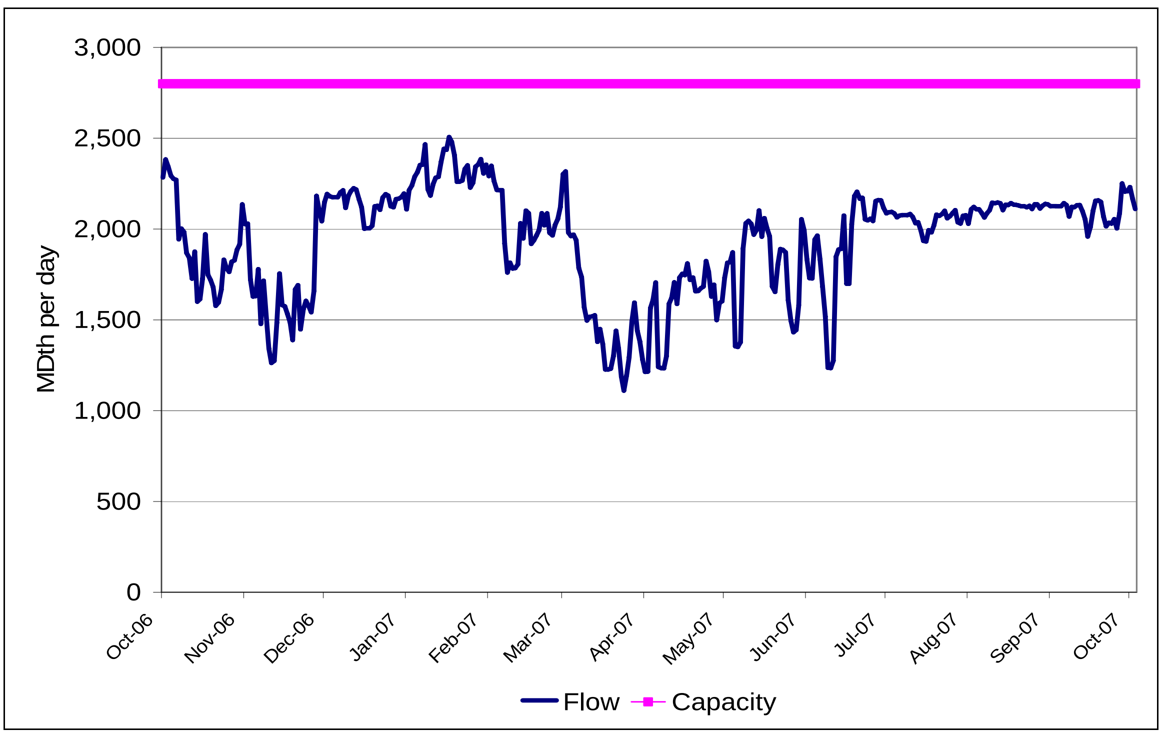

Source: ICF International Base Case

Northwest Pipeline flow at Sumas is projected to increase as consumption in Washington and Oregon natural gas markets increase. Northwest pipeline capacity at Sumas appears to be sufficient to meet projected pipeline flow through the latter part of next decade with or without direct LNG imports into the region. By 2020, flow could reach and exceed levels that occurred in 2000.

If an LNG terminal is sited in the Pacific Northwest, no additional pipeline capacity is projected to be needed through the forecast period to 2025. If the Pacific Northwest has no direct LNG imports, pipeline capacity may begin to be strained after 2020. However, since the market is highly seasonal, incremental pipeline capacity or additional natural gas storage[45] could be used to satisfy winter consumption. Incremental pipeline capacity need not originate at Sumas in the North but could originate in the East or South.

Daily Canadian imports at Kingsgate on GTN from October 2006 through October 2007 are shown in Exhibit 2.23. Capacity at the border is approximately 2,800 MDth per day, however the station has been known to flow nearly 3,000 MDth per day in the past. Most gas flowing on GTN transverses the Pacific Northwest to California. However, GTN has interconnects with Northwest Pipeline at Spokane Washington and Stanfield Oregon. Southwest Washington gas consumers access GTN supplies mainly through the larger Stanfield interconnect. This pipeline route is contingent on pipeline capacity between Stanfield and Southwest Washington (discussed below). Similar to Sumas, receipts at Kingsgate come from exclusively Canadian sources.

**Exhibit 2.23: Current Capacity and Daily Receipts, GTN Kingsgate Station (MDth per Day)**




Source: ICF International

Currently, there are very large amounts of spare pipeline capacity on GTN. Approximately 200 MDth per of long-term firm capacity is currently posted as available on GTN's electronic bulletin board. From October 2006 to September 2007, pipeline receipts at Kingsgate averaged less than 2,000 MDth per day leaving an average of 900 MDth per day of unutilized pipeline capacity.

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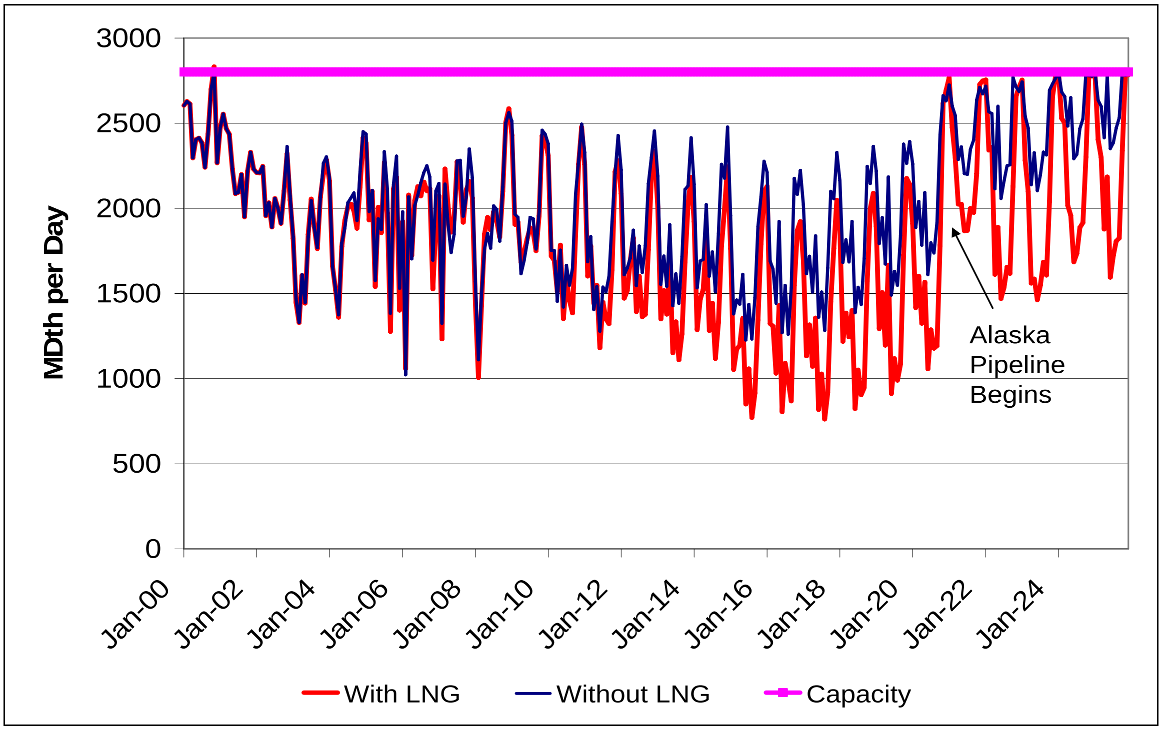
45 Storage expansions beyond the expansions currently planned for the Jackson Prairie field which are already assumed in ICF's Base Case projection.

Monthly projected Kingsgate receipts through 2025 are shown in Exhibit 2.24. Projected flows with and without a 2012 Pacific Northwest LNG import terminal are shown. Flow on GTN is projected to decline from current levels and spare pipeline capacity is projected to increase. An LNG terminal reduces flow on GTN by 200 to 300 MMcf per day in the summer, and by 500 to 600 MMcf per day in the summer.

**Exhibit 2.24: Projected Monthly Pipeline Average Flow versus Capacity – Kingsgate Station Idaho (MDth per Day)**

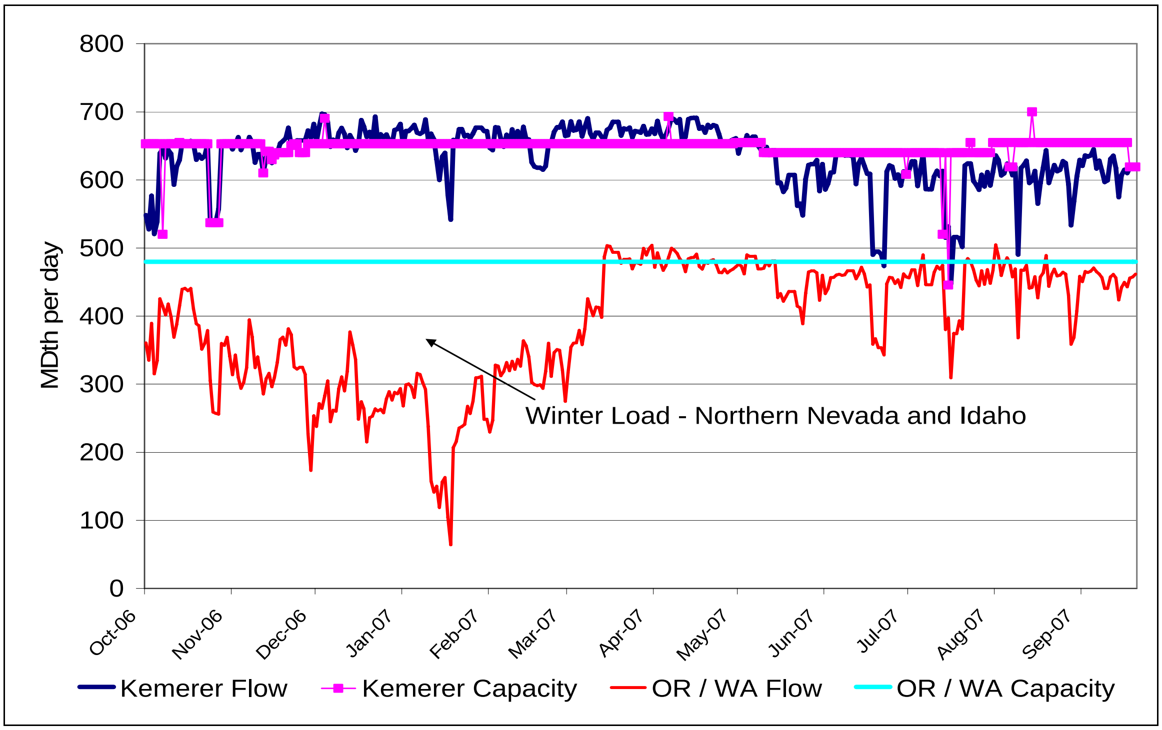



Source: ICF International Base Case

Average spare pipeline capacity in the range of 1.0 to 1.5 Bcf per day is projected for most of the next decade. However, if the Alaska pipeline project to Alberta is built, existing pipeline infrastructure will be used to move gas to the U.S. Lower-48. GTN receipts could flow near capacity in the winter months.

Imports of Rockies gas into the Pacific Northwest for October 2006 to September 2006 are shown in Exhibit 2.25. The Kemerer compressor station located in southwest Wyoming is a key bottleneck for Rockies imports to the north. Flow at the Idaho / Oregon border into the Pacific Northwest is essentially equal to flow at Kemerer less deliveries to Idaho and the northern Nevada markets. Northern Nevada markets, including Reno, are served by Northwest pipeline through an interconnect with Paiute Pipeline.

**Exhibit 2.25: Current Capacity and Daily Throughput, Northwest Pipeline – Kemerer Station and WA / OR Border (MDth per Day)**



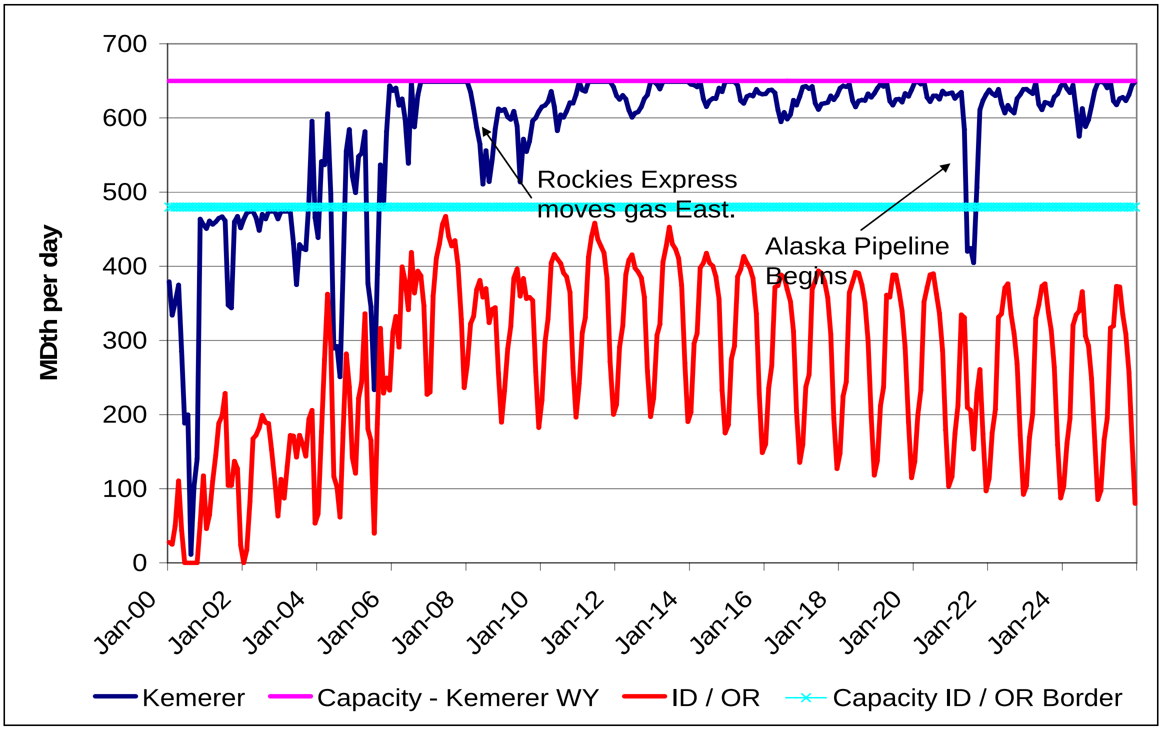

Source: ICF International

Rockies production is currently severely pipeline constrained. All routes out of the area are fully utilized; the route through Kemerer is no exception. The Kemerer station runs at full capacity of 650 MMcf per day with only minor operational variations.

Pipeline utilization rates downstream of Kemmerer can also run at capacity but usually only at certain times of the year. Pipeline flow at the Idaho / Oregon border has recently run near capacity in the summer months. However, in the winter months a greater volume of gas supplies are delivered prior to this pipeline segment to serve the Idaho and Nevada markets. However, this winter seasonal spare capacity cannot be utilized by Pacific Northwest consumers because there is not a gas supply source in Idaho to fill it.

Monthly projected pipeline throughput at the Kemerer, Wyoming Station and at the Idaho / Oregon border through 2025 is shown in Exhibit 2.26. The pattern is not projected to change significantly from current seasonal flow. There are no anticipated pipeline capacity additions.

**Exhibit 2.26: Projected Monthly Pipeline Average Flow versus Capacity - Kemerer Station and WA / OR Border (MDth per Day)**




Source: ICF International Base Case

Throughput through the Kemerer station in Wyoming remains near capacity throughout the projection. Flow is below capacity for only two relatively brief periods; in 2008 when the 1.8 Bcf per day Rockies Express pipeline is initially built to bring gas east and in 2020 when Alaska gas initially flows into the Pacific Northwest. Pipeline flow at the Idaho Oregon border is projected to continue to fluctuate seasonally with consumption in the Idaho and Nevada markets. In the summer months when consumption in upstream markets is relatively low, the segment flows full. In winter months there is projected spare capacity.

Incremental Northwest Pipeline capacity from Wyoming to Stanfield, Oregon would be highly beneficial to Southwest Washington consumers. However, expansions cannot be accomplished easily through incremental compression alone. Additional pipeline would be needed for most of the route[46]. To bring gas west from the Rockies other pipeline projects and / or expansions are more likely to be built.

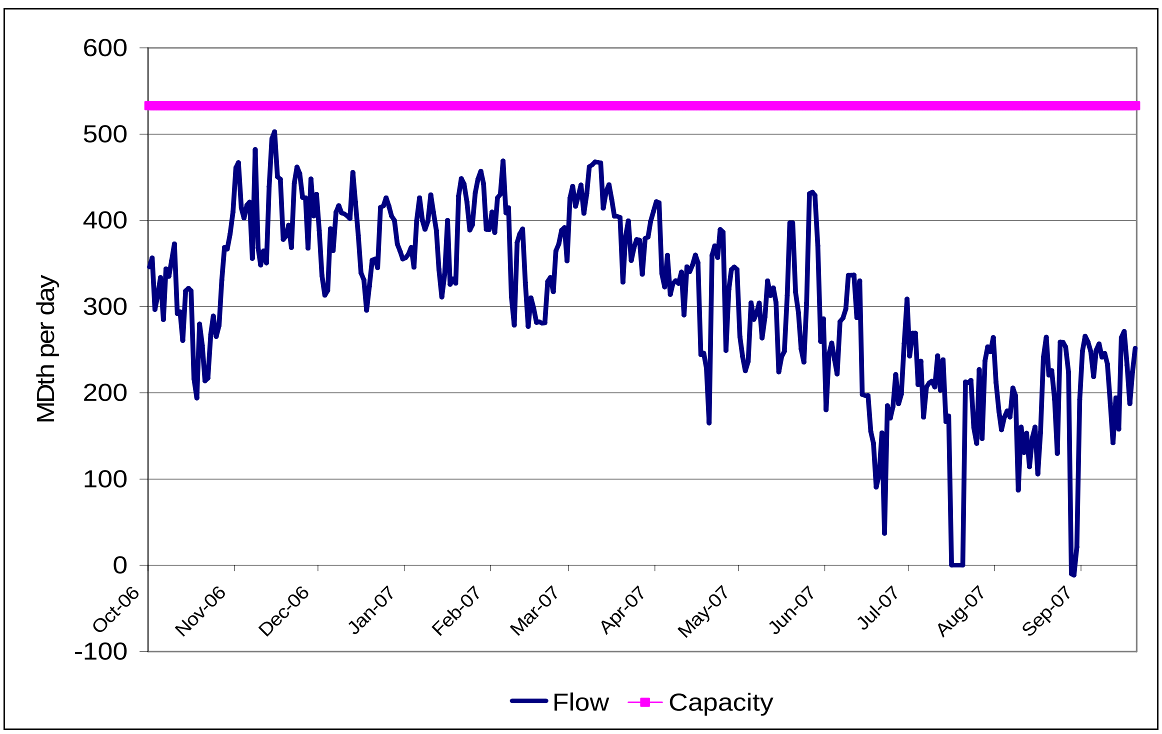
[46] A detailed economic and engineering study for an incremental Northwest Pipeline expansion was beyond the scope of this study.

**Northwest Pipeline Throughput in Southwest Washington**

The Southwest Washington area is served exclusively by Northwest Pipeline. The pipeline segment serving the region is bidirectional. As previously mentioned above, the pipeline capacity from the east is 550 MMcf per day. Pipeline capacity from the north (or west[47]) is 630 MMcf per day. Flow is generally from east to west. When necessary, gas from the Jackson Prairie storage field can also flow from the north thereby serving the Southwest Washington market from two directions.

Throughput on Northwest Pipeline into the Washougal Compressor station (gas entering the Vancouver market from the east) for October 2006 to September 2006 is shown in Exhibit 2.27. Flow on this segment of pipe is much higher in the winter and often flows between 400 and 500 MMcf per day. In the summer, flow averages near 200 MMcf per day and at times can reverse and flow west to east. In the summer, Canadian supplies from Sumas are almost sufficient to serve markets from Seattle to southern Oregon and meet injection requirements into the Mist and Jackson Prairie storage fields.

**Exhibit 2.27: Current Capacity and Daily Throughput, Northwest Pipeline – Washougal Compressor Station (Just East of Vancouver) (MDth per Day)**

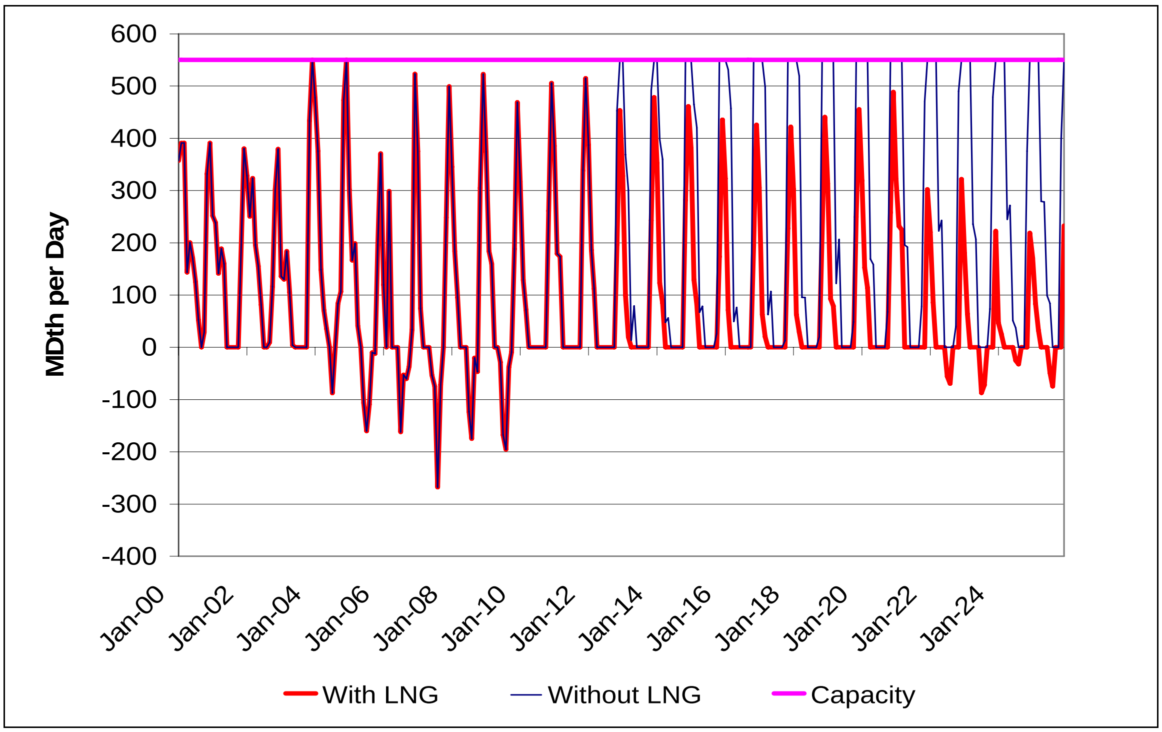



Source: ICF International

[47] Northwest's mainline turns to the north at the Vancouver area.

Monthly projected throughput at the Washougal Station is shown in Exhibit 2.28. Forecasted flow with and without a 2012 Pacific Northwest LNG import terminal are shown. With the addition of an LNG terminal on the Oregon or Washington coast, maximum monthly average flow is expected to be below capacity throughout the projection to 2025. Without LNG imports, the pipeline is projected to flow at or near capacity during the winter months. However, this alone does not imply that the Southwest Washington market will be pipeline constrained. As mentioned above, there is capacity from Sumas to the Southwest Washington area. However, Sumas imports are Canadian supplies only.

**Exhibit 2.28: Projected Monthly Pipeline Average Flow versus Capacity - Washougal Compressor Station (Just East of Vancouver) (MDth per Day)**




Source: ICF International Base Case

Flow on Northwest Pipeline into the Vancouver is projected to maintain a highly seasonal pattern with winter throughput much higher than summer. The seasonal pattern is important. Average pipeline flow is closer to 300 MMcf per day or just over half of the pipeline capacity. Therefore, natural gas storage which would tend to level seasonal fluctuations, would be a viable alternative to incremental pipeline capacity.

## Conclusions

The review of the Portland/Vancouver natural gas supply corridor can be summarized with the following statements:

**Positive Factors**

- Natural gas supply is expected to remain available. There is an estimated 37 years of Western Canadian and Rockies resource available at current production levels and current technology. Advances in technology will increase that value.
    - Rockies are expected to grow from 8 Bcf per day in 2007 to over 12 Bcf per day by 2025.
    - Canadian gas supplies will always be available if the prevailing market price is paid.
- Pipeline capacity into Southwest Washington on Northwest pipeline is about 550 MMcf per day from the east and 630 MMcf per day from the north/west. Southwest Washington can be served from both directions simultaneously.
    - Total pipeline capacity into the Southwest Washington market is over 1.2 Bcf per day.
    - Annual consumption in Southwest Washington is an average of about 125 MMcf per day.
- Regional seasonal and peak day consumption growth is expected to grow slower than annual consumption at a rate closer to 2 percent.
    - Most of the growth is in power generation consumption which has a larger impact on summer load as opposed to the winter peak months.
- Due to recent declines in industrial sector gas consumption, regional gas load won't reach consumption levels that occurred in 2000 until the year 2012.
- Rockies gas supplies via Northwest pipeline are projected to be the most economical gas supply source for Southwest Washington.
    - Net cost of Rockies gas delivered is expected to range from 20 to 50 cents below Henry Hub prices from 2008 to 2025.

- There are three LNG import terminals proposed for the Oregon coast.
    - All have a capacity of 1 Bcf per day or greater.
    - Practical in-service dates are probably not earlier than 2012.
    - If any LNG terminal is sited in the Pacific Northwest, no incremental import pipeline capacity will be needed to Southwest Washington or the Pacific Northwest in general from any direction.
- Northwest pipeline capacity of 1.3 Bcf per day at the Canadian border at Sumas Washington is projected to be adequate until 2020.
    - By 2020, imports may reach levels seen in the year 2000. Sumas imports are accessible to Southwest Washington markets.
- GTN is projected to have an average of 1 to 1.5 Bcf per day of spare Canadian import capacity at Kingsgate, Idaho for the foreseeable future.
    - GTN may fill up if an Alaska project brings gas to the U.S. Lower-48.
- Capacity along Northwest's pipeline entering Southwest Washington from the east is not projected to reach capacity during peak winter months to about 2012.

- However, this does not mean the Southwest Washington market is pipeline constrained. Pipeline capacity for Canadian imports at Sumas may be used.

- Due to the highly seasonal nature of the Southwest Washington market and the Pacific Northwest in general, natural gas storage will be a direct substitute for incremental pipeline capacity.

**Concerns**

- The Pacific Northwest has essentially no natural gas production. The natural gas market including Southwest Washington must import all of its natural gas from other regions.
- Southwest Washington is served exclusively by Northwest Pipeline.
- Annual consumption in the Pacific Northwest is projected to grow at about 3 percent from 2007 to 2025 driven mainly by power generation consumption. This is higher than projected national averages
    - Consumption in Southwest Washington may be higher if population growth trends continue.

- Pacific Northwest gas prices are expected to rise relative to Henry Hub.
    - Pacific Northwest gas prices currently sell at a $1 discount to Henry Hub.
    - This price differential is expected to narrow and trend to near parity by 2015 as LNG into the Gulf of Mexico relatively lowers Henry Hub prices and large capacity pipeline projects across the country levelize North American West and East gas prices.

- The benefit of relatively inexpensive Rockies supplies will go to exiting legacy holders of Northwest Pipeline capacity.
    - The pipeline cannot be easily expanded from Wyoming to the Northwest.
    - Pipeline capacity is expected to remain full out of Wyoming to the northwest throughout the projection to 2025. No incremental pipeline capacity is expected.

- The cost of delivered Western Canadian gas relative to Henry Hub is expected to increase.
    - The delivered cost of Western Canadian gas supplies to Southwest Washington is expected to increase form about 15 cents per MMBtu above Henry Hub prices to between 50 cents and $1 per MMBtu above Henry Hub prices from 2008 to 2025. beyond.
    - Declining Canadian production and increased local demand will raise the relative price of Western Canadian gas supplies.
    - Arctic project development from Alaska could reduce Canadian delivered gas by about 50 cents per MMBtu. However such projects are anticipated late next decade at the earliest.

## Recommendations

Based on information collected for this study, there are several recommendations that should be considered by Southwest Washington gas consumers to maintain pipeline adequacy and economic pipeline supplies.

1. **Rockies Gas Supplies - Analyze Pipeline Projects that Transport Rockies Gas West – Contract for Capacity if Economically Viable.** - The current route of Rockies gas supplies to the Pacific Northwest via Northwest Pipeline is constrained and cannot be economically expanded. However, other potential routes should be examined[48]. Rockies gas is projected to be less expensive than future Canadian supplies. Proposed projects to move Rockies gas west mainly involve expanded pipeline capacity to California markets or to Malin. Expected costs are most likely significantly greater than the current 38 cents per MMBtu transport rate of Northwest Pipeline. Additional transportation costs will be needed to bring it north to the Pacific Northwest (via backhaul most likely), but this should use existing pipeline infrastructure. Delivered costs should be compared to projected Canadian delivered supplies.

2. **LNG Imports - Analyze Cost and Price impacts of Direct Pacific Northwest LNG Imports – Contract for Capacity if Economically Viable. -** As mentioned above, LNG imports in the Pacific Northwest would eliminate the need for any foreseeable incremental pipeline import capacity. LNG imports could be a reliable source of natural gas supplies. Although, LNG imports would be priced at market rates and market rates will tend to follow national trends, they will depress regional price differences. LNG will have a small negative impact on natural gas prices.

3. **Natural gas Storage. - Analyze Cost and Benefits of Additional Storage beyond Current Expansion Plans -** Additional natural gas storage will increase the ability to store higher volumes of less expensive Rockies supplies. Due to the seasonal nature of all of the Pacific Northwest market, natural gas storage is also a direct substitute for any incremental pipeline capacity. Storage expansions beyond the planned expansions for the Jackson Prairie field should be considered as the market grows.

4. **Arctic Gas Development - Support Arctic Gas Development. -** Arctic gas development will have a direct impact on Western Canadian gas prices. Western Canada delivers over 90 percent of the gas supplies into the Pacific Northwest. Any price reduction in Western Canada will directly impact prices in the Pacific Northwest. An Alaska project is expected to have at least a 50 cent per MMBtu impact.

[48] An economic analysis of pipeline projects from the Rockies to the Pacific Northwest was beyond the scope of this report. The expansion of Northwest Pipeline to bring Rockies gas to Southwest Washington was also beyond the scope of the study.

# 3 Glossary

| | |
|---|---|
| Barrel | One barrel equals 42 gallons. |
| Bcf, Bcfd | Billion cubic feet (Bcf) and billion cubic feet per day (Bcfd). One Bcf of natural gas equals 1,000 Dth (at 1,000 Btu/cf) |
| Branded-Unbranded | Branded gasoline is gasoline sold at a loading rack or a terminal to a buyer who agrees to sell the product under the seller's gasoline brand. Branded gasoline buyers also have the sellers' additives and typically have better insurance of supply. Unbranded buyers can buy gasoline at prices below branded (when supply is plentiful), but may not be able to find supply in a tight market. |
| CARBOB | California sub-octane grade meeting other California based requirements as well. Blended with other components. |
| Dth | One Dekatherm (Dth) equals one MMBtu. |
| DTW | Price for gasoline delivered into a service station (DTW is "dealer tankwagon" price. |
| E10 | Suboctane gasoline blended with 10% ethanol; also any gasoline with 10 percent ethanol. |
| EIA | US Energy Information Administration. |
| GW | Gigawatt |
| KM | KinderMorgan pipeline from Portland to Eugene. |
| Mcf, MMcf, MMcfd | Thousand cubic feet (Mcf), million cubic feet (MMcf) and million cubic feet per day (MMcfd). |
| MBtu, MMBtu | Thousand British thermal units (MBtu) and million British thermal units (MMBtu). |
| MDthd | Thousand Decatherms per day |
| MW | Megawatt |
| NYMEX | Price for crude oil, gasoline & No. 2 heating oil delivered in New York Harbor in the futures contract month upon expiration. |
| OPIS | "Oil Price Information Service" that focuses on reporting US rack and spot market prices. OPIS publishes reported prices at multiple US terminals. |
| Pipeline Cycles | Pipeline cycles are the staged receipts of fuels into pipelines in an orderly manner. For example, a pipeline may sequence batches of regular unleaded gasoline, then premium, then jet fuel, then low sulfur diesel, etc. Shippers must have their batches for shipments ready to meet to pipelines cycle schedule. |
| Platt's | Oil price information service that tracks US and global pricing transactions. Platt's quotes are judged reliable benchmarks for contractual transactions. |
| R/T | Round trip for a marine voyage. Days from initial connection at the load port to a return at the load port after discharge of product. |
| Rack | Prices for transactions at a terminal loading rack (into a truck) from suppliers to distributors/jobbers. |
| Spot | Wholesale prices for cargo, barge, or pipeline volumes of petroleum products at specific locations. |

| | |
|---|---|
| Sub-octane | Reduced octane grades of gasoline produced to allow blending of higher octane components. This is usually done to allow ethanol to be blended at terminal loading racks without producing gasoline at higher octane levels. |
| Tariff | Fee paid to a pipeline company for volumes shipped on the pipeline; tariff charge is regulated by FERC (Federal Energy Regulatory Commission). |
| Terminal | Petroleum product tank farm which receives products by pipeline or barge and re-ships product either into trucks for customers, or trans-ships into barge and/or other pipelines for further distribution |
| TBD (oil volume) | TBD is thousands of barrels per day. |
| Tcf | Trillion cubic feet |
| Trans-shipment | The process where an oil terminal receives gasoline by one mode of transportation, and then re-ships the product in either the same mode or another mode (e.g., pipeline, barge, tanker, etc). |
| ULSD, LSD | Ultra Low Sulfur Diesel fuel (<15 PPM sulfur); Low sulfur diesel (<500 PPM sulfur). |
| TWh | Terawatt-hours |
| Vapor Pressure | Vapor pressure is the Reid Vapor Pressure of gasoline, a measure of the tendency of gasoline to release vapor. Vapor pressure in gasoline is increased in the winter by adding butane at the refinery to improve cold weather ignition; vapor pressure is reduced in the summer as mandated by EPA to minimize gasoline vapor losses upon fueling. |
| $/Dth | Dollars per Decatherm |
| $/MMBtu | Dollars per Million British Thermal Units |