Convergence: Natural Gas and Electricity in Washington

A Survey of the Pacific Northwest Natural Gas Industry on the Eve of a New Era in Electric Generation

WASHINGTON STATE
Office of Trade & Economic Development

Energy Policy Division
925 Plum Street SE, Bldg 4
PO Box 43173
Olympia, WA 98504-3173

May 2001

Printed copies of this report are available by calling (360) 956-2096 or e-mail karend@ep.cted.wa.gov.

TDD users call (360) 753-7427

This document is also available on the Internet at http://www.energy.cted.wa.gov

Printed on recycled paper

Executive Summary

This report examines trends in the demand for and supply of natural gas for Washington and the Pacific Northwest in light of current plans to construct several thousand megawatts of new natural gas-fired electric generating capacity. Construction of even a fraction of the projects that have been proposed for Washington, Oregon, and Idaho will greatly increase the region's demand for natural gas. This raises serious questions about the ability of the region's gas delivery system to meet this new demand without adverse consequences for existing natural gas consumers. The extreme price events of the last several months, caused in part by a sudden, large increase in consumption of natural gas for electricity generation, provide a cautionary example of the strong forces that can be unleashed by unplanned demand growth.

Past and Present Trends in the Natural Gas Industry

Natural gas was introduced to the Pacific Northwest with the completion of the Northwest Pipeline system in 1957, which connected the region to natural gas fields in the Rocky Mountains. In the 1960s, additional pipelines were constructed that connected the region to Canadian sources of gas. Within local communities, gas is distributed by four investor-owned utilities and three cities.

Until 1985, the price of wholesale natural gas was regulated by the federal government. Producers could earn only a "fair rate of return" on investments in natural gas production. As a result, very few gas wells were drilled, and by the mid-1970's, demand for natural gas began to outstrip available supply. Deregulation of the natural gas industry began during the 1980s. Prices were decontrolled federally, and the state allowed customers to purchase their own gas supplies. After 1985, wholesale prices plummeted and consumption began to grow rapidly.

In the 1990s, natural gas began to be burned in large quantities for electric generation. The new combined cycle combustion turbine technology, coupled with low gas prices, made gas the fuel of choice for electric generation. Applications to construct over 2000 megawatts (MW) of gas-fired electric generating capacity were approved by the Washington Energy Facility Site Evaluation Council by 1996. A 248 MW plant was completed in 1997 and 900 MW of gas-fired capacity came on line in Oregon and Idaho. Over 12,000 MW of new natural gas-fired generation are in various stages of construction, permitting, or planning in the Pacific Northwest. If even half of these plants were built, the region's natural gas consumption would grow by 50%.

Whether this level of construction poses problems for the industry depends on the timing of both new power plants coming on line and expansion of the region's ability to deliver low-priced gas. If pipeline expansions precede or accompany the interconnections of new plants and if new gas fields are brought on line at a reasonable cost, then increased demand will be accommodated with minimal disruption to existing customers. But if all of the necessary events don't occur in the proper sequence, the industry may experience price spikes leading to temporary economic dislocation, long-term upward pressure on gas prices, or both.

Moreover, the Northwest will increasingly be subject to forces over which it has no control. Demand from new plants in other western states, combined with increased pipeline capacity from producing areas in the Rockies and Western Canada to East Coast markets, will place pressure on the Northwest's natural gas infrastructure even if the region doesn't build a single new plant. The convergence of the electricity and natural gas industries means that these effects will also be felt in electricity markets.

The Events of 2000 and Early 2001

The extreme consequences from the events of Summer/Fall 2000 raise a number of questions about the appropriateness of existing company strategies and regulatory policies. The seeds of this situation date back to the early 1990s, when the West Coast was awash in cheap energy. Depressed gas prices led to limited exploration, and low electricity prices caused increasing pressure to deregulate retail electricity markets, creating regulatory uncertainty that inhibited the construction of new power plants. By the end of the decade, electric loads were growing rapidly, but the impact was masked by favorable weather and hydroelectric conditions.

All of this came to a sudden end in the summer of 2000. Sustained hot weather in California meant high levels of demand for electricity, while drier than average hydroelectric conditions meant reduced hydropower exports from the Northwest to California. Electricity prices spiked to record levels in June, and the market endured repeated, sustained periods of high prices throughout the summer. Greatly increased use of gas-fired generators meant that price pressures spilled over into natural gas markets.

By November and December, the combination of high prices, reduced inventories of natural gas in storage, and heavy reliance on gas for electric generation created monumental challenges. Temperatures were well below average across the country, and gas storage was at critical levels, particularly in California. Pipeline capacity into California and from the California border to major markets within the state became severely constrained, leading to huge differentials in the price of natural gas at various locations in the west. While wholesale gas prices in Wyoming and Alberta were frequently less than one-half the levels in the Northwest and California, pipeline capacity limitations meant that local market prices for natural gas would soar.

Three of Washington's natural gas utilities implemented rate increases in January, 2001 resulting in gas bills that were 50% to 90% higher than they were at beginning of 2000. Electric utilities caught short of power by dry hydroelectric conditions imposed temporary surcharges as high as 58% on electric rates to recover power purchased at extremely high prices. A number of large energy users curtailed production due to high utility costs for both gas and electricity, and several that were exposed to market electricity prices began operating diesel generators in late 2000.

Weather in December, 2001 did not reach anywhere near record cold levels in the Northwest, so the strain on the system could be much greater. Plans to greatly expand gas-fired electricity generation up and down the West Coast could lead to further strains on natural gas supply and deliverability, especially in the near term.

Natural Gas Pipelines Serving the Pacific Northwest

The Pacific Northwest is served by two interstate pipelines operated by the Northwest Pipeline Corporation, a subsidiary of Williams, and PG&E Gas Transmission, Northwest (GTN). These pipelines deliver natural gas from Canadian and domestic sources to customers in Washington, Oregon, California and other western states. Shippers, including local distribution companies, large industrial customers, and energy marketers purchase capacity on the pipelines to deliver gas from particular suppliers and receipt points on the system to particular delivery points.

Northwest Pipeline is a bi-directional pipeline that can deliver gas either from supply basins in the Rocky Mountains or from Canada through an interconnection with Westcoast Pipeline at Sumas, Washington. Northwest Pipeline interconnects with local utilities along the I-5 corridor, enters eastern Washington through the Columbia Gorge, and connects to utilities in eastern Washington via a spur that ends in the Spokane area. Gas can flow from either Canadian or Rocky Mountain sources to the Pacific Northwest, as long as the market isn't attempting to flow too much gas in one direction. Approximately 73% of the natural gas on Northwest Pipeline is Canadian gas that enters the pipeline at Sumas, Washington or Stanfield, Oregon. However, contracted supplies don't always match actual gas flows due to a phenomenon called displacement, in which contracted gas flows in opposite directions negate each other. On a contractual basis, between 53% and 68% of the gas on Northwest Pipeline comes from Canada.

Prices at key delivery points on Northwest Pipeline have a significant influence on natural gas flows. When Canadian prices are higher than domestic prices, as has been the case recently, shippers want to move natural gas north from the Rocky Mountain region to the Pacific Northwest. However, under certain conditions, the pipeline becomes constrained and contract demand must be met with gas flows from the other direction. When there is a significant disparity between the price of natural gas at different points in the system, this can require the use of operational flow orders, requiring certain shippers to flow gas in a particular direction, in order to achieve system balance. Such an order was called on Northwest Pipeline in November, 2000, with severe consequences for some market participants.

The GTN pipeline connects the region with gas supply in Alberta. The GTN system is unidirectional; gas flows southbound from its Kingsgate, British Columbia interconnection with TransCanada, enters Washington near Spokane, crosses into Oregon south of the Tri-Cities, and continues to the California-Oregon border near Malin, Oregon. The majority of gas transported on the GTN system is delivered to California, but additional demand in this region could be accommodated through expansion. GTN interconnects with the Northwest Pipeline near Stanfield, Spokane, and Palouse, Washington where gas is frequently exchanged between the pipelines.

GTN has been operating at or near capacity for a number of months. The northern part of the system has been operating at 90 - 100% of capacity, depending to some degree on supply basin pricing dynamics. The southern end of the system has been operating at virtually 100% capacity since summer, 2000.

While the existing pipelines are fully subscribed, each has the ability to expand its capacity. The first step is to announce an "open season" in which any shipper can request and commit to paying for additional capacity. The cost of additional capacity can be "rolled in" to rates paid by existing customers, or charged only to new shippers, known as "incremental" pricing. Pipeline expansion is regulated by the Federal Energy Regulatory Commission (FERC.)

Northwest Pipeline recently completed an open season for expansion from Sumas to Chehalis. This will allow additional daily flows of 224,000 decatherms (or 224 MDth) per day, enough to supply two 600 MW power plants. Northwest Pipeline has additional plans to fix an existing constraint in the Kemmerer, Wyoming region. Williams, parent company of Northwest Pipeline, and BC Hydro are planning a 90 MDth/day pipeline project from Sumas, Washington to Vancouver Island, called the Georgia Strait Crossing project.

GTN recently announced the results of a similar-sized open season, in which the winning bids were submitted by power generating companies. Interest was expressed in an additional 2,000 MDth/day of gas deliverability, roughly ten times the 200 MDth/day that was proposed. As a result, GTN is planning for an additional expansion targeting a 2003 in-service date.

Natural Gas Production

Canadian natural gas comes from fields in the far north of British Columbia and Alberta, a geologic area known as the Western Canadian Sedimentary Basin (WCSB). It is piped south either through British Columbia on a pipeline owned by Westcoast Energy, Inc., or through Alberta on a pipeline owned by TransCanada to Kingsgate. The past five years have been a period of soaring activity in the Canadian gas industry. The number of wells drilled annually has more than doubled since 1995. However, increased drilling has not necessarily led to major increases in gas supply, as the size of the gas deposits now being developed is much smaller than in the past.

About half of U.S. reserves are in Texas, Louisiana, and in offshore wells in the Gulf of Mexico, and a quarter are in the Rocky Mountain states of New Mexico, Wyoming, and Colorado. After falling off during the 1990s, natural gas drilling in the U.S. has picked up dramatically over the past 18 months. The Rocky Mountain states are the most important source of domestic natural gas supply to the Pacific Northwest, but new supplies anywhere on the continent will increase supply available to the Northwest by displacing gas closer to the region.

One of the more promising new domestic source of natural gas is coal bed methane. Coal bed methane development could contribute significantly to meeting natural gas demand, but it is expensive and involves difficult environmental issues not present with conventional gas production.

Alaska's North Slope is potentially the largest source of new natural gas resources. A number of projects are under consideration that would bring Alaska gas to markets in Canada and the lower 48 states; competing pipeline projects would follow the McKenzie River or the Alaska-Canada Highway into northern British Columbia. New Canadian sources of natural gas include coal bed methane in the WCSB and so-called "Frontier" gas in the far north of Canada.

If the price of gas stays high enough for long enough, it may become economic to invest in large-scale facilities for importing liquefied natural gas (LNG). Increased imports of LNG in the short term are most likely to come from the Middle East, where vast natural gas reserves remain largely untapped, to the East Coast. Plans have recently been announced to explore bringing LNG to California from gas fields in Australia.

While new gas supplies are being located and developed continuously, production at existing wells continues to decline. Even if production from new supplies outpaces depletion of existing resources, the cost of new supplies may continue to rise. Diminishing reserves among traditional large-pool resources and higher costs of bringing large new sources of gas such as Canadian Frontier gas or Alaska gas to the lower 48 states may not be entirely offset by advancements in exploration and drilling technology and improvements in delivery infrastructure.

Conclusions and Recommendations for Further Study

It is increasingly apparent that wholesale electricity and natural gas prices are subject to extreme price volatility, and increasing convergence of the electricity and natural gas markets means that extreme events are likely to affect both markets simultaneously. This has a number of important implications:

- Electric utilities may wish to review resource plans in light of the newly understood risks. Utilities have a variety of tools at their disposal to protect against price volatility. Each carries a unique risk profile; choices made will reflect company risk tolerance. The state may wish to consider ways to encourage utilities to maintain diverse resource portfolios.

- The potential for simultaneous price spikes in electricity and natural gas markets suggests that ownership of gas-fired resources may not provide much of a price hedge. Utilities may wish to consider fixed cost resources such as wind generation or energy efficiency. The state may wish to consider ways to encourage additional investment in energy conservation and renewable resources as a hedge against volatile natural gas prices.

- Regulatory policies can have a major impact on company purchasing strategies. Purchased gas adjustment mechanisms allow natural gas utilities in Washington to pass the risk of market price volatility on to retail customers. The Washington Utilities and Transportation Commission (WUTC) may wish to review existing policies in light of new information about the extent of gas price volatility, to ensure that they continue to provide appropriate incentives for companies to make good resource management decisions and to protect consumers from bad ones.

- Retail energy rates that better reflect wholesale market conditions might encourage more conservation during times of tight supplies. Utilities and regulators should consider mechanisms that would encourage utilities and customers to better respond to market conditions by managing customer demand, while ensuring that customers retain the value of rate-based resources and are given the tools they need to respond to changing rates.

New natural gas-fired power plants will greatly increase the region's demand for gas, even if only a portion of planned projects are actually constructed. The state may wish to:

- Consider addressing as part of the energy facility siting process the potential cumulative impacts of all approved power plants on regional natural gas supply. A study of these impacts, combined with a condition that plants begin construction within a specified period of time after approval, would ensure that cumulative impacts on all consumers of natural gas are well understood.

- Consider how new gas-fired generators will affect the region's ability to meet simultaneous peak demands on the electricity and natural gas systems. Requiring new generators to demonstrate sufficient pipeline or storage capacity for their peak needs, or allowing limited use of a backup fuel such as distillate oil or liquefied natural gas, would help to alleviate pressure on both systems.

- Consider policies that would encourage the direct use of natural gas at the customer location and improve the efficiency of existing uses of natural gas. These efforts would reduce the demand for gas-fired electric generation and provide for more efficient utilization of available natural gas resources.

Increased pipeline capacity from producing areas in Canada and the U.S. Rockies to markets in the Midwest and East Coast regions means that the price of natural gas for Northwest customers will be much more closely tied to continent-wide events than in the past. To prepare for this eventuality, the state may wish to:

- Examine projected natural gas supply and demand on a continent-wide basis, to determine the likelihood that increased demand in this and other regions can be met with additional supplies, and the effect this will have on competition for and prices of resources that have traditionally supplied the Northwest.

- Examine the potential for new sources of natural gas production in areas that will realistically meet future demands in the Northwest. This would include an examination of the economic, technical, and political state of development of new resources in the Rocky Mountain area (including coal bed methane), the Western Canadian Sedimentary Basin, the far North of Canada, and the Alaska North Slope, and an analysis of how gas from those areas may be delivered to this region.