EXECUTIVE SUMMARY

Imperial Oil Resources Ventures Limited, the Aboriginal Pipeline Group (APG), ConocoPhillips Canada (North) Limited, Shell Canada Limited, and ExxonMobil Canada Properties (collectively, the Mackenzie Valley Pipeline Co-Venturers) are proposing to construct a large-diameter, high-pressure natural gas transmission pipeline extending approximately 1,400 kilometers (870 miles) from the northwestern corner of the Northwest Territories (NWT) to a proposed interconnection with the intra-Alberta gas transmission system at the Alberta-NWT boundary. The objective of the Mackenzie Valley Pipeline (Mackenzie Pipeline, or Pipeline) is to connect the large resources of natural gas located in the Mackenzie Delta region with the growing gas consuming markets of Alberta, Central and Eastern Canada, and the United States.

As part of the project, the Mackenzie Valley Pipeline Co-Venturers commissioned the team of Navigant Consulting, Inc. (NCI) and Energy and Environmental Analysis, Inc. (EEA) (collectively, the NCI-EEA Team) to prepare an assessment of the long-term market need for natural gas produced from the Mackenzie Delta region. The NCI-EEA Team was also asked to investigate the adequacy of the existing intra-Alberta and export gas pipeline infrastructure to receive and takeaway gas that would be delivered to Alberta by the Mackenzie Valley Pipeline.

This report presents the findings and conclusions of the gas demand, supply and infrastructure analysis prepared by the NCI-EEA Team. The analysis considered a Base Case and three Sensitivity Cases incorporating alternative assumptions concerning the initial capacity of the Mackenzie Pipeline, potential expansion of the Pipeline's capacity, alternative levels of gas demand in Canada and the United States, and the potential commencement of operation of a pipeline delivering Alaskan gas to markets in Canada and the U.S. Lower 48 states. Taken together, the scenarios bracket the range of market conditions likely to exist during the first two decades of Mackenzie Pipeline operations. Analysis of the Sensitivity Case results underscores the robustness of the Study's basic conclusions regarding the need for the incremental gas supplies transported by the Pipeline.

Key Findings and Conclusions

The overall conclusion of this Report is that Canadian and U.S. gas markets support construction of the proposed 34.0 million cubic metre per day (Mm^{3}d) or 1.2 billion cubic feet per day (Bcfd) Mackenzie Pipeline in the 2009 timeframe and possible expansion of the Pipeline's capacity in 2015 and 2020. Further, the analysis indicates that there will be sufficient capacity on the intra-Alberta gas transmission system, and on the pipelines with takeaway capacity from the Western Canada Sedimentary Basin (WCSB), to accommodate the projected deliveries of Mackenzie Delta gas.

During the study period, the outlook is for steady increases in residential and commercial gas consumption, robust growth in gas demand for electric power generation, and a large increase in gas usage for bitumen extraction, processing, and related cogeneration in the Alberta oil sands industry. As a result of these trends, by the first full year of Mackenzie Pipeline deliveries, in 2010, natural gas demand in Canada and the U.S. Lower 48 is projected to be 313.4 Mm^3d (11.1 Bcfd) or 16% greater than in 2002 (See Table ES-1).

The growth in demand is expected to outstrip gas production in traditional producing basins by a widening margin, including frontier gas resources and liquefied natural gas (LNG). By bringing a large incremental supply of gas to the marketplace, the Mackenzie Pipeline will help fill the growing supply shortfall.

The fundamental conclusions of the study are consistent in all the scenarios examined in the analysis, further indicating the importance of the Mackenzie Pipeline in meeting future gas requirements in Canada and the U.S. Lower 48.

Table ES-1 summarizes the major findings of the analysis for the Base Case and the three Sensitivity Cases. The specific findings of the Base Case and the Sensitivity Cases regarding gas demand and supply, and intra-Alberta pipeline infrastructure and takeaway capacity, are summarized in the following pages.

Table ES-1
Summary of Key Study Results

	Base Case	Expans. Case	Low Demand Case	Alaskan Pipeline Case	Base Case	Expans. Case	Low Demand Case	Alaskan Pipeline Case
	Mm^3d				Bcfd			
Start of Mackenzie Pipeline	Q4 2009	Same as Base Case			Q4 2009	Same as Base Case		
Initial Capacity	34.0	"			1.2	"		
Expansion No. 1	NA	2015	NA	NA	NA	2015	NA	NA
Expanded Capacity	NA	42.5	NA	NA	NA	1.5	NA	NA
Expansion No. 2	NA	2020	NA	NA	NA	2020	NA	NA
Expanded Capacity	NA	51.0	NA	NA	NA	1.8	NA	NA
Start of Alaskan Pipeline	NA	NA	NA	2013	NA	NA	NA	2013
Initial Capacity	NA	NA	NA	70.8	NA	NA	NA	2.5
Expansion Date	NA	NA	NA	2014	NA	NA	NA	2014
Expanded Capacity	NA	NA	NA	113.3	NA	NA	NA	4.0
Cdn. Real GDP Growth, % p.a.	2.6	2.6	2.1	2.6	2.6	2.6	2.1	2.6
U.S. Real GDP Growth, p.a.	2.8	2.8	2.3	2.8	2.8	2.8	2.3	2.8
Canadian and U.S. Lower 48 Gas Demand								
2002	1,938.7	1,938.7	1,938.7	1,938.7	68.4	68.4	68.4	68.4
2010	2,252.1	2,252.1	2,254.7	2,252.1	79.5	79.5	79.6	79.5
2015	2,501.4	2,501.4	2,385.0	2,495.8	88.3	88.3	84.2	88.1
2020	2,684.1	2,688.4	2,539.4	2,660.1	94.7	94.9	89.6	93.9
2030	2,808.4	2,821.5	2,571.1	2,784.7	99.1	99.6	90.8	98.3
Canadian and U.S. Lower 48 Gas Production								
2002	1,918.2	1,918.2	1,918.2	1,918.2	67.7	67.7	67.7	67.7
2010	2,099.0	2,099.2	2,076.5	2,099.2	74.1	74.1	73.3	74.1
2015	2,175.4	2,175.6	2,158.6	2,155.8	76.8	76.8	76.2	76.1
2020	2,179.2	2,187.0	2,164.3	2,164.3	76.9	77.2	76.4	76.4
2030	2,076.1	2,087.8	2,025.5	2,068.0	73.3	73.7	71.5	73.0
U.S. Lower 48 LNG Imports								
2002	17.0	17.0	17.0	17.0	0.6	0.6	0.6	0.6
2010	201.1	201.1	187.0	201.1	7.1	7.1	6.6	7.1
2015	379.6	379.6	235.1	266.3	13.4	13.4	8.3	9.4
2020	541.1	541.1	368.3	427.8	19.1	19.1	13.0	15.1
2030	759.2	759.2	526.9	645.9	26.8	26.8	18.6	22.8
Gas Exports from WCSB								
2002	351.0	351.0	351.0	351.0	12.4	12.4	12.4	12.4
2010	367.1	367.4	364.0	367.1	13.0	13.0	12.9	13.0
2015	361.8	362.9	363.2	455.0	12.8	12.8	12.8	16.1
2020	336.0	342.2	346.2	424.9	11.9	12.1	12.2	15.0
2030	270.5	285.0	297.2	364.9	9.6	10.1	10.5	12.9
WCSB Export Pipeline Capacity								
2002	421.0	421.0	421.0	421.0	14.9	14.9	14.9	14.9
2010	435.4	435.4	435.4	435.4	15.4	15.4	15.4	15.4
2015	435.4	435.4	435.4	520.4	15.4	15.4	15.4	18.4
2020	435.4	435.4	435.4	520.4	15.4	15.4	15.4	18.4
2030	435.4	435.4	435.4	520.4	15.4	15.4	15.4	18.4

Mackenzie Base Case

Gas Demand Outlook

From 2002 to 2010, the first full year of operation of the Mackenzie Pipeline, total gas demand in Canada and the U.S. Lower 48 is projected to grow by 313.4 Mm^3d (11.1 Bcfd) or 16%, including increases of 52.3 Mm^3d (1.8 Bcfd) or 21% in Canada and 261.1 Mm^3d (9.2 Bcfd) or 15% in the United States Lower 48. From 2010 through 2030, gas demand in Canada and the U.S. Lower 48 is projected to expand by an additional 556.3 Mm^3d (19.6 Bcfd) or 25%, with growth of 100.3 Mm^3d (3.5 Bcfd) or 34% in Canada and 456.0 Mm^3d (16.1 Bcfd) or 23% in the U.S. Lower 48. The projected growth in gas demand will create a significant need for the incremental gas supplies delivered by the Mackenzie Pipeline during the initial 21 years of its operations (to 2030). Even if demand growth is less than projected, the need for a pipeline to access Mackenzie Delta resources remains underpinned by the anticipated decline in gas supplies.

Within Canada, Alberta will be the fastest-growing gas market during the forecast period. The major growth markets in the province will be the extraction and processing of bitumen in the Alberta oil sands, and electric power generation. During the 2003-2030 period, gas consumption by the Alberta oil sands bitumen production industry (excluding cogeneration requirements) is projected to nearly quadruple from 14.5 Mm^3d (0.5 Bcfd) to 55.0 Mm^3d (1.9 Bcfd). In the same period, power generation requirements in Alberta are projected to grow 2.8-fold from 11.5 Mm^3d (0.4 Bcfd) to nearly 31.0 Mm^3d (1.1 Bcfd).[1] Spurred also by growth in power generation, moderate increases in gas demand are also projected in Ontario, British Columbia, and Quebec, where combined gas consumption is expected to be 77.9 Mm^3d (2.7 Bcfd) or 62% greater in 2030 than in 2002.

Power generation requirements are also the major driver of increases in U.S. gas demand, particularly in the near and medium term. By 2006, the United States is projected to add 236,000 MW of gas-fired combined cycle and combustion turbine capacity, more than doubling gas usage for power generation in the Lower 48 from 332.9 Mm^3d (11.8 Bcfd) in 2002 to 674.6 Mm^3d (23.8 Bcfd) by 2015. Thereafter, power generation gas use is projected to level off because of technological advances pertaining to coal combustion and utilization of renewable energy sources as well as an increasing cost advantage in favour of coal as the real price of coal continues to decline. U.S. industrial gas consumption follows an opposite pattern, with the 2002 level not being regained until about 2018 followed by a resumption of growth in the latter years of the forecast. Residential and commercial demand is projected to grow steadily throughout the forecast period.

[1] Includes oil sands cogeneration facilities.

In the key U.S. regional markets that account for virtually all of Canada's gas exports, the Pacific Northwest, California, and the Midwestern and Northeastern United States, gas demand is projected to grow significantly throughout the forecast period. As a result, these regions could absorb substantially greater quantities of Canadian gas in the years ahead if supplies are available. From 2003 to 2010, total gas demand in these four U.S. regions is anticipated to increase by 156.5 Mm^3d (5.5 Bcfd) or 21%, with a further increase of 226.1 Mm^3d (8.0 Bcfd) or 25% expected by 2030.

Gas Supply Outlook

In contrast to the strong demand growth, gas production in Canada and the United States is projected to grow only moderately through 2030. In the Base Case, U.S. Lower 48 gas production is forecast to peak at 1,592.1 Mm^3d (56.2 Bcfd) in 2020 and Canadian production is expected to peak at 592.1 Mm^3d (20.9 Bcfd) in 2016. Combined Canadian and U.S. Lower 48 gas production is expected to peak at 2181.3 Mm^3d (77.0 Bcfd) in 2016, an increase of 263.5 Mm^3d (9.3 Bcfd) or 14% over the 2002 level.

The underlying factor behind the weakening supply response is the long-term decline in the productive capacity of the mature producing regions along the U.S. Gulf Coast, in the Mid-continent, San Juan and Permian Basins, and in the WCSB where production is expected to fall throughout the forecast period or begin to decline. With the exception of the Rocky Mountains and the deepwater Gulf of Mexico, other regions are expected to show modest gains in production at best. The production declines in these regions reflect the decline in the quantity and quality of remaining producible gas reserves, increases in well decline rates, and lower initial productivities of newly connected wells – all of which are having a severe impact on deliverability in most regions.

Consequently, a much greater part of gas supply in the future will have to come from non-traditional sources of supply. In fact, the Study Base Case analysis indicates that a significant shift to currently untapped resources will take place over the next two decades. Gas supplies from new producing "frontiers" in the Mackenzie Delta, the Rocky Mountain Region, the deep-water area of the Gulf of Mexico, and the Eastern Canada offshore will constitute a growing and essential component of North America's gas supply. According to the Base Case results, 521.2 Mm^3d (18.4 Bcfd) or 23% of total Canadian and U.S. Lower-48 gas demand will be met by gas from these sources in 2010 compared with only 15% in 2002. By 2020, about 680.0 Mm^3d (24.0 Bcfd) or 25% of combined Canadian and Lower-48 demand is projected to be supplied by gas from these new frontier areas. At the same time, aggregate production from all other areas will decline and constitute a smaller share of total demand. In short, much of the growth of the gas market is likely to be sustained by development of currently untapped supplies from areas that are generally more remote from the consuming markets throughout North America.

In addition, significant LNG imports will be required to meet rising U.S. gas demand in the face of declining production in many of the gas supply regions of the U.S. and Canada. In the Base Case, import capacity at the four existing LNG terminals is projected to roughly double by 2007 and major new import terminals are expected to be built in the Gulf of Mexico, Baja California, southern Florida, and other regions. As a result, net imports of LNG are projected to expand to about 764.9 Mm^3d (27.0 Bcfd) by 2030, accounting for 31% of total gas consumption in the U.S. Lower 48.

Mackenzie Expansion Case

In this Sensitivity Case, the delivery capacity of the Mackenzie Pipeline is expanded to 42.5 Mm^3d (1.5 Bcfd) in November 2015 and 51.0 Mm^3d (1.8 Bcfd) in November 2020. The expansions are accomplished by adding infill compression to the Pipeline. For the purpose of the analysis the Pipeline's toll was assumed to be the same as in the Base Case. All other assumptions were also the same as in the Base Case. The Mackenzie expansions increase total Canadian gas supply by 1.4% in 2016 and 2.9% in 2021, while total supply in Canada and the U.S. Lower 48 increases by 0.4% and 0.8%, respectively.

NCI's analysis indicated that the increases in throughput on the WCSB export corridors compared with the Base Case would be quite small. For this reason no additions to WCSB export pipeline capacity (or pipeline tolls) would be required. Given the outlook for minimal growth in Alberta gas production for the next ten years followed by declining production, there would also likely be sufficient capacity on the TransCanada Alberta (NGTL) System to facilitate the increased flow of Mackenzie Delta gas that would occur in the Expansion Case. Consequently, no changes in the NGTL pipeline tolls are anticipated.

Low Gas Demand Case

In the Low Gas Demand Sensitivity Case, real GDP in both Canada and the United States is assumed to increase by 0.5 percentage points less each year than in the Base Case (and have a growth rate that is about 18% less). As a result, overall economic activity in Canada and U.S. is about 4% less than in the Base Case by 2010, 8% less by 2020, and 13% less by 2030. At the lower growth levels, total gas demand in Canada and the U.S. is projected to be 280.5 Mm^3d (9.9 Bcfd) or 10% lower than in the Base Case. Over 60% of the reduction occurs in the power generation sector and another 23% in the industrial sector. In response to the drop in demand, the overall volume of LNG imports declines. By 2030, LNG imports to the U.S. Lower 48 are projected to be 229.5 Mm^3d (8.1 Bcfd) or 30% less than in the Base Case. Gas production in Canada is expected to be from 8.5 Mm^3d to 11.3 Mm^3d (0.3 to 0.4 Bcfd) lower than in the Base Case, and U.S. gas production, less by 14.2 Mm^3d to 42.5 Mm^3d (0.5 to 1.5 Bcfd). The combination of reduced LNG imports and lower gas production brings gas supply into balance with demand in the Low Demand Case.

The Low Demand case analysis indicates that the Mackenzie Delta will still provide an important source of incremental gas supplies to Canadian and U.S. markets even if natural gas demand grows substantially less than expected in the Base Case. Despite lower economic growth, gas demand is still projected to increase substantially between 2002 and the start of the Mackenzie Pipeline in 2009. Gas production continues to expand at a lower rate than gas demand, and significant increases in "frontier gas supplies" are still required to balance supply and demand.

Given that demand growth is less robust than in the Base Case, one would expect that no reinforcements of either the NGTL System or the export pipelines taking gas from the WCSB would be required. In fact, the Low Demand Case analysis indicated that total export flows and flows on the various export corridors would be essentially the same as in the Base Case until about 2015. Thereafter, exports are slightly greater than in the Base Case because the reduction in WCSB demand exceeds the fall in production. In addition, investments in LNG facilities in the United States are less in this Case, increasing U.S. demand for imports of Canadian gas. According to the analysis, it is unlikely that NGTL tolls would be much different than in the Base Case.

Alaskan Pipeline Case

In this Case, an Alaskan pipeline is assumed to begin delivering 70.8 Mm^3d (2.5 Bcfd) of gas from the North Slope of Alaska to Alberta in January 2013, and to increase deliveries to 113.3 Mm^3d (4.0 Bcfd in 2014 through additional compression). As in the Base Case, a 34.0 Mm^3d (1.2 Bcfd) Mackenzie Pipeline begins operations in the fourth quarter of 2009. The Alaskan pipeline is assumed to follow the Southern or Alaskan Highway route to a terminus near Boundary Lake, Alberta, where the gas is delivered into the TransCanada, Alliance, and other pipeline systems. No dedicated facilities downstream of Boundary Lake are built as part of the Alaskan pipeline project.

The Alaskan Sensitivity analysis shows that the addition of a large Alaskan pipeline in the middle of the next decade does not alter the fundamental mismatch between the ever-increasing gas demand and weakening gas production growth observed in this Study. Moreover, while large in absolute terms, deliveries of Alaskan gas would represent less than a 5% increase in supply to the overall Canadian and U.S. Lower 48 gas market which is projected to require 2,494.9 Mm^3d (88.1 Bcfd) of gas in 2015 and 2,784.7 Mm^3d (98.3 Bcfd) in 2030.

In the Alaskan Case it was necessary to increase the WCSB takeaway capacity by 76.5 Mm^3d (2.7 Bcfd) in 2013 and by an additional 8.5 Mm^3d (0.3 Bcfd) in 2014. The increases were pro-rated across the existing export pipelines as follows: In 2013, 11.3 Mm^3d (0.4 Bcfd) of capacity is added on the Northwest Pipeline corridor, 8.5 Mm^3d (0.3 Bcfd) on Alliance, 17.0 Mm^3d (0.6 Bcfd) on Gas Transmission Northwest, and 39.7 Mm^3d (1.4 Bcfd) on the TransCanada Mainline. The capacity on Northern Border was increased by 8.5 Mm^3d (0.3 Bcfd) in 2014.

Whether or not such capacity additions would result in toll increases would depend on how the costs compare with the incremental revenues, with the latter being partly a function of market share. Because of the manner in which the additional takeaway capacity was allocated, the export pipelines' respective market shares remained approximately the same as in the Base Case. However, the large increase in capacity that was assumed to occur on the TransCanada Mainline allowed it to increase volumes at the expense of the other pipelines serving the U.S. Midwest. For this reason, TransCanada's capacity utilization rate improved more than that of the other transporters.

Intra-Alberta Infrastructure and Pipeline Takeaway Capacity

The Study also examined the implications of 34.0 Mm^3d (1.2 Bcfd) of Mackenzie Delta natural gas being delivered to Alberta commencing in 2009 for the intra-Alberta gas transportation system and WCSB takeaway capacity.

The current plan is to build the Mackenzie Pipeline to the Alberta-NWT boundary and depend upon TransCanada to extend the NGTL system north to connect with the Pipeline. Such an extension would require several enhancements to the NGTL System. For example, the system would need to be extended from its existing terminus at Bootis Hill to the Alberta/NWT boundary – a distance of 66 kilometers. Given the large incremental volume of gas from the Mackenzie Delta that would flow onto the NGTL system, and the short distance from Bootis Hill to the Alberta/NWT boundary, there would likely be a reduction in the NGTL tolls.

Once Mackenzie Delta volumes enter the NGTL System, they can be transported to intra-Alberta delivery points and to the Alberta border export points via the West and East Legs of the System. Via the West Leg, the gas could be transported south from Bootis Hill to numerous intra-Alberta delivery points and to British Columbia and Saskatchewan border export points. No capacity additions would be required because of the considerable spare capacity created when the Alliance Pipeline came into service.

Given that gas production is declining in eastern Alberta, and also because demand is increasing there due to the growth in oil sands bitumen processing requirements and other end uses, spare capacity on the NGTL System East Leg is also growing. It was assumed that NGTL would install new facilities during the next three to five years to more directly link the gas-producing areas in northwest Alberta with regions in eastern Alberta where gas demand is increasing. Mackenzie Delta volumes in excess of the gas requirements in these regions could flow into the East Leg of the system for transportation to additional intra-Alberta delivery points and to the major Alberta/Saskatchewan border export delivery points at Empress and McNeill.

To assess the potential impact of Mackenzie Delta gas flows on the takeaway capacity of the pipelines that remove western Canadian gas to markets in eastern Canada and the United States, the Study examined whether the existing transmission capacity will be adequate to deliver the projected flows of gas from Alberta and the WCSB region as a whole. With WCSB region gas demand increasing and production falling, gas exports from the WCSB could be expected to decline during the 2010-2020 period unless new supplies from northern Canada or Alaska are introduced to the region. Given the supply/demand analysis indicated that the potential drop in gas exports absent the Mackenzie Pipeline would be greater than the capacity of the proposed Pipeline, the Study concluded that no additions to takeaway capacity would be required to accommodate incremental gas exports made possible by the Mackenzie Pipeline in the Base Case scenario.

The stable flows along the WCSB gas export corridors indicated in the Base Case through 2010 confirm that no expansions to the takeaway capacities of pipelines receiving gas for export from the region will be required. Absent expansions, pipeline rate bases would tend to decline due to depreciation. In general, therefore, no increases in tolls are anticipated to result from the onset of Mackenzie Pipeline deliveries to Alberta. For this reason, the toll impacts of the Mackenzie Pipeline for shippers on the WCSB export pipelines are likely to be neutral or positive (i.e. reduction in tolls) during the first 21 years of the Pipeline's operation (to 2030).

Potential Risks and Uncertainties

Although the market environment for the proposed Mackenzie Pipeline is expected to be positive under the Base Case assumptions, development of the project is subject to risks and uncertainties to the Co-Venturers. Principal risks and uncertainties include:

- Slower development of heavy oil and oil sands production in Alberta, or greater use of coal for meeting projected fuel requirements, could reduce regional gas demand and hence the capacity to absorb Mackenzie Delta production.
- More rapid expansion of gas production in general could meet a larger share of future gas demand.
- Increased gas production in Alberta, which could occur if coalbed methane production grows more rapidly than assumed, especially if coupled with markedly slower growth in oil sands gas demand, could increase pipeline capacity utilization within Alberta and on the major export pipelines from Alberta to other markets. Higher utilization of existing capacity could reduce the amount of spare capacity available to deliver Mackenzie Delta production to major markets.
- Overbuilding of LNG capacity could lower gas prices and lessen the capacity of U.S. and Canadian markets to absorb Mackenzie Pipeline volumes.

- Increases in the price of gas relative to oil and coal could encourage more rapid development of lower cost energy supplies (e.g., coal), perhaps facilitated by technological breakthroughs.
- Changes in energy policy in Canada and the United States could promote alternative energy sources and thereby reduce the market's capacity to absorb Mackenzie Delta gas production. Particularly important initiatives include the renewed focus on nuclear power, the promotion of cleaner coal-combustion technologies, and renewable energy portfolio standards. If these initiatives are realized, gas-fired power generation could be lower than expected.

1 INTRODUCTION AND ORGANIZATION

The Mackenzie Pipeline Co-Venturers (Co-Venturers) are proposing to construct a large-diameter, high-pressure natural gas transmission pipeline to deliver the large resources of natural gas located in the Mackenzie Delta region of the Northwest Territories (NWT) to the growing gas consuming markets of Alberta, Central and Eastern Canada, and the United States. The Mackenzie Pipeline Project (Mackenzie Pipeline, or Pipeline) would extend approximately 1,400 km (870 miles) from the Mackenzie River Delta to an interconnection with the intra-Alberta gas transmission system of TransCanada Ltd. at the Alberta-NWT boundary. The pipeline is proposed to begin commercial operations in November 2009. The Mackenzie Pipeline would have an initial transmission capacity to Alberta of 34.0 Mm^3d (1.2 Bcfd), with the potential to increase capacity to 51.0 Mm^3d (1.8 Bcfd) through infill compression.

As part of the overall project, the Co-Venturers commissioned the team of Navigant Consulting, Inc. (NCI) and Energy and Environmental Analysis, Inc. (EEA) (collectively, the NCI-EEA Team) to prepare an assessment of the long-term market need for natural gas produced in the Mackenzie Delta region. The market assessment is intended to respond to the National Energy Board's (NEB, or Board) Filing Manual for Facilities Applications. As outlined in the Draft Filing Manual issued in December 2003, the gas market analysis provided in support of a proposed natural gas pipeline should provide sufficient information for the Board to determine that adequate markets exist for the incremental volumes that would be available to the marketplace as a result of the construction of the proposed pipeline. The market information is to include a description of the major downstream consuming markets, a discussion of potential competition to serve the markets from other pipelines and sources of natural gas, and a discussion of the physical capacity of downstream facilities to accept the incremental volumes of natural gas that would be delivered. This Study addresses each of these matters.

1.1 Scenarios Examined in the Study

The Study examines the impacts of the Mackenzie Pipeline under a Base Case and three Sensitivity Cases. Collectively, these scenarios bracket the range of market conditions and other factors reasonably expected to occur in the 2003-2030 period. The Base Case assumes that the Mackenzie Pipeline begins delivering 34.0 Mm^3d (1.2 Bcfd) of natural gas to Alberta in November 2009. For the purpose of the Base Case, the Mackenzie Pipeline is assumed to be the only transporter of northern frontier gas supplies to Canadian and U.S. markets in the 2003-2030 timeframe.

To test the impact of possible expansions of the Mackenzie Pipeline, a Mackenzie Pipeline Expansion Sensitivity Case was conducted assuming that the delivery capacity of the Pipeline to Alberta is increased to 42.5 Mm^3d (1.5 Bcfd) in November 2015 and to 51.0 Mm^3d (1.8 Bcfd) in November 2020. A Low Gas Demand Case was then examined to test the performance of the Pipeline if natural gas demand grows more slowly than in the Base Case. For the purpose of this Sensitivity Case, the reduction in gas demand is assumed to result from a slowdown in economic growth in Canada and the United States.

Finally, an Alaskan Pipeline Sensitivity Case was conducted assuming that an Alaskan Gas Pipeline begins delivering gas to Alberta in January 2013 with an initial capacity of 70.8 Mm^3d (2.5 Bcfd). In January 2014, the capacity of the Alaskan Pipeline is expanded to 113.3 Mm^3d (4.0 Bcfd). Together with the 34.0 Mm^3d (1.2 Bcfd) Mackenzie Pipeline, the total volume of northern frontier gas flowing into Alberta and downstream markets increases to 147.3 Mm^3d (5.2 Bcfd) in 2014 and remains at that level through the end of the forecast period in 2030. The Alaskan Pipeline Sensitivity Case yields insights into how natural gas supply and demand could be expected to respond to the simultaneous construction of both northern frontier gas pipelines.

1.2 Methodology

The gas demand/supply analysis presented in this Report was prepared using a combination of analytical tools and models. Given its importance to the absorption of Mackenzie Delta gas supplies, the forecast of gas demand for oil sands bitumen production activity in Alberta was projected by NCI based on a detailed review of the outlook for investment in bitumen surface mining and upgrading facilities, and the further development of in situ bitumen production capacity and related upgrading facilities during the forecast period. The review included development of appropriate gas use coefficients to apply to projections of bitumen production and upgrading, and estimates of how the coefficients and the volume of in situ production upgraded in Canada could change during the study period. The outcome of this analysis was a judgmental forecast of gas requirements in relation to Alberta oil sands bitumen production.

NCI also prepared forecasts of gas demand for electric power generation in Alberta, Ontario, British Columbia and Quebec by projecting electrical generation capacity by type of fuel and the amount of electricity demand likely to be met each year by gas-fired generation capacity. Essentially, gas demand for power generation becomes a function of the assumed amount of available gas-fired generation capacity, capacity utilization rates, and heat rates.

Other components of Canadian and U.S. gas demand were forecast econometrically by EEA based on historical relationships between gas demand and macroeconomic drivers, such as gross domestic product (GDP) and industrial production growth. On the supply side, EEA utilized its Hydrocarbon Supply Model (HSM) for the base projection of underlying long-term gas production and supply trends. The base projections of activity and deliverability from the HSM are modified in the market simulation analysis, based upon supply and demand conditions and upstream activity levels.

The resulting demand and supply forecasts were input into Energy and Environmental Analysis Inc.'s Gas Market Data and Forecasting System (GMDFS), a widely respected natural gas forecasting system with the capability to track and analyze the performance of North American natural gas markets on a monthly basis. At the heart of the system is a comprehensive gas transmission network that solves for natural gas supply and demand in the U.S., Canada, and northern Mexico. Specifically, the model solves for monthly natural gas production and demand, storage injections and withdrawals, pipeline flows, and location for a detailed natural gas pipeline network comprised of over 100 nodes (or market hubs). Results are available at the node level. In the power generation sector, the model solves for monthly U.S. electricity demand, power generation by type of fuel, generating capacity additions, and fuel use.

The model simulates monthly gas market performance to 2030, considering the impact of a wide range of variables, including: trends in the U.S. and Canadian resource base, technology, and regional deliverability trends; growth rates for economic drivers, such as GDP and industrial production for the U.S. and Canada; projected prices of crude oil and alternative fuels; power generating capacity by technology and fuel supply (coal, oil-gas steam, combustion turbine, and gas-fired combined cycle); 30-year normal weather and hydrological conditions; pipeline and storage expansions; LNG imports and exports; and other annual and seasonal factors.

1.3 Study Organization

This Report consists of an Executive Summary and seven sections. This Introduction comprises Section 1.

Section 2 presents the results of the Base Case market simulation from 2002 through 2030 (forecast period). In this section forecasts of natural gas demand and supply for Canada and the United States combined and for each nation separately are presented and discussed. The outlook for Canadian gas export flows is also examined.

Section 3 provides overviews of the eight regional markets that are expected to consume the bulk of the gas delivered by the Mackenzie Pipeline. The regions examined are: Alberta, Ontario, Quebec, the U.S. Pacific Northwest, California, and the Midwestern and Northeastern United States. British Columbia is also examined due to its importance in the overall gas supply picture for the U.S. Pacific Northwest.

Section 4 presents a detailed analysis of the outlook for gas supply and deliverability in Canada and the United States during the forecast period. Included are in depth reviews of trends in production, reserves, well productivity, and other factors in the major gas producing basins in Canada and the United States.

Section 5 assesses the adequacy of intra-Alberta gas transmission capacity and export pipelines to accommodate gas volumes from the Mackenzie Delta that will be delivered onto the TransCanada Alberta System at the Alberta/Northwest Territories boundary.

Section 6 presents the implications of the three Sensitivity Cases that were undertaken – the Mackenzie Expansion Case, a Low Gas Demand Sensitivity, and an Alaska Gas Pipeline Case -- for gas supply and demand and for intra-Alberta and WCSB takeaway capacity infrastructure. The discussion includes a review of the adequacy of WCSB export facilities to accommodate projected export flows from Western Canada.

The overall conclusions and observations from the Study are presented in Section 7.

Throughout this Report, gas demand, supply pipeline flows, and pipeline capacities in Canada and the United States are presented in million cubic metres per day (Mm^3d) and billion standard cubic feet per day (Bcfd). Note: the conversion factor used was 28.32861 million cubic metres of gas per billion cubic feet of gas.

2 BASE CASE ANALYSIS

This Section presents the results of the market simulation analysis conducted for the Base Case, which assumes that 34.0 Mm^3d (1.2 Bcfd) of Mackenzie Delta gas production begins flowing into Alberta in November 2009. The Mackenzie Pipeline's capacity remains at this level for the remainder of the forecast period.

The analysis is organized in five subsections. Section 2.1 summaries the key assumptions used in the Base Case. Section 2.2 discusses the outlook for gas demand in Canada and the U.S. Lower 48 States through 2030. Section 2.3 presents the outlook for gas supply in Canada and the U.S. Lower 48 based on the detailed analysis of reserves, production, and deliverability presented in Section 4. Section 2.4 discusses the balance between gas demand and supply in the Base Case. Section 2.5 analyzes Canadian export flows to downstream markets.

2.1 Key Assumptions

The principal drivers of natural gas demand growth in Canada and the United States during the forecast period will be economic growth and the growth of industrial production (including oil sands bitumen), growth in electricity demand, and oil and coal prices. The major assumptions used in the analysis are summarized in Table 2-1. In the Base Case, real gross domestic product (GDP) in Canada and the United States is projected to expand by 2.6% and 2.8% per year, respectively, throughout the 2003-2030 period. For Canada, the forecast reflects a moderate slowdown from the 3.1% annual growth recorded in the 1991-2002 period. The slowdown reflects a number of issues that could dampen the outlook for Canadian investment and spending, including uncertainties over the specific measures likely to be adopted to implement Canada's commitment under the Kyoto Accord and their potential impacts on economic growth. For the United States, the forecast assumes that economic recovery will continue to gain momentum in 2004 and beyond, spurred by a renewal of business investment in plants and equipment. The resulting rebound in employment is expected to strengthen consumer purchasing power and create the conditions required for sustainable economic growth in the United States.

The Base Case assumes that real industrial output expands 2.4% and 2.8% annually in Canada and the United States, respectively. In Canada, the growth in industrial production is assumed to be slower than in the last 10 years owing to the same factors weighing on overall GDP growth. In the United States, the outlook reflects the convergence in the growth of industrial production and GDP observed in recent years.

Growth in electricity sales is a key driver in the forecast of gas demand for electric generation. Based on the above macroeconomic assumptions, electricity sales are projected to increase 1.9% per year in Canada and 1.8% per year in the United States.

Table 2-1
Key Assumptions for Base Case

	Annual % Change or Value
Real GDP Growth, % p.a.	
Canada	2.6%
United States	2.8%
Real Industrial Production, % p.a.	
Canada	2.4%
United States	2.8%
Electricity Sales	
Canada	1.9%
United States	1.8%
Real Oil Price (WTI), U.S. $ per Barrel	
2003 (end of year)	$24.00
2030 (average)	$20.00
Real Price of Coal, U.S. $ per MMBtu	
2003 (average)	$1.20
2030 (average)	$0.82

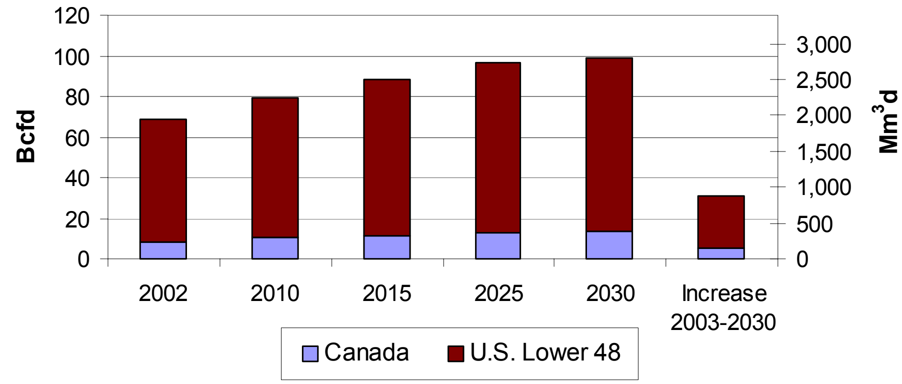
During the forecast period, the real benchmark price of West Texas Intermediate (WTI) crude oil at Cushing, OK is assumed to decline from $24 per barrel by the end of 2003 to $20 per barrel ($2003 U.S.) in 2030. The real price of coal is assumed to decline by 1.5% per year, from $1.24 per MMBtu in 2002 to $0.82 per MMBtu in 2030. The analysis also assumes an average inflation rate of 2.5% per year in Canada and the United States. Finally, the analysis assumes 30-year normal temperature and weather conditions, no major market distortions or natural disasters, epidemics, or other disturbances.

2.2 Canada and U.S. Gas Demand Outlook

Under the Base Case assumptions, gas demand in Canada and the U.S. Lower 48 States is projected to expand by 869.7 Mm^3d (30.7 Bcfd) or 45% from 1,938.7 Mm^3d (68.4 Bcfd) in 2002 to 2,808.4 Mm^3d (99.1 Bcfd) in 2030 (Figure 2-1). During this period, total gas consumption in Canada and the U.S. Lower 48 is projected to grow by an average of 1.3% per year. In Canada, total gas consumption is projected to expand from 242.4 Mm^3d (8.6 Bcfd) in 2002 to 395.0 Mm^3d (13.9 Bcfd) in 2030, an increase of 152.6 Mm^3d

(5.4 Bcfd). The major demand drivers in Canada will be the growth in gas consumption for electric power generation and the rapid increase in gas demand for oil sands bitumen extraction and processing in Alberta. In the U.S. Lower 48, gas demand is projected to expand from 1,696.3 Mm^3d (59.9 Bcfd) in 2002 to 2,413.4 Mm^3d (85.2 Bcfd) in 2030, an increase of 717.1 Mm^3d (25.3 Bcfd) or 42%, also reflecting robust growth in gas use for electric power generation during the first 15 years of the forecast period.

Figure 2-1
Forecast of Canadian and U.S. Lower 48 Gas Demand



By 2010, the first full year of operation of the Mackenzie Pipeline, gas demand in Canada and the U.S. Lower 48 is projected to be 313.4 Mm^3d (11.1) Bcfd or 16% higher than in 2002. During the following 20 years, Canadian and U.S. Lower 48 gas demand is projected to expand another 556.3 Mm^3d (19.6 Bcfd) or 25%. The substantial growth in Canadian and U.S. gas demand throughout the forecast period is an important indicator of the need for the incremental gas supplies accessed by the Mackenzie Pipeline.

Figure 2-2 and Table 2-2 illustrate the composition of forecast gas demand and demand growth in Canada and the U.S. Lower 48. Roughly half of the growth in gas demand during the forecast period is consumed by the power generation sector, followed by the industrial (17%), residential (17%), and commercial sectors (14%). Most of the growth in power generation demand occurs between 2003 and 2020. In the latter years of the forecast, especially after 2025, power generation gas demand in Canada and the U.S. actually declines owing to the increased competition from coal, oil and, to a lesser degree, renewable energy generation. The factors underlying these trends are discussed further below.

Figure 2-2
Forecast of Canadian and U.S. Lower 48 Gas Demand by Sector

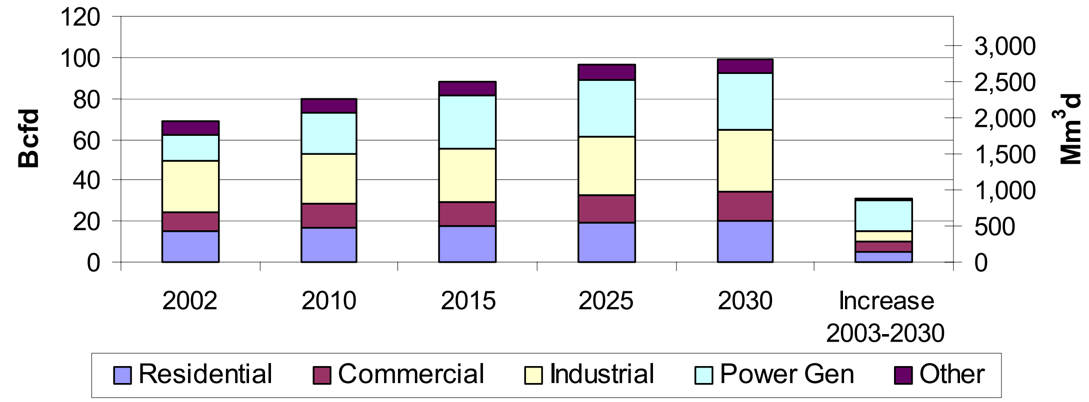
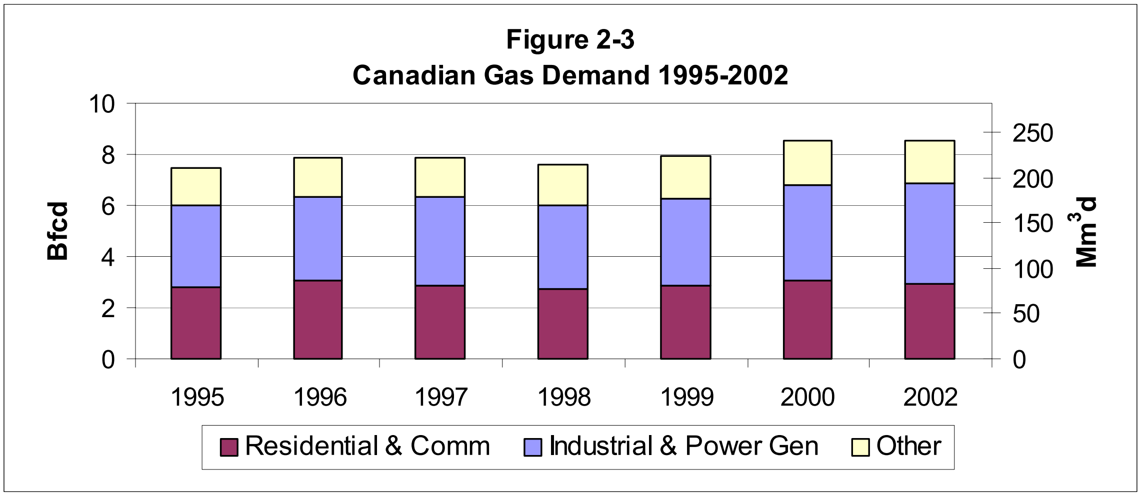


Table 2-2: Canadian and U.S. Lower 48 Gas Demand (Mm^3d and Bcfd)

						Increase (Mm^3d)			
Mm^3d	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
U.S. & Can. Total	1,938.66	2,252.06	2,501.41	2,731.39	2,808.40	313.39	249.35	229.98	77.01
Residential	421.38	485.08	504.58	549.42	573.18	63.70	19.50	44.84	23.76
Commercial	275.95	320.22	338.68	381.35	401.22	44.27	18.46	42.67	19.88
Industrial	704.57	696.45	728.56	800.90	854.36	-8.12	32.11	72.35	53.46
Power Generation	359.94	556.27	727.81	800.04	783.76	196.33	171.54	72.23	-16.29
Other	176.83	194.04	201.78	199.68	195.88	17.21	7.74	-2.10	-3.80
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
U.S. & Can. Total	68.43	79.50	88.30	96.42	99.14	11.06	8.80	8.12	2.72
Residential	14.87	17.12	17.81	19.39	20.23	2.25	0.69	1.58	0.84
Commercial	9.74	11.30	11.96	13.46	14.16	1.56	0.65	1.51	0.70
Industrial	24.87	24.58	25.72	28.27	30.16	-0.29	1.13	2.55	1.89
Power Generation	12.71	19.64	25.69	28.24	27.67	6.93	6.06	2.55	-0.57
Other	6.24	6.85	7.12	7.05	6.91	0.61	0.27	-0.07	-0.13

2.2.1 Canada Gas Demand Overview

In 2002, Canada consumed 242.4 Mm^3d (8.6 Bcfd) of natural gas, an increase of 28.3 Mm^3d (1.0 Bcfd) over 1995 (See Figure 2-3). From 1995 through 2002, gas demand grew at an average annual rate of 2.0% per year. The industrial and power generation sectors accounted for roughly three-quarters of the demand growth during this period, with the residential and commercial sectors providing most of the remainder.



The Base Case forecast of Canadian gas demand by end-use sector is provided in Table 2-3. Overall, gas demand in Canada is projected to expand an average of 1.8% per year from 242.4 Mm^3d (8.6 Bcfd) in 2002, to 395.0 Mm^3d (13.9 Bcfd) in 2030. The following sections discuss the underlying trends in the residential and commercial, industrial, and power generation demand that drive the forecast.

Table 2-3: Canadian Gas Demand (Mm^3d and Bcfd)

						Increase (Mm^3d)			
Mm^3d	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Canada Total	242.40	294.69	323.43	366.08	395.00	52.29	28.75	42.64	28.92
Residential	49.04	53.82	56.91	63.14	66.29	4.78	3.09	6.23	3.16
Commercial	33.64	37.11	39.28	43.75	46.00	3.46	2.17	4.47	2.26
Industrial	83.91	105.80	119.91	131.12	143.31	21.89	14.12	11.20	12.19
Power Generation	27.09	45.64	53.24	76.37	89.25	18.55	7.61	23.13	12.88
Other	48.73	52.33	54.09	51.70	50.14	3.61	1.76	-2.38	-1.56
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Canada Total	8.56	10.40	11.42	12.92	13.94	1.85	1.01	1.51	1.02
Residential	1.73	1.90	2.01	2.23	2.34	0.17	0.11	0.22	0.11
Commercial	1.19	1.31	1.39	1.54	1.62	0.12	0.08	0.16	0.08
Industrial	2.96	3.73	4.23	4.63	5.06	0.77	0.50	0.40	0.43
Power Generation	0.96	1.61	1.88	2.70	3.15	0.65	0.27	0.82	0.45
Other	1.72	1.85	1.91	1.83	1.77	0.13	0.06	-0.08	-0.06

Residential and Commercial Demand

During the 2003 to 2030 period, residential gas demand in Canada is forecast to grow at just under 1.1% per year, 0.3% per year higher than in the 1995-2002 period. By 2030, residential demand is projected to reach 66.3 Mm^3d (2.3 Bcfd), 35% higher than in 2002. Considerable variations in regional growth rates exist, reflecting differences in the percentage of homes that rely on natural gas for heating. Residential demand grows fastest in British Columbia (2.0% per year), Alberta (1.1%) and Ontario (1.1%) which, combined, account for nearly 86% of Canadian residential gas consumption. The estimates assume significant penetration of new, more efficient furnaces in the residential sector in response to the higher cost of gas. As a consequence, the rate of growth in residential gas consumption is lower than the growth in households and housing units in the individual Canadian provinces and is also lower than projected by other government and private forecasters.

Commercial gas demand in Canada is also projected to grow an average of 1.1% per year through 2030. Commercial demand is most influenced by economic growth, new construction, equipment retrofits and the penetration of onsite customer generation. As in the residential sector, the penetration of more efficient heating units partially offsets the effects of increased commercial floor space. Our forecast also anticipates relatively modest penetration of customer on-site electricity generation.

Industrial Demand

In the Base Case, industrial gas demand in Canada is projected to grow an average of 2.0% per year to 143.3 Mm^3d (5.1 Bcfd) in 2030, an increase of 59.4 Mm^3d (2.1 Bcfd) over 2002. As shown in Table 2-4, gas demand for bitumen extraction in Alberta is expected to account for a major share of the growth in Canadian industrial gas demand during the forecast period. As discussed in the Alberta regional analysis in Section 2.6, natural gas consumption for bitumen extraction and processing is projected to more than double from 14.5 Mm^3d (0.5 Bcfd) in 2002 to 31.7 Mm^3d (1.1 Bcfd) in 2010. During the following twenty years, oil sands thermal gas demand is projected to grow an additional 23.2 Mm^3d (0.8 Bcfd) to 55.0 Mm^3d (1.9 Bcfd) in 2030. As a result of these growth trends, the oil sands share of total industrial gas demand in Canada increases to 38% by 2030. These figures exclude gas consumption by cogeneration facilities built at oil sands bitumen production facilities, which is included in power generation gas demand.

Table 2-4: Composition of Canadian Industrial Gas Demand (Mm^3d and Bcfd)

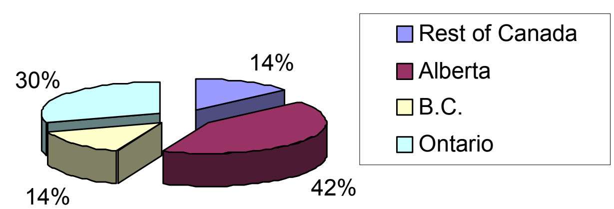
						Increase (Mm^3d)			
Mm^3d	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Canada Total	83.91	105.80	119.91	131.12	143.31	21.89	14.12	11.20	12.19
Alberta Oil Sands	14.45	31.73	35.98	47.59	54.96	17.28	4.25	11.61	7.37
Other Industrial	69.46	74.07	83.94	83.53	88.35	4.61	9.87	-0.41	4.82
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Canada Total	2.96	3.73	4.23	4.63	5.06	0.77	0.50	0.40	0.43
Alberta Oil Sands	0.51	1.12	1.27	1.68	1.94	0.61	0.15	0.41	0.26
Other Industrial	2.45	2.61	2.96	2.95	3.12	0.16	0.35	-0.01	0.17
% of Total									
Alberta Oil Sands	17%	30%	30%	36%	38%				
Other Industrial	83%	70%	70%	64%	62%				

Much of the remaining industrial gas demand in Canada is consumed by the manufacturing, agricultural, petrochemical, and mining industries. During the forecast period, other industrial gas demand in Canada is projected to grow 0.9% per year. The more energy-intensive industries, such as petrochemicals, cement, and others, are relatively price-sensitive and have experienced plant shutdowns and shifts in production to other countries as a result of the higher energy costs experienced in the last few years. This factor, combined with the growing share of high technology and service industries in Canadian industry, helps explain why growth in industrial gas demand is likely to be slower than the overall rise in industrial production in Canada.

Power Generation Demand

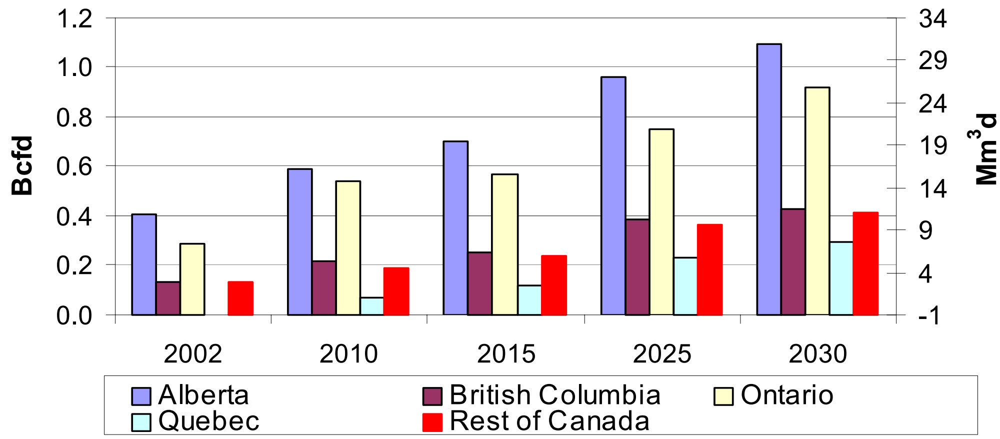
Figure 2-4 illustrates the regional composition of Canadian gas demand for power generation in 2002. Gas use for electric power generation, including cogeneration, will continue to be the fastest growing segment of the overall Canadian gas market. In the Base Case, gas demand for power generation in Canada is projected to increase by 18.6 Mm^3d (0.7 Bcfd), from 27.1 Mm^3d (1.0 Bcfd) in 2002 to 45.6 Mm^3d (1.6 Bcfd) in 2010. Electric generation demand continues to grow during the remainder of the forecast period, reaching 89.3 Mm^3d (3.2 Bcfd) in 2030, about double the 2010 amount.

Figure 2-4
Canadian Power Generation Gas Demand by Province in 2002



The growth of gas demand for power generation will vary by region reflecting population growth patterns, the age of the current generating stock, commitment to renewal energy sources, and economic conditions. Nonetheless, as shown in Figure 2-5 and Table 2-5, power generation gas demand is expected to at least triple in each of Canada's largest provinces and in the rest of Canada combined. As a result, the shares of the various provinces in total power generation gas demand will remain relatively constant over the forecast period.

Figure 2-5
Growth in Canadian Power Generation Gas Demand by Province



Within today's planning horizons, the lion's share of the anticipated new capacity is expected to be in gas-fired combustion turbines owing to cost and environmental advantages. However, beginning around 2015, we anticipate some shift in investment to occur from gas-fired to coal-burning facilities due to the widening gap between the relative cost of gas and coal and reductions in the cost of coal-fired power generation as a result of technology improvements.

Table 2-5: Canadian Power Generation Gas Demand by Province (Bcfd & Mm^3d)

						Increase (Mm^3d)			
Mm^3d	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Total Canada	27.09	45.64	53.24	76.37	89.25	18.55	7.61	23.13	12.88
Alberta	11.53	16.77	19.86	27.28	30.99	5.25	3.09	7.42	3.71
British Columbia	3.81	6.19	7.09	10.91	12.14	2.38	0.90	3.81	1.23
Ontario	8.06	15.31	16.10	21.35	26.04	7.26	0.78	5.26	4.69
Quebec	0.00	1.90	3.45	6.54	8.33	1.90	1.55	3.09	1.78
Subtotal	23.40	40.18	46.50	66.08	77.49	16.78	6.32	19.58	11.41
Rest of Canada	3.69	5.46	6.74	10.29	11.76	1.77	1.29	3.55	1.48
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Total Canada	0.96	1.61	1.88	2.70	3.15	0.65	0.27	0.82	0.45
Alberta	0.41	0.59	0.70	0.96	1.09	0.19	0.11	0.26	0.13
British Columbia	0.13	0.22	0.25	0.38	0.43	0.08	0.03	0.13	0.04
Ontario	0.28	0.54	0.57	0.75	0.92	0.26	0.03	0.19	0.17
Quebec	0.00	0.07	0.12	0.23	0.29	0.07	0.05	0.11	0.06
Subtotal	0.83	1.42	1.64	2.33	2.74	0.59	0.22	0.69	0.40
Rest of Canada	0.13	0.19	0.24	0.36	0.42	0.06	0.05	0.13	0.05

2.2.2 U.S. Gas Demand Overview

As indicated in Table 2-6, in 2002 U.S. Lower 48 gas demand averaged 1,696.3 Mm³d (59.9 Bcfd). In the Base Case, Lower 48 gas demand is projected to grow an average of just under 1.3% per year to reach 2,413.4 Mm³d (85.2 Bcfd) in 2030. Between 2002 and 2010, gas demand in the Lower 48 states is projected to expand by 261.1 Mm³d (9.2 Bcfd) or 15%, with an additional increase of 456.0 Mm³d (16.1 Bcfd) or 23% occurring by 2030.

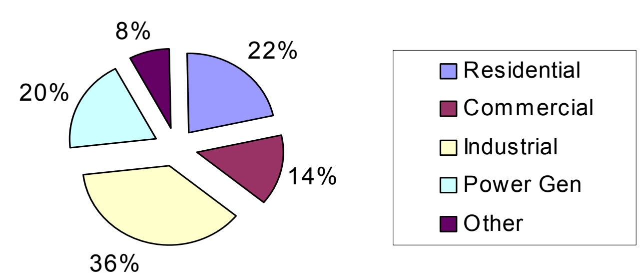
Table 2-6: U.S. Lower 48 Gas Demand (Mm³d and Bcfd)

						Increase (Mm³d)			
Mm³d	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
U.S. Total	1,696.26	1,957.37	2,177.97	2,365.31	2,413.40	261.11	220.60	187.34	48.09
Residential	372.34	431.26	447.67	486.28	506.88	58.92	16.41	38.61	20.60
Commercial	242.30	283.11	299.40	337.60	355.22	40.81	16.29	38.20	17.62
Industrial	620.66	590.65	608.64	669.79	711.05	-30.01	17.99	61.14	41.27
Power Generation	332.85	510.64	674.57	723.67	694.50	177.79	163.93	49.10	-29.17
Other	128.11	141.71	147.69	147.98	145.74	13.60	5.99	0.28	-2.23
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
U.S. Total	59.88	69.10	76.88	83.50	85.19	9.22	7.79	6.61	1.70
Residential	13.14	15.22	15.80	17.17	17.89	2.08	0.58	1.36	0.73
Commercial	8.55	9.99	10.57	11.92	12.54	1.44	0.58	1.35	0.62
Industrial	21.91	20.85	21.49	23.64	25.10	-1.06	0.63	2.16	1.46
Power Generation	11.75	18.03	23.81	25.55	24.52	6.28	5.79	1.73	-1.03
Other	4.52	5.00	5.21	5.22	5.14	0.48	0.21	0.01	-0.08

Residential and Commercial Demand

As indicated in Figure 2-6, residential consumption accounted for 22% of U.S. Lower 48 gas demand in 2002. Space and water heating account for over 90% of total residential gas use. According to the U.S. Energy Information Administration (EIA), new homes built today in the United States are an average of 18% larger than existing homes, with correspondingly greater needs for space heating and, to a lesser extent, water heating. However, owing to improvements in equipment efficiency and changes in building codes, energy use per square foot for new construction is typically lower. As a result, forecast growth in residential gas consumption remains on par with historical trends.

Figure 2-6
Composition of U.S. Lower 48 Gas Demand in 2002

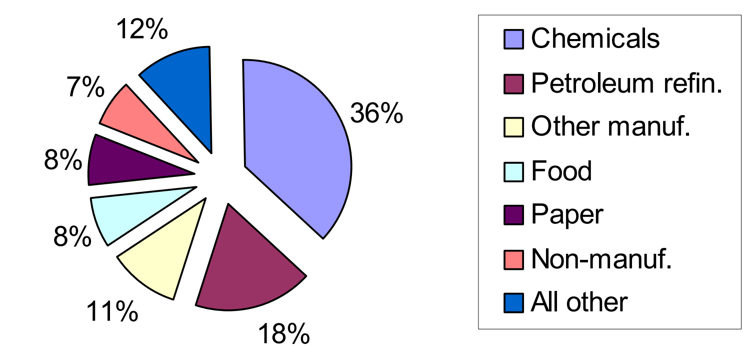


Commercial gas use in the U.S. Lower 48 averaged 242.3 Mm^3d (8.6 Bcfd) in 2002, representing 14% of total gas consumption in the Lower 48 States. Commercial gas demand is primarily driven by regional economic growth, new commercial construction, heating, ventilation and air conditioning (HVAC) equipment retrofits, and the introduction of customer on-site generation. As in the residential sector, changes in building standards and the penetration of new and more efficient furnaces are expected to dampen the growth in commercial gas consumption. In the Base Case, commercial demand is projected to increase 1.4% per year to 355.2 Mm^3d (12.5 Bcfd) in 2030, an increase of 112.9 Mm^3d (4.0 Bcfd) over 2002.

Industrial Demand

At 37% of current Lower 48 U.S. gas consumption, future trends in industrial gas consumption will have an important impact on the overall growth in U.S. gas demand. Since the late 1990s, the industrial sector in the United States has been buffeted by a series of forces, including domestic recession, collapse of the Asian economies, sluggish growth in Europe, and intense competition from foreign manufacturers. Adding to these pressures has been the recent sharp rise in natural gas prices, which has prompted such prominent officials as the Chairman of the U.S. Federal Reserve Board to express concerns over the long-term viability of a large portion of the U.S. industrial capital stock if natural gas prices were to continue to rise unabated.

Figure 2-7
Composition of U.S. Lower 48 Industrial Gas Demand in 2002



The analysis included a review of gas consumption by application (feedstock, boiler fuel, process heat, and other) for each of the major energy consuming industry sectors in the U.S. Lower 48 at the two-digit Standard Industrial Classification (SIC) level. The relative shares of the major industrial sectors in 2002 are shown in Figure 2-7. For each of the major applications, total gas consumption and the ratio of gas expenditures to total value added were examined. Based on the analysis, the risk of loss of existing gas demand to fuel switching, foreign competition, and process change was evaluated. The analysis concluded that certain energy-intensive industries, including ammonia, chlor-alkali, and iron and steel, are likely to experience a loss of existing gas demand. In many other industries, however, energy costs per unit of value added are less than 3% and other factors point to growth in gas demand at rates only slightly lower than output growth owing to technology efficiency improvements. The forecast of industrial demand in the U.S. Lower 48 presented in Table 2-7 reflects the balance of these trends.

Table 2-7: Forecast of U.S. Lower 48 Industrial Gas Demand (Mm³d and Bcfd)

						Increase (Mm³d)			
Mm³d	2002	2010	2015	2025	2030	2003-2010	2011-2015	2016-2025	2026-2030
Industrial Total	626.88	596.84	615.08	676.63	718.46	-30.04	18.24	61.55	41.83
Chemicals	232.45	210.25	215.22	236.33	251.15	-22.20	4.97	21.11	14.82
Petroleum refining	110.44	103.61	106.41	111.92	114.71	-6.83	2.79	5.51	2.79
Other manufacturing	66.75	66.98	72.10	88.87	101.83	0.23	5.12	16.76	12.96
Food	48.82	49.05	51.30	56.42	59.14	0.23	2.25	5.12	2.72
Paper	47.96	46.88	45.25	43.93	43.39	-1.09	-1.63	-1.32	-0.54
Non-manufacturing	46.18	48.59	51.92	59.76	64.19	2.41	3.34	7.84	4.42
Stone Clay, glass	29.26	32.91	36.56	45.02	50.53	3.65	3.65	8.46	5.51
Iron & steel	25.46	21.34	20.02	19.02	18.55	-4.11	-1.32	-1.01	-0.47
Other primary metals	12.81	11.64	11.72	11.64	11.56	-1.16	0.08	-0.08	-0.08
Primary aluminum	6.75	5.59	4.58	3.73	3.41	-1.16	-1.01	-0.85	-0.31
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Industrial Total	22.13	21.07	21.71	23.88	25.36	-1.06	0.64	2.17	1.48
Chemicals	8.21	7.42	7.60	8.34	8.87	-0.78	0.18	0.75	0.52
Petroleum refining	3.90	3.66	3.76	3.95	4.05	-0.24	0.10	0.19	0.10
Other manufacturing	2.36	2.36	2.55	3.14	3.59	0.01	0.18	0.59	0.46
Food	1.72	1.73	1.81	1.99	2.09	0.01	0.08	0.18	0.10
Paper	1.69	1.65	1.60	1.55	1.53	-0.04	-0.06	-0.05	-0.02
Non-manufacturing	1.63	1.72	1.83	2.11	2.27	0.08	0.12	0.28	0.16
Stone Clay, glass	1.03	1.16	1.29	1.59	1.78	0.13	0.13	0.30	0.19
Iron & steel	0.90	0.75	0.71	0.67	0.65	-0.15	-0.05	-0.04	-0.02
Other primary metals	0.45	0.41	0.41	0.41	0.41	-0.04	0.00	0.00	0.00
Primary aluminum	0.24	0.20	0.16	0.13	0.12	-0.04	-0.04	-0.03	-0.01

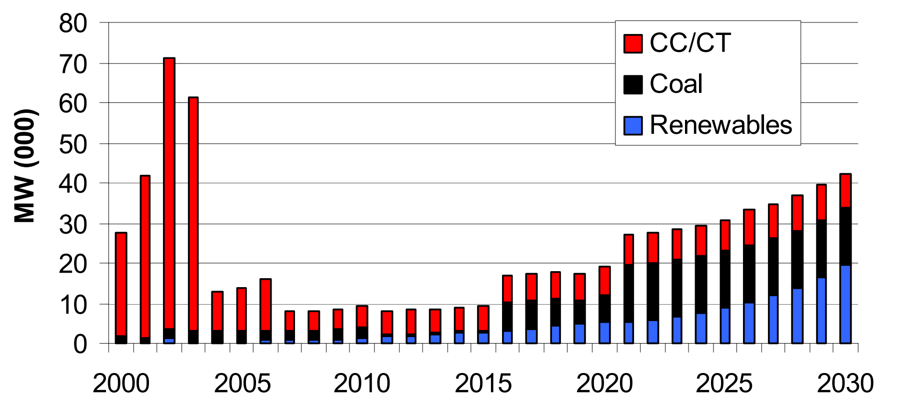
In the forecast, total U.S. Lower 48 industrial gas demand is expected to decline by 30.0 Mm³d (1.1 Bcfd) or about 5% between 2002 and 2010. Most of the reduction occurs in chemicals and petroleum refining. In the chemicals industry, gas usage as ammonia feedstock declines 40% from 34.0 Mm³d (1.2 Bcfd) in 2002 to 19.8 Mm³d (0.7 Bcfd) in 2010. Ammonia feedstock consumption falls further to 15.9 Mm³d (0.6 Bcfd) in 2030. Gas consumption by the chemicals industry remains flat through 2015 before resuming modest growth in the last 15 years of the forecast, mainly on the strength of increased gas use for boiler fuel and process heat applications. Gas consumption in the primary aluminum industry also falls steadily, although this sector accounts for a small share of total industrial gas consumption. In contrast, gas consumption is projected to expand in numerous other industrial sectors, including other manufacturing, food, stone, clay and glassware, and non-manufacturing. In these industries, gas expenditures as a percentage of value added is relatively low and consequently firms experiencing favorable business conditions are able to grow in spite of higher input costs.

Power Generation Demand

The forecast of gas demand for power generation was developed in several steps. First, growth in U.S. electricity consumption was forecast based on the expected growth in population, GDP, and industrial production in each of the full-state National Electric Reliability Council (NERC) regions in the United States. Next, the amount of new generating capacity required to meet demand and maintain prudent reserve margins was estimated. Based on assumptions about the age of the current generating stock, nuclear and hydroelectric license renewals,[2] the relative prices of coal, natural gas, and fuel oil, trends in environmental policies, and related variables, the projected increase in generating capacity by type of capacity and fuel type is calculated. Finally, based on assumptions about plant operating rates, which are significantly influenced by fuel costs, the fuel requirements of each type of generating unit are projected.

Under the macroeconomic assumptions of the Base Case, electricity consumption and peak demand in the U.S. Lower 48 are both projected to grow an average of 1.9% per year during 2003-2030. To meet the projected increase in peak demand, total electric generating capacity in the U.S. Lower 48 is projected to grow by 468,090 MW from 865,000 MW in 2002 to 1,333,900 MW in 2030. Continuing the trend of recent years, gas-fired combined cycle (CC) and combustion turbines (CT) units are projected to provide virtually all of the increase in generating capacity between 2002 and 2006 (see Figure 2-8). During this period, CC/CT capacity additions average nearly 32,000 MW per year, resulting in a total increase in CC/CT capacity of 236,000 MW by 2006. After 2006, the amount of new CC/CT generating capacity added each year slows sharply due to surplus capacity built during the period of rapid expansion. As a result of these factors, the annual increase in CC/CT capacity averages only 5,500 MW per year from 2007 through 2015. This is equivalent to the construction of only about ten 550 MW plants per year throughout the entire United States.

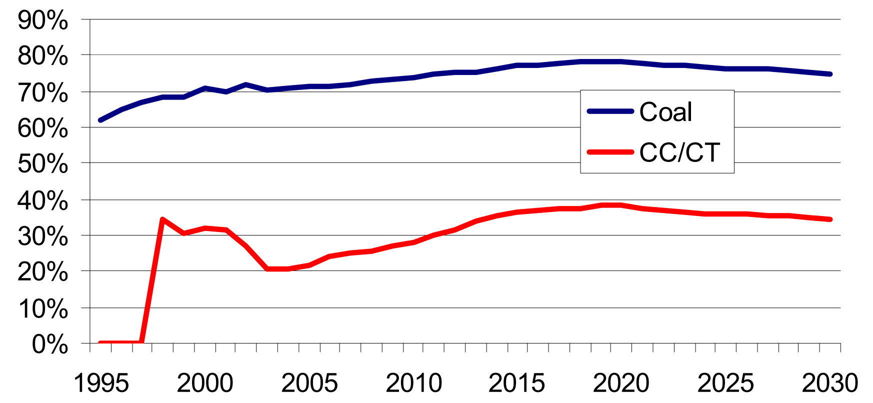
Figure 2-8
U.S. Capacity Additions by Type



[2] The analysis assumes that all existing nuclear generating units in Canada and the United States are granted extensions of their operating licenses before the current licenses expire.

After 2015, CC/CT capacity additions increase modestly. During this period, however, the growth in CC/CT capacity is surpassed by projected increases in coal-fired and renewable generating capacity (wind, solar, other). The growth in renewable generation is particularly strong, averaging 8,500 MW per year in the 2016-2030 period, a ten-fold increase over 2002-2006. After 2015, the U.S. also begins to see large increases in coal-fired generation, reflecting improvements in coal technology as well as increased competitiveness of coal generation because of further declines in the real price of coal. This is reflected in the decline in capacity utilization rates of CC/CT units after 2020 and the increase in coal utilization over the forecast period (Figure 2-9).

Figure 2-9
Capacity Utilization Rates in the U.S.



The impact of the above trends on U.S. electric generation (supply) is shown in Figure 2-10. Owing to the boom in merchant power development, gas-fired CC/CTs gained market share rapidly in the late 1990s and early 2000s, mainly at the expense of coal generation. However, after about 2015 coal generation makes a comeback as a result of the factors noted above. During the latter years of the forecast, the share of renewable generation begins to expand, while remaining a relatively small share of the overall U.S. electricity supply.

Figure 2-10
U.S. Electricity Generation by Type

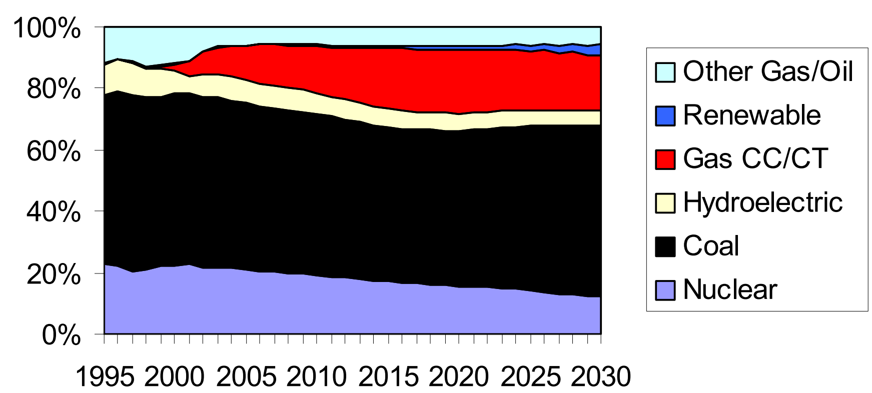
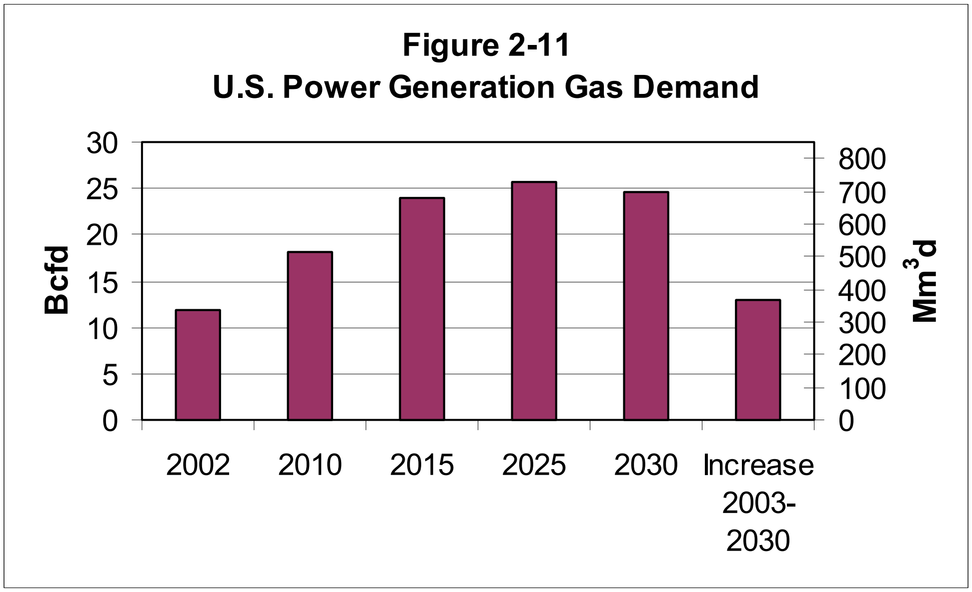
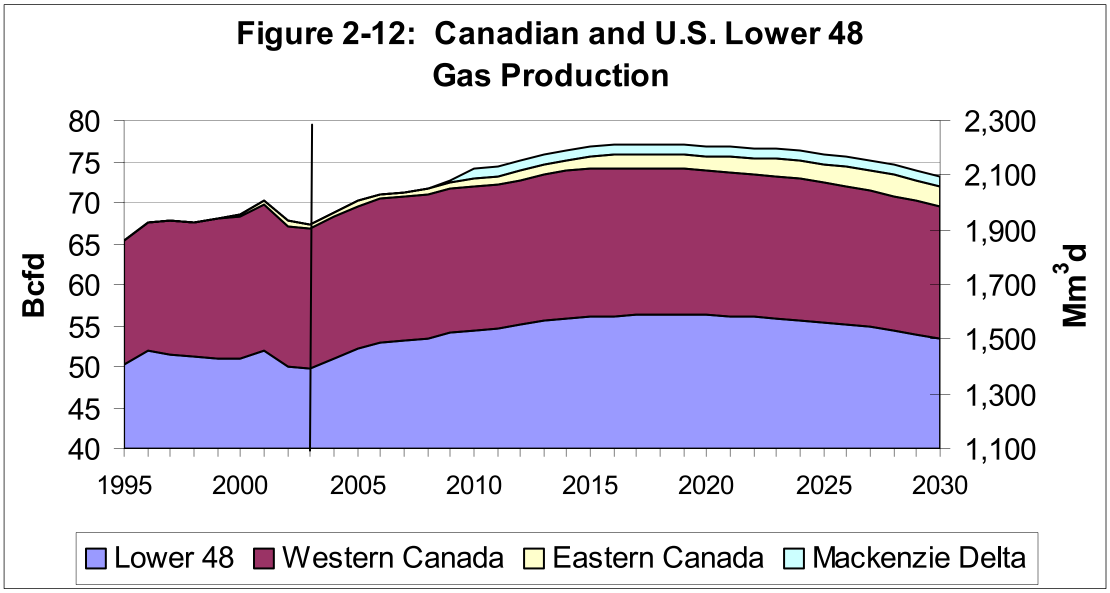


Figure 2-11 presents the forecast of gas demand for power generation resulting from the above analysis. As shown in the figure, power generation demand in the United States is projected to more than double from nearly 340 Mm^3d (12 Bcfd) in 2002 to almost 737 Mm^3d (26 Bcfd) in 2025. Thereafter, demand slips as coal and renewable generation supply increasing amounts of power to U.S. electricity consumers.



2.3 Gas Supply Outlook

This section summarizes the conclusions of the detailed analysis of production and deliverability provided in Section 4 of this report. Figure 2-12 presents the forecast of total gas production in Canada and the United States in the Base Case. The forecast projects a substantial decline in conventional gas production in Canada and the U.S. Lower 48 that is only partially offset by incremental deliveries of gas from the Mackenzie Delta. The forecast reflects an assessment that as existing natural gas supplies mature, production in these regions will undergo a long-term decline. Consequently, production must increase in unconventional and frontier areas to offset the declines in existing resources.



In the Base Case, production from existing supply sources in the U.S. Lower 48 (including Onshore Gulf of Mexico, Gulf Shelf, Gulf Slope, the Anadarko, Permian, and San Juan Basins, Opal Area, DJ Basin, Wind River Basin, Powder River Basin) is expected to struggle simply to remain constant. During the forecast period, significant declines in output are expected in the Gulf of Mexico shelf, the Mid-Continent, and the San Juan and Permian Basins. By 2020, production from these areas is expected to fall 141.6 Mm^3d (5.0 Bcfd) or 25% below 2002 levels. By 2030, production is expected to be 215.3 Mm^3d (7.6 Bcfd) or 37% lower than in 2002. With the exception of the Rocky Mountains and the deepwater Gulf of Mexico, other regions will show slight gains in production at best.

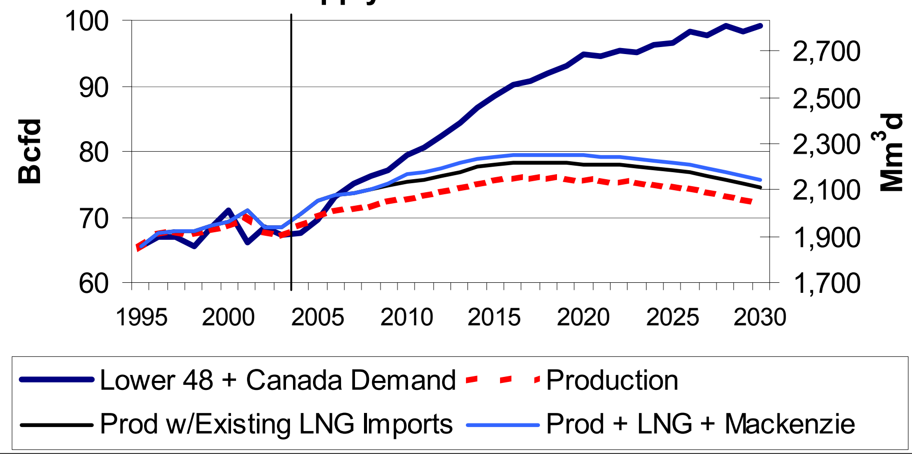
The declines in production from existing supply sources are mainly due to the lack of quality drilling prospects in these areas. As a result, a much greater share of future gas supply will need to come from non-traditional sources of supply. In addition to the Mackenzie Delta, the "new frontier" supplies include continued development of deepwater gas in the Gulf of Mexico, conventional and unconventional gas from the Rocky Mountains, significant development of Eastern Canada offshore gas, and LNG imports. In the Base Case, supply from new producing frontiers is projected to account for nearly one-third of North America's gas supply by 2010, and nearly one-half of the total by 2020. By contrast, supply from "traditional" sources is projected to decline from about 1,615 Mm^3d (57 Bcfd) today to less than 1,558 Mm^3d (55 Bcfd) by 2020, as production from mature basins continues to decline. Hence, much of the growth of the gas market over the next 30 years is likely to be sustained by development of currently untapped supplies from areas that are generally more remote from the consuming markets throughout North America.

2.4 Canada and U.S. Lower 48 Demand/Supply Balance

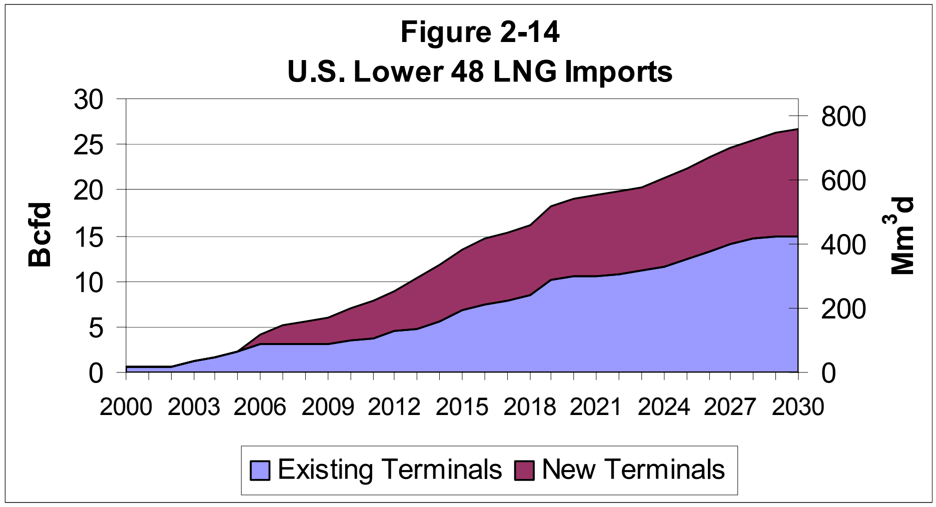
Figure 2-13 compares the forecast of gas demand in Canada and the U.S. Lower 48 with the production outlook discussed above. The dark blue line at the top of the graph plots the forecast of total gas demand in both nations while the dashed red line shows the forecast of domestic gas production. The black line shows domestic production plus net imports of LNG from the four existing U.S. import terminals (Everett, MA; Cove Point, MD; Elba Island, GA; Lake Charles, LA). With the resumption of imports by Cove Point, these existing terminals have a combined baseload import capacity of about 68.0 Mm^3d (2.4 Bcfd). The light blue line shows production plus existing LNG import capacity plus deliveries from the Mackenzie Pipeline beginning in late 2009.

In the past, domestic gas production has essentially matched total gas demand in Canada and the United States. In the Base Case, both nations are projected to be "self-sufficient" in natural gas through 2005. Beginning in 2006, however, domestic production in Canada and the U.S. is projected to fall short of demand by an increasing amount. From about 56.7 Mm^3d (2.0 Bcfd) in 2006, the shortfall between domestic production and demand is projected to grow to 187.0 Mm^3d (6.6 Bcfd) in 2010, 359.8 Mm^3d (12.7 Bcfd) in 2015 and 538.2 Mm^3d (19.0 Bcfd) in 2020. Increased LNG imports from the four existing U.S. import terminals do not significantly change this situation, delaying the point at which demand outstrips supply by only one year, to 2007. Mackenzie Delta volumes also provide an important and welcome addition to North American gas supply, but even with its full deliveries of 34.0 Mm^3d (1.2 Bcfd) in 2010, demand in Canada and the U.S. Lower 48 still exceeds supply by 85.0 Mm^3d (3.0 Bcfd). The shortfall is projected to grow to 257.8 Mm^3d (9.1 Bcfd) in 2015, 436.2 Mm^3d (15.4 Bcfd) in 2020 and 665.7 Mm^3d (23.5 Bcfd) in 2030. The ability of Canadian and U.S. markets to fully absorb Mackenzie Pipeline deliveries testifies to the strong need for the incremental gas supplies delivered by the Mackenzie Pipeline.

Figure 2-13: Canada and U.S. Lower 48 Gas Supply/Demand Balance

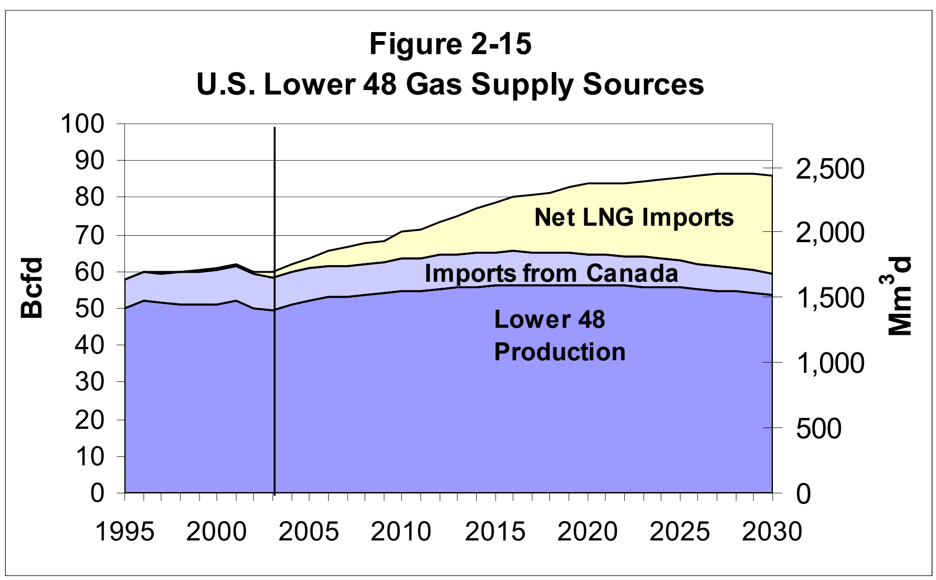


In the Base Case, the gap between supply and demand is projected to be filled by increased LNG imports, requiring both expansions of existing terminal capacity and construction of substantial new LNG import facilities in the middle and later years of the forecast. In the Base Case, net imports of LNG are projected to rise steadily to an average of 201.1 Mm³d (7.1 Bcfd) in 2010, 538.2 Mm³d (19 Bcfd) in 2020, and 764.9 Mm³d (27.0 Bcfd) in 2030 (see Figure 2-14). As a result, the share of U.S. Lower 48 gas demand provided by LNG increases rapidly. By 2030, net LNG imports are projected to account for 31% of total Lower 48 gas consumption, compared with 1% in 2002.



2.5 Canadian Exports to U.S. Lower 48

The projected leveling off of Canadian gas production, coupled with the increase in gas demand in Alberta and other Canadian provinces, results in a decline in the volume of Canadian gas available for export to the U.S. Lower 48 in the Base Case (see Figure 2-15). From a peak of 266.3 Mm³d (9.4 Bcfd) in 2002, U.S. Lower 48 net imports of gas from Canada are projected to fall to 235.1 Mm³d (8.3 Bcfd) in 2008. Net imports rebound after 2009 as deliveries of Mackenzie Delta supplies plus increased CBM production augment total Canadian gas supplies. However, net imports into the U.S. Lower 48 from Canada resume their steady decline in 2018, falling to 235.1 Mm³d (8.3 Bcfd) in 2020 and 167.1 Mm³d (5.9 Bcfd) in 2030.



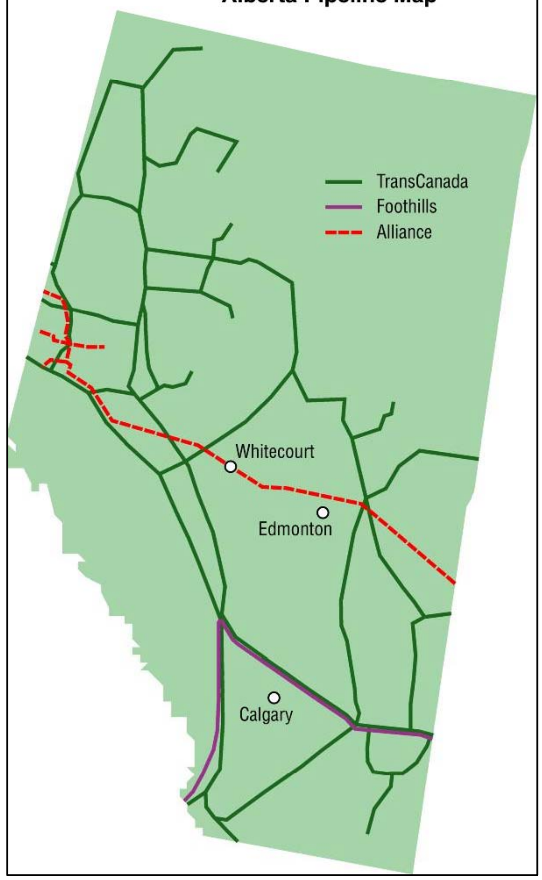
3 REGIONAL MARKET ANALYSIS

This section examines in detail the outlook for gas demand in eight key regional markets. Within Canada, the markets reviewed are Alberta, British Columbia, Quebec and Ontario. The U.S. markets examined are the Pacific Northwest, California, and the Midwestern and Northeastern United States. These markets presently account for virtually all exports of natural gas from Western Canada. Hence, they will be key to the absorption of gas delivered by the Mackenzie Pipeline. In each case the main drivers influencing natural gas demand and the long-term demand outlook are examined by sector.

3.1 Alberta

With a population of 3.1 million, 10% of Canada's population, Alberta accounts for over 30% of Canada's natural gas consumption. According to Statistics Canada data, natural gas provides 43% of the Province's total energy requirements, followed by coal (27%), oil (26%) and other energy sources (4%). Figure 3-1 shows Alberta gas transmission pipelines.

Figure 3-1
Alberta Pipeline Map



In 2002, Alberta natural gas consumption, including lease and plant gas, averaged 89.7 Mm^3d (3.2 Bcfd). Nearly half of the total was consumed by industry (principally oil sands bitumen production, pipelines, fertilizer and petrochemical manufacturing) and electricity power generation. Most of the remainder, about 30%, was consumed in the commercial and residential sectors, primarily for space heating.

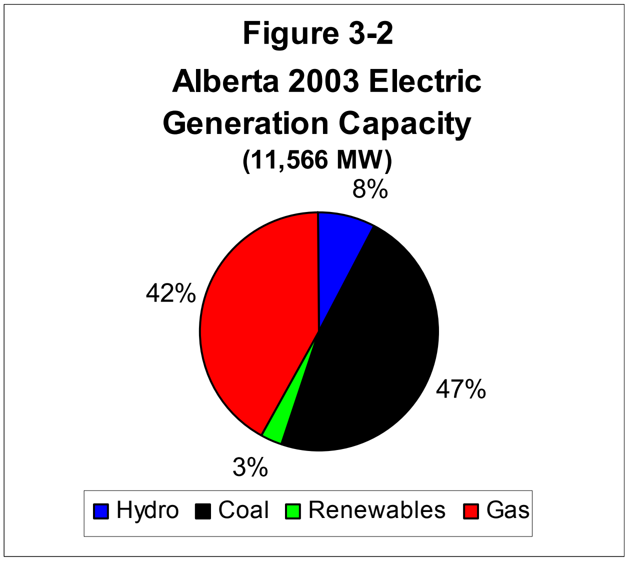
Residential gas demand is expected to grow more rapidly in Alberta than elsewhere in Canada in the next decade due to stronger population growth reflecting net in-migration and economic factors such as oil sands employment opportunities. Growth in commercial gas demand will reflect both the strength of the Alberta economy and growth in the number of households. While residential and commercial gas consumption will continue to expand steadily, a much greater share of the increase in gas demand will come from additional gas-fired power generation, including cogeneration at surface mining and in situ oil sands bitumen production and upgrading facilities, and from the thermal requirements of the oil sands facility operations.

Given the prominence of industry in Alberta's gas requirements, there is greater price sensitivity in Alberta than in regions where the demand is more price-inelastic. There is also greater potential for substituting lower-priced energy sources if gas prices increase more rapidly than the prices of other fuels. Indeed, during the sharp rise in gas prices in 2000-2001, a fertilizer plant shut down temporarily and two cement companies were investigating the possibility of replacing gas used for process heat with coal or used tires. However, Alberta gas consumers have an advantage over consumers in Central Canada in that the cost of transporting gas to the burner-tip is much lower. Lower delivery costs and plentiful supplies of coal, liquefied petroleum gases, and other fuels makes Alberta an attractive location for manufacturing notwithstanding the greater distances from major markets. For these reasons, Alberta's gas demand is reasonably stable and unlikely to shrink substantially absent a major shift in relative fuel prices.

Electric Generation Demand

Alberta peak electricity demand was 8,570 MW in 2002 and electricity sales totaled approximately 66 billion kWh. Current generating capacity is about 11,600 MW, of which 5,475 MW is coal-fired steam generation and 4,879 MW gas-fired capacity. Hydroelectric and other renewable generation sources account for the remainder. Much of the gas-fired generation capacity was commissioned during the last five years in conjunction with cogeneration facilities required for oil sands bitumen production activities. Major new gas-fired independent power production (IPP) facilities such as Calpine Corporation's Calgary Energy Centre and non-oil sands cogeneration facilities such as those at Nova Chemical Corporation's Joffre polyethylene plant site were constructed during this period.

With the recent growth, gas-fired generation accounts for about 40% of Alberta's total generating capacity. The outlook for continued growth in electricity sales (projected to increase 2.3% per year) and the relative economics of the available types of generation suggest that the share of gas-fired generating capacity will continue to increase through the forecast period, while coal's share will likely fall. Figures 3-2 and 3-3 show how total Alberta electric generation capacity is anticipated to increase from 2003 to 2030 in the Base Case, and how the composition of generation capacity by type is expected to change. Gas-fired capacity is anticipated to represent 53% of total capacity in 2030 compared with 42% in 2003.



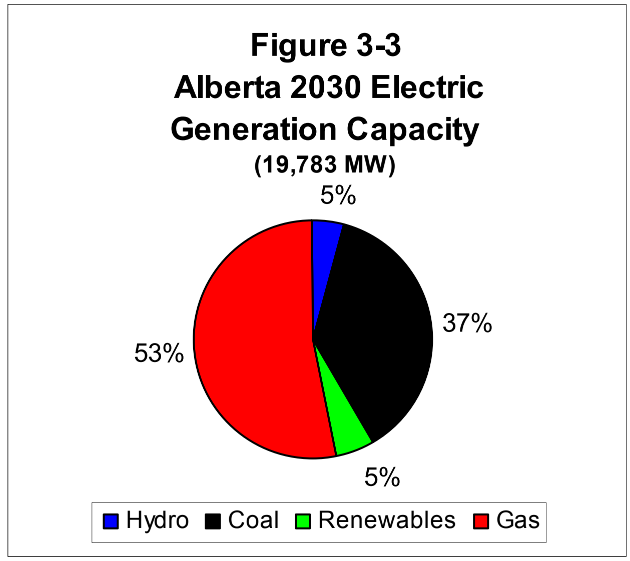
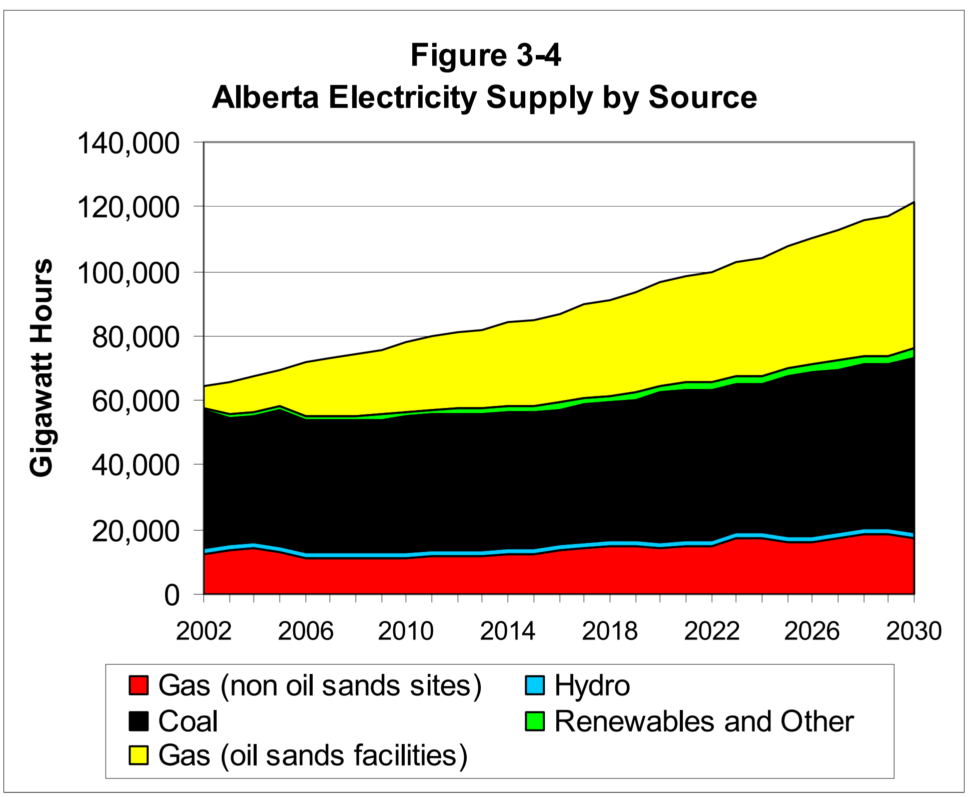
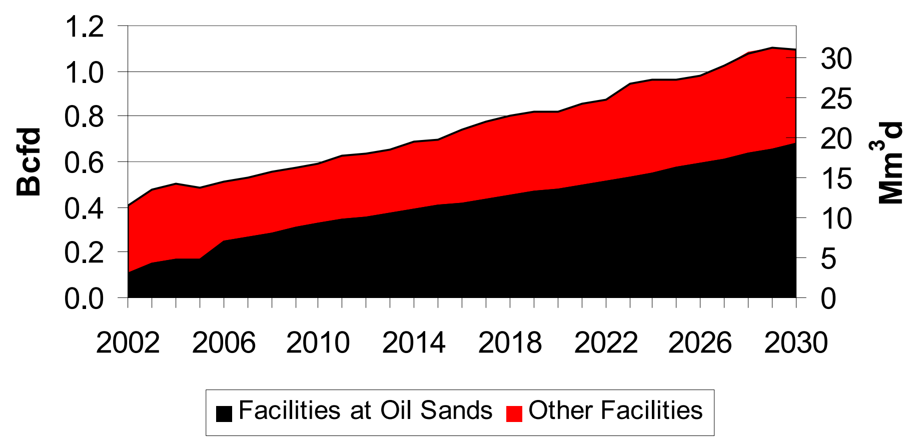


Figure 3-4 shows how the composition of electricity generated in the province is anticipated to change by source. We estimate that the share of Alberta electrical energy requirements supplied by gas-fired generation will increase from about 36% today to about 46% in 2015 and 51% in 2030. During the same period, natural gas consumption by Alberta's expanded fleet of gas-fired generation and cogeneration facilities is estimated to grow from 11.5 Mm³d (0.4 Bcfd) in 2002 to 19.9 Mm³d (0.7 Bcfd) in 2015 and 31.0 Mm³d (1.1 Bcfd) in 2030.



As illustrated by Figure 3-5, after about 2015 the lion's share of Alberta power generation gas demand is expected to be consumed by facilities located at oil sand bitumen production and upgrading sites.

Figure 3-5
Gas Requirements for Alberta Power Generation



Oil Sands Requirements

The demand for natural gas for the production of bitumen and synthetic crude oil from Alberta's oil sands will depend more on the amount of new investment, and the types of technologies employed, than on general economic conditions. For this reason, the forecast of gas demand in the oil sands industry was based on assumptions regarding the overall growth of investment and production rather than an econometric forecast based on historical trends.

There are essentially two kinds of production utilized in the oil sands industry: surface mining and in situ production. The first, employed at the Suncor and Syncrude facilities, involves the surface mining of bitumen-rich sand, processing to separate the bitumen from the sand, and upgrading the bitumen to produce a form of synthetic crude oil. In situ production involves injecting steam and/or chemicals to reduce the viscosity of the bitumen, allowing it to be pumped to the surface where it can be mixed with diluents such as pentanes plus and piped to a refinery that can accommodate it or to a specially-designed upgrader.

The first step in the process of estimating gas requirements for oil sands bitumen production and upgrading involved projecting bitumen production from both techniques. Through 2011, the projections contained in the Alberta Energy and Utility Board's (EUB) 2002 report "Alberta's Reserves 2001 and Supply/Demand Outlook 2002-2011" (Reserves/Outlook Report) were used except that the surface mining forecast was adjusted to reflect new information pertaining to the True North and Horizon projects.[3] In its report, the EUB projected that crude bitumen production from surface mining and in situ activities combined would about double from 1991 to 2001. The EUB projected mining-type bitumen production to grow an average of 12.7% per year from 2002 to 2011. Bitumen production from in situ operations was projected to increase at an average annual rate of almost 10 %, yielding total crude bitumen production from oil sands of about 350 Mm^3d (2.2 million barrels a day or 2.2 MMBD) by 2011, implying annual average growth of 11.6% over the 2001 level. Synthetic crude oil production was projected to increase from 56 Mm^3d (0.35 MMBD) in 2001 to 190 Mm^3d (1.2 MMBD) in 2011, an average growth rate of 13.7% per year.

In projecting future bitumen supply from surface mining and in situ operations, the EUB considered production from both existing facilities and anticipated expansions and new projects.[4] Projects with considerable uncertainty surrounding their scope and timing were generally excluded. The Board assumed that cost overruns, construction delays and other factors would likely affect the timing of the various projects and, therefore, adjustments were made to the proponents' project schedules, as appropriate.

Given the accelerating growth in oil sands bitumen production, the expected ability of U.S. markets to absorb increased quantities of Canadian bitumen and synthetic crude oils, and Alberta's enormous reserves of oil sands bitumen, some analysts have predicted that production growth from 2011 to 2030 will be at least as robust as the 11% to 12% annual growth projected by the EUB for the current decade. While a possibility, increases in financing costs, environmental concerns and costs (including uncertainties with respect to the manner and impact of Canada's implementation of the Kyoto Protocol), market and pipeline constraints, lower crude oil prices and other factors appear likely to slow investment in oil sands activity. For this reason, without attempting to identify specific projects likely to be initiated after 2011, the market analysis was based on the following assumptions:

- Crude bitumen production from surface mining activities was forecast to increase an average of 2.0% per year from 2012 through 2030. Slower growth,

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[3] The resulting projection is consistent with the EUB 2003 report on the same topic that was released in May 2003.

[4] These included: expected expansions at the Suncor Fort McMurray facilities, including completion of Millennium and Voyageur Phases I and II; expected expansions at the Syncrude facility, including stages three and four of the four-stage project that began in 1996; the Albian Sands project which was on track to commence production in 2003 and be expanded in 2008; and the Canadian Natural Resources Limited Horizon project. Among the upgrading or synthetic crude oil production projects included were the Shell Scotford facility, Suncor's Millennium, Firebag, and Voyager projects, Syncrude debottlenecking and new Aurora trains, and the OPTI/Nexen Long Lake facility.

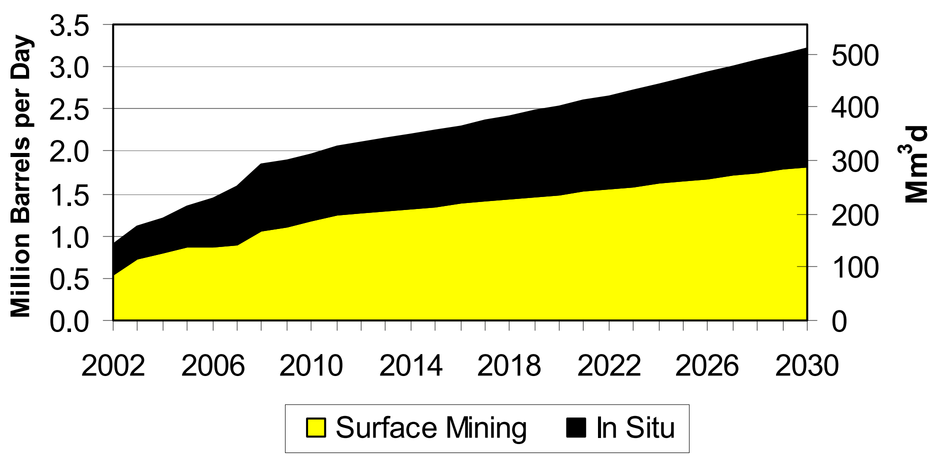
followed by acceleration, reflects the historical pattern. However, history has shown that oil sands production growth usually slows for a period following periods of rapid expansion, an outlook that appears reasonable given the many uncertainties facing the industry.

- In situ bitumen production was projected to increase 3.0% per year during the 2012-2030 period, compared with the EUB's projection of 9.9% annual growth through 2011; and

- An increasing share of in situ bitumen production will be upgraded to synthetic crude oil --- reaching 24% in 2012 and 42% by 2030.

Under these assumptions, after reaching 317 Mm^3d (2 million barrels per day) by 2011, total crude oil bitumen production is forecast to grow to nearly 400 Mm^3d (2.5 million barrels per day) by 2020 and exceed 500 Mm^3d (3.2 million barrels per day) by 2030. This is illustrated by Figure 3-6.

Figure 3-6
Oil Sands Bitumen Production



To determine the gas requirements of the projected oil sands activity, the following natural gas use coefficients rates, measured in cubic metres of gas per cubic metre of bitumen (Mcf of gas per barrel) were applied to estimate the volume of gas required to produce synthetic and upgraded crude oil from surface mining and in situ sources. The coefficients used in the analysis are shown in Table 3-1.

Table 3-1 Natural Gas Use Coefficients For Bitumen Production			
Activity	m^3 of Gas per m^3 of Bitumen	m^3 of Gas per Barrel of Bitumen	Mcf of Gas per Barrel of Bitumen
Mined Bitumen Production and Upgrading	59.97	9.52	0.336
In Situ Bitumen Production	151.70	24.08	0.850
In Situ Bitumen Upgrading	133.85	21.25	0.750

Except for the upgrading of bitumen produced via in situ methods, for which an estimate was not provided, the above coefficients are the same as those used by the EUB to forecast oil sands gas demand in its Reserves/Outlook Report. In our judgment, however, it is very likely that these rates, which reflect current usage practices, will be reduced by innovations that reduce or virtually eliminate gas requirements in some cases, especially if gas prices are expected to increase in real terms. For example, the technology being introduced in the Nexen/OPTI Long Lake project involves the combustion of asphalts to produce the synthetic gas used to generate steam for in situ bitumen production and upgrading, thus largely eliminating consumption of natural gas. The subsurface combustion of bitumen to reduce viscosity would have a similar effect. Substitution of other fuels for natural gas in oil sands bitumen production and upgrading would be hastened if the real price of gas were to increase on a permanent basis. Due to the likelihood that emerging technologies will, in fact, reduce gas requirements, we assumed that the use coefficients for in situ bitumen production would gradually decline to 116 cubic metres of gas per cubic metre of product (0.65 thousand cubic feet per barrel commencing in 2005.[5]

Figure 3-7 provides the gas demand forecast that results from the growth rates for bitumen production and upgrading and the natural gas use coefficients discussed above. Under these assumptions, the gas requirements associated with the production and upgrading of bitumen from Alberta oil sands are estimated to be 19.5 Mm^3d (0.7 Bcfd) greater in 2010 than in 2001 as a result of projects that, for the most part, are being completed or planned. By 2015, oil sands gas requirements (excluding related power generation requirements) are estimated to grow to about 36.0 Mm^3d (1.3 Bcfd). By 2030, oil sands gas requirements are projected to reach 55.0 Mm^3d (1.9 Bcfd), almost four times greater than in 2002.[6]

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[5] For in situ bitumen upgrading, the gas use coefficient of 133.9 m^3/m^3 (0.8 Mcf per barrel) used in this analysis compares with somewhat higher coefficients that have reportedly been used for analysis in relation to the potential utilization of upgraded refineries. The lower coefficient used in this study was based on the assumption that totally new facilities will embody technological improvements and therefore be more efficient.

[6] The above forecast is in line with the analysis contained in the NEB's Spring 2003 Report, *Canada's Energy Future,* which projects that gas demand for bitumen processing could reach 48.2 Mm^3d (1.7 Bcfd) by 2025 (average of the Supply Push and TechnoVert Scenarios).

Figure 3-7: Natural Gas Demand for Oil Sands Bitumen Production and Upgrading

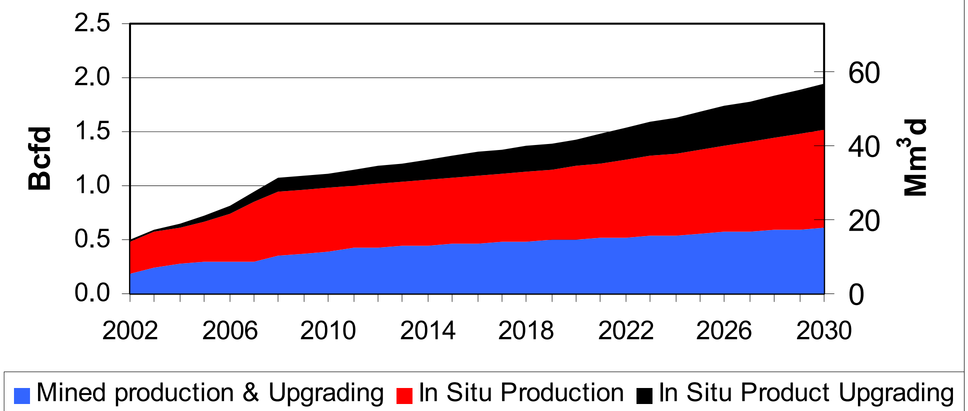


Table 3-2 presents the forecast of total Alberta gas demand in the Base Case analysis. Between 2002 and 2010, gas demand in the province is forecast to increase by 21.5 Mm^{3}d (0.8 Bcfd) or 24%. The largest share of the increase 14.8 Mm^{3}d (0.5 Bcfd) will be consumed by the industrial sector, especially the expanding oil sands bitumen industry. Electric power generation (including cogeneration) will account for most of the remaining growth. From 2010 through 2015, Alberta gas demand is predicted to grow an additional 9.6 Mm^{3}d (0.3. Bcfd) or 8.7% of which about 5.0 Mm^{3}d (0.2 Bcfd) will be required by the industrial sector (again, mainly for oil sands bitumen production) and 3.1 Mm^{3}d (0.1 Bcfd) for power generation. Over the entire 2003-2030 period, Alberta gas demand, including pipeline fuel and lease/plant requirements, is projected to increase by 58.0 Mm^{3}d (2.0 Bcfd) or nearly 60% to 147.7 Mm^{3}d (5.2 Bcfd).

Table 3-2: Alberta Gas Demand (Mm^{3}d and Bcfd)

						Increase (Mm^{3}d)			
Mm^{3}d	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Alberta Total	89.72	111.22	120.79	137.55	147.67	21.50	9.56	16.77	10.12
Residential	12.25	13.08	13.93	15.56	16.40	0.83	0.85	1.63	0.84
Commercial	5.96	5.99	6.19	6.53	6.74	0.03	0.21	0.34	0.20
Industrial	28.03	42.85	47.89	57.80	64.70	14.82	5.04	9.92	6.90
Power Generation	11.53	16.77	19.86	27.28	30.99	5.25	3.09	7.42	3.71
Other	31.96	32.54	32.91	30.38	28.84	0.58	0.37	-2.53	-1.53
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Alberta Total	3.17	3.93	4.26	4.86	5.21	0.76	0.34	0.59	0.36
Residential	0.43	0.46	0.49	0.55	0.58	0.03	0.03	0.06	0.03
Commercial	0.21	0.21	0.22	0.23	0.24	0.00	0.01	0.01	0.01
Industrial	0.99	1.51	1.69	2.04	2.28	0.52	0.18	0.35	0.24
Power Generation	0.41	0.59	0.70	0.96	1.09	0.19	0.11	0.26	0.13
Other	1.13	1.15	1.16	1.07	1.02	0.02	0.01	-0.09	-0.05

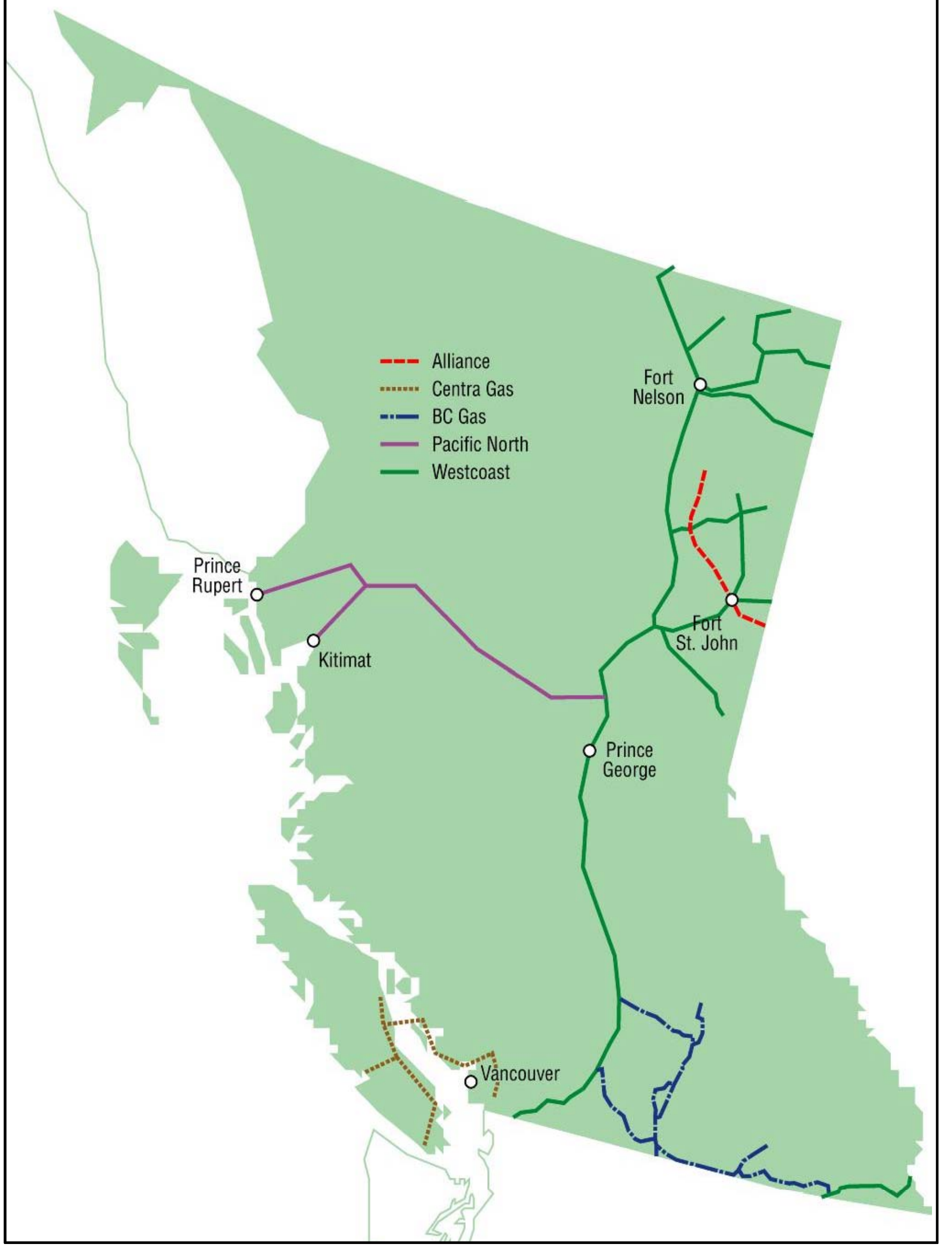
Alberta Export Pipeline Capacity
With gas production of approximately 399.4 Mm^3d (14.1 Bcfd) and domestic consumption of approximately 91 Mm^3d (3.2 Bcfd), Alberta is a major exporter and supplier of natural gas to markets in Ontario, Quebec, the Pacific Northwest, California, and the US Midwest and Northeast regions. TransCanada-Alberta (Nova Gas Transmission Ltd.) is the primary gas gathering and transmission pipeline system in Alberta. Gas is delivered to export points via TransCanada-Alberta, Foothills Pipeline (recently acquired by TransCanada Corporation), and by Alliance Pipeline, which receives gas in northeastern British Columbia and northwestern Alberta primarily for delivery to markets served by the Chicago hub. ATCO Pipelines, which interconnects with the TransCanada-Alberta System, delivers gas to major industrial customers and to gas distributors within Alberta. The TransCanada-Alberta System also transports gas to many intra-Alberta delivery points.

Many experts consider that Alberta gas production has peaked or is about to peak, although views differ over the rate of future decline. In the Base Case projections, total gas production in Alberta, including coalbed methane and other non-conventional supplies, is projected to peak at 407.9 Mm^3d (14.4 Bcfd) in 2016 and then steadily decline to 396.6 Mm^3d (14.0 Bcfd), in 2020 and 365.4 Mm^3d (12.9 Bcfd) in 2030. Over the forecast period, the combination of rising demand and falling production will lead to a reduction in the quantity of gas available for export to markets outside Alberta. From 2002 to 2010, for example, the exportable surplus will shrink by 25.5 Mm^3d (0.9 Bcfd) as Alberta demand grows by 21.5 Mm^3d (0.8 Bcfd) while production falls 2.8 Mm^3d (0.1 Bcfd). By 2015, total Alberta gas demand is projected to be 31.1 Mm^3d (1.1 Bcfd) higher than in 2002 while production gains only 11.3 Mm^3d (0.4 Bcfd). By 2020 and 2025, these trends will reduce the export surplus by 42.5 Mm^3d and 107.6 Mm^3d (1.5 Bcfd and 3.8 Bcfd), respectively, compared with 2002. These trends are a clear indication of the need for the incremental supplies of gas accessed by the Mackenzie Pipeline. As noted in the following sections, gas demand in Ontario, Quebec and in the major U.S. regional markets for Alberta gas is also projected to expand while production outside Alberta has difficulty remaining steady. This further underscores the market need for Mackenzie Delta gas supplies.

3.2 British Columbia

British Columbia, with a population of about 4.2 million and a strong resource and industrial base, represents approximately 13% of Canadian gas demand, about the same as its share of the Canadian population. Oil provides 38% of the province's energy requirements, followed by natural gas (27%), hydroelectric power (18%), and other sources of energy (16%). Figure 3-8 shows gas transmission pipelines in British Colombia.

Figure 3-8
British Columbia Pipeline Map



In 2002, British Columbia gas consumption averaged 28.3 Mm^3d (1.0 Bcfd). Industry accounted for 37% of total gas consumption. The residential and commercial sectors accounted for 26% and 20%, respectively, while electric power generation consumed 13% of total B.C. gas demand. The province is self-sufficient in gas and exports slightly more than it consumes.

The industrial load is largely resource-driven, with the lumber, pulp and paper, mining, and metals industries very significant. Some of the industrial demand is fuel-switchable as illustrated during the winter of 2000-2001 when a number of customers, including the University of British Columbia, switched to fuel oil and several pulp and paper mills switched to wood waste. In the residential and commercial sectors, conservation measures and energy efficiency investments are believed to have resulted in sustainable decreases in demand.

In the years ahead, gas demand in the residential and commercial sectors is expected to increase in accordance with the growth in economic activity with some continued dampening as the result of efficiency and conservation measures. In the industrial sector, load will rise as economic activity expands but, at the same time, it will continue to be price sensitive.

Power Generation Requirements
Gas requirements for British Columbia's power generation were forecast judgmentally since many of the uncertainties affecting the outlook are not likely to be adequately captured by econometric equations derived from historical data. The first step in preparing the forecast was to estimate the increase in gas-fired generating capacity during the forecast period.

Figure 3-9
British Columbia 2003
Electric Generation Capacity
(11,100 MW)

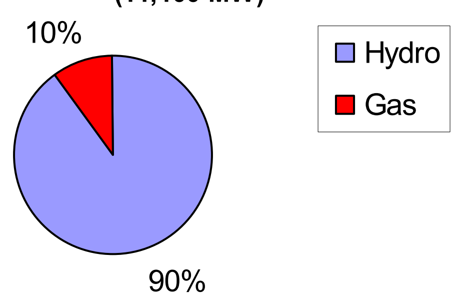
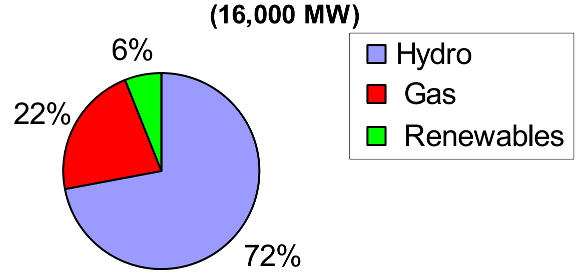


Figure 3-10
British Columbia 2030
Electric Generation Capacity
(16,000 MW)



BC Hydro's long-term demand growth projections (updated in October 2002) expect total electrical energy requirements in the province to grow by an average of 1.7% per year in the next ten years and 1.5% per year thereafter. A major driver is the growth in the province's population, which is projected to grow more than 25% through 2020. These trends were extrapolated to estimate peak demand growth from 2022 to 2030. Of the 4,900 MW increase in peak demand and generating capacity through 2030, natural gas-fired generation is assumed to account for 2,400 MW.

Hydroelectric capacity is projected to increase by 1,500 MW. Spurred by the government's intention to facilitate investment in renewable resources, renewable generating capacity (including small hydropower production), is projected to increase by 1,000 MW. Figures 3-9 and 3-10 show how British Columbia electric generation capacity, and the composition of that capacity, were assumed to change in the Base Case from 2003 to 2030.

Natural gas requirements were estimated by applying capacity utilization and heat rate assumptions to the estimated gas-fired capacity available each year. As shown in Figure 3-11, power generation gas requirements are projected to increase from 3.8 Mm^3d (0.1 Bcfd) in 2002 to 12.1 Mm^3d (0.4 Bcfd) in 2030.

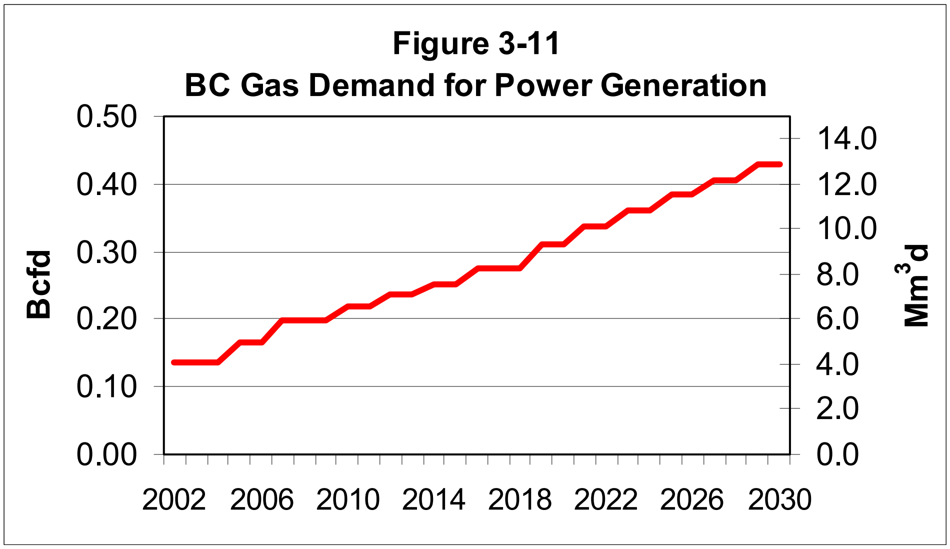


Table 3-3: British Columbia Gas Demand (Mm^3d and Bcfd)

						Increase (Mm^3d)			
Mm^3d	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
B.C. Total	27.93	33.54	37.35	41.63	45.08	5.61	3.81	4.28	3.45
Residential	5.61	6.96	7.68	9.07	9.80	1.34	0.72	1.40	0.73
Commercial	4.58	5.44	5.92	6.80	7.28	0.86	0.48	0.87	0.48
Industrial	8.02	8.41	9.60	8.15	9.78	0.39	1.19	-1.45	1.63
Power Generation	3.81	6.19	7.09	10.91	12.14	2.38	0.90	3.81	1.23
Other	5.90	6.55	7.06	6.70	6.08	0.64	0.51	-0.36	-0.61
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
B.C. Total	0.99	1.18	1.32	1.47	1.59	0.20	0.13	0.15	0.12
Residential	0.20	0.25	0.27	0.32	0.35	0.05	0.03	0.05	0.03
Commercial	0.16	0.19	0.21	0.24	0.26	0.03	0.02	0.03	0.02
Industrial	0.28	0.30	0.34	0.29	0.35	0.01	0.04	-0.05	0.06
Power Generation	0.13	0.22	0.25	0.38	0.43	0.08	0.03	0.13	0.04
Other	0.21	0.23	0.25	0.24	0.21	0.02	0.02	-0.01	-0.02

Table 3-3 indicates how British Columbia gas demand is forecast to increase through the forecast period, both in total and by sector. Residential gas demand is projected to increase by 4.2 Mm^3d (0.15 Bcfd) or 75% from 2002 to 2030. During the same period, combined commercial and industrial demand is indicated to grow 4.5 Mm^3d (0.2 Bcfd) or 39%. Total British Columbia gas demand is forecast to increase by almost 5.6 Mm^3d

(0.2 Bcfd) or 19% by 2010, and 11.5 Mm^3d (0.4 Bcfd) or 35% from 2010 to 2030, raising total consumption in the province to 45.1 Mm^3d (1.6 Bcfd) in 2030, 61% higher than in 2002.

British Columbia produced natural gas at the rate of 68.0 Mm^3d (2.4 Bcfd) during 2001. With more than sufficient gas supply and deliverability capacity to meet its own requirements, the province is a net exporter of gas.
The main gatherer and transporter of gas in British Columbia is Duke Energy Gas Transmission Canada (DEGT), which purchased the former Westcoast Pipeline System in 2002. DEGT moves gas from the southern Territories and northeastern and eastern B.C. to the provincial market centers served by the utility arm of Terasen Corporation (formerly BC Gas) and Pacific Northern Gas, and to the international border at Huntingdon, B.C./Sumas, Washington where the pipeline connects with Northwest Pipeline and other pipelines. The DEGT system also connects with the TransCanada Alberta system at Gordondale, Alberta where exchanges of gas can take place in either direction, depending on requirements.

Gas is transported from Alberta near the southeast corner of British Columbia to Kingsgate, British Columbia, by the TransCanada/Alberta System where it connects to Terasen's Southern Crossing Pipeline that provides seasonal peaking service to the B.C. Lower mainland.

The Alliance Pipeline receives gas production in the Aitken Creek (storage) and Fort St. John areas of northeastern BC and transports it to Alberta and to markets served by the Chicago hub.

Although BC has some production storage service it is rather unique for a market of its size in not having significant market storage capacity. Essentially, Terasen relies on the link with TransCanada and storage facilities in Washington State to meet its peaking requirements.

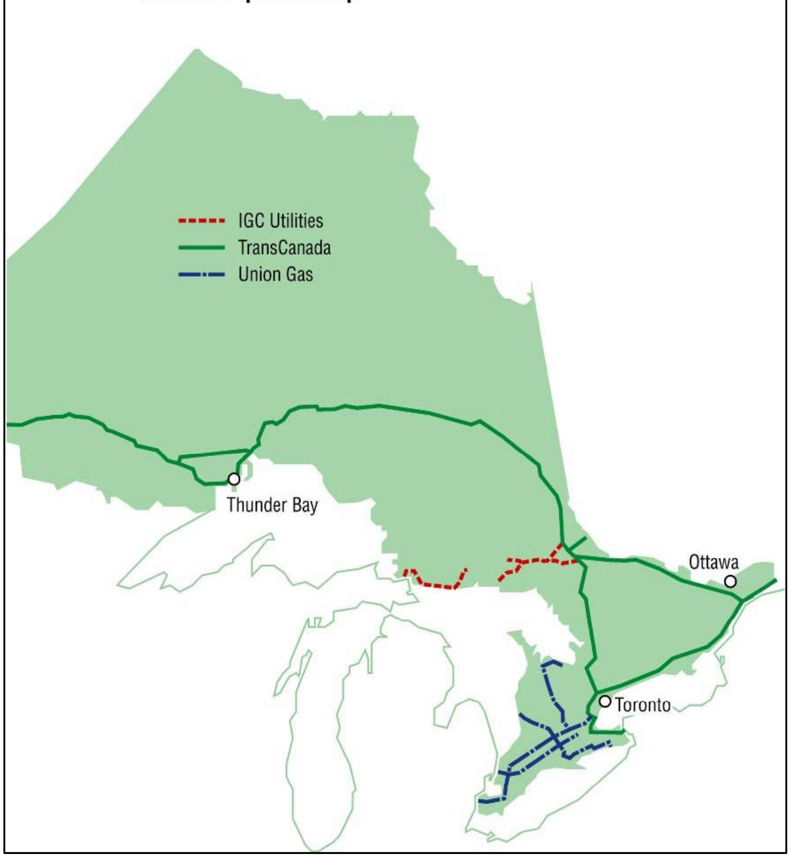
British Columbia remains a net exporter of gas throughout the forecast period but net exports gradually decline. The trend is driven by the steady rise in provincial gas consumption. As noted above, total consumption increases by about 17.2 Mm^3d (0.6 Bcfd during the forecast period. In contrast, production falls from a peak of 82.1 Mm^3d (2.9 Bcfd) in 2016 to 70.8 Mm^3d (2.5 Bcfd) by 2030. As a consequence, net exports decline from approximately 42.5 Mm^3d (1.5 Bcfd) in 2002 to 25.5 Mm^3d (0.9 Bcfd) in 2030. This is reflected in a reduction in export flows both to the Pacific Northwest and California via the Huntingdon/Sumas border point, and to Alberta via Alliance Pipeline.

Flows of Alberta gas to Kingsgate remain fairly stable throughout the period. Most of the gas is exported except for volumes that flow through the Southern Crossing Pipeline to help supply Terasen's Lower Mainland network.

3.3 Ontario

Ontario has a population of slightly more than 12 million, 39% of Canada's population. The province accounts for 38% of Canada's gas demand. Oil supplies one-third of Ontario's energy requirements and coal and nuclear energy about 10% and 11%, respectively, as reported in the NEB's October 2002 Natural Gas Market Update. Hydroelectric power provides 4% of the total energy consumption while the natural gas share is about 30%. Figure 3-12 shows gas transmission pipelines in Ontario.

Figure 3-12
Ontario Pipeline Map



Ontario end-use gas demand totaled 70.8 Mm^3d (2.5 Bcfd) in 2001 -- the most recent year for which recorded data are available. The industrial and residential sectors accounted for 36% and 33% of total demand for gas, respectively, followed by commercial and power generation usage, with 20% and 11% of the total, respectively. Ontario industrial demand is diversified across a number of important industries such as mining, pulp and paper, cement, steel, fertilizer, and automotive and other manufacturing.

Ontario residential, commercial, and most industrial gas demand, while relatively stable when adjusted for business cycle fluctuations, has tended to soften in recent years due to conservation measures and energy efficiency investments. Gas demand for power generation is expected to increase through the forecast period as gas-fired generation provides most of the increase in customer demands owing to the environmental and cost advantages of gas generation.

Ontario residential, commercial, and industrial sector demand (excluding cogeneration requirements) was projected econometrically within the simulation model. Power sector gas demand was forecast judgmentally by NCI. This involved projecting Ontario electricity generation capacity by type of fuel and then adjusting capacity utilization rates to ensure that electricity supply was in balance with forecast electricity demand.

Ontario peak electricity demand was 24,296 MW in 2002. The electric generating stock is dominated by nuclear, hydro and coal-fired generation facilities that together account for 86% of the province's total capacity. Gas-fired generation presently accounts for only 7% of the total. The relatively high-cost Lennox oil- and gas-fired power plant represents another 7% of total capacity. Since the facility generally burns oil, it is not included with the other gas-fired capacity. The share of renewable and other generation facilities is less than 1%.

Based on the Ontario Independent Market Operator's (IMO) most recent long-term plan and other analysis, NCI projected that total Ontario electric generation capacity would grow to 36,000 MW by 2030, an increase of almost 50% over the current level.[7] As shown by Figures 3-13 and 3-14, the composition of capacity is also anticipated to change considerably between now and 2030. In the forecast, no new nuclear, coal, or large hydroelectric generation facilities are built in Ontario before 2030 and some existing coal units are expected to be retired. New capacity is anticipated to consist of either gas-fired or renewable generating plants. As a consequence, the natural gas share of total generating capacity is anticipated to double (from 7% to 14%) while the renewable share grows to about 12% from today's negligible amount, in part due to recent changes in government policy. At the same time the combined share of nuclear, coal and hydro facilities is expected to drop from 86% today to less than 70% by 2030.

Figure 3-13
Ontario 2003
Electric Generation Capacity
(29,500 MW)

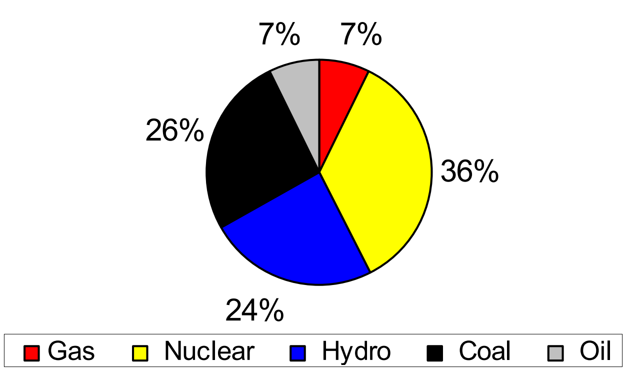
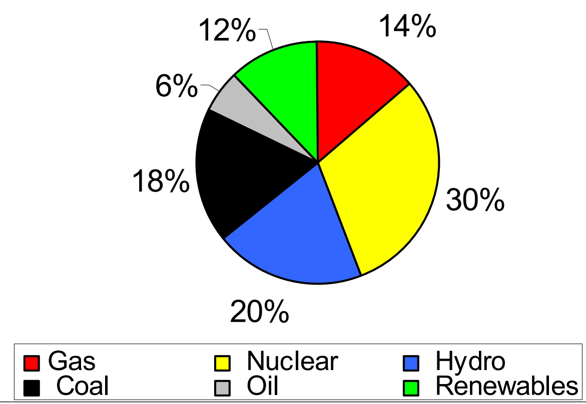


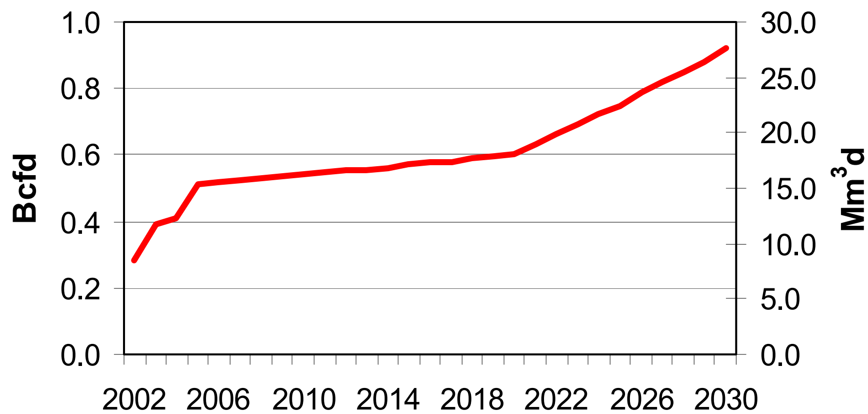
Figure 3-14
Ontario 2030
Electric Generation Capacity
(36,000 MW)



[7] "An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2004 to December 2013", report of the Independent Electricity Market Operator, March 31, 2003.

Consistent with the IMO's projections, Ontario's total electricity consumption is assumed to increase by 1.1% per year through 2030. Generation by fuel type was estimated by multiplying the projected capacity of each type by capacity utilization rates derived from historical information and knowledge of the Ontario electricity market. In the forecast, natural gas-fired generation was projected to grow from 14 billion kWh in 2003 to 19 billion kWh in 2010 and over 32 billion kWh in 2030. This would boost the gas share of total generation to about 14% in 2030 compared with about 7% in 2003. As a consequence, gas consumption for power generation in Ontario is projected to grow from an average of 8.1 Mm^3d (0.3 Bcfd) in 2002 to about 15.3 Mm^3d (0.5 Bcfd) in 2010 and then to reach 26.0 Mm^3d (0.9 Bcfd) by 2030. Figure 3-15 illustrates this.

Figure 3-15
Ontario Power Generation Gas Demand



As summarized in Table 3-4, total Ontario gas demand is projected to increase by 15.3 Mm^3d (0.5 Bcfd) by 2010. Between 2010 and 2030, gas demand grows another 29.2 Mm^3d (1.0 Bcfd) to 121.4 Mm^3d (4.3 Bcfd), nearly 58% greater than the 2002 level of 77.0 Mm^3d (2.7 Bcfd).

Table 3-4: Ontario Gas Demand (Mm^{3}d and Bcfd)									
						Increase (Mm^{3}d)			
Mm^{3}d	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Ontario Total	76.95	92.21	101.14	113.08	121.44	15.26	8.93	11.94	8.36
Residential	24.18	26.67	28.00	30.80	32.19	2.49	1.33	2.80	1.39
Commercial	14.11	15.75	16.61	18.52	19.45	1.64	0.86	1.91	0.93
Industrial	27.21	30.56	36.64	38.71	39.86	3.35	6.08	2.07	1.15
Power Generation	8.06	15.31	16.10	21.35	26.04	7.26	0.78	5.26	4.69
Other	3.40	3.91	3.79	3.69	3.89	0.51	-0.12	-0.10	0.20
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Ontario Total	2.72	3.25	3.57	3.99	4.29	0.54	0.32	0.42	0.30
Residential	0.85	0.94	0.99	1.09	1.14	0.09	0.05	0.10	0.05
Commercial	0.50	0.56	0.59	0.65	0.69	0.06	0.03	0.07	0.03
Industrial	0.96	1.08	1.29	1.37	1.41	0.12	0.21	0.07	0.04
Power Generation	0.28	0.54	0.57	0.75	0.92	0.26	0.03	0.19	0.17
Other	0.12	0.14	0.13	0.13	0.14	0.02	0.00	0.00	0.01

About 40% of the overall increase in Ontario gas requirements to 2030 will be consumed for electric power generation. The remainder will be consumed by the residential, commercial and industrial sectors.

Gas is supplied to Ontario customers via two major distribution companies, Enbridge Gas Distribution and Union Gas (now owned by Duke Energy). In addition to its gas distribution facilities, Union Gas operates important gas transmission facilities that connect with the TransCanada system, Vector Pipeline, Great Lakes Gas Transmission Company, and several other U.S. pipelines.

Union Gas obtains about three-fourths of its gas supply from western Canada.[8] The remainder comes from U.S. sources, mainly via pipeline connections to the rapidly growing Dawn hub in southwestern Ontario. In 1999, Enbridge Gas obtained about 90% of its gas from the WCSB.[9] Most of the direct sales gas, for which Union Gas, Enbridge, and others serve only as transporters, is also purchased from suppliers in Western Canada. Local Ontario gas production is very small and can meet only a small portion of Ontario's gas requirements. In sum, Ontario's gas market is heavily dependent on supplies from the WCSB. As this source of supply declines, Ontario gas consumers will need to locate alternative supply sources.

In the Base Case, about 85.0 Mm^{3}d (3.0 Bcfd) of gas flowed to Ontario via the TransCanada Mainline in 2002. Despite the 45.3 Mm^{3}d (1.6 Bcfd) increase in the province's gas demand through 2030, flows of WCSB gas to Ontario via TransCanada decline by about 8.5 Mm^{3}d (0.3 Bcfd) during this period. The gap between demand and WCSB flows is met from two sources: (1) reductions in gas volumes flowing out of Ontario into both Quebec and the United States (via Niagara), and (2) an increase in the volume of gas flowing into Ontario from the US at Dawn.

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[8] See the NEB's October 2002 report, *Canadian Natural Gas Market, Dynamics and Pricing.*

[9] Canadian Natural Gas Market Dynamics and Pricing, NEB, November 2000,

3.4 Quebec

Quebec, with a population of 7.5 million, is much less dependent on natural gas for its energy needs than Ontario. According to the NEB's October 2002 assessment, natural gas accounted for only 14% of Quebec's energy requirements compared with 42% for oil and 31% for hydroelectric power. Nuclear and coal together supplied under 5% of total energy requirements. The Province has about 24% of Canada's population but accounts for only 8% of the country's total gas demand, one-fifth the share of Ontario. Figure 3-16 shows gas transmission pipelines in Quebec.

Figure 3-16
Quebec Pipeline Map

The Quebec gas market also differs from that of Ontario due to the widespread use of electricity for residential sector heating and cooling, which reflects the abundance of low-cost hydroelectric power. Use of natural gas for electric power generation is also negligible at present. Quebec's strong industrial sector, which includes mining and smelting, pulp and paper companies, oil refineries, chemical production, and other activities, accounts for most of the gas consumed in the province.

In 2001 Quebec's end-use natural gas consumption was about 19.8 Mm^3d (0.7 Bcfd). About 67% of the total was consumed by the industrial sector (excluding cogeneration); residential and commercial usage accounted for 9% and 24% of the total, respectively.

The Quebec gas market is heavily weighted to the industrial sector. As a result, gas demand is more sensitive to changes in gas price than in markets with lower percentages of industrial consumption. In recent years, roughly one-half of total industrial consumption was transported using interruptible transportation, which indicates the switchable nature of the industrial load. The major competition to natural gas comes from heavy fuel oil supplied by three Quebec refineries and from imports. When gas prices soared during the 2000-01 winter heating season, about 20% of Gaz Metropolitain's interruptible load customers, representing about 25% of system volumes including pulp and paper loads, reportedly switched to oil. This underscores the potential for substantial load loss if the price of gas were to move sharply higher relative to oil.

Until now, virtually all of the gas consumed in Quebec has been sourced in Western Canada. Gas entering Alberta from the Mackenzie Delta will have access to the Quebec market via the same transportation facilities that are in place today. However, northern gas will have to compete with gas from the Atlantic Coast Offshore, LNG, and possibly the Gulf of St. Lawrence. The efforts of Gaz Metropolitain and its industrial and commercial customers to diversify their sources of supply will intensify the competition among these potential suppliers.[10]

Figure 3-17
Quebec 2003
Electric Generation Capacity
(36,400 MW)

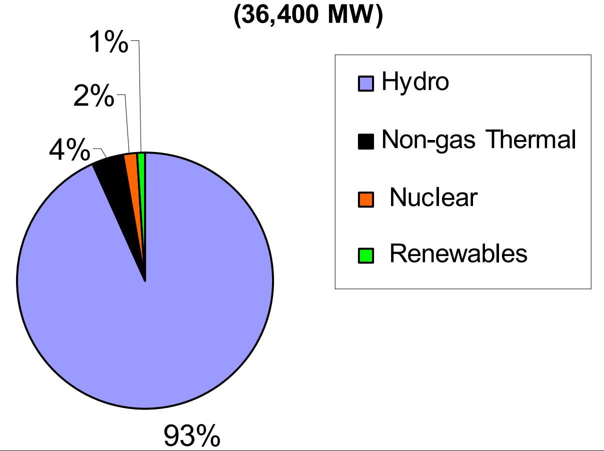
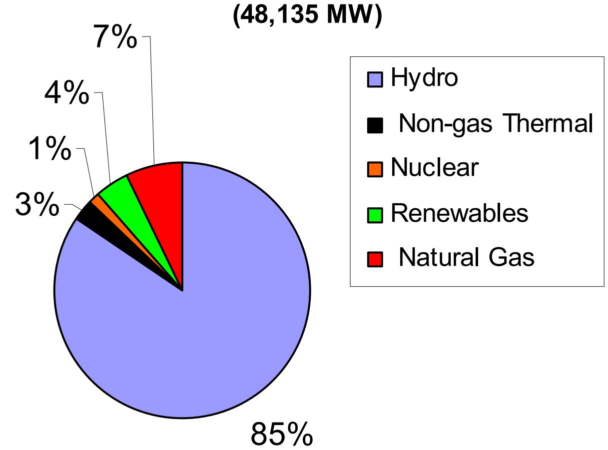


Figure 3-18
Quebec 2030 Electric
Generation Capacity
(48,135 MW)



According to the National Energy Board's 2003 *Canada's Energy Future* publication, Quebec's electric generation capacity was about 36,400 MW in 2003 of which 93% was hydroelectric capacity. Non-gas thermal power plants accounted for about 4% of total capacity while gas-fired generation was all but absent from the generation fleet. The Gentilly II nuclear facility and a small amount of wind power and biomass generation provided the remainder.

[10] The former provincial government completed a policy paper that supports gas exploration in the Gulf of St. Lawrence.

Figure 3-17 shows the composition of electric generation capacity in Quebec in 2003, and Figure 3-18, the anticipated total capacity and composition in 2030.

Quebec Government policy requires Hydro Quebec Distribution to call for tenders to meet electricity requirements greater than 165 Billion kWh, a threshold expected to be crossed in 2005. Energy up to the threshold amount comes from the so-called "Heritage Pool" which is comprised of the existing hydroelectric and thermal capacity.

Hydro Quebec Distribution has already begun to call for tenders for supplies in excess of the Heritage Pool ceiling. The recent announcement that TransCanada Power will build and operate a 550 MW cogeneration plant at the Becancour industrial site near Trois Rivieres with a late 2006 completion date and sell all of the power output to Hydro Quebec Distribution is one indication that gas will become a significant element of Quebec's power generation portfolio as time goes on. Eventually, some of the gas required could come from LNG facilities on the St. Lawrence or from gas production in the Gulf of St. Lawrence if either prove to be feasible.

Hydro Quebec Distribution has also called for tenders for power produced from small hydro facilities and biomass and indicated that it will be requesting bids for the output of up to 1,000 megawatts of wind generation. The utility has already contracted for wind energy from capacity of approximately 100 MW and has indicated that it will likely increase these purchases by about 100 MW per year until the 1,000 MW target is reached.

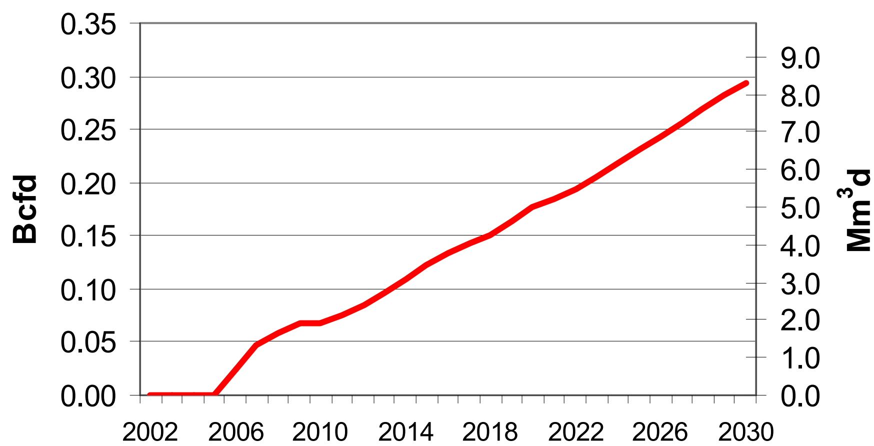
Hydro Quebec's 2002 strategic plan indicated that about 2,045 MW of additional hydro capacity was under construction. With that added capacity and small amounts of incremental capacity from wind, small hydro and other generation, there should be sufficient generation capacity overall to meet the Province's requirements until 2005. During the following five years, the Hydro Quebec plan indicates that about 1,600 MW will need to be added to meet anticipated demand growth. During the 2010-20 period another 4,600 MW of capacity will be needed to meet demand growth. Another 5,000 MW will probably be needed in the following decade.

Comparison of Figure 3-17 and Figure 3-18 indicates how Quebec electric generation capacity, and the composition of that capacity, are assumed to change in the Base Case from 2003 to 2030. Taking into account the government's directive for competitive bidding to procure the electrical energy needs of Quebecers in excess of 165 billion kWh, and the government's commitment to developing a local gas supply capability and as well a significant renewable energy capacity, our analysis assumed that gas-fired generation capacity would grow to 3,500 MW during the forecast period.[11] In 2030,

[11] This appears to be modest in comparison to the National Energy 2003 "Supply Push" scenario provided in the Canada's Energy Future analysis which indicates 4,547 MW of gas-fired capacity in Quebec by 2025.

although hydro capacity will be significantly greater than in 2003, it will account for only 85% of overall generation capacity mainly because of the inroads made by the development of gas-fired and renewable capacity. Applying capacity utilization and heat rate assumptions to the assumed stock of gas-fired capacity indicates that the demand for gas to generate electricity could increase to 1.9 Mm³d (0.1 Bcfd) by 2010 from 2002's negligible volumes, and reach 3.5 Mm³d (0.1 Bcfd) by 2015. This is illustrated in Figure 3-19.

Figure 3-19
Quebec Power Generation Gas Demand



The forecast of Quebec's gas demand is shown in Table 3-5. Gas requirements excluding power generation were forecast econometrically. In the Base Case projections, gas demand in Quebec increases 5.5 Mm³d (0.2 Bcfd) by 2010 with an additional 10.8 Mm³d (0.4 Bcfd) of growth expected in the remainder of the forecast period. Through the entire 2003-2030 period, gas demand is projected to increase 16.3 Mm³d (0.6 Bcfd), about half of which will be attributable to the assumed power generation gas requirements. The increase in residential demand is expected to be small. Combined commercial and industrial demand, excluding power generation, is anticipated to increase 7.4 Mm³d (0.3 Bcfd) to reach 24.3 Mm³d (0.9 Bcfd) in 2030.

Gas is supplied to Quebec solely via the TransCanada Mainline that supplies gas to the main distributor of gas in Quebec, Gaz Metropolitain Inc. (GMI), near Montreal. The TransQuebec and Maritimes (TQM) Pipeline, jointly owned by TransCanada and GMI, transports gas further east, to Quebec City. A wholly owned subsidiary of GMI, Champion Pipe Line Corporation, operates two pipelines in the Abitibi and Temiscamingue regions northwest of GMI's main distribution facilities.

Table 3-5: Quebec Gas Demand (Mm^3d and Bcfd)									
						Increase (Mm^3d)			
Mm^3d	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Quebec Total	19.43	24.91	28.18	32.30	35.69	5.48	3.26	4.12	3.39
Residential	1.88	2.11	2.22	2.44	2.55	0.24	0.11	0.23	0.11
Commercial	4.87	5.75	6.19	7.16	7.61	0.88	0.44	0.96	0.45
Industrial	12.03	14.48	15.70	15.63	16.65	2.45	1.22	-0.07	1.02
Power Generation	0.00	1.90	3.45	6.54	8.33	1.90	1.55	3.09	1.78
Other	0.65	0.67	0.62	0.53	0.55	0.02	-0.05	-0.09	0.02
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Quebec Total	0.69	0.88	0.99	1.14	1.26	0.19	0.12	0.15	0.12
Residential	0.07	0.07	0.08	0.09	0.09	0.01	0.00	0.01	0.00
Commercial	0.17	0.20	0.22	0.25	0.27	0.03	0.02	0.03	0.02
Industrial	0.42	0.51	0.55	0.55	0.59	0.09	0.04	0.00	0.04
Power Generation	0.00	0.07	0.12	0.23	0.29	0.07	0.05	0.11	0.06
Other	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00

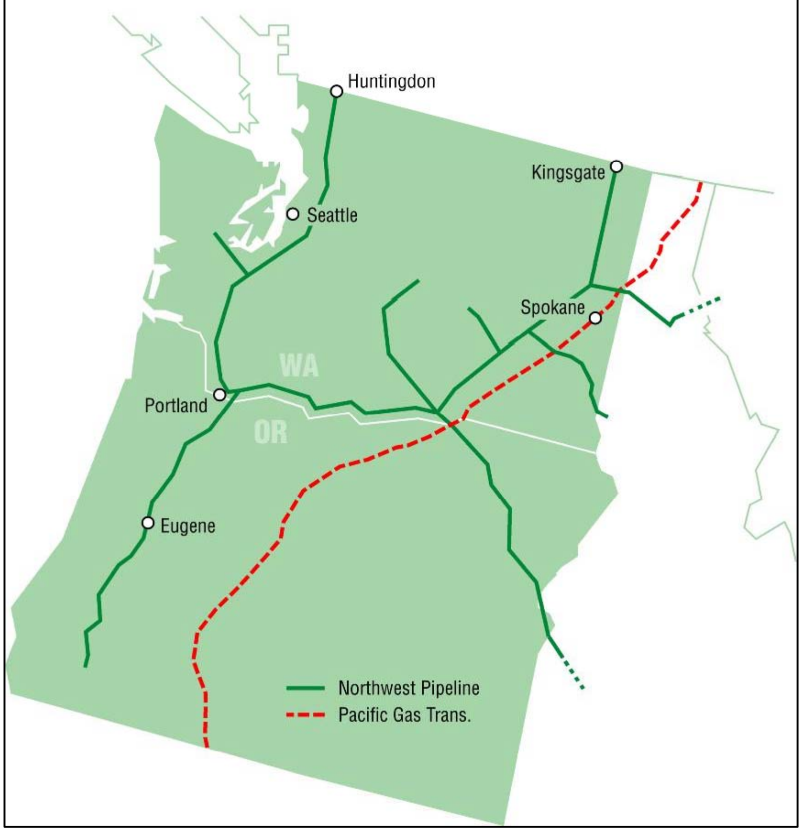
Quebec has no gas production of its own and, as noted earlier, obtains almost all of its supplies from the WCSB via the TransCanada mainline. There are two export points. A TQM extension connects with the Portland Natural Gas Transmission System to ship gas to markets in the Northeastern United States. The TransCanada System has also been extended from Montreal to Philipsburg, Vermont, where it connects with Vermont Gas Systems Inc.

In the Base Case, the roughly 16.3 Mm^3d (0.6 Bcfd) increase in Quebec's total gas demand through 2030 indicated in Table 3-5 can be accommodated without difficulty. However, the model results indicate a substantial 22.7 Mm^3d (0.8 Bcfd) decline in exports of gas from Quebec to Vermont and Eastern New York during the forecast period. As a consequence, the total amount of gas flowing into Quebec in 2030 is about 56.7 Mm^3d (2.0 Bcfd) less than in 2002.

3.5 The Pacific Northwest

The U.S. market regions that absorb most of Canada's gas exports are the Pacific Northwest, California, and the Midwestern and Northeastern United States. The following sections examine the current situation and outlook in each of these important market regions.

Figure 3-20
Pacific Northwest Pipeline Map



For the purpose of this analysis, the Pacific Northwest region is comprised of the states of Washington and Oregon, which have populations of 6 million and 3.5 million, respectively. In 2002, natural gas consumption in the two-state region averaged 42.5 Mm^3d (1.5 Bcfd), 4% of total U.S. gas consumption. Residential demand accounted for 17% of the total, commercial usage 12%, and industrial demand (excluding cogeneration) 42%. Gas demand for power generation accounted for 23% of total gas demand. Figure 3-20 shows gas transmission pipelines in this region.

The Pacific Northwest has a strong manufacturing base that includes pulp and paper, mining, lumber, chemicals, airplane construction and electronics. Because of the region's population, resource base, and proximity to the large California market and Pacific ports it is generally regarded as a favorable site for new enterprises. It is reasonable to expect, therefore, that the area will continue to benefit from fairly steady economic growth through the forecast period. Much of the growth will be in the commercial sector and in electronics manufacturing. Buoyed by strong population growth and housing construction, residential gas demand is expected to rise more rapidly in the Pacific Northwest than in the US as a whole.

Until recently, gas demand for electrical generation has been relatively insignificant because of the region's strong hydro resources. Hydro generation capacity accounts for nearly 90% of total electricity generation capacity in the region. The rest is split among coal, nuclear, gas and other facilities.

More than 12,000 MW of incremental gas-fired electrical generation capacity are reportedly in various stages of development or consideration throughout the region including nearly 8,000 MW in Washington, alone, and 4,500 MW in Oregon. Although many of the proposed facilities will not be developed, based on the most recent information available with respect to new gas-fired capacity installations, the forecast indicates that gas demand for power generation in the U.S. Pacific Northwest will grow more rapidly than for the U.S. as a whole. This and growing residential sector demand will provide most of the growth opportunities for Canadian gas.

Table 3-6: Pacific Northwest Gas Demand (Mm^3d and Bcfd)

						Increase (Mm^3d)			
Mm^3d	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
PNW Total	43.63	52.05	65.99	77.73	84.29	8.41	13.94	11.75	6.56
Residential	7.38	10.93	12.08	14.46	15.84	3.54	1.15	2.38	1.38
Commercial	5.41	7.15	7.78	8.93	9.58	1.74	0.63	1.15	0.64
Industrial	18.22	19.05	19.42	20.77	22.13	0.82	0.37	1.35	1.36
Power Generation	9.99	11.93	23.68	30.76	34.22	1.94	11.76	7.07	3.46
Other	2.62	3.00	3.02	2.82	2.53	0.37	0.03	-0.20	-0.29
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
PNW Total	1.54	1.84	2.33	2.74	2.98	0.30	0.49	0.41	0.23
Residential	0.26	0.39	0.43	0.51	0.56	0.13	0.04	0.08	0.05
Commercial	0.19	0.25	0.27	0.32	0.34	0.06	0.02	0.04	0.02
Industrial	0.64	0.67	0.69	0.73	0.78	0.03	0.01	0.05	0.05
Power Generation	0.35	0.42	0.84	1.09	1.21	0.07	0.41	0.25	0.12
Other	0.09	0.11	0.11	0.10	0.09	0.01	0.00	-0.01	-0.01

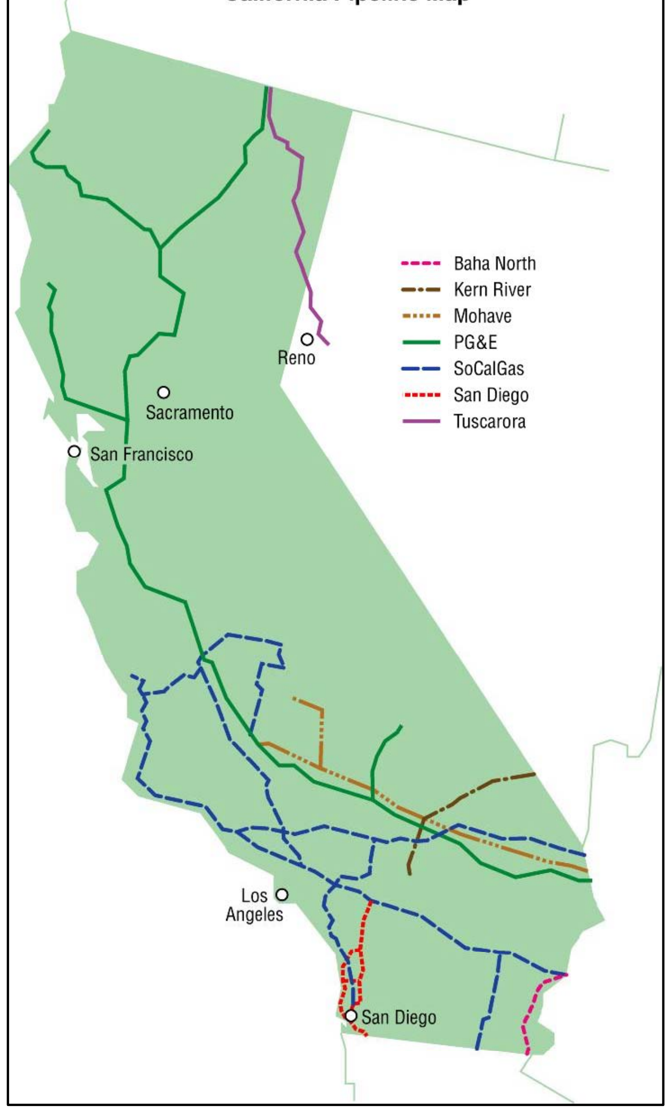
Table 3-6 indicates how gas demand in the Pacific Northwest is anticipated to increase through the forecast period, both in total and by sector. In the Base Case, Pacific Northwest end-use gas consumption is indicated to increase 8.4 Mm^3d (0.3 Bcfd) during the period from 2002 to 2010 to reach 52.1 Mm^3d (1.8 Bcfd), and then increase 32.2 Mm^3d (1.1 Bcfd) during the 2010 to 2030 period to reach 84.3 Mm^3d (3.0 Bcfd). Essentially, the region's requirements will almost double during the forecast period.

As anticipated, most of the demand growth will be in relation to the requirements of an expanding fleet of gas-fired electricity generation units. Power generation gas requirements are expected to grow to 11.9 Mm^3d (0.4 Bcfd) in 2010 and 34.2 Mm^3d (1.2 Bcfd) in 2030 compared with 10.0 Mm^3d (0.4 Bcfd) in 2002. Population-driven housing growth will result in fairly robust growth in the residential sector's demand for gas through the forecast period, adding 3.6 Mm^3d (0.1 Bcfd) by 2010 and another 4.9 Mm^3d (0.2 Bcfd) by 2030. Commercial sector demand is increasing by only 4.2 Mm^3d (0.2 Bcfd) through the entire 2002 to 2030 period. Industrial gas demand excluding power generation is indicated as growing only a bit more rapidly, on average, than total US gas demand, increasing from 18.2 Mm^3d (0.6 Bcfd) in 2002 to 22.1 Mm^3d (0.8 Bcfd) in 2030.

3.6 California

California, with a population of 34 million, 10% greater than Canada's, represents a large gas market in itself. In 2002 the state consumed 158.6 Mm^3d (5.6 Bcfd) of gas, about 7% of combined U.S. and Canadian gas requirements. Industrial usage (excluding cogeneration) accounted for the largest (39%) share of California's end-use gas consumption in 2002. Residential and commercial customers consumed 22% and 11%, respectively. Figure 3-21 shows gas transmission pipelines in California.

Figure 3-21
California Pipeline Map



The prominence of California's industrial sector reflects the State's 10% share of all U.S. manufacturing output. Electronic and electrical equipment manufacturing is California's largest industry in terms of value added. Industrial machinery, instruments, aerospace, shipbuilding, automobile assembly, food processing, and wine making, are also important activities. California also ranks third, after Oregon and Washington, in forestry and lumber operations, and fourth in mining activities (including oil and gas production).

The major manufacturing activities are concentrated in southern California and in the San Francisco Bay Area. The aircraft industry, which is heavily depended on military spending, is centered along the Los Angeles to San Diego corridor. Automobile assembly operations are located in Fremont and in the San Fernando Valley near Los Angeles. There are major shipbuilding facilities in San Diego and an array of diverse manufacturing activities, including chemicals, printing, and food processing in and around San Francisco.

With consumption of 36.1 Mm^{3}d (1.3 Bcfd), electric power generation accounted for 23% of California's gas consumption in 2002. According to California Energy Commission (CEC), 37% of the electrical energy consumed in California was produced from natural gas-fired generation in 2002, nine-tenths of which was located in California. Hydroelectric generation provided 19%, nuclear energy 15%, and renewable generation 11%. The remaining 20% was supplied by coal-fired generation, 40% of which was imported from the Desert Southwest and the Pacific Northwest.

Table 3-7 indicates how California gas demand is anticipated to increase through the forecast period, both in total and by sector. The Base Case analysis projects that power generation will account for most of the growth in California gas demand during the forecast period. Between 2002 and 2010, gas usage for power generation is projected to nearly double from 36.1 Mm^{3}d (1.3 Bcfd) to 69.1 Mm^{3}d (2.4 Bcfd), with further growth to 116.7 Mm^{3}d (4.1 Bcfd) expected by 2025. Growth will taper off after 2025, as gas-fired generation becomes less competitive with other resources. Gas demand growth in the residential, commercial, and industrial sectors is projected to grow 26%, 41%, and 32%, respectively, between 2003 and 2030.

Table 3-7: California Gas Demand (Mm^{3}d and Bcfd)

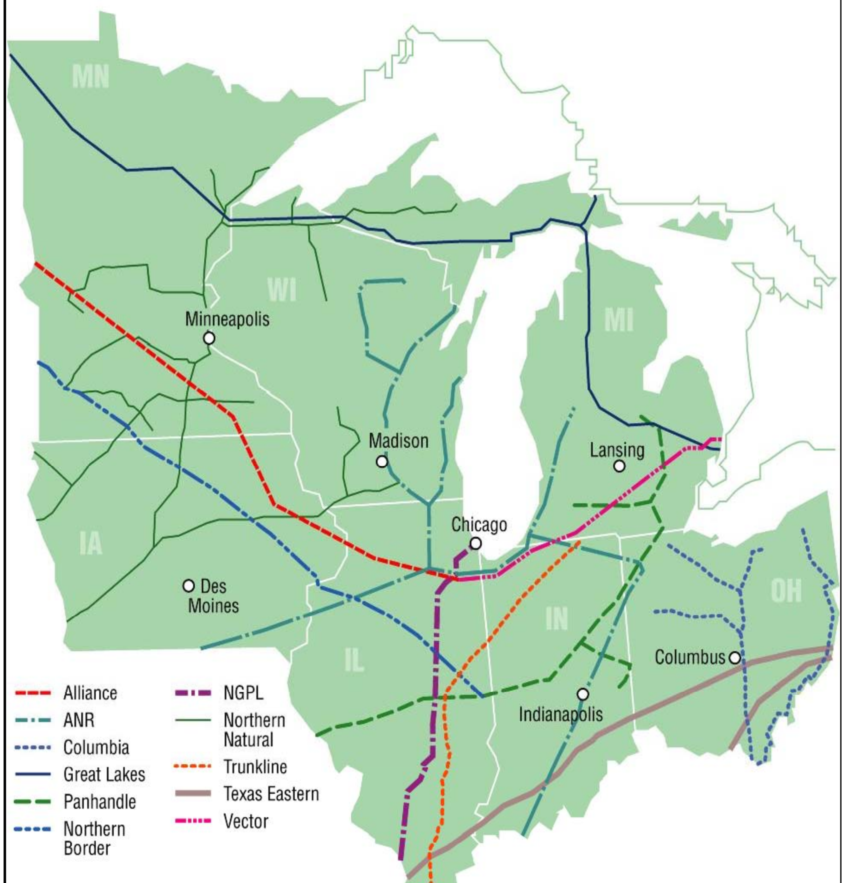
						Increase (Mm^{3}d)			
Mm^{3}d	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
California Total	158.89	203.60	224.82	269.18	282.54	44.71	21.22	44.36	13.36
Residential	34.82	41.06	41.61	42.96	43.80	6.24	0.55	1.36	0.84
Commercial	17.46	20.42	21.58	23.75	24.65	2.96	1.17	2.16	0.90
Industrial	62.15	64.03	67.39	76.29	81.86	1.88	3.36	8.90	5.56
Power Generation	36.06	69.13	84.92	116.67	122.97	33.07	15.78	31.76	6.29
Other	8.39	8.96	9.32	9.50	9.26	0.57	0.36	0.18	-0.24
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
California Total	5.61	7.19	7.94	9.50	9.97	1.58	0.75	1.57	0.47
Residential	1.23	1.45	1.47	1.52	1.55	0.22	0.02	0.05	0.03
Commercial	0.62	0.72	0.76	0.84	0.87	0.10	0.04	0.08	0.03
Industrial	2.19	2.26	2.38	2.69	2.89	0.07	0.12	0.31	0.20
Power Generation	1.27	2.44	3.00	4.12	4.34	1.17	0.56	1.12	0.22
Other	0.30	0.32	0.33	0.34	0.33	0.02	0.01	0.01	-0.01

The composition of California gas supply changes markedly during the forecast period. In the Base Case analysis, Rocky Mountain gas and LNG imports are expected to supply a growing share of the State's future gas consumption. In contrast, shares of local gas production, imports from Canada, and supplies from the San Juan Basin are projected to decline in relative importance. In-state gas production is projected to grow 10% to about 28.3 Mm^{3}d (1.0 Bcfd) by 2017 but decline thereafter, causing its share to fall from the current 16% to 9% in 2030. Gas imports from Canada are projected to remain at the current level of about 39.7 Mm^{3}d (1.4 Bcfd) through 2010 and then decline to about 28 .3 Mm^{3}d (1.0 Bcfd) in 2030. As a result, Canada's share of California's gas supply falls from 25% to 10% during the period. Gas from the Rocky Mountain region, including coalbed methane, increases rapidly from 17.0 Mm³d (0.6 Bcfd) today to 28.3 Mm³d (1.0 Bcfd) in 2010 and 65.2 Mm³d (2.3 Bcfd) in 2030. As a result, the Rocky Mountain share doubles from 11% in 2002 to 23% in 2030. With imports of LNG expected to begin in 2006 and grow to 70.8 Mm³d (2.5 Bcfd) in 2030, LNG is expected to supply 14% of total consumption in 2010 and 25% in 2030. Supplies from the San Juan Basin and all other U.S. sources except the Rocky Mountains increase from 76.5 Mm³d (2.7 Bcfd) in 2002 to 87.8 Mm³d (3.1 Bcfd) in 2030, but their share of total California supply falls from 48% to 31% during the intervening years.

3.7 Midwestern United States

The Midwestern United States, comprised of the states of Ohio, Indiana, Illinois, Michigan, Minnesota, and Wisconsin, has a population of approximately 50 million. In 2002 this region's gas consumption averaged 297.7 (10.5 Bcfd) – about 15% of total Canadian and U.S. Lower 48 gas consumption. The residential sector accounted for 40% of the region's gas requirements in 2002. Commercial and industrial usage (excluding cogeneration) accounted for 21% and 34%, respectively of 2002 demand. Figure 3-22 shows gas transmission pipelines in the Midwest.

Figure 3-22
Midwestern U.S. Pipeline Map



The Midwest's large industrial sector consists of a wide range of energy intensive industries, including automotive manufacturing, glass, cement, chemical, and tire production. Only 2% of total gas consumption was used for power generation, reflecting the region's heavy dependence on coal-fired electric generation.

Gas demand for power generation is anticipated to increase over the next 10 years as gas-fired capacity is installed to replace existing coal plants that reach the end of their useful service lives. After 2015 however, gas-fired power generation falls back to minimal levels as declining real coal prices make it more difficult for gas-fired generating facilities to compete.

Table 3-8 indicates how gas demand in the U.S. Midwest is forecast to increase through the forecast period, both in total and by sector. Industrial sector gas demand, excluding cogeneration, will remain essentially flat through 2010 but is anticipated to stage a comeback during the final 20 years of the forecast horizon. By 2030, industrial gas consumption in the Midwestern U.S. is projected to average 120.0 Mm^3d (4.2 Bcfd), 19 % higher than in 2010.

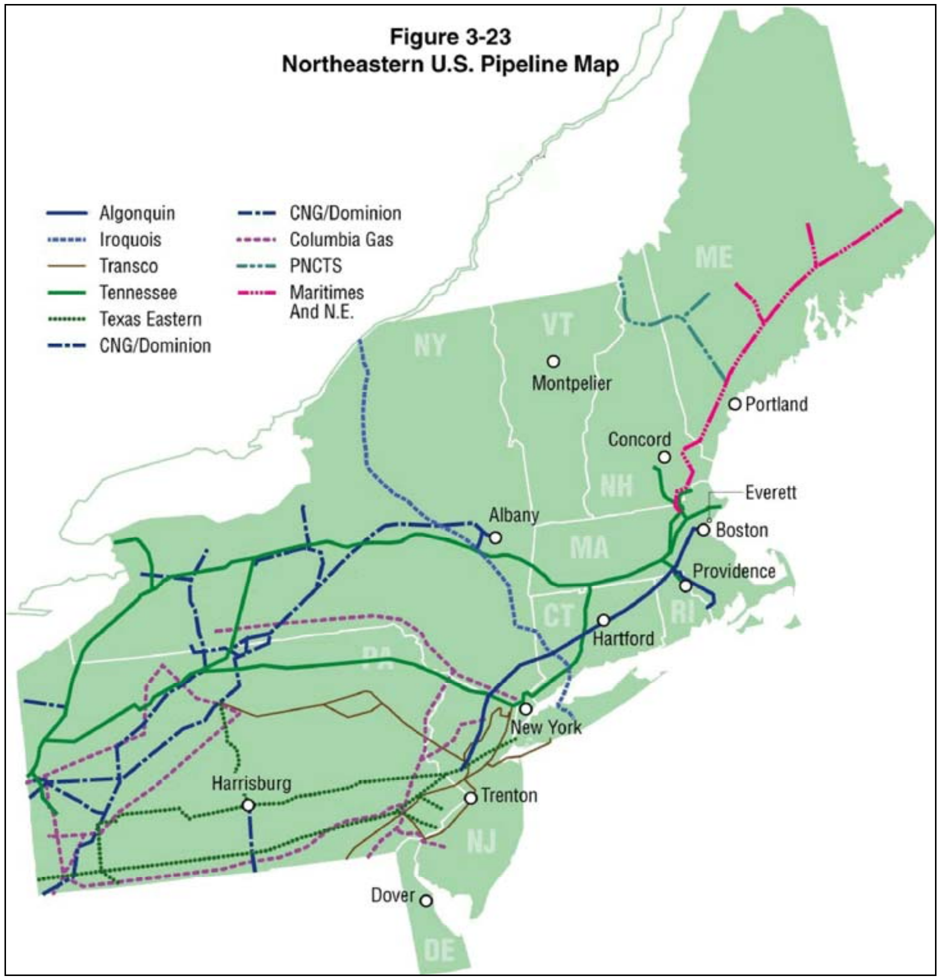
Residential and commercial sector gas demand both increase strongly, growing by 36% and 39%, respectively, between 2003 and 2030. As a result of these trends, in the Base Case, total Midwestern U.S. gas consumption expands by 82.2 Mm^3d (2.9 Bcfd) or 28% from 297.7 Mm^3d (10.5 Bcfd) in 2002 to 379.9 Mm^3d (13.4 Bcfd) in 2030.

Table 3-8: Midwestern U.S. Gas Demand (Mm^3d and Bcfd)

						Increase (Mm^3d)			
Mm^3d	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Midwest Total	297.67	337.12	350.17	368.44	379.91	39.44	13.05	18.27	11.47
Residential	119.01	140.64	145.18	155.81	161.77	21.63	4.54	10.63	5.96
Commercial	62.66	73.83	76.77	83.64	87.04	11.17	2.94	6.87	3.39
Industrial	100.91	98.84	101.93	112.49	120.02	-2.07	3.09	10.56	7.54
Power Generation	6.05	13.25	15.44	5.77	0.03	7.21	2.19	-9.67	-5.73
Other	9.05	10.55	10.84	10.73	11.04	1.50	0.29	-0.11	0.31
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Midwest Total	10.51	11.90	12.36	13.01	13.41	1.39	0.46	0.64	0.40
Residential	4.20	4.96	5.12	5.50	5.71	0.76	0.16	0.38	0.21
Commercial	2.21	2.61	2.71	2.95	3.07	0.39	0.10	0.24	0.12
Industrial	3.56	3.49	3.60	3.97	4.24	-0.07	0.11	0.37	0.27
Power Generation	0.21	0.47	0.55	0.20	0.00	0.25	0.08	-0.34	-0.20
Other	0.32	0.37	0.38	0.38	0.39	0.05	0.01	0.00	0.01

Throughout the forecast, gas production in the Midwest remains stable at about 22.7 Mm^3d (0.8 Bcfd), meeting about 8% of the region's requirements initially but much less as demand increases. Net gas imports from Canada currently provide one-third of the Midwest's requirements. The Canadian share is expected to remain at this level until about 2010. Thereafter, net gas imports from Canada decline steadily as growing demand and declining production in Western Canada reduce export flows to the Midwestern U.S. With stable production and less Canadian supply, the Midwest becomes more dependent on other sources of supply, particularly LNG and Gulf of Mexico supplies. By 2030, local production and net imports of Canadian gas represent only 7% of consumption requirements.

3.8 Northeastern United States



In this Study, the Northeastern United States is defined as the ten-state region that stretches from Maine to Delaware along the eastern seaboard of the United States.[12] The region has a combined population of 55 million. In 2002, this heavily populated region consumed 248.5 Mm^3d (8.8 Bcfd) of gas, 13% of the daily gas requirements of Canada and the United States. The largest share (32%) was consumed by the residential sector, which burned 78.6 Mm^3d (2.8 Bcfd) of gas in 2002. The commercial and industrial sectors consumed 25% and 22%, respectively. Power generation accounted for 20% of 2002 demand. Figure 3-23 shows gas transmission pipelines in the U.S Northeast.

Although the Northeast region has a large population, the industrial sector's share of the region's gas consumption is less than that of the other regions that constitute the main U.S. markets for Canadian gas. This reflects the region's higher concentration of wholesale and retail trade and other services. Although there are important manufacturing industries, they constitute a smaller portion of overall economic activity than in California, the Pacific Northwest or the Midwestern U.S.

[12] That is, the Northeastern United States includes the six New England states (Maine, New Hampshire, Vermont, Massachusetts, Connecticut, and Rhode Island), plus New Jersey, New York, Pennsylvania, and Delaware.

Table 3-9: Northeastern U.S. Gas Demand (Mm^3d and Bcfd)									
						Increase (Mm^3d)			
Mm^3d	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Northeast Total	248.54	312.46	343.41	363.39	384.55	63.92	30.96	19.97	21.16
Residential	78.62	93.60	97.34	106.28	111.15	14.98	3.74	8.94	4.86
Commercial	62.46	78.55	85.71	101.55	108.96	16.09	7.16	15.84	7.41
Industrial	53.59	51.48	53.04	58.93	63.05	-2.11	1.55	5.89	4.12
Power Generation	49.19	83.41	101.80	91.25	96.05	34.22	18.39	-10.55	4.79
Other	4.67	5.41	5.52	5.36	5.34	0.74	0.11	-0.16	-0.02
						Increase (Bcfd)			
Bcfd	**2002**	**2010**	**2015**	**2025**	**2030**	**2003-2010**	**2011-2015**	**2016-2025**	**2026-2030**
Northeast Total	8.77	11.03	12.12	12.83	13.57	2.26	1.09	0.70	0.75
Residential	2.78	3.30	3.44	3.75	3.92	0.53	0.13	0.32	0.17
Commercial	2.20	2.77	3.03	3.58	3.85	0.57	0.25	0.56	0.26
Industrial	1.89	1.82	1.87	2.08	2.23	-0.07	0.05	0.21	0.15
Power Generation	1.74	2.94	3.59	3.22	3.39	1.21	0.65	-0.37	0.17
Other	0.16	0.19	0.19	0.19	0.19	0.03	0.00	-0.01	0.00

Table 3-9 summarizes the outlook for gas demand in the Northeastern U.S. through the forecast period, both in total and by sector. Most of the growth in the region's gas demand in the next ten years is projected to come from the power generation sector as many new gas-fired power plants are built to replace aging coal and nuclear facilities and to maintain operating margins. However, this trend is anticipated to diminish in the second half of the forecast period. After 2015, the natural gas share of both replacement and incremental generating capacity is expected to decline due to the increased competitiveness of coal-fired generation using improved coal combustion technologies, and the widening differential between natural gas and coal prices.

Industrial gas requirements will grow less rapidly in the Northeast than in the United States as a whole for several reasons. First, manufacturing growth is anticipated to be concentrated in regions with faster population growth, like the southeastern U.S. and California. Second, manufacturing investment will be more attracted to regions such as the West, Southeast, and Northwest, where energy costs are generally lower. In addition, the industrial sector share of gas demand has already been shrinking in the Northeast as local economies shift from goods to services producing activities.

The Base Case analysis projects gas demand for power generation to more than double from 49.2 Mm^3d (1.7 Bcfd) in 2002 to 101.8 Mm^3d (3.6 Bcfd) in 2015, after which it will decline somewhat as aging gas-fired plants are replaced by more efficient gas units and coal becomes more competitive. In 2030, gas demand for power generation is projected to be 96.1 Mm^3d (3.4 Bcfd), somewhat lower than in 2015, but 46.9 Mm^3d (1.7 Bcfd) or 95% greater than in 2002.

Industrial gas requirements, excluding cogeneration, are projected to grow to 63.1 Mm^3d (2.2 Bcfd) in 2030, an increase of 9.5 Mm^3d (0.3 Bcfd) or 18% over 2002. Residential demand is expected to grow 32.5 Mm^3d (1.1 Bcfd) or 41% to 111.2 Mm^3d (3.9 Bcfd) while commercial demand expands 46.5 Mm^3d (1.7 Bcfd) or 74% to 109.0 Mm^3d

(3.9 Bcfd). The region's total demand is thus projected to reach 384.6 Mm^3d (13.6 Bcfd) in 2030, an increase of 136.0 Mm^3d (4.8 Bcfd) or 55% over 2002.

To meet its gas requirements, the Northeast turns increasingly to LNG and Eastern Canadian offshore production as the demands on western Canadian supplies from inside Canada and other regions increase during the forecast period. The volume of LNG imported directly into the Northeast region increases from 8.5 Mm^3d (0.3 Bcfd) in 2002 to 53.8 Mm^3d (1.9 Bcfd) by 2010, 96.3 Mm^3d (3.4 Bcfd) by 2020, and 113.3 Mm^3d (4.0 Bcfd) by 2030. As a result, the share of total gas consumption supplied by direct LNG imports steadily rises to 29% in 2030. Gas supplies from the eastern Canada offshore increase from 11.3 Mm^3d (0.4 Bcfd) in 2002 to 62.3 Mm^3d (2.2 Bcfd) in 2030, when they account for 16% of the Northeast market. Supplies from the WCSB, which currently meet 17% of the region's gas needs, decline from 42.5 Mm^3d (1.5 Bcfd) in 2002 to 8.5 Mm^3d (0.3 Bcfd) in 2030, only 2% of the market. An additional 14.2 Mm^3d (0.5 Bcfd) of gas is obtained from other U.S. regions, including LNG imported into the southeastern U.S. and Gulf of Mexico regions.

4 GAS SUPPLY AND DELIVERABILITY ANALYSIS

4.1 Overview

In the future, natural gas production will come from a mixture of mature production basins and new sources of supply. To the extent that the lower cost resource is depleted in existing basins, other sources of gas need to be developed. However, the growth of gas deliverability in the Base Case must also be augmented with substantial amounts of LNG to meet the growing needs of the market.

In the Base Case, production from existing supply sources in the U.S. Lower 48 will struggle to remain constant. The Base Case projects significant declines in the shelf of the Gulf of Mexico, the Mid-Continent, the San Juan Basin, and the Permian Basin. Production from these areas will decline 226.6 Mm^3d (8.0 Bcfd) by 2030. Other regions, except for the Rockies and the deep Gulf, will show slight gains in production at best.

The declines in production from existing supply sources are mainly due to the lack of high quality drilling prospects in the areas. Already, the North American gas market is experiencing declines in some basins. Recent historical production trends have shown significant declines in the shallow waters of the Gulf of Mexico and the Mid-Continent producing area. Recent historical production has been fairly flat in the Permian and San Juan Basins. Gas producers have had to work harder to develop additional deliverability. In 2001, a banner year for drilling with well over 1,100 active rigs, producers completed nearly 22,000 gas wells, but increased deliverability by only about 28.0 Mm^3d (1.0 Bcfd) in the U.S. In the surrounding historical years when drilling activity was much lower, deliverability remained flat or declined. Producers are working harder in mature areas, but are developing less productive gas resources. Whether it is due to increased decline rates, lower reserves, or a higher percentage of nonconventional wells (tight sands, coal bed methane, or shale), it appears that more wells are needed just to maintain the current rate of production.

In order for production to be maintained as fields naturally deplete, more expensive formations must be completed. The wells may be in deeper formations that have higher temperatures and pressures or the gas may be sour (containing sulfur) and more corrosive, requiring additional processing. Less permeable formations may be drilled. Such wells need to be fractured down hole in order to be produced economically. In general, most of the large natural gas reservoirs have been found. Future fields will be smaller and need to be more numerous to maintain the same level of production.

Growth in gas demand, and declining productive capacity in mature producing areas will result in an increased reliance on new producing frontiers in the future. The Base

Case projects that a much larger share of gas supply in the future will come from non-traditional sources of supply, sometimes referred to as "new frontier" gas supplies, including:

- Continued development of deepwater gas in the Gulf of Mexico;
- Continued development of conventional and unconventional gas from the Rocky Mountains;
- Development of Mackenzie Delta gas; and
- Significant development of Eastern Canada offshore gas.

A significant shift to currently untapped resources will take place over the next two decades. In fact, gas supplies from new producing frontiers in the Mackenzie Delta, the Rocky Mountain Region, the deep-water area of the Gulf of Mexico, and the Eastern Canada offshore will constitute a growing and substantial component of North America's gas supply. According to the study Base Case analysis, 521.2 Mm^3d (18.4 Bcfd) or 23% of total Canadian and U.S. Lower-48 gas demand will come from these sources in 2010 compared with only 15% in 2002. By 2020, nearly 680 Mm^3d (24.0 Bcfd) or 25% of combined Canadian and Lower-48 demand is projected to be met by gas from these "new frontier" areas. At the same time, aggregate production from all other areas will decline and constitute a smaller share. In short, much of the growth of the gas market over the next 27 years is likely to be sustained by development of currently untapped supplies from areas that are generally more remote from the consuming markets throughout North America, as well as imports of LNG.

4.2 Methodology for Gas Production Forecasts

The EEA modeling system relies upon the interaction of two models, the Gas Model Data Forecasting System (GMDFS) and the Hydrocarbon Supply Model (HSM).

GMDFS

As noted earlier, the study utilized EEA's GMDFS framework to track and forecast monthly behavior in Canadian and U.S. natural gas markets. The model simulates monthly gas markets to 2030, considering the impact of:

- Key gas supply drivers including U.S. and Canadian resource base, technology, and regional deliverability trends.
- Growth rates for economic drivers, such as GDP and industrial production for the U.S. and Canada.
- Growth rates for electricity end-use intensity by "full-state NERC" Region.
- Projected prices of crude oil and alternative fuels.
- Power generating capacity by type of capacity (i.e., coal, oil-gas steam, combustion turbine, and gas-fired combined cycle), nuclear retirements, and projected nuclear, hydro, and coal unit generation.
- Weather and hydrological conditions.

- Pipeline and storage expansions and changes to projected storage injection and withdrawal patterns,
- LNG imports and Mexican exports, and seasonal LNG requirements.

The GMDFS relies upon the Hydrocarbon Supply Model (described below) for the base projection of underlying long-term supply trends. The base projections of activity and deliverability from the Hydrocarbon Supply Model (HSM) are modified in the GMDFS, based upon supply and demand conditions and upstream activity levels.

HSM

The HSM was used to investigate gas supply issues for National Petroleum Council's (NPC) 1992, 1999, and 2003 studies on natural gas and is the source of the underlying long-term trends in gas supplies depicted the GMDFS. The HSM was developed by EEA for the Gas Technology Institute (GTI) in the early 1980s and has undergone numerous updates and improvements since then. The HSM is a PC-based analytical framework designed for the simulation, forecasting and analysis of natural gas, crude oil and natural gas liquids supply and cost trends in the United States and Canada. It is a process-engineering model with a very detailed representation of potential gas resources and the technologies with which those resources can be proven and produced.

The model covers the U.S. Lower 48, Alaska and Canada. The U.S. Lower 48 is broken down into thirteen onshore regions and four offshore regions. The onshore regions in the model are divided into four depth intervals: 0-5,000 feet, 5-10,000 feet, 10-15,000 feet, and below 15,000 feet. The offshore regions are divided into up to eight water depths. Each depth interval within each region is modeled with a unique resource base, exploratory find rates, drilling costs, and well production profiles. Canada is divided into five regions which are further divided into intervals representing drilling depths or subregional areas. Resources in the HSM are divided into three general categories: new field, field appreciation, and nonconventional.

Supply Nodes and HSM Regions

Output from the GMDFS is by model node, while the HSM analysis is by region. Figure 4-1 depicts the HSM model regions.[13]

[13] The map contained in Figure 4-1 is meant to illustrate the main gas-producing regions in Canada and the United States that are addressed within the HSM framework. It is not intended to accurately portray production prospects in particular areas or sub-regions. For example, segments of the "No Potential" zone may have potential but, as a whole, the zone is not regarded as holding much gas.

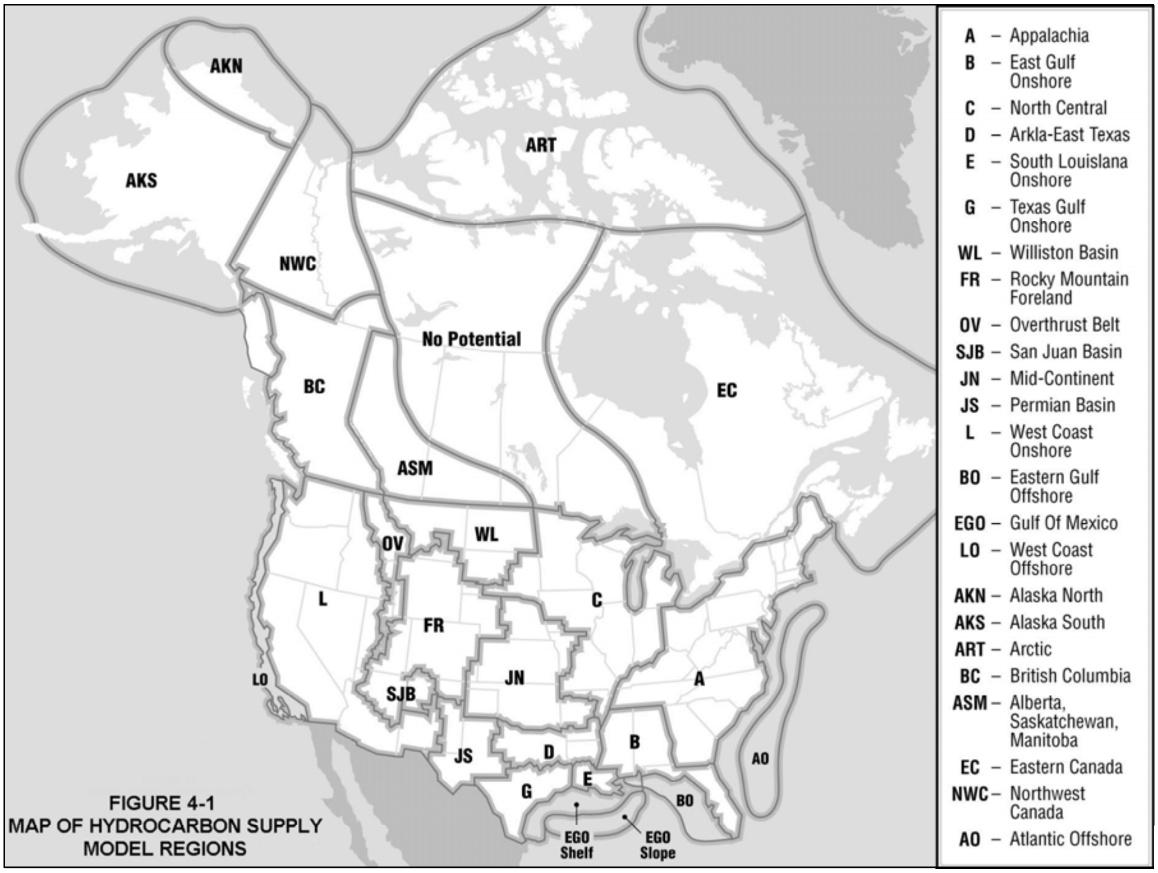


FIGURE 4-1
MAP OF HYDROCARBON SUPPLY
MODEL REGIONS

4.3 Resource Characterization in the HSM

The HSM uses resource base estimates, exploratory finding rates, drilling costs, and well production profiles to describe the operational nature of the exploration and production activities of both oil and gas. This approach captures the complexity of the process and allows the distinction between exploratory and economic success.

Conventional Undiscovered Resources

The central element in the supply modeling procedure is the estimate and distribution of the undiscovered gas resource available for exploration and subsequent development. The conventional undiscovered resource includes resources in undiscovered fields in both known and speculative plays. Known plays are those in which discoveries have been made. Speculative plays usually have a strong conceptual basis but no actual discoveries, and include areas that have very little seismic coverage or drilling data. The undiscovered conventional resource in the model is uniquely described for each region and depth by an exploration finding rate for each field size class. There are 20 field size classes ranging from about 635 cubic metres of oil equivalent to 317 million cubic metres (4,000 BOE to 2 billion BOE). Each size class is twice the size of the next smaller class.[14]

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[14] For conversion to metric it was assumed that there are 6.3 barrels of oil equivalent per cubic metre.

Historical drilling and production data used to define the characteristics (largest field, number and rank of fields, shape of the distribution, etc.) of the field size distributions and finding rates. In frontier areas, the field size distributions are developed from geologic analogs.

The exploration process in an area rapidly increases geologic "knowledge" by condemning some parts of an area as non-prospective and identifying others as having high potential. During the early exploration of an area, many of the very large fields are found. As exploratory drilling progresses, it tends to be concentrated in known productive areas where smaller fields are targeted, thus leading to an increase in the number of fields discovered per unit of exploration activity. However, the number of fields of a given size per unit of activity eventually decreases with time.

The Arps-Roberts equation was developed in 1958 to describe the phenomenon that a decreasing number of fields of a given size will be found per unit of exploration and results in an exponential decline in the rate at which all field size classes are found. However, historical data indicate that while this may be true for large fields, small to medium fields are found in greater numbers than predicted by Arps-Roberts. To adequately model the number of small fields found per unit of drilling activity, the HSM employs a modified Arps-Roberts find rate equation called the double-exponential equation. This formulation adds a term to the Arps-Roberts equation to account for the concentration over time of drilling in known areas, targeting of smaller fields, and the learning curve from exploratory drilling.

The HSM simulates the exploration process for total hydrocarbons. Because oil and gas usually occur in similar geologic settings, their exploration, development, and production histories are necessarily intertwined. The model explores for hydrocarbons and once they are found, allocates them to oil and non-associated gas. The user-specified relative occurrence of gas to oil for each region and depth interval forms the basis for a split of discovered hydrocarbons between oil and gas. Associated and dissolved gas and natural gas liquids are determined from ratios applied to the discovered oil and non-associated gas volumes.

In the U.S. the model makes a further distinction between high and low permeability gas. Low permeability gas is generally defined as that gas occurring in formations with a permeability of less than 0.1 millidarcy. The historical record includes many instances of fields being exploited that are, under this definition, low permeability gas. Thus, undiscovered low permeability fields in these areas are described in the finding rate equations and field size distributions developed from the analysis of the historical record.

Table 4-1 shows the relationship between the GMDFS model nodes and HSM regions.

Table 4-1: Hydrocarbon Supply Model Regions and Corresponding GMDFS Model Nodes

HSM Region no.	HSM Region code	HSM Region name	GMDFS Model Node
1	A	Appalachia	05 (New York)
1	A	Appalachia	06 (Pennsylvania)
1	A	Appalachia	11 (Ohio)
1	A	Appalachia	18 (Tennessee/Kentucky)
1	A	Appalachia	19 (Virginia/Maryland)
1	A	Appalachia	80 (West Virginia)
2	B	Eastern Gulf Onshore	10 (Florida)
2	B	Eastern Gulf Onshore	54 (Northern Alabama)
2	B	Eastern Gulf Onshore	56 (Mississippi/Southern Alabama)
3	C	North Central	17 (Michigan)
3	C	North Central	14 (Indiana)
3	C	North Central	15 (S. Illinois)
4	D	Arkla - East Texas	61- D (Northern Louisiana/Arkansas)
4	D	Arkla - East Texas	64 (Texas RRC 5 and 6)
5	E	South Louisiana	58 (Southeastern Louisiana)
5	E	South Louisiana	60 (Henry Hub Area)
6	G	Texas Gulf Onshore	65 (Texas RRC 3)
6	G	Texas Gulf Onshore	66 (Texas RRC 1, 2, and 4)
7	WL	Williston Basin	41 (Montana/North Dakota)
7	WL	Williston Basin	24 (Ventura)
8	FR	Rocky Mtn. Foreland	29 (DJ Basin)
8	FR	Rocky Mtn. Foreland	30 (partial) - FR (Opal Area)
8	FR	Rocky Mtn. Foreland	34 (Powder River Basin)
8	FR	Rocky Mtn. Foreland	83 (Wind River Basin)
8	FR	Rocky Mtn. Foreland	31 (Cheyenne)
9	SJ	San Juan Basin	32 (San Juan Basin)
10	OV	Overthrust Belt	30 (partial) -OV (Opal Area)
11	JN	Mid-Continent	28 (Oklahoma/Kansas)
11	JN	Mid-Continent	61 - JN (Northern Louisiana/Arkansas)
11	JN	Mid-Continent	68 (partial) -JN (Northwest Texas)
12	JS	Permian Basin	63 (Permian Basin)
12	JS	Permian Basin	68 (partial) -JS (Northwest Texas)
13	L	West Coast Onshore	36 (Southern California)
13	L	West Coast Onshore	37 (California EOR)
13	L	West Coast Onshore	38 (Northern California)
14	BO	Eastern Gulf of Mexico	55 (Norphlet Trend)
14	BO	Eastern Gulf of Mexico	71 (Sale 181)
15	EGO	Cent. & West. Gulf of Mex.	57 (Eastern Gulf Shelf)
15	EGO	Cent. & West. Gulf of Mex.	59 (Viosca Knoll/Destoto Canyon/Miss. Canyon/Destin Dome)
15	EGO	Cent. & West. Gulf of Mex.	62 (Central Gulf Shelf)
15	EGO	Cent. & West. Gulf of Mex.	67 (Offshore Texas)
15	EGO	Cent. & West. Gulf of Mex.	69 (East Breaks and Garden Banks)
15	EGO	Cent. & West. Gulf of Mex.	70 (Green Canyon)
16	LO	West Coast Offshore	39 (Pacific Offshore)
17	AO	Atlantic Offshore	50 (Atantic offshhore)
18	AKS	Alaska South	87 (Southern Alaska)
19	AKN	Alaska North	89 (Northern Alaska)
20	ASM	Alberta, Sas. Man.	74 (Alberta)
20	ASM	Alberta, Sas. Man.	76 (Saskatchewan)
21	BC	British Columbia	72 (British Columbia)
22	NWC	Northwest Canada	86 (MacKenzie Delta)
23	EC	Eastern Canada	49 (Eastern Canada/Maritimes)
23	EC	Eastern Canada	78 (Dawn)
24	ART	Arctic Canada	None

Once the results of an exploratory program are determined, an economic analysis of each of the field sizes using all of the parameters is utilized to determine which of the fields are economic for development. The overall economics of the exploration program are then evaluated to determine if they provide an acceptably attractive investment opportunity and, if not, the exploration program is deferred.

After a field is "discovered," the model simulates the process by which reserves are developed in the field over time. The number of wells required for field development is largely predicated on field area and volume. The largest fields have the highest recoveries per well but still require the most wells for full development. Historical data on number of wells drilled in fields of a specific size class, average recovery per well, and cost components are utilized to model drilling requirements for fields in each region and depth interval.

Nonconventional Resources

Coalbed methane, tight gas, and shale gas are modeled separately in the HSM. The HSM contains over 200 "cells" to model nonconventional gas in the U.S. and Canada. Each cell contains a representation of the resource and the cost components to drill and produce the resource. Data items that are included are drilling depth, recovery per well, drilling and completion cost, stimulation cost, and a typical production profile. Economics are evaluated on an after-tax discounted cash flow (DCF) basis.

Drilling and Completion Costs

The HSM uses estimates of capital and operating costs for the exploration, development, and production phases of a discovery for field economic calculations. Regional costs vary due to geography, climate, and reservoir depth.

In addition to the standard costs of drilling and completion, gas wells drilled in tight reservoirs are assumed to have additional well stimulation costs. These costs apply only to the onshore regions because no tight gas is modeled for the offshore regions.

The HSM calculates changes to constant dollar base drilling costs over time as industry activity and business conditions change. Regression-based algorithms estimated from a review of historical data are utilized to create an index of future costs.

Rate of Return

The HSM attempts to replicate the decision-making process used by producers in determining the annual level of exploration and development activity that will take place in each supply region. Of the many assumptions required to do this, one of the criteria is the minimum real rate of return (ROR) required from the after-tax DCF analysis of a project.

In establishing the annual exploration program, an after-tax, DCF analysis is performed for potential exploration and production programs in each region/depth interval with the model. The HSM then selects which exploration programs will be undertaken, based upon a ranking by profit index and after considering any inertial and capital constraints imposed. The resulting exploration program is then carried out, yielding an inventory of discoveries for development. Another DCF analysis is then done for the discoveries to determine which of these developments would be economic.

4.4 Well Productivity and Decline Rate Analysis

Estimated Ultimate Recovery (EUR) Per Well

A key component of the analysis of historical data for the HSM is the analysis of gas well recoveries and decline rates. Figure 4-2 presents data on recent trends in gas completion activity and recovery per well. The data show that since 1990, recovery per new gas completion has been declining in the Gulf of Mexico and Western Canada.

The first table in Figure 4-2 presents the data for the U.S. Lower 48 onshore. Interestingly, Estimated Ultimate Recovery (EUR) per connection for the onshore has been remarkably stable, remaining at a level of about 25.5 Mm^3 to 28.3 Mm^3 (0.9 to 1.0 Bcf). These data exclude coalbed methane and shale gas. Inclusion of these wells would result in a decline in mean EUR per well for recent years, since average recoveries for coalbed and shale are lower and there have been thousands of new coalbed and shale wells.

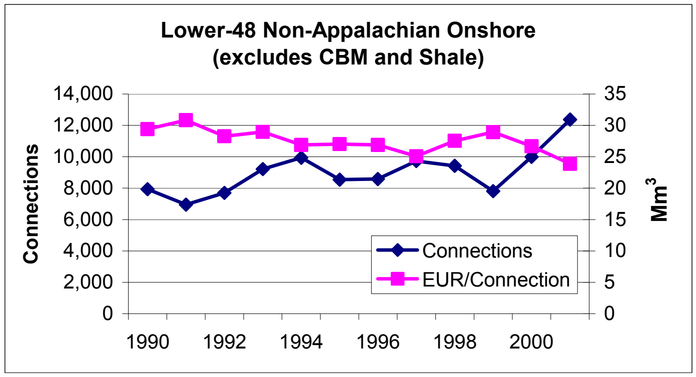
The second table shows the Gulf of Mexico shelf excluding the Norphlet. Here, average recovery per new connection has declined substantially, from about 141.6 Mm^3 (5.0 Bcf) to a current level of below 99.2 Mm^3 (3.5 Bcf).

The third table presents data for the WCSB and shows a steep decline in recovery per well, corresponding to a large increase in gas well connections. Average recovery per connection has declined from 48.2 Mm^3 (1.7 Bcf) to below 14.2 Mm^3 (0.5 Bcf). Most of the decline in EUR per completion has been the result of the drilling activity shift to shallower productivity wells.

Figure 4-2
Lower 48 and Canada Gas Connections and
Expected Ultimate Recovery (EUR) Per Connection
(Mm^3)

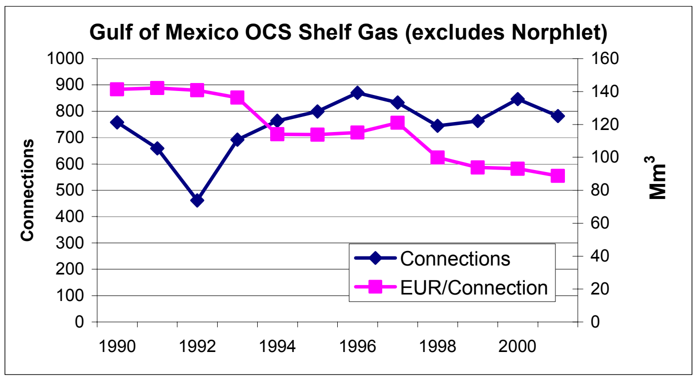
Lower-48 Non-Appalachian Onshore (excludes CBM and Shale)

	Gas Connections	EUR/Connection Mm^3	Bcf
1990	7,931	29.4	1.038
1991	6,953	30.8	1.088
1992	7,693	28.3	0.997
1993	9,218	29.0	1.022
1994	9,942	26.9	0.949
1995	8,544	27.0	0.954
1996	8,587	26.9	0.949
1997	9,723	25.1	0.886
1998	9,426	27.5	0.972
1999	7,807	28.9	1.021
2000	9,986	26.7	0.942
2001	12,367	23.9	0.843



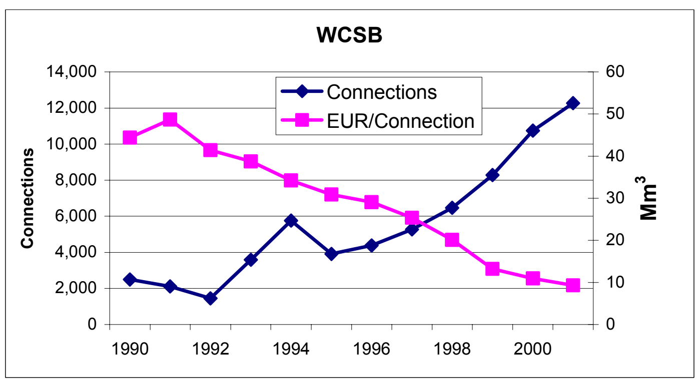
Gulf of Mexico OCS Shelf - excludes Norphlet

	Gas Connections	EUR/Connection Mm^3	Bcf
1990	758	141.3	4.989
1991	659	142.1	5.015
1992	461	140.8	4.969
1993	692	136.3	4.812
1994	764	114.0	4.024
1995	799	113.7	4.015
1996	870	115.1	4.064
1997	833	121.0	4.271
1998	745	99.9	3.526
1999	763	93.8	3.310
2000	846	93.0	3.283
2001	782	88.7	3.132



WCSB

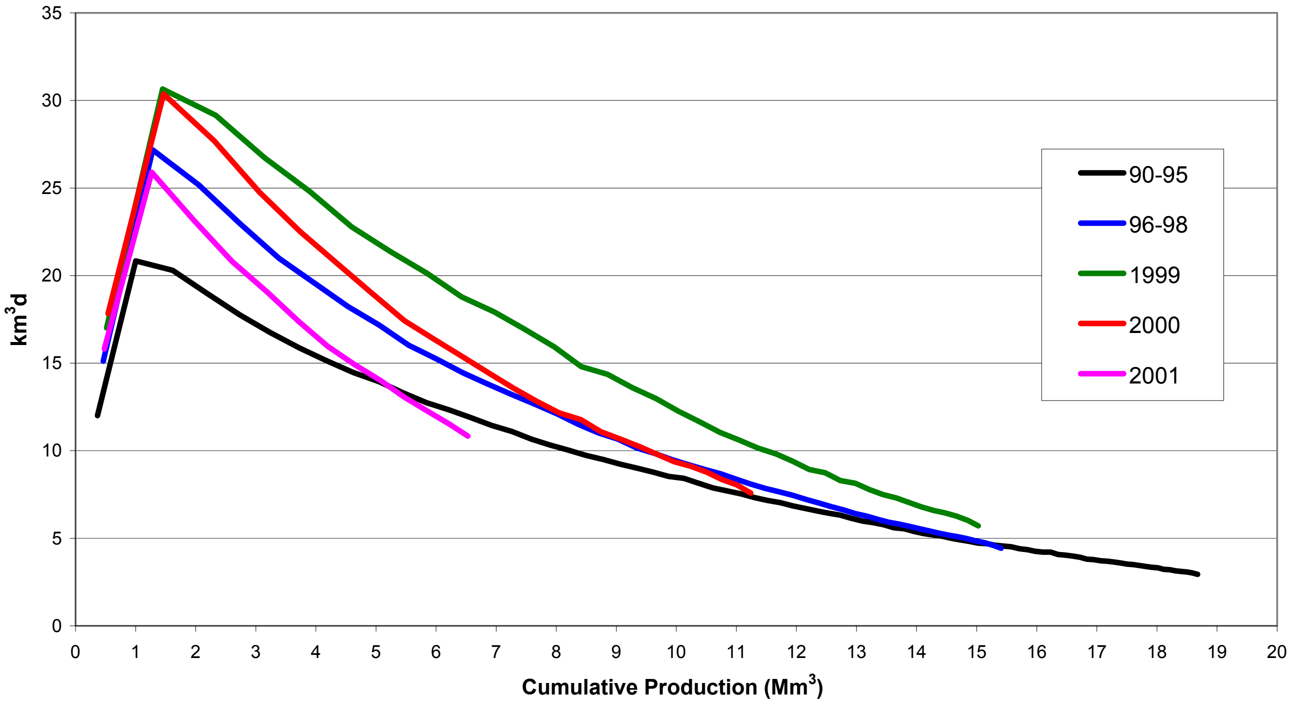
	Gas Connections	EUR/Connection Mm^3	Bcf
1990	2501	44.394	1.567
1991	2118	48.690	1.719
1992	1453	41.425	1.462
1993	3592	38.748	1.368
1994	5767	34.226	1.208
1995	3913	30.884	1.090
1996	4387	29.052	1.026
1997	5268	25.373	0.896
1998	6476	20.142	0.711
1999	8289	13.223	0.467
2000	10752	10.982	0.388
2001	12266	9.294	0.328



Decline Rates for New Gas Wells
Figures 4-3 through 4-8 present the results of a recent EEA analysis of decline rates by well vintage for the U.S. Lower 48 onshore, the Gulf of Mexico shelf and the WCSB. In the metric unit figures the production rates shown on the vertical axis are expressed in thousands of cubic metres per day (km³d). In the imperial unit figures, the production rates are presented in millions of cubic feet per day (MMcfd).

Figures 4-3 and 4-4 show the results of the U.S. Lower 48 Non-Appalachian Onshore analysis for non-coalbed non-shale gas. The oldest completion vintage in the analysis is the 1990-95 grouping. This vintage is shown to have the flattest decline rate. Subsequent vintages are shown to have steeper decline rates. The peak rate of production for the average (non-coalbed, non-shale) completion increased greatly after 1995, from 20.8 km³d (0.7 MMcfd) to about 30.6 km³d (1.1 MMcfd), before declining slightly.

Figure 4-3: Lower 48 Non-Appalachian Onshore Gas Well Rate vs. Cumulative Production by Connection Vintage
Raw Gas Well Gas - Excludes Coalbed and Shale



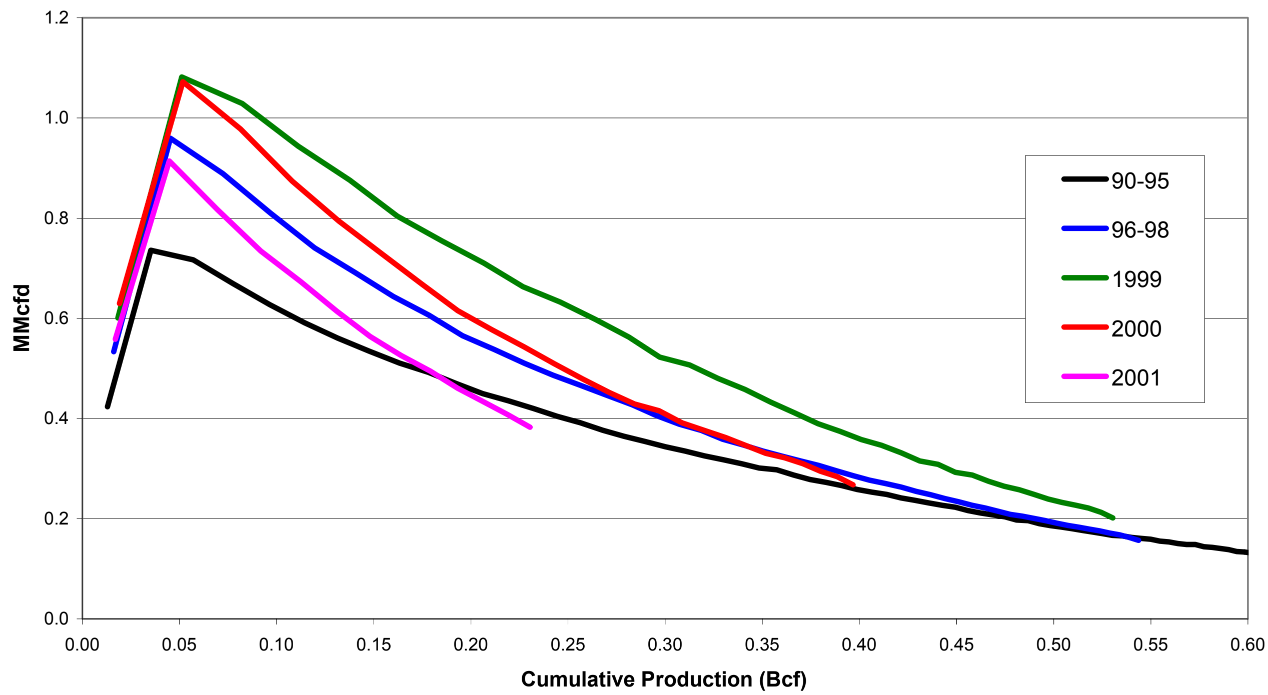


Figure 4-4: Lower 48 Non-Appalachian Onshore Gas Well Rate vs. Cumulative Production by Connection Vintage
Raw Gas Well Gas - Excludes Coalbed and Shale

Figures 4-5 and 4-6 present the results for the Gulf of Mexico shelf data excluding the Eastern Gulf of Mexico Norphlet trend. In this case, the oldest vintage also shows a lower rate of decline than subsequent vintages. However, there is only a slight increase in the decline rate after 1998. The peak rate of production increased from about 146 km^3d (5.2 MMcfd) to about 176 km^3d (6.2 MMcfd) before declining in recent years.

Figure 4-5: Gulf of Mexico Shelf Gas Well Rate vs. Cumulative Production by Connection Vintage Class - Raw Gas Well Gas - Excludes Norphlet

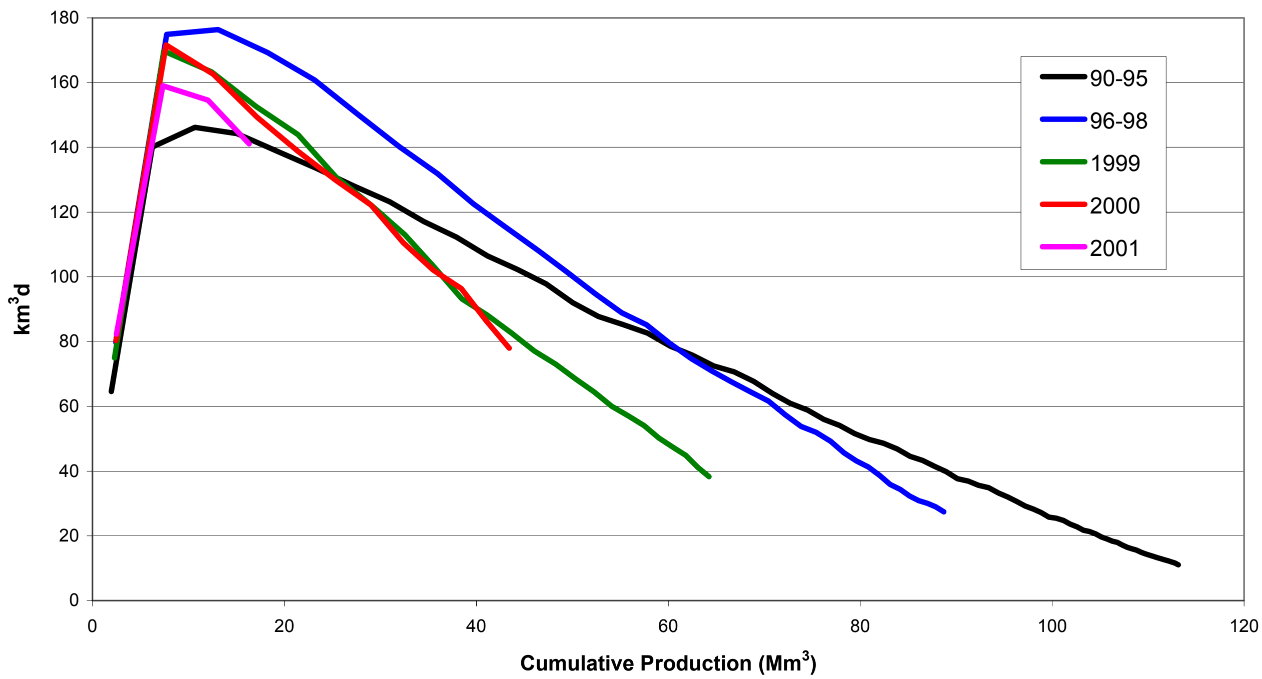
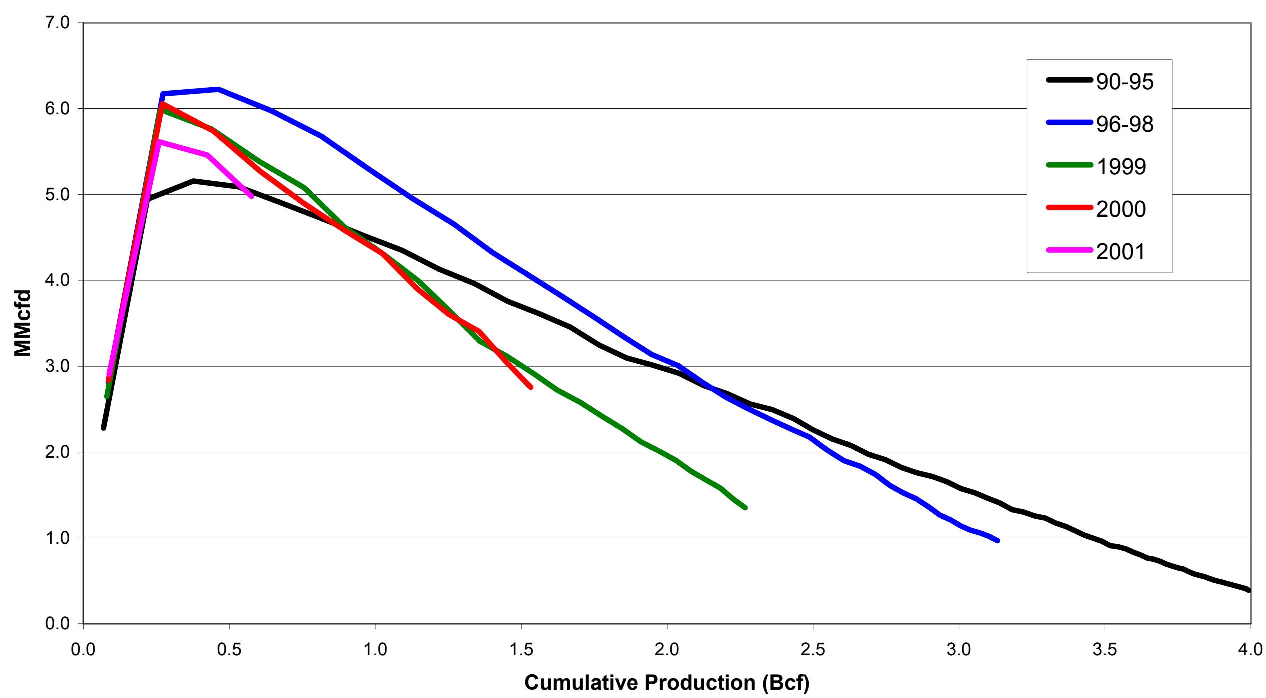


Figure 4-6: Gulf of Mexico Shelf Gas Well Rate vs. Cumulative Production by Connection Vintage Class - Raw Gas Well Gas - Excludes Norphlet



Figures 4-7 and 4-8 present the Western Canada Sedimentary Basin data in metric and imperial units, respectively. Again, there is an obvious increase in the decline rates between the 1990-95 and the 1996-98 curves. There appears to be only a slight increase in decline rates for subsequent vintages. The peak rate of production for the oldest vintage was 22.9 km³d (0.8 MMcfd). This was stable through 1998 completions, but it has fallen greatly over the past few years, to approximately 13 km³d (0.5 MMcfd).

Figure 4-7: WCSB Gas Well Rate vs. Cumulative Production by Connection Vintage Class - Raw Gas Well Gas

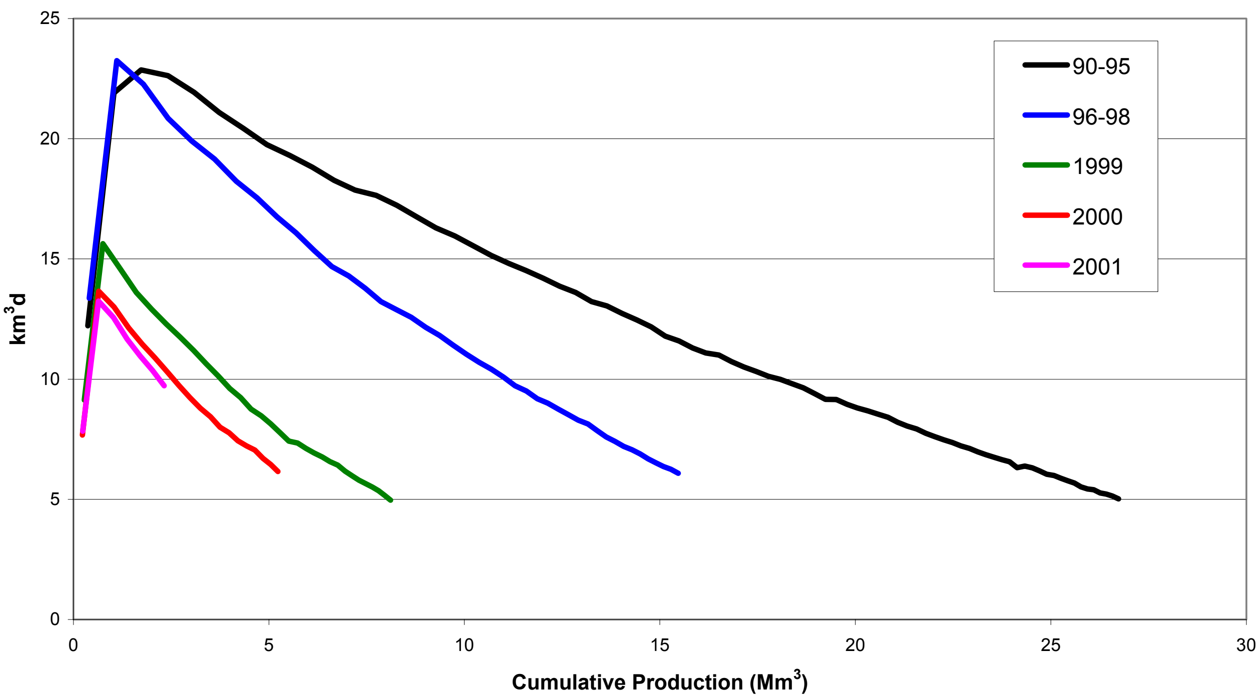
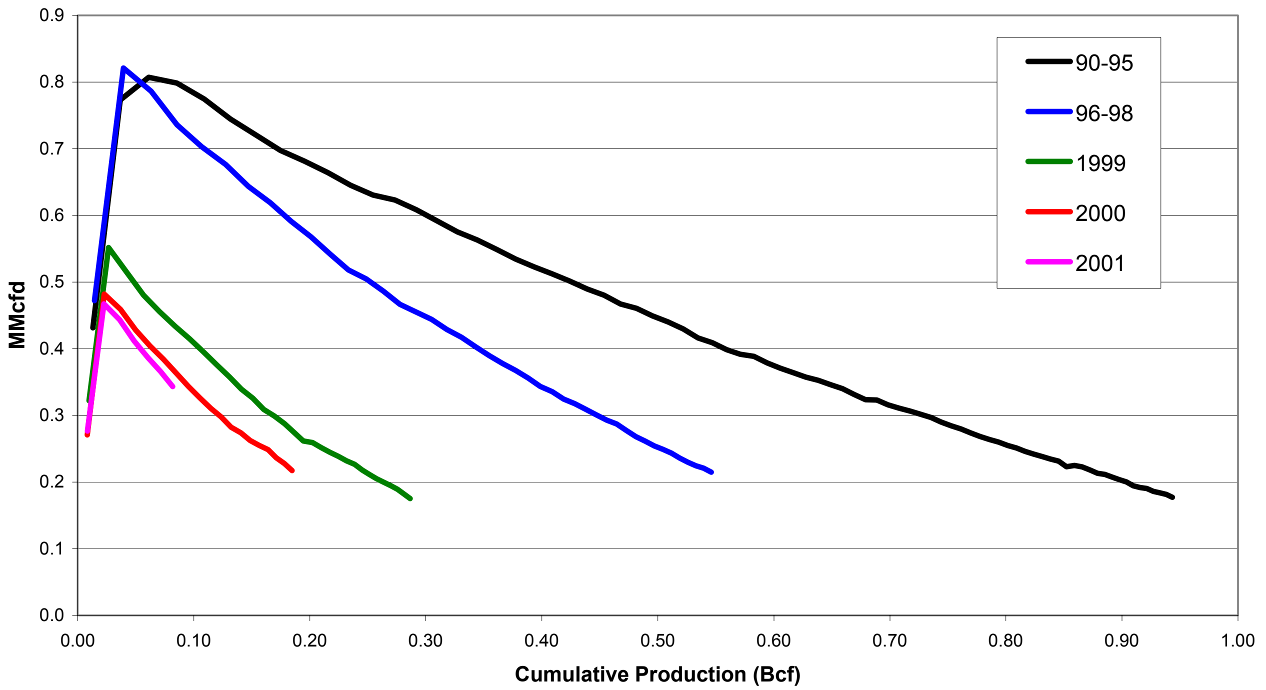


Figure 4-8: WCSB Gas Well Rate vs. Cumulative Production by Connection Vintage Class - Raw Gas Well Gas



Summary of EUR and Decline Rate Trends
On average, the U.S. Lower 48 onshore (excluding coalbed and shale) has experienced relatively stable EUR per well trends. At the same time the decline rates have steepened. Interestingly, the average peak rate of production increased. This appears to support the hypothesis that producers are using technology to recover the gas more quickly.

In the Gulf of Mexico shelf, EUR per completion has declined by about one-third since 1990. Decline rates have steepened here as well. As in the onshore, peak rates increased after 1995, perhaps indicating that new technologies are being used. In Western Canada, average EUR per well has declined by more than 50% since 1990, largely due to the drilling shift within the ASM region. Production decline rates steepened substantially after 1995. The average peak rate of production also dropped off after 1999.

4.5 North American Gas Resource Base

There are 24 North American regions including the U.S. Lower 48, Canada, and Alaska. Table 4-2 is a summary of the discovered and undiscovered dry marketable, recoverable total gas resource base for the U.S. Lower 48 and Canada. Total gas is defined as the sum of non-associated (gas well) gas and associated/dissolved (oil well) gas. The first three columns represent proved resources. These columns are cumulative production, proven reserves, and proved ultimate recovery (the sum of production and reserves). U.S. Lower 48 proved ultimate recovery as of January 1, 2002 was 31,229,858 Mm^3 (1,102.4 Tcf) and Canada's ultimate recovery was 5,314,193 Mm^3 (187.6 Tcf).

Unproven resources have been categorized as growth (reserve appreciation), new (conventional) fields, shale, coalbed, and tight gas. There is also a category of "other" which includes resources such as low-Btu gas in the Rockies. U.S. Lower 48 total unproven resources are assessed at 35,905,807 Mm^3 (1,267.5 Tcf) and Canada's total unproven resources at 15,073,711 Mm^3 (532.1 Tcf).

The sum of ultimate recovery and unproved resources is "all-time" recovery (shown in the last column). In theory, all-time recovery should remain constant as the resource is developed and produced, and more gas is shifted from unproven to proven. However, the history of North American resource assessments is that all-time recovery estimates tend to increase through time as industry gains knowledge about frontier areas and as technology improves. As a result, estimates of undiscovered gas have increased despite large-scale reserve additions.

The gas volumes presented in the table do not represent all of the remaining gas that will ultimately be available. Resources such as gas hydrates and extremely low permeability tight gas are not included. For example, the tight gas resources of the Green River Basin in SW Wyoming have been assessed by the United States Geological Survey (USGS). Only a small fraction of this resource is assumed to be recoverable. In general, resources not included in the table are those that are projected to be beyond the ability of industry to produce economically throughout the forecast period. Another consideration in evaluating the undiscovered resource base is the ongoing nature of nonconventional and frontier resource assessments. Coalbed methane in particular is still being assessed by the USGS (and Canadian groups for the Western Canada resource), and assessments are expected to increase substantially within a few years.

It should also be noted that the table includes both accessible and inaccessible resources. For example, most or all of the resource base in the U.S. Lower 48 Atlantic and Pacific Offshore is inaccessible, and a large percentage of the Foreland region (includes Rocky Mountain Region basins in Colorado, Wyoming, Utah and Wyoming) is either inaccessible or available with limitations. Most of the Eastern Gulf area is also currently off limits.

The resource volumes in the model are a function of technology. Technology is constantly improving and impacts the recoverable resource base. As well recovery improves, operators may access a higher percentage of gas in place. Seismic technology allows exploration of depth intervals that were not previously accessible. Offshore technology allows access to deeper waters and difficult plays. The advanced technology resource base shown in Table 4-2 assumes a level of technology available by 2015.

TABLE 4-2
Natural Gas Ultimate Recovery
and Undiscovered Resources as of January 1, 2002
Advanced Technology
(Technically recoverable resource)

(Mm^3 Dry Gas)

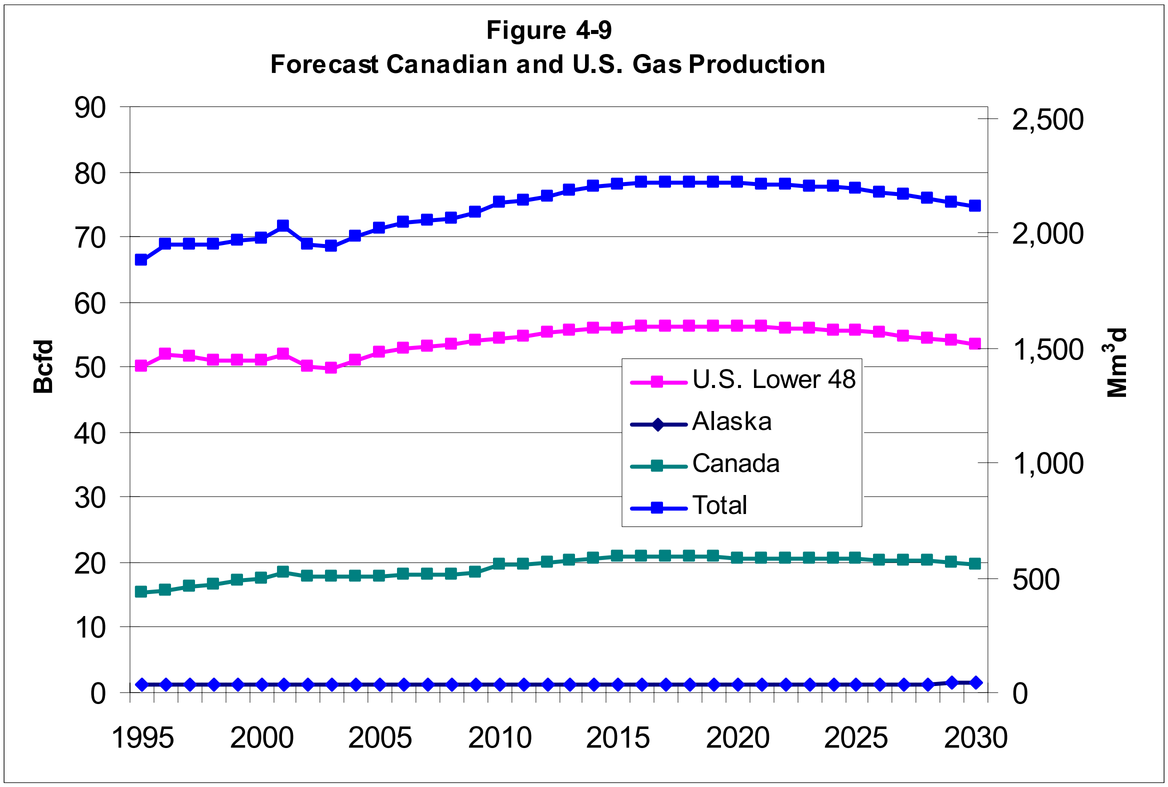
	Model Region	Cumulative Production	Proven Reserves	Ultimate Recovery	Old Field Appreciation	Discovered Undeveloped	New Fields	Shale	Coalbed	Tight	Other	Total Unproven	Expected All Time Recovery
1	A: Appalachia	1,299,915	266,176	1,566,091	57,734		738,669	662,578	550,510	517,450		2,526,941	4,093,031
2	B: Eastern Gulf Onshore	336,034	90,623	426,657	133,059		228,329		147,564			508,952	935,609
3	C: North Central	181,416	84,306	265,722	74,986		253,683	621,813	71,331			1,021,813	1,287,535
4	D: Arkla - East Texas	1,827,620	402,210	2,229,830	645,722		599,377	204,164		844,646		2,293,909	4,523,739
5	E: South Louisiana	2,892,493	146,884	3,039,377	515,382		382,408					897,790	3,937,167
6	G: Texas Gulf Onshore	4,126,601	459,178	4,585,779	1,387,082		1,115,156			258,187		2,760,425	7,346,204
7	WL: Williston Basin	127,195	36,431	163,626	60,283		81,926					142,210	305,836
8	FR: Rocky Mtn. Foreland	869,858	822,578	1,692,436	742,068		2,566,459		1,473,088	3,880,227	416,119	9,077,960	10,770,397
9	SJB: San Juan Basin	825,326	555,836	1,381,161	304,759		164,108		284,929			753,796	2,134,958
10	OV: Overthrust Belt	117,365	21,785	139,150	17,592		273,456					291,048	430,198
11	JN: Mid-Continent	5,095,581	680,170	5,775,751	1,294,958		1,057,252		211,020	479,405		3,042,635	8,818,385
12	JS: Permian Basin	2,985,779	463,909	3,449,688	503,399		834,873			553,003		1,891,275	5,340,963
13	L: West Coast Onshore	902,578	73,711	976,289	152,805		551,331					704,136	1,680,425
14	BO: Eastern Gulf of Mexico	99,943	96,912	196,856	55,184		1,147,394					1,202,578	1,399,433
15	EGO: Cent. & West. Gulf of Mex.	4,521,275	729,405	5,250,680	2,090,793		5,220,057					7,310,850	12,561,530
16	LO: West Coast Offshore	73,059	17,705	90,765	26,431		586,771					613,201	703,966
17	AO: Atlantic Offshore	0	0	0	0		866,289					866,289	866,289
	Lower 48 total	**26,282,040**	**4,947,819**	**31,229,858**	**8,062,238**		**16,667,535**	**1,488,555**	**2,738,442**	**6,532,918**	**416,119**	**35,905,807**	**67,135,666**
20	ASM: Alberta, Sas. Man.	3,139,433	1,361,388	4,500,822	339,943		2,286,232		1,133,144	708,215		4,467,535	8,968,357
21	BC: British Columbia	429,547	266,884	696,431	70,595		931,416		113,314			1,115,326	1,811,756
22	NWC: Northwest Canada	2,125	1,048	3,173	0	283,286	2,293,824					2,577,110	2,580,283
23	EC: Eastern Canada	40,028	73,739	113,768	13,824	311,615	3,045,779					3,371,218	3,484,986
24	ART: Arctic Canada	0	0	0	0	396,601	3,145,921					3,542,521	3,542,521
	Canada total	**3,611,133**	**1,703,059**	**5,314,193**	**424,363**	**991,501**	**11,703,173**		**1,246,459**	**708,215**		**15,073,711**	**20,387,904**

(Bcf Dry Gas)

	Model Region	Cumulative Production	Proven Reserves	Ultimate Recovery	Old Field Appreciation	Discovered Undeveloped	New Fields	Shale	Coalbed	Tight	Other	Total Unproven	Expected All Time Recovery
1	A: Appalachia	45,887	9,396	55,283	2,038		26,075	23,389	19,433	18,266		89,201	144,484
2	B: Eastern Gulf Onshore	11,862	3,199	15,061	4,697		8,060		5,209			17,966	33,027
3	C: North Central	6,404	2,976	9,380	2,647		8,955	21,950	2,518			36,070	45,450
4	D: Arkla - East Texas	64,515	14,198	78,713	22,794		21,158	7,207		29,816		80,975	159,688
5	E: South Louisiana	102,105	5,185	107,290	18,193		13,499					31,692	138,982
6	G: Texas Gulf Onshore	145,669	16,209	161,878	48,964		39,365			9,114		97,443	259,321
7	WL: Williston Basin	4,490	1,286	5,776	2,128		2,892					5,020	10,796
8	FR: Rocky Mtn. Foreland	30,706	29,037	59,743	26,195		90,596		52,000	136,972	14,689	320,452	380,195
9	SJB: San Juan Basin	29,134	19,621	48,755	10,758		5,793		10,058			26,609	75,364
10	OV: Overthrust Belt	4,143	769	4,912	621		9,653					10,274	15,186
11	JN: Mid-Continent	179,874	24,010	203,884	45,712		37,321		7,449	16,923		107,405	311,289
12	JS: Permian Basin	105,398	16,376	121,774	17,770		29,471			19,521		66,762	188,536
13	L: West Coast Onshore	31,861	2,602	34,463	5,394		19,462					24,856	59,319
14	BO: Eastern Gulf of Mexico	3,528	3,421	6,949	1,948		40,503					42,451	49,400
15	EGO: Cent. & West. Gulf of Mex.	159,601	25,748	185,349	73,805		184,268					258,073	443,422
16	LO: West Coast Offshore	2,579	625	3,204	933		20,713					21,646	24,850
17	AO: Atlantic Offshore	0	0	0	0		30,580					30,580	30,580
	Lower 48 total	**927,756**	**174,658**	**1,102,414**	**284,597**		**588,364**	**52,546**	**96,667**	**230,612**	**14,689**	**1,267,475**	**2,369,889**
20	ASM: Alberta, Sas. Man.	110,822	48,057	158,879	12,000		80,704		40,000	25,000		157,704	316,583
21	BC: British Columbia	15,163	9,421	24,584	2,492		32,879		4,000			39,371	63,955
22	NWC: Northwest Canada	75	37	112	0	10,000	80,972					90,972	91,084
23	EC: Eastern Canada	1,413	2,603	4,016	488	11,000	107,516					119,004	123,020
24	ART: Arctic Canada	0	0	0	0	14,000	111,051					125,051	125,051
	Canada total	**127,473**	**60,118**	**187,591**	**14,980**	**35,000**	**413,122**	**0**	**44,000**	**25,000**	**0**	**532,102**	**719,693**

4.6 Production Forecasts

The Base Case gas production forecast for the U.S. Lower 48, Canada, and Alaska is presented in Figures 4-9 and 4-10, and Table 4-3. The production forecast shows only moderate overall growth in annual gas production through 2030.



In the Base Case, U.S. Lower 48 gas production is forecast to peak in 2020 at 1,592.1 Mm^3d (56.2 Bcfd) and Canadian production is expected to peak in 2016 at 592.1 Mm^3d (20.9 Bcfd). Combined Canadian and U.S. production gas production is expected to peak at 2,181.3 Mm^3d (77.0 Bcfd) in 2016, representing an increase of 263.5 Mm^3d (9.3 Bcfd) or 14% over the 2002 level. The Alaska production shown in Figure 4-9 of about 34.0 Mm^3d (1.2 Bcfd) represents South Alaska production of about 14.2 Mm^3d (0.5 Bcfd) and North Alaska production of about 19.8 Mm^3d (0.7 Bcfd) that is consumed on the North Slope for field operations.

Figure 4-10
Gas Production Forecast for Western Canada Sedimentary Basin

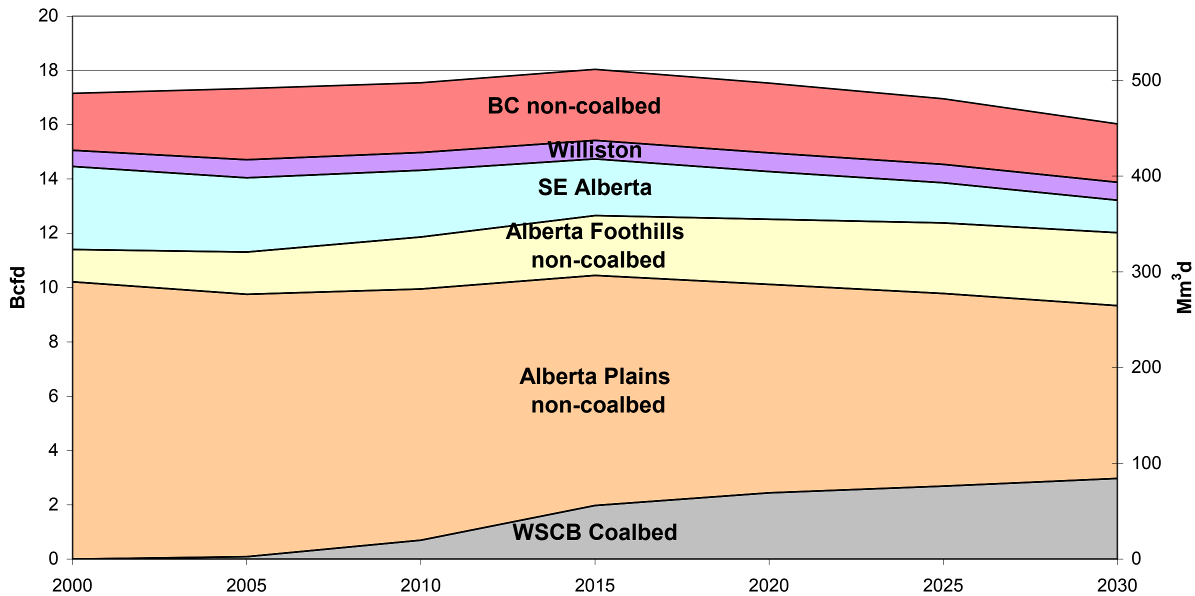


Figure 4-10 presents the gas production forecast for the Western Canada Sedimentary Basin. The forecast shows production increasing from the current rate of about 484.4 Mm^3d (17.1 Bcfd) to 509.9 Mm^3d (18.0 Bcfd) in 2015, before declining gradually through the remainder of the forecast. Coalbed methane production is forecast to increase to approximately 85.0 Mm^3d (3.0 Bcfd) by 2030.

Table 4-3
Node Production Aggregated by Hydrocarbon Model Region
(Mm^3d)

HSM		Historical						Projection					
Region		1997	1998	1999	2000	2001	2002	2005	2010	2015	2020	2025	2030
01_A	Appalachia	43.57	42.21	43.68	43.95	43.49	43.12	46.74	49.55	51.57	52.18	51.66	50.09
02_B	Eastern Gulf Onshore	21.54	21.10	21.41	21.33	20.44	20.60	20.60	20.17	20.12	19.90	19.56	19.14
03_C	North Central	19.30	18.72	17.65	16.19	12.66	13.70	14.11	13.99	12.84	11.65	10.43	9.21
04_D	Arkla - East Texas	111.78	107.54	103.67	109.48	118.62	115.64	135.47	138.61	138.46	137.60	136.04	134.14
05_E	South Louisiana	89.78	87.41	79.72	80.13	76.98	77.34	77.62	77.07	76.27	74.00	69.91	64.20
06_G	Texas Gulf Onshore	198.03	193.26	199.27	202.20	169.02	177.66	164.92	165.04	164.53	162.23	154.41	142.25
07_WL	Williston Basin	7.97	8.15	8.36	8.55	8.43	8.67	8.63	8.85	8.17	7.68	7.62	6.28
08_FR	Rocky Mtn. Foreland	84.82	92.73	100.11	107.72	134.70	128.88	158.70	202.51	249.74	287.91	315.17	331.83
09_SJ	San Juan Basin	108.19	111.18	111.98	110.93	107.17	108.23	105.84	99.88	93.91	87.94	82.34	77.11
10_OV	Overthrust Belt	14.69	15.74	16.36	16.59	18.70	18.30	20.88	26.31	23.88	18.40	20.59	21.92
11_JN	Mid-Continent	216.01	205.10	199.87	195.00	165.96	177.36	161.12	151.45	143.18	133.96	124.11	113.96
12_JS	Permian Basin	114.04	112.36	111.71	109.93	100.54	103.81	99.96	95.23	90.47	85.69	79.59	72.95
13_L	West Coast Onshore	17.27	19.99	21.82	22.07	22.51	22.44	23.15	24.70	25.65	25.68	24.95	23.82
14_BO	Eastern Gulf of Mexico	32.91	32.32	32.46	31.86	28.96	29.53	28.50	38.73	37.92	35.85	31.78	27.70
15_EGO	Cent & West GOM	376.86	375.80	374.55	366.95	373.67	367.66	409.44	426.53	446.37	448.01	439.57	417.43
16_LO	West Coast Offshore	3.61	3.82	3.81	3.75	3.69	3.65	3.75	3.78	3.58	3.29	2.98	2.67
17_ AO	Atlantic Offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18_AKS	Alaska South	12.65	12.36	13.61	13.03	13.57	13.45	14.10	14.98	15.99	17.22	18.65	20.41
19_AKN	Alaska North	20.60	20.75	20.75	20.64	19.17	19.39	19.04	20.04	19.87	19.67	19.50	19.34
20_ASM	Alberta, Sas. Man.	402.27	409.55	424.50	426.61	412.56	415.76	416.63	420.57	428.72	415.45	402.54	383.03
21_BC	British Columbia	54.45	56.92	58.07	59.41	71.65	69.15	74.41	76.37	82.25	81.31	77.90	71.17
22_NWC	Northwest Canada	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.51	34.51	34.51	34.51	34.51
23_EC	Eastern Canada	1.53	1.56	1.55	11.39	17.41	16.69	17.45	25.12	43.22	56.02	66.60	72.65
24_ART	Arctic Canada	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Mm^3d		**1,951.84**	**1,948.59**	**1,964.90**	**1,977.73**	**1,939.90**	**1,951.03**	**2,021.05**	**2,133.98**	**2,211.24**	**2,216.13**	**2,190.39**	**2,115.80**
Lower 48		1,460.34	1,447.44	1,446.42	1,446.66	1,405.55	1,416.58	1,479.42	1,542.39	1,586.68	1,591.96	1,570.70	1,514.71
Alaska		33.25	33.11	34.36	33.67	32.73	32.84	33.14	35.02	35.86	36.89	38.15	39.75
Canada		458.25	468.03	484.12	497.41	501.62	501.61	508.48	556.56	588.70	587.28	581.54	561.35
Total Mm^3 per year		**712,422**	**711,236**	**717,189**	**721,872**	**708,064**	**712,126**	**737,682**	**778,903**	**807,101**	**808,889**	**799,491**	**772,269**
Lower 48		533,025	528,317	527,944	528,029	513,025	517,053	539,989	562,974	579,137	581,067	573,304	552,868
Alaska		12,135	12,086	12,543	12,289	11,948	11,986	12,097	12,783	13,090	13,463	13,925	14,509
Canada		167,261	170,832	176,702	181,554	183,091	183,087	185,597	203,145	214,874	214,359	212,261	204,891

(Bcfd)

HSM		Historical						Projection					
Region		1997	1998	1999	2000	2001	2002	2005	2010	2015	2020	2025	2030
01_A	Appalachia	1.54	1.49	1.54	1.55	1.54	1.52	1.65	1.75	1.82	1.84	1.82	1.77
02_B	Eastern Gulf Onshore	0.76	0.74	0.76	0.75	0.72	0.73	0.73	0.71	0.71	0.70	0.69	0.68
03_C	North Central	0.68	0.66	0.62	0.57	0.45	0.48	0.50	0.49	0.45	0.41	0.37	0.33
04_D	Arkla - East Texas	3.95	3.80	3.66	3.86	4.19	4.08	4.78	4.89	4.89	4.86	4.80	4.74
05_E	South Louisiana	3.17	3.09	2.81	2.83	2.72	2.73	2.74	2.72	2.69	2.61	2.47	2.27
06_G	Texas Gulf Onshore	6.99	6.82	7.03	7.14	5.97	6.27	5.82	5.83	5.81	5.73	5.45	5.02
07_WL	Williston Basin	0.28	0.29	0.30	0.30	0.30	0.31	0.30	0.31	0.29	0.27	0.27	0.22
08_FR	Rocky Mtn. Foreland	2.99	3.27	3.53	3.80	4.76	4.55	5.60	7.15	8.82	10.16	11.13	11.71
09_SJ	San Juan Basin	3.82	3.92	3.95	3.92	3.78	3.82	3.74	3.53	3.31	3.10	2.91	2.72
10_OV	Overthrust Belt	0.52	0.56	0.58	0.59	0.66	0.65	0.74	0.93	0.84	0.65	0.73	0.77
11_JN	Mid-Continent	7.63	7.24	7.06	6.88	5.86	6.26	5.69	5.35	5.05	4.73	4.38	4.02
12_JS	Permian Basin	4.03	3.97	3.94	3.88	3.55	3.66	3.53	3.36	3.19	3.02	2.81	2.57
13_L	West Coast Onshore	0.61	0.71	0.77	0.78	0.79	0.79	0.82	0.87	0.91	0.91	0.88	0.84
14_BO	Eastern Gulf of Mexico	1.16	1.14	1.15	1.12	1.02	1.04	1.01	1.37	1.34	1.27	1.12	0.98
15_EGO	Cent & West GOM	13.30	13.27	13.22	12.95	13.19	12.98	14.45	15.06	15.76	15.81	15.52	14.74
16_LO	West Coast Offshore	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.12	0.11	0.09
17_ AO	Atlantic Offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18_AKS	Alaska South	0.45	0.44	0.48	0.46	0.48	0.47	0.50	0.53	0.56	0.61	0.66	0.72
19_AKN	Alaska North	0.73	0.73	0.73	0.73	0.68	0.68	0.67	0.71	0.70	0.69	0.69	0.68
20_ASM	Alberta, Sas. Man.	14.20	14.46	14.98	15.06	14.56	14.68	14.71	14.85	15.13	14.67	14.21	13.52
21_BC	British Columbia	1.92	2.01	2.05	2.10	2.53	2.44	2.63	2.70	2.90	2.87	2.75	2.51
22_NWC	Northwest Canada	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.22	1.22	1.22	1.22	1.22
23_EC	Eastern Canada	0.05	0.06	0.05	0.40	0.61	0.59	0.62	0.89	1.53	1.98	2.35	2.56
24_ART	Arctic Canada	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Bcfd		**68.90**	**68.79**	**69.36**	**69.81**	**68.48**	**68.87**	**71.34**	**75.33**	**78.06**	**78.23**	**77.32**	**74.69**
Lower 48		51.55	51.09	51.06	51.07	49.62	50.01	52.22	54.45	56.01	56.20	55.45	53.47
Alaska		1.17	1.17	1.21	1.19	1.16	1.16	1.17	1.24	1.27	1.30	1.35	1.40
Canada		16.18	16.52	17.09	17.56	17.71	17.71	17.95	19.65	20.78	20.73	20.53	19.82
Total Bcf per year		**25,148**	**25,107**	**25,317**	**25,482**	**24,995**	**25,138**	**26,040**	**27,495**	**28,491**	**28,554**	**28,222**	**27,261**
Lower 48		18,816	18,650	18,636	18,639	18,110	18,252	19,062	19,873	20,444	20,512	20,238	19,516
Alaska		428	427	443	434	422	423	427	451	462	475	492	512
Canada		5,904	6,030	6,238	6,409	6,463	6,463	6,552	7,171	7,585	7,567	7,493	7,233

Figure 4-11 shows the U.S. Lower 48 production forecast broken out by well vintages. The WCSB forecast is presented in Figure 4-12.

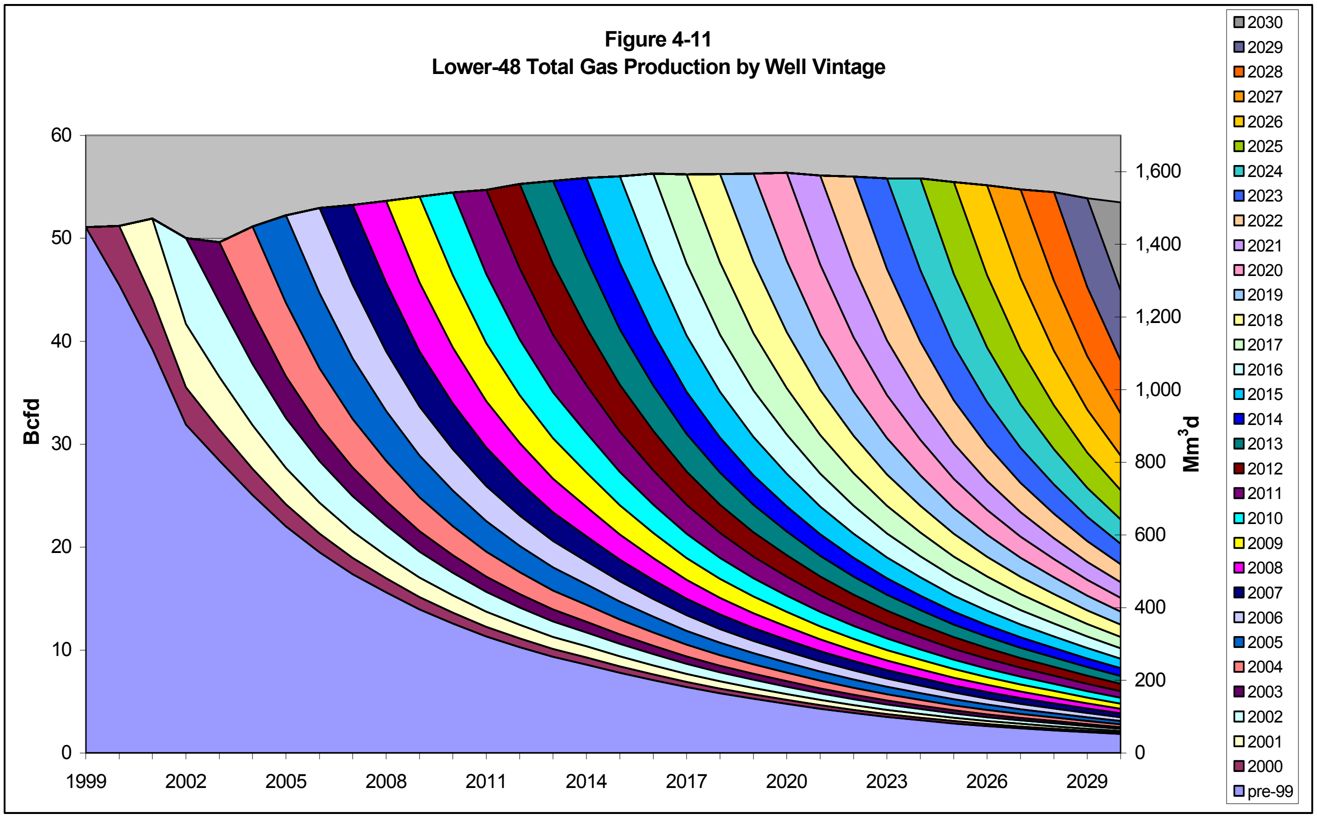


Figure 4-11
Lower-48 Total Gas Production by Well Vintage

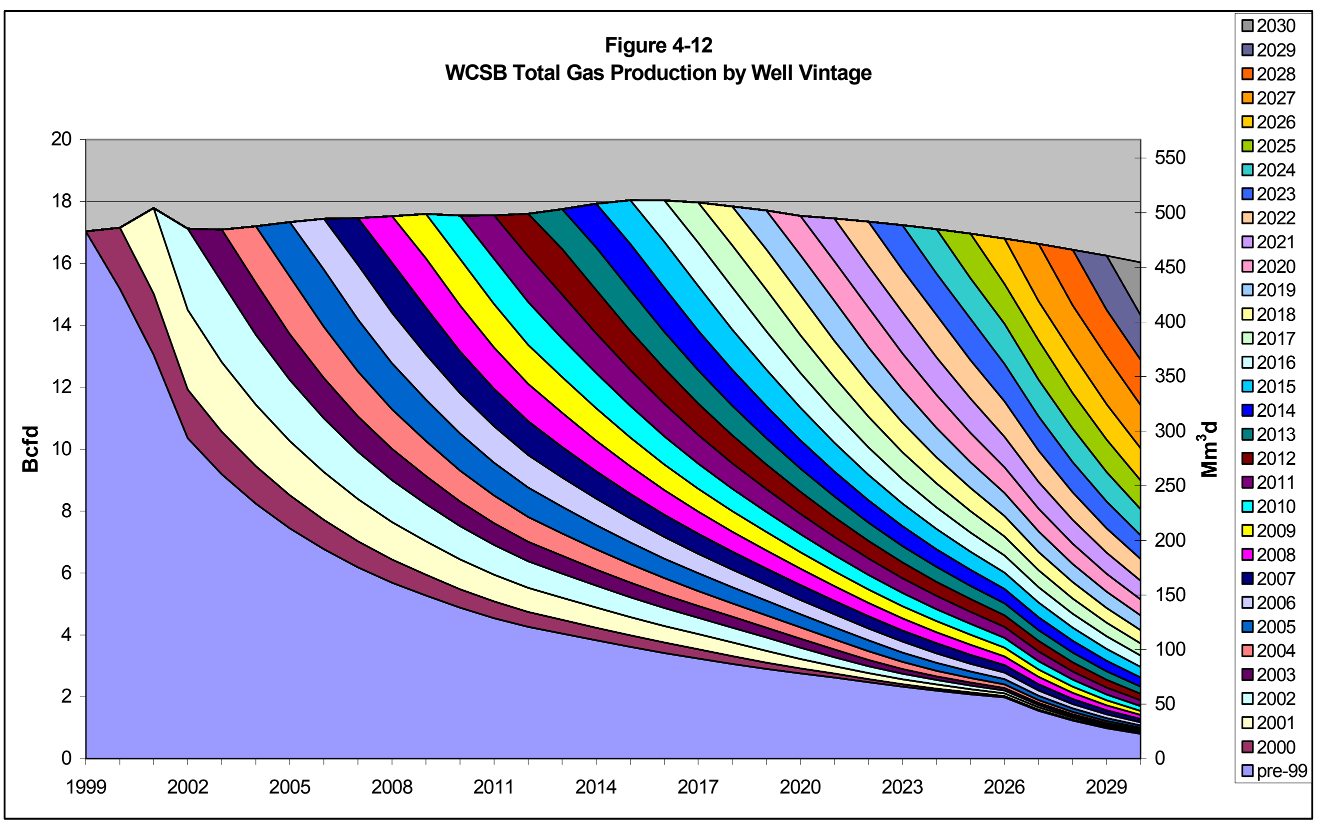


Figure 4-12
WCSB Total Gas Production by Well Vintage

Figures 4-11 and 4-12 illustrate the contrast in vintage production decline rates through the forecast period. In addition, they show the contribution of the older "pre-1999" reserves to the production forecast. For example, Figure 4-11 shows that by 2010, the pre-1999 reserves are expected to contribute only about 25% of annual production in the U.S. Lower 48. As shown in Figure 4-12, in the WCSB the pre-1999 reserves are expected to contribute about one-third of 2010 production.

The following is a discussion of activity and production trends in the most important North American producing regions as selected on the basis of gas production in 2010.[15]

Table 4-4 provides a listing of regions sorted by 2010 and 2020 gas production.

Alberta, Saskatchewan, and Manitoba

The Western Canada Sedimentary Basin accounts for most of the gas production in Canada. The HSM has two regions in the Western Canada Sedimentary Basin: the Alberta, Saskatchewan, Manitoba (ASM) region and the British Columbia (B.C.) region. These regions are divided into seven subregions as shown in Figure 4-13.

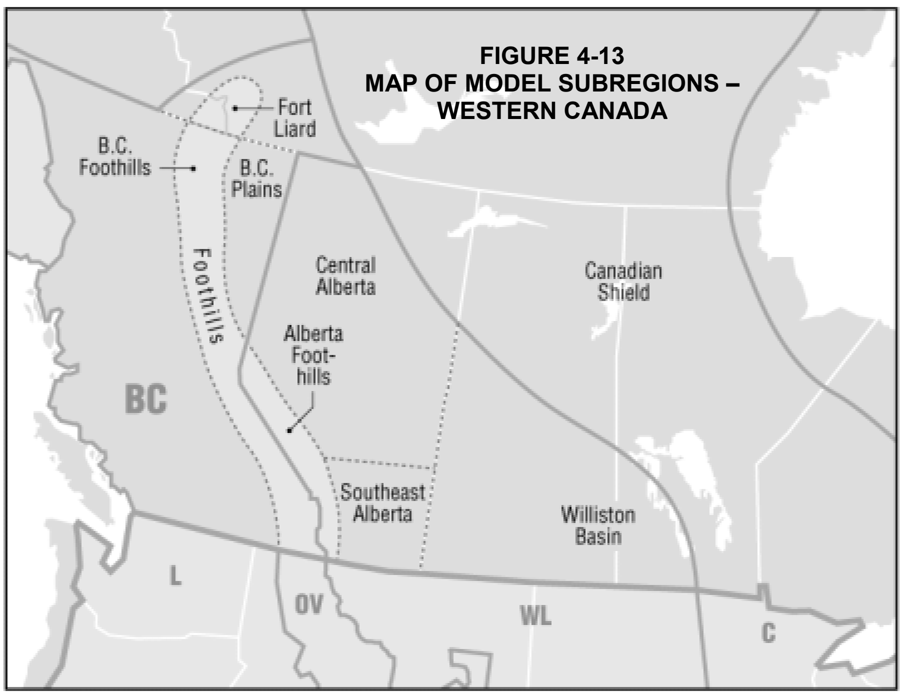


FIGURE 4-13
MAP OF MODEL SUBREGIONS – WESTERN CANADA

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[15] The regions discussed represent about 80 percent of estimated North American gas production in 2010.

Table 4-4
Natural Gas Production by HSM Region - 2010 through 2030
(cumulative contribution in descending order)
(Mm^3d and Bcfd)

Rank	HSM Region		2010 Mm^3d	2010 Bcfd	2010 Cum %	2020		2020 Mm^3d	2020 Bcfd	2020 Cum %	2030		2030 Mm^3d	2030 Bcfd	2030 Cum %
1	15_EGO	Cent. & West. Gulf of Mex.	426.53	15.06	20%	15_EGO	Cent. & West. Gulf of Mex	448.01	15.81	20%	15_EGO	Cent. & West. Gulf of Mex	417.43	14.74	20%
2	20_ASM	Alberta, Sas. Man.	420.57	14.85	40%	20_ASM	Alberta, Sas. Man.	415.45	14.67	39%	20_ASM	Alberta, Sas. Man.	383.03	13.52	38%
3	08_FR	Rocky Mtn. Foreland	202.51	7.15	49%	08_FR	Rocky Mtn. Foreland	287.91	10.16	52%	08_FR	Rocky Mtn. Foreland	331.83	11.71	54%
4	06_G	Texas Gulf Onshore	165.04	5.83	57%	06_G	Texas Gulf Onshore	162.23	5.73	59%	06_G	Texas Gulf Onshore	142.25	5.02	60%
5	11_JN	Mid-Continent	151.45	5.35	64%	04_D	Arkla - East Texas	137.60	4.86	65%	04_D	Arkla - East Texas	134.14	4.74	67%
6	04_D	Arkla - East Texas	138.61	4.89	71%	11_JN	Mid-Continent	133.96	4.73	72%	11_JN	Mid-Continent	113.96	4.02	72%
7	09_SJ	San Juan Basin	99.88	3.53	75%	09_SJ	San Juan Basin	87.94	3.10	75%	09_SJ	San Juan Basin	77.11	2.72	76%
8	12_JS	Permian Basin	95.23	3.36	80%	12_JS	Permian Basin	85.69	3.02	79%	12_JS	Permian Basin	72.95	2.57	79%
9	05_E	South Louisiana	77.07	2.72	83%	21_BC	British Columbia	81.31	2.87	83%	23_EC	Eastern Canada	72.65	2.56	82%
10	21_BC	British Columbia	76.37	2.70	87%	05_E	South Louisiana	74.00	2.61	86%	21_BC	British Columbia	71.17	2.51	86%
11	01_A	Appalachia	49.55	1.75	89%	23_EC	Eastern Canada	56.02	1.98	89%	05_E	South Louisiana	64.20	2.27	89%
12	14_BO	Eastern Gulf of Mexico	38.73	1.37	91%	01_A	Appalachia	52.18	1.84	91%	01_A	Appalachia	50.09	1.77	91%
13	22_NWC	Northwest Canada	34.51	1.22	93%	14_BO	Eastern Gulf of Mexico	35.85	1.27	93%	22_NWC	Northwest Canada	34.51	1.22	93%
14	10_OV	Overthrust Belt	26.31	0.93	94%	22_NWC	Northwest Canada	34.51	1.22	94%	14_BO	Eastern Gulf of Mexico	27.70	0.98	94%
15	23_EC	Eastern Canada	25.12	0.89	95%	13_L	West Coast Onshore	25.68	0.91	96%	13_L	West Coast Onshore	23.82	0.84	95%
16	13_L	West Coast Onshore	24.70	0.87	96%	02_B	Eastern Gulf Onshore	19.90	0.70	96%	10_OV	Overthrust Belt	21.92	0.77	96%
17	02_B	Eastern Gulf Onshore	20.17	0.71	97%	19_AKN	Alaska North	19.67	0.69	97%	18_AKS	Alaska South	20.41	0.72	97%
18	19_AKN	Alaska North	20.04	0.71	98%	10_OV	Overthrust Belt	18.40	0.65	98%	19_AKN	Alaska North	19.34	0.68	98%
19	18_AKS	Alaska South	14.98	0.53	99%	18_AKS	Alaska South	17.22	0.61	99%	02_B	Eastern Gulf Onshore	19.14	0.68	99%
20	03_C	North Central	13.99	0.49	99%	03_C	North Central	11.65	0.41	100%	03_C	North Central	9.21	0.33	100%
21	07_WL	Williston Basin	8.85	0.31	100%	07_WL	Williston Basin	7.68	0.27	100%	07_WL	Williston Basin	6.28	0.22	100%
22	16_LO	West Coast Offshore	3.78	0.13	100%	16_LO	West Coast Offshore	3.29	0.12	100%	16_LO	West Coast Offshore	2.67	0.09	100%
23	17_ AO	Atlantic Offshore	0.00	0.00	100%	17_ AO	Atlantic Offshore	0.00	0.00	100%	17_ AO	Atlantic Offshore	0.00	0.00	100%
24	24_ART	Arctic Canada	0.00	0.00	100%	24_ART	Arctic Canada	0.00	0.00	100%	24_ART	Arctic Canada	0.00	0.00	100%
	North America Total		2,133.98	75.33				2,216.13	78.23				2,115.80	74.69	

The ASM region is a major gas producing area, and represents the majority of western Canadian production. Table 4-2 shows that ASM has produced 3,139,433 Mm^3 (110.8 Tcf) of gas and has proven reserves of 1,361,388 Mm^3 (48.1 Tcf). Undiscovered resources are assessed at 4,467,535 Mm^3 (157.7 Tcf). The resource base includes 339,943 Mm^3 (12.0 Tcf) of reserve appreciation, 2,286,232 Mm^3 (80.7 Tcf) of new fields, 1,133,144 Mm^3 (40.0 Tcf) of coalbed methane, and 708,215 Mm^3 (25.0 Tcf) of tight sands.

As indicated on Table 4-3, daily gas production in 2002 was 415.8 Mm^3d (14.7 Bcfd). Production is projected to be 416.6 Mm^3d (14.7 Bcfd) in 2005, 420.6 Mm^3d (14.9 Bcfd) in 2010, 415.5 Mm^3d (14.7 Bcfd) in 2020, and 383.0 Mm^3d (13.5 Bcfd) in 2030. The total production decline from 2002 through 2030 is 32.7 Mm^3d (1.2 Bcfd).

The ASM region includes four subregions in the Hydrocarbon Model: Central Alberta, Southeast Alberta, Alberta Foothills, and Williston Basin. The primary gas productive area is the Alberta Plains, which includes production from formations ranging in age from Devonian to Cretaceous.

- The Central Alberta subregion includes most of the current ASM production. It includes conventional, tight, and coalbed resources.

- Southeast (SE) Alberta is the location of a high level of recent gas drilling activity directed toward development of shallow Cretaceous sands.

- The Foothills are similar to the U.S. Western Overthrust Belt, and are characterized by complex geology and deep, expensive wells.

- The Williston Basin subregion is generally oil prone although the associated gas production is significant.

Table 4-5 and Figure 4-14 present the detailed production projection by node and subregion for the ASM and BC regions. Alberta production dominates the projection, representing 96% of 2002 ASM production and 82% of ASM plus BC production. Alberta production will decline gradually through 2030. BC production grows by 14.2 Mm^3d (0.5 Bcfd) before starting to decline after 2020. Saskatchewan production remains relatively constant.

Most of the conventional gas production increase in the ASM region will occur in the deeper portions of the Central Alberta and Foothills subregions. Recent studies have shown that relatively few wells have been completed below 10,000 feet in the WCSB. Development drilling in the shallow sands of SE Alberta will continue to dominate drilling statistics in the near term, but will not add substantially to overall basin production.

Coalbed Methane and Tight Gas

Total WCSB coalbed methane production including the B.C. portion is forecast to increase to 69.1 Mm^3d (2.4 Bcfd) by 2020 and 84.1 Mm^3d (3.0 Bcfd) by 2030, as shown in Table 4-5.

The ASM region is expected to see a rapid emergence of coalbed methane production. Commercial production began in 2002 in the Palliser play area of Alberta. Activity in this play is projected to continue to increase, and by 2010 Alberta will be producing an estimated 16.2 Mm^3d (0.6 Bcfd). By 2020, production of 60.2 Mm^3d (2.1 Bcfd) is anticipated, increasing to 73.9 Mm^3d (2.6 Bcfd) by 2030 (Table 4-5).

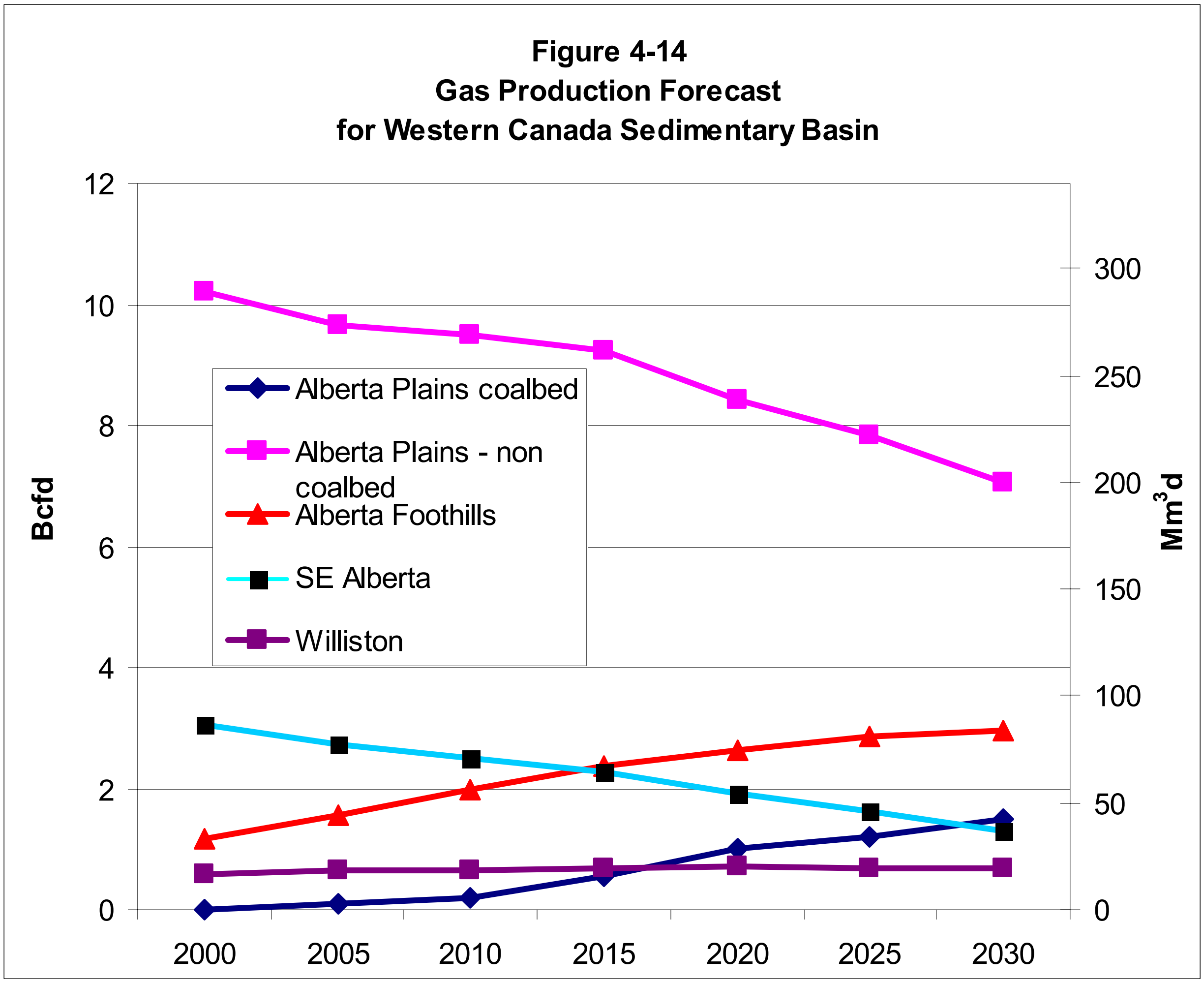
Tight gas resources in the "Deep Basin gas trap" (Elmworth-Wapiti fields) have been developed for 20 years, but large undeveloped resources remain. This area is similar to the Green River Basin in Wyoming. New technologies have reduced the cost of developing tight gas and significant growth in activity is expected.

Table 4-5
Subregion Gas Production - Western Canada
HSM Node Output
(Mm^{3}d)

Node		2000	2005	2010	2015	2020	2025	2030
72	BC	59.41	74.41	76.37	82.25	81.31	77.90	71.17
74	Alberta	409.97	397.79	401.94	409.26	395.89	383.27	364.34
76	Saskatchewan	16.64	18.83	18.62	19.46	19.56	19.27	18.68
Total		486.02	491.04	496.94	510.97	496.76	480.44	454.19
	ASM total	426.61	416.63	420.57	428.72	415.45	402.54	383.03
	BC total	59.41	74.41	76.37	82.25	81.31	77.90	71.17
	WCSB total	486.02	491.04	496.94	510.97	496.76	480.44	454.19
Breakout by Subregion								
ASM Region								
	ASM coalbed methane	0.00	2.55	16.15	47.88	60.62	66.86	73.94
	Alberta Plains (non coalbed)	289.35	273.66	261.96	239.97	217.48	200.90	180.26
	Alberta Foothills (non coalbed)	33.61	44.22	54.31	62.41	68.00	73.72	76.34
	SE Alberta	86.89	77.54	69.55	59.03	49.82	41.94	33.80
	Williston	16.76	18.63	18.60	19.42	19.52	19.13	18.70
	Total	426.61	416.61	420.57	428.71	415.44	402.55	383.04
BC Region								
	BC coalbed methane	0.00	0.00	3.68	8.22	8.50	9.35	10.20
	BC Plains (non coalbed)	43.25	49.21	39.27	35.21	33.44	31.49	28.00
	BC Foothills (non coalbed)	12.97	13.20	18.23	19.41	21.47	20.22	17.98
	Fort Liard	3.19	12.00	15.19	19.41	17.89	16.85	14.98
	Total	59.41	74.41	76.37	82.25	81.31	77.90	71.17
	WCSB total	486.02	491.04	496.94	510.97	496.76	480.44	454.19
	WCSB coalbed total	0.00	2.55	19.83	56.09	69.12	76.20	84.14

(Bcfd)

Node		2000	2005	2010	2015	2020	2025	2030
72	BC	2.10	2.63	2.70	2.90	2.87	2.75	2.51
74	Alberta	14.47	14.04	14.19	14.45	13.98	13.53	12.86
76	Saskatchewan	0.59	0.66	0.66	0.69	0.69	0.68	0.66
Total		17.16	17.33	17.54	18.04	17.54	16.96	16.03
	ASM total	15.06	14.71	14.85	15.13	14.67	14.21	13.52
	BC total	2.10	2.63	2.70	2.90	2.87	2.75	2.51
	WCSB total	17.16	17.33	17.54	18.04	17.54	16.96	16.03
Breakout by Subregion (BCFD)								
ASM Region								
	ASM coalbed methane	0.00	0.09	0.57	1.69	2.14	2.36	2.61
	Alberta Plains (non coalbed)	10.21	9.66	9.25	8.47	7.68	7.09	6.36
	Alberta Foothills (non coalbed)	1.19	1.56	1.92	2.20	2.40	2.60	2.69
	SE Alberta	3.07	2.74	2.45	2.08	1.76	1.48	1.19
	Williston	0.59	0.66	0.66	0.69	0.69	0.68	0.66
	Total	15.06	14.71	14.85	15.13	14.66	14.21	13.52
BC Region								
	BC coalbed methane	0.00	0.00	0.13	0.29	0.30	0.33	0.36
	BC Plains (non coalbed)	1.53	1.74	1.39	1.24	1.18	1.11	0.99
	BC Foothills (non coalbed)	0.46	0.47	0.64	0.69	0.76	0.71	0.63
	Fort Liard	0.11	0.42	0.54	0.69	0.63	0.59	0.53
	Total	2.10	2.63	2.70	2.90	2.87	2.75	2.51
	WCSB total	17.16	17.33	17.54	18.04	17.54	16.96	16.03
	WCSB coalbed total	0.00	0.09	0.70	1.98	2.44	2.69	2.97



British Columbia
The British Columbia Region represents an important component of the Western Canada Sedimentary Basin. The BC part of the basin is not as maturely developed as the ASM region and holds large undiscovered gas potential.

Table 4-2 indicates that this region has produced 429,547 Mm^3 (15.2 Tcf) of gas and has proven reserves of 266,884 Mm^3 (9.4 Tcf). Undiscovered resources are assessed to be 1,115,326 Mm^3 (39.4 Tcf). The resource base includes 70,595 Mm^3 (2.5 Tcf) of reserve appreciation potential and 931,416 Mm^3 (32.9 Tcf) of new fields, and 113,314 Mm^3 (4.0 Tcf) of coalbed methane. As noted on Table 4-3, daily production in 2002 was 69.2 Mm^3d (2.4 Bcfd). Production is projected to be 74.4 Mm^3d (2.6 Bcfd) in 2005, 76.5 Mm^3d (2.7 Bcfd) in 2010, 81.3 Mm^3d (2.9 Bcfd) in 2020, and 71.7 Mm^3d (2.5 Bcfd) in 2030.

The region includes the following HSM subregions: BC Plains, BC Foothills, and Fort Liard. All three areas will contribute to future gas production. Table 4-5 shows the expected breakout of production through 2030. The Plains region production will generally decline, while the Foothills and Fort Liard areas are expected to see production growth. Coalbed production in BC is expected to be 3.7 Mm^3d (0.1 Bcfd) by 2010 and 10.2 Mm^3d (0.4 Bcfd) by 2030. Plains region production is expected to increase over the next few years with the development of the Greater Sierra play. Although Fort Liard development activity has been disappointing since the initial discoveries were announced, the longer-term potential from the area is expected to be approximately 17.0 Mm^3d (0.6 Bcfd).

Mackenzie Delta Region

Production from the Mackenzie Delta is represented by the Northwest Canada region (model Node 86). Production is assumed to start in 2009, and the full rate of production is assumed to be 34.0 Mm^3d (1.2 Bcfd) starting in 2010 and continuing through the forecast period.

Central and Western Gulf of Mexico

The Central and Western Gulf of Mexico is one of the principal North American gas supply regions. Table 4-2 shows that the region has produced 4,521,275 Mm^3 (159.6 Tcf) of gas, and has proven reserves of 729,405 Mm^3 (25.7 Tcf). Undiscovered resources are assessed at 7,310,850 Mm^3 (258.1 Tcf). The Eastern Gulf of Mexico (east of Alabama) is a separate region in the model.

As indicated by Table 4-3, year 2002 daily production was 367.7 Mm^3d (13.0 Bcfd). Production is projected to be 409.4 Mm^3d (14.5 Bcfd) in 2005, 426.5 Mm^3d (15.1 Bcfd) in 2010, 448.0 Mm^3d (15.8 Bcfd) in 2020, and 417.4 Mm^3d (14.7 Bcfd) in 2030. The total production rate increase from 2002 through 2020 is 80.4 Mm^3d (2.8 Bcfd) and through 2030 is 49.8 Mm^3d (1.8 Bcfd). This region ranks second to the Foreland (Rockies) region in volume of production growth.

Table 4-6 presents the detailed production trends for the Central and Western Gulf of Mexico. Gas production from the shelf (< 200 meters) is declining while deepwater production is increasing. Shelf production was approximately 265.7 Mm^3d (9.4 Bcfd) in 2000, and is projected to fall to 213.7 Mm^3d (7.5 Bcfd) in 2005, 192.1 Mm^3d (6.8 Bcfd) in 2010, and 162.5 Mm^3d (5.7 Bcfd) in 2020. Deepwater production was approximately 101.2 Mm^3d (3.6 Bcfd) 2000, and will grow to 285.5 Mm^3d (10.1 Bcfd) by 2020 and 289.0 Mm^3d (10.2 Bcfd) in 2030.

Deepwater fields are still being discovered, but the average size of recent discoveries has been smaller than expected, and it has taken longer than anticipated to obtain gas production from some of the new large fields. Forecasting deepwater production is made difficult by reporting delays for historical production and incomplete information on recent deepwater discoveries.

Approximately 260 deepwater Gulf of Mexico fields have been discovered through 2002, and approximately 90-100 fields are producing. Numerous fields are scheduled to come online over the next few years. Several currently non-producing deepwater fields are said to be among the largest discoveries ever made in the Gulf.

Table 4-6
Subregion Gas Production - Gulf of Mexico (Region EGO)
HSM Node Output

(Mm^3d)

Node		2000	2005	2010	2015	2020	2025	2030
57	(Eastern Gulf Shelf)	42.62	37.95	35.19	33.94	30.08	26.20	21.88
59	(Viosca Knoll/Desoto Can/Miss Can/Destin) - deepwater	53.42	99.95	117.56	131.64	138.40	140.93	139.19
62	(Central Gulf Shelf)	189.45	144.15	128.37	119.85	110.06	100.18	90.69
67	(Offshore Texas) - shelf	33.65	31.57	28.52	25.47	22.38	19.29	15.82
69	(East Breaks and Garden Banks) - deepwater	31.27	62.24	73.31	82.84	87.10	89.27	85.74
70	(Green Canyon) - deepwater	16.55	33.57	43.58	52.63	59.99	63.70	64.10
	Total	366.95	409.44	426.53	446.37	448.01	439.57	417.43
	Shelf total (model output)	265.72	213.67	192.08	179.26	162.53	145.67	128.40
	Deepwater total (model output)	101.24	195.76	234.45	267.11	285.49	293.90	289.03
	Total	366.95	409.44	426.53	446.37	448.01	439.57	417.43

(Bcfd)

Node		2000	2005	2010	2015	2020	2025	2030
57	(Eastern Gulf Shelf)	1.50	1.34	1.24	1.20	1.06	0.92	0.77
59	(Viosca Knoll/Desoto Can/Miss Can/Destin) - deepwater	1.89	3.53	4.15	4.65	4.89	4.97	4.91
62	(Central Gulf Shelf)	6.69	5.09	4.53	4.23	3.89	3.54	3.20
67	(Offshore Texas) - shelf	1.19	1.11	1.01	0.90	0.79	0.68	0.56
69	(East Breaks and Garden Banks) - deepwater	1.10	2.20	2.59	2.92	3.07	3.15	3.03
70	(Green Canyon) - deepwater	0.58	1.18	1.54	1.86	2.12	2.25	2.26
	Total	12.95	14.45	15.06	15.76	15.81	15.52	14.74
	Shelf total (model output)	9.38	7.54	6.78	6.33	5.74	5.14	4.53
	Deepwater total (model output)	3.57	6.91	8.28	9.43	10.08	10.37	10.20
	Total	12.95	14.45	15.06	15.76	15.81	15.52	14.74

While the shelf is projected to continue to decline, several emerging plays are expected to slow the decline. There is excellent potential for deep drilling on the shelf (>15,000 feet) and the Minerals Management Service of the Department of the Interior has now offered royalty relief for this resource, which has already begun to stimulate activity. The subsalt play is primarily located on the outer portion of the shelf (with a portion in deepwater) and has excellent potential.

Foreland Region

The Foreland Region includes the Rocky Mountain Basins of Colorado, Wyoming, Utah, and Montana. The Overthrust Belt of Wyoming and Utah is a separate region in the model. The region includes the Green River, Wind River, Piceance, Uinta, and Denver Basins. Table 4-2 shows that the Foreland Region has produced 869,858 Mm^3 (30.7 Tcf) of gas and has proven reserves of 822,578 Mm^3 (29.0 Tcf). Undiscovered resources are assessed at 9,077,960 Mm^3 (320.4 Tcf). The resource base includes 742,068 Mm^3 (26.2 Tcf) of reserve appreciation, 2,566,459 Mm^3 (90.6 Tcf) of new fields, 1,473,088 Mm^3 (52.0 Tcf) of coalbed methane, and 3,880,227 Mm^3 (137.0 Tcf) of tight sands.

Year 2002 daily production was 128.9 Mm^3d (4.6 Bcfd). Production is projected to be 158.7 Mm^3d (5.6 Bcfd) in 2005, 202.5 Mm^3d (7.2 Bcfd) in 2010, 287.9 (10.2 Bcfd) in 2020 and 331.8 Mm^3d (11.7 Bcfd) in 2030. The total production rate increase from 2002 through 2020 is 159.0 Mm^3d (5.6 Bcfd) and through 2030 is 203.0 Mm^3d (7.2 Bcfd). This is the highest volume of production growth of any region in the projection.

Access restrictions are expected to negatively impact future production and are incorporated into the forecast. Studies by the National Petroleum Council have shown that a large percentage of the undiscovered resource base is either off limits or subjected to higher costs and/or significant regulatory delays.

The Foreland Region continues to experience increases in deliverability and production, primarily from coalbed methane in the Powder River Basin and from tight gas development. Increased pipeline capacity from the basin is an important factor, and capacity continues to expand, improving the economics of activity in the region.

Coalbed Methane

Powder River Basin development will continue at a rapid pace, with production increasing from the current rate of 26.9 Mm^3d (0.95 Bcfd) to over 56.6 Mm^3d (2.0 Bcfd) by 2010. The basin has approximately 679,887 Mm^3 (24.0 Tcf) of recoverable resources, which represents 60,000 potential wells if average recovery is 11.3 Mm^3 (0.40 Bcfd) and economic production can be established across the basin. Another area of active development is the Ferron play in East-Central Utah. Beyond these two basins, the next emerging basin is the Greater Green River, where pilot projects are underway and one operator has plans for a 3,800 well program.

Tight Gas
Tight gas development will continue to expand in Southwest Wyoming (Green River Basin), Northwest Colorado (Piceance Basin), and Northeast Colorado (Denver Basin). In all of these areas, a large number of development well sites have been defined and plans are in place for increased activity.

Texas Gulf Onshore
The South Texas region, or Texas Gulf Coast, includes Texas Railroad Districts 1 through 4. Table 4-2 shows that the region has produced 4,126,601 Mm^3 (145.7 Tcf) of gas and has proven reserves of 459,178 Mm^3 (16.2 Tcf). Undiscovered resources are assessed to be 2,760,425 Mm^3 (97.4 Tcf). The resource base includes 1,387,082 Mm^3 (49.0 Tcf) of reserve appreciation, 1,115,156 Mm^3 (39.4 Tcf) of new fields, and 258,187 Mm^3 (9.1 Tcf) of tight sands.

As per Table 4-3, year 2002 daily production was 177.7 Mm^3d (6.3 Bcfd). Production is projected to be 164.9 Mm^3d (5.8 Bcfd) in 2005, 165.04 Mm^3d (5.8 Bcfd) in 2010, 162.2 Mm^3d (5.7 Bcfd) in 2020 and 142.3 Mm^3d (5.0 Bcfd) in 2030. The total production rate decline from 2002 through 2020 is 15.4 Mm^3d (0.5 Bcfd) and through 2030 is 35.4 Mm^3d (1.3 Bcfd).

Model Node 65 includes Texas District 3 (Southeastern Texas) and Node 66 includes Districts 1, 2 and 4 (central Gulf Coast and South Texas). Both areas will decline slightly through 2005, followed by relatively flat production through 2020.

Mid-Continent
The Mid-Continent region is one of the oldest producing regions in the U.S., and includes portions of Oklahoma, Kansas, and the Texas Panhandle. Table 4-2 shows that the region has produced 5,095,581 Mm^3 (179.9 Tcf) of gas and has proven reserves of 680,170 Mm^3 (24.0 Tcf). Undiscovered resources are assessed at 3,042,635 Mm^3 (107.4 Tcf). The resource base includes 1,294,958 Mm^3 (45.7 Tcf) of reserve appreciation, 1,057,252 Mm^3 (3.3 Tcf) of new fields, 211,020 Mm^3 (7.4 Tcf) of coalbed methane, and 479,405 Mm^3 (16.9 Tcf) of tight sands.

As per Table 4-3, year 2002 daily production was 178.5 Mm^3d (6.3 Bcfd). Production is projected to be 161 5 Mm^3d (5.7 Bcfd) in 2005, 150.1 Mm^3d (5.3 Bcfd) in 2010, 133.1 Mm^3d (4.7 Bcfd) in 2020, and 113.3 Mm^3d (4.0 Bcfd) in 2030. The total production rate decline from 2002 through 2020 is 43.4 Mm^3d (1.5 Bcfd) and through 2030 is 63.4 Mm^3d (2.2 Bcfd).

Gas production in the Mid-Continent has generally been declining, and is projected to continue a gradual decline through the end of the forecast. The region has large undeveloped tight gas and deep gas resources, as well as emerging coalbed resources in areas such as the Arkoma and Cherokee Basins. The Anadarko Basin in Western

Oklahoma still has good potential below 15,000 feet. However, complex geology and low permeability makes the deep gas expensive and difficult to develop, and activity in this play is not expected to reverse the regional downward trend. Coalbed methane development activity in recent years has lagged expectations.

Arkla-East Texas

The Arkla-East Texas region includes districts 5, 6, 9 and 7B in East Texas as well as North Louisiana. Table 4-2 shows that the region has produced 1,827,620 Mm^3 (64.5 Tcf) of gas and has proven reserves of 402,210 Mm^3 (14.2 Tcf). Undiscovered resources are assessed to be 2,293,909 (81.0 Tcf). The resource base includes 645,722 Mm^3 (22.8 Tcf) of reserve appreciation, 599,377 Mm^3 (21.1 Tcf) of new fields, 204,164 Mm^3 (7.2 Tcf) of shale gas, and 844,646 Mm^3 (29.8 Tcf) of tight sands.

As indicated on Table 4-3, year 2002 production was 115.6 Mm^3d (4.1 Bcfd). Production is projected to be 135.5 Mm^3d (4.8 Bcfd) in 2005, 138.6 Mm^3d (4.9 Bcfd) in 2010, approximately the same rate in 2020, and 134.1 Mm^3d (4.7 Bcfd) in 2030. The increase in the total production rate from 2002 through 2020 is 22.0 Mm^3d (0.8 Bcfd), and through 2030 is 18.5 Mm^3d (0.7 Bcfd).

Most of the production growth will be nonconventional gas and is expected to occur in East Texas Districts 5 and 6 (Bossier play) and North Texas District 9 (Barnett Shale).

Tight Gas

Tight gas sand development is active in the region as exemplified by the Bossier play, which is one of the most active plays in the country. East Texas contains extensive tight gas deposits in the Jurassic, and this resource will become increasingly important.

Shale Gas

The Barnett Shale of North Texas District 9 is included in this region and has an estimated resource volume of 198,300 Mm^3 (7 Tcf). Barnett Shale production increased from 3.1 Mm^3d (0.11 Bcfd) in 1999 to over 17.0 Mm^3d (0.60 Bcfd) currently. Growth in Barnett production will account for a significant amount of the Arkla- East Texas production growth through 2005.

San Juan Basin

The San Juan Basin of northwestern New Mexico and southwestern Colorado and is a heavily gas-prone basin with production dominated by coalbed methane and tight gas. Table 4-2 shows that the region has produced 825,326 Mm^3 (29.1 Tcf) of gas and has proved reserves of 555,836 Mm^3 (19.6 Tcf). Undiscovered resources are assessed to be 753,796 Mm^3 (26.6 Tcf). The resource base includes 304,759 Mm^3 (10.8 Tcf) of reserve appreciation, 164,108 Mm^3 (5.8 Tcf) of new fields, and 284,929 Mm^3 (10.0 Tcf) of coalbed methane. Low permeability gas development is included in the reserve appreciation resource.

As indicated on Table 4-3, year 2002 daily production was 108.2 Mm^3d (3.8 Bcfd). Production is projected to be 105.8 Mm^3d (3.7 Bcfd) in 2005, 99.9 Mm^3d (3.5 Bcfd) in 2010, 87.9 Mm^3d (3.1 Bcfd) in 2020, and 77.1 Mm^3d (2.7 Bcfd) in 2030.

Production from the Fruitland coalbed play is in decline, and has been declining for several years. However, overall production from the basin will decline very gradually because of the ongoing tight gas infill development program in the basin, as well as continued development of the coalbed resource.

Permian Basin

The Permian Basin Region is an oil-prone region, but contains large undeveloped deep gas resources, including conventional non-associated gas and tight gas. The Permian Basin includes portions of West Texas and Southeast New Mexico.

Table 4-2 shows that the region has produced 2,985,779 Mm^3 (105.4 Tcf) of gas and has proven reserves of 463,909 Mm^3 (16.4 Tcf). Undiscovered resources are assessed to be 1,891,275 Mm^3 (66.8 Tcf). The resource base includes 503,399 Mm^3 (17.8 Tcf) of reserve appreciation, 834,873 Mm^3 (29.5 Tcf) of new fields, and 553,003 Mm^3 (19.5 Tcf) of tight sands.

As indicated by Table 4-3, year 2002 daily production was 103.8 Mm^3d (3.7 Bcfd). Production is projected to be 100.0 Mm^3d (3.5 Bcfd) in 2005, 95.2 Mm^3d (3.4 Bcfd) in 2010, 85.7 Mm^3d (3.0 Bcfd) in 2020, and 73.0 Mm^3d (2.6 Bcfd) in 2030. The total production rate decline from 2002 through 2020 is 18.1 Mm^3d (0.6 Bcfd); from 2002 through 2030 it is 30.9 Mm^3d (1.1 Bcfd).

4.7 Technology Drivers in Projections

Upstream technology advances play a critical role in North American gas supply, and estimates of future technology improvement are a key driver in the HSM. Table 4-7 summarizes the upstream technology assumptions that underlie the projection. There are four major categories of technology:

- New field exploration efficiency;
- Platform cost reduction;
- Drilling and completion cost reduction; and
- Improved recovery per well.

Table 4-7
Technology Drivers in the Hydrocarbon Supply Model

	Annual Improve-ment
New Field Exploration Efficiency	
2000	1.5%
2010	1.8%
2015	2.2%
Platform Cost Reduction	1.5%
D&C Cost Reduction	
Onshore and shelf	2.5%
Deepwater	3.0%
Improvements in Recovery Per Well	
Conventional gas	1.0%
Low permeability gas	2.1%
Nonconventional gas	1.5-3.0%

New Field Exploration Efficiency

New field exploration efficiency is measured as the success rate of new field wildcat drilling. Improved success rates result from advanced seismic and other exploration methods, improved wireline logging, and improved drilling systems. Annual improvement in the aggregate impact of these technologies is projected to increase from current rates of 1.5% per year to 2.2% per year by 2015.

Platform Cost Reduction

The cost of offshore production platforms is a major factor in the economics of offshore gas production. Over the past decade, costs have declined greatly, especially in deepwater. Cost reduction has resulted from both specific technologies and from the development of novel concepts such as spar platforms and mini-TLPs. Cost reduction is projected to average 1.5% per year through the projection.

Drilling and Completion Cost Reduction

Technologies such as integrated well planning, directional drilling, and improved completion methods are reducing the total drilling and completion costs for field development. The model assumes that the deepwater play will experience the greatest cost reduction, with a 3% annual improvement.

Recovery Per Well
Improved recovery per well has resulted from advanced stimulation techniques, integrated well planning, and information technology. The greatest impact occurs in nonconventional reservoirs, where improvements are projected to range from 1.5% to 3% per year.

Production Impact of Advanced Technology
In recent years, the impact of technology advance on future rates of production has been evaluated with the HSM. A faster rate of technology advance, using the input parameters shown in Table 4.7, has been shown to have an impact of approximately 28, 328.6 Mm^3 (1 Tcf) per year by 2015. A slower than expected technology advance has been shown to result in about 42,493 Mm^3 (1.5 Tcf) per year less production than would otherwise have been forecast.

4.8 Summary and Discussion
The combined U.S. and Canadian unproved and undiscovered gas resource base is robust and is sufficient to sustain decades of future production. Total unproved resources are approximately 50,991,498 Mm^3 (1,800 Tcf). This volume exceeds the sum of cumulative production and proved reserves to date.

Despite the large resource base, the production forecast shows only moderate overall growth in annual gas production through 2030. U.S. Lower 48 gas production is forecast to peak in 2020 at 1,592 Mm^3d (56.2 Bcfd) and Canadian production is expected to peak in 2016 at 592 Mm^3d (20.9 Bcfd). Including Alaska, Canadian and U.S. gas production through 2030 is expected to peak at 2,218 Mm^3d (78.3 Bcfd) in 2016, representing an increase of 274.8 Mm^3d (9.7 Bcfd) or 14% over the 2002 level.

U.S. Lower 48
The results of upstream efforts in both the U.S. and Canada over the past few years have been somewhat disappointing. Activity and reserve additions on the Gulf of Mexico shelf have not met expectations. Deepwater Gulf gas production is still increasing rapidly, but there have been delays and scale-backs in some projects. Nonconventional gas production is increasing, but land access and permitting delays in the Rockies have had a negative impact, and it is still far from certain that industry will be allowed to fully develop areas such as the Powder River Basin. With some exceptions, onshore new field wildcat drilling activity has been very disappointing.

The wellhead gas price increases in 2001 resulted in a surge of U.S. Lower 48 onshore drilling, but did not add the volume of gas production that would have been expected. While there is still uncertainty about why there was not more of a production response, the following factors were important:

- Increasing maturity of shallow to intermediate drilling depths both onshore and offshore;

- Targeting of quick payout shallow development prospects as opposed to higher quality but more costly targets; and
- Emphasis on re-completions and other activity in existing wellbores.

Much has been written about the acceleration in decline rates in recent years, especially in the Gulf of Mexico shelf. While this increase has been documented, it does not reflect a drastic decline in the quality of the remaining resource base. Increased decline rates have resulted from several factors, including new technologies that recover the gas reserves faster, and the emphasis on recompletions that can economically target smaller reservoirs in existing wells. A shift to deeper exploration will produce a corresponding improvement in well recoveries and decline rates.

Canada

The Base Case forecast has Canadian gas production peaking at 592.1 Mm^3d (20.9 Bcfd) in 2016. The largest share of production comes from the WCSB, where production is expected to peak around 2015 at 509.9 Mm^3d (18.0 Bcfd). In Western Canada, most recent gas drilling activity has been directed toward low risk shallow prospects in Alberta, although a significant surge in exploration is now occurring in the BC Plains, with very promising discoveries in the "Greater Sierra" play. Analysis of WCSB gas completions shows a dramatic decline in EUR per well, in combination with a significant steepening of the decline rates. However, much of the decline results from the change in emphasis to shallow, low risk development wells.

The Base Case forecast of Alberta production is higher than the EUB latest projection. In its analysis, the EUB anticipates that conventional gas production in Alberta will recover slightly in 2003 but decline continuously thereafter. The EUB's forecast assumes that the number of successful wells drilled per year will plateau at 11,000 wells per year during 2005-2006 and then fall back to 10,000 wells per year during the remainder of the 2003-2012 forecast period.[16] Essentially, this is because each year's production from new wells is expected to be insufficient to overcome the decline in production from existing wells.

The EUB assumed that the initial productivities of gas wells connected in southeastern Alberta would decline by 40% from 2003 to 2012, and that initial productivities of wells elsewhere in the province would slip by 20% over the same period. The production decline rates used by the EUB for forecasting deliverability in each of the first four years of a newly connected Alberta well are 34%, 27%, 23%, and 1%, respectively. Thereafter, the production decline rate is assumed to remain constant, at 18%. As a consequence, in the EUB forecast conventional gas production in Alberta declines by 65.2 Mm^3d (2.3 Bcfd) or 16% from 2003 to 2012.

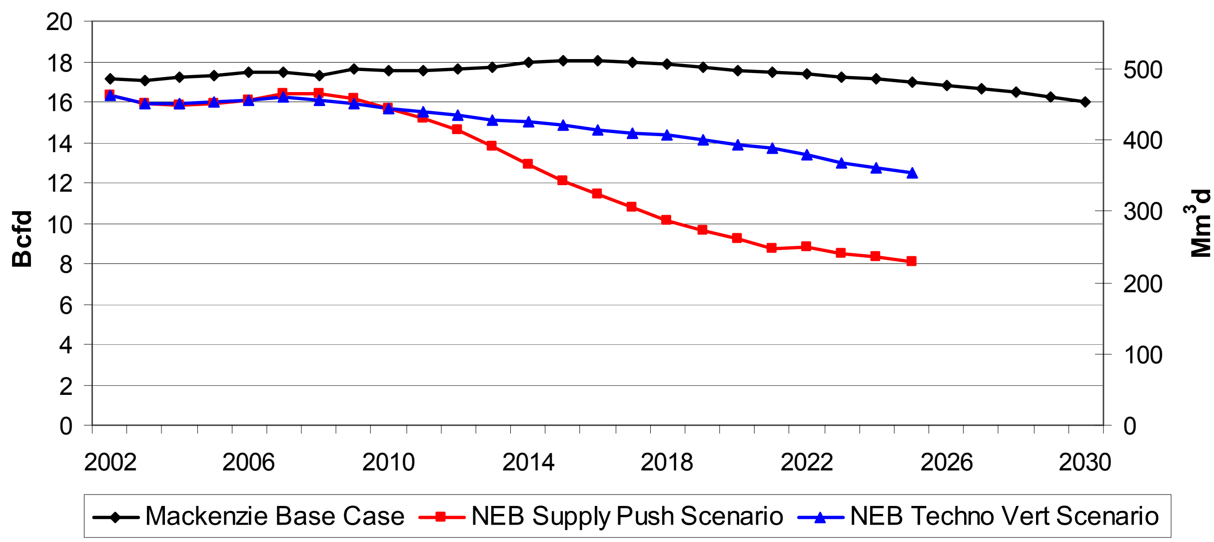
[16] Alberta's Reserves 2002 and Supply/Demand Outlook 2003-2012

Alberta's gas reserves represent approximately 90% of the reserves in the WCSB as a whole. Given the extent of exploration and production that has occurred throughout the WCSB it is becoming clear that reserves are declining in the Basin as a whole, and not just in Alberta. The NEB provided estimates of initial productivity and decline rates by WCSB subregion in its December 2002 report, "Short-term Deliverability from the WCSB 2002-2004". That report indicated that the average initial productivity per connected gas well has been declining in the WCSB over the last decade and is now only about half what it was ten years ago. This reflects the fact that more wells are now being connected in areas with lower productivity as well as generally lower productivity characteristics of individual wells. Average decline rates have also been increasing. As a result, the amount of gas that is likely to be recovered from a typical WCSB well connection is indicated as being less than 25% of what it was in 1995.

In general, the EUB's Alberta assessment and the NEB's analysis of gas production in the WCSB region as a whole are quite similar. Both analyses point to declining conventional gas production because the remaining pool of producible gas has diminished, initial well productivities have declined, and decline rates have risen. Although they are somewhat more conservative, the EUB and NEB analyses corroborate the outlook for declining conventional WCSB gas production discussed in this section. Conventional production has essentially peaked in Alberta but modest increases in British Columbia and CBM production development are anticipated to keep total WCSB production from declining for another ten to fifteen years. Thereafter, increasing CBM production will not likely be sufficient to offset declining conventional gas production throughout the Basin and total production will inevitably turn downward. By 2030, the WCSB gas projection rate is projected to be approximately 56.7 Mm^3d (2.0 Bcfd) less than the 509.9 Mm^3d (18.0 Bcfd) peak daily rate that the Base Case analysis indicates will occur around 2015.

Figure 4-15 compares the Base Case forecast of WCSB production with the scenarios presented in the NEB's 2003 report on Canada's Energy Future. In combination with the likelihood of a substantial increase in gas demand in the WCSB supply region, the prospect of declining or even flat WCSB production suggests that gas exports from the region could begin to decline as early as 2010 without the arrival of new gas supplies. If the decline in production comes sooner or if the magnitude is greater than indicated in the Base Case analysis then the consequences for gas exports will be more serious. The implications of declining production decline for WCSB takeaway capacity are discussed in Sections 5 and 6 in the context of both the Base Case and the sensitivity analyses.

Figure 4-15
Comparison of WCSB Gas Production Projections



Commercial coalbed methane production has begun in Alberta, but development has been slower than previously anticipated and the operators have released very little information over the past year. While the coalbed resource has excellent potential and covers a very large area of the basin, it will take many years to attain a production rate of 28 Mm^3d (1 Bcfd). Peak production in the forecast is 85 Mm^3d (3.0 Bcfd) by 2030. This resource will be more challenging to develop than that of the Powder River Basin, and therefore it is not anticipated that production from the WCSB will grow as rapidly as in that Basin, where production increased from almost zero to over 25.5 Mm^3d (0.9 Bcfd) over a period of a few years.

Eastern Canada offshore gas production will continue to expand through 2030. However, production growth through 2005 will be smaller than previously anticipated, due primarily to the recently announced delay in developing the Panuke discovery off Nova Scotia. Once the Panuke play has been fully confirmed with additional discoveries, it is anticipated that additional pipeline capacity will be installed and the Nova Scotia offshore area will begin to make a very large contribution. Gas production from the Grand Banks area off Newfoundland is also anticipated.

5 INTRA-ALBERTA AND GAS PIPELINE TAKEAWAY INFRASTRUCTURE

5.1 Introduction

This section assesses the capability of the intra-Alberta pipeline system and the main export pipelines from the Western Canada Sedimentary Basin (WCSB) to deliver Mackenzie Delta gas to markets in eastern Canada, the Pacific Northwest, California, and the Midwestern and Northeastern United States during the forecast period. It contains a discussion of Alberta's gas pipeline infrastructure from the perspective of the transmission capacity available to transport gas to and from key export points, and the potential need for expansions to takeaway capacity. The implications for intra-Alberta tolls and tolls on the various pipelines that export gas from the WCSB are also examined.

In addition to analyzing data and reports in the public domain, representatives of various pipeline companies engaged in transporting gas within and from Alberta were consulted. Both the analysis and the consultations indicated that flows of Mackenzie Delta gas to Alberta would not be constrained by the existing intra-Alberta and regional gas transportation infrastructure. Only limited enhancements to the existing intra-Alberta gas transmission system appear needed to facilitate the receipt of Mackenzie Delta Gas into the intra-Alberta system and to deliver the augmented Alberta supplies to export markets. By improving the efficiency of the system, such modifications would benefit all of the shippers. Moreover, because the cost of the improvements are likely to be small in relation to the increase in contract volumes, the impacts on Alberta pipeline tolls are likely to be favourable.

The facilities analysis was first undertaken with respect to the Base Case scenario in which the Mackenzie Pipeline begins to deliver gas to Alberta in late 2009 and no Alaskan gas pipeline is constructed during the forecast period. The implications of the three sensitivity cases examined in this report (Mackenzie Expansion Case, Low Demand Case, and Alaskan Pipeline Case) for intra-Alberta and WCSB takeaway pipeline capacity and tolls were then examined and compared with the Base Case. Throughout the analysis it was assumed that ex-Alberta gas flows from each of the main WCSB border delivery points would be consistent with the volumes projected by the market simulation analysis undertaken for the respective cases.

5.2 Intra-Alberta Infrastructure

TransCanada's Alberta System, or the NGTL System, is now 100% owned by TransCanada Ltd. It is a large natural gas transmission system that gathers natural gas for use within Alberta and delivers gas to provincial boundary points where it is received into TransCanada's Canadian Mainline, the TransCanada BC System, and other pipelines. The 22,700-kilometer Alberta system is one of the largest carriers of gas in North America. During 2002, the System delivered 322.9 Mm^3d (11.4 Bcfd) of natural gas, compared with 314.4 Mm^3d (11.1 Bcfd) in 2001 and 348.4 Mm^3d (12.3 Bcfd) in 2000.

In 2002, the volumes transported were equivalent to 17% of total North American gas production and 68% of the natural gas produced in the WCSB.

The NGTL System is regulated by the Alberta Energy and Utilities Board (EUB), primarily under the provisions of the *Gas Utilities Act* (Alberta) (GUA) and the *Pipeline Act* (Alberta). Under the GUA, the rates, tolls, and other charges, and terms and conditions of service are subject to the approval of the EUB.

The NGTL System essentially has two main legs, for convenience labeled the "West Leg" and "East Leg".[17] The West Leg receives gas at Gordondale near the British Columbia border and from receipt points in northwest Alberta and transports it southeast to the James River interchange (100 kilometers northwest of Calgary) and then to the Princess compression station located 180 kilometers east of Calgary. The East Leg collects and receives gas from areas as far as 250 kilometers north and east of Edmonton to Princess and transports it to Empress and McNeill on the Alberta/ Saskatchewan border for export. The NGTL and integrated Foothills Pipeline system connects the James River interchange on the West Leg to an export point on the British Columbia/Alberta border in southwest Alberta.

As noted in NGTL's December 2002 Annual Plan, at the end of 2001 the System had 944 receipt points throughout Alberta and 173 delivery points, including the three large border export points. The receipt and delivery points have significant impacts on the sizing of the facilities required to meet transportation obligations. In general, system throughput capacity increases in size as one moves from the collection points, located mainly in the northern half of the province, to the main intra-Alberta delivery points in the Fort McMurray and Edmonton-Fort Saskatchewan areas, the Calgary area, Joffre, Carseland, Medicine Hat, and the southeast and southwest Alberta border export points.

The NGTL System is designed to meet the peak day requirements of firm transportation receipt (producer) and delivery (consumer) customers. The facilities are designed to provide efficient and equitable service to customers and ensure that customers putting gas into, or withdrawing gas from the system, are not constrained. This involves careful planning to ensure that capacity additions keep up with the growth in service requirements on both the supply and demand side. Essentially, there must be sufficient gathering and transport capacity to meet daily requirements.

NGTL projects export volumes on the basis of known and expected Firm Transportation Service Agreements at the export points and on the outlook for market growth in each region, the competitiveness of Alberta gas in each of the key markets, and a general assessment of the North American gas supply and demand outlook. The maximum day

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[17] A detailed map of the NGTL System is available at: Transcanada.com/Alberta/info_postings/new map/Alberta_ system_map_2002.pdf

intra-Alberta delivery forecast is developed from forecasts provided by industrial plant operators with respect to their expected maximum, average, and minimum delivery requirements and other information, such as growth rates for specific demand sectors.

According to NGTL's December 2002 annual plan, on average about 85% of the gas transported on the NGTL system is shipped to export points and removed from the system. The remaining gas is delivered to intra-Alberta delivery points.

The December 2002 Annual Plan indicates that the NGTL system is projected to deliver 342.8 Mm^3d to 383.6 Mm^3d (12.1 Bcfd to 13.5 Bcfd) of gas on a maximum demand winter day in the next several years. In the 2004/05 gas year, about 173.4 Mm^3d (6.1 Bcfd) is likely be shipped to the Empress and McNeill Alberta/Saskatchewan border points and 81.1 Mm^3d (2.9 Bcfd) to the Alberta/British Columbia border on a winter peak day (Table 5-1). Most of the gas shipped to the two Saskatchewan border points will be exported to markets in eastern Canada and the Midwestern and Northeastern United States via the TransCanada Mainline and Foothills systems. Most of the gas delivered to the British Columbia border flows to markets in the Pacific Northwest and California.

Gas not transported to border points is delivered to intra-Alberta delivery points. NGTL projects that maximum intra-Alberta deliveries will increase from the current 89.5 Mm^3d (3.2 Bcfd) to 115.3 Mm^3d (4.1 Bcfd) by the 2006/07 gas year.[18] The growth is mainly attributable to the anticipated growth of gas demand at oil sands bitumen production and upgrading facilities as well as increased demand for gas for power generation at oil sands cogeneration plants and other facilities.

Of the 173 delivery points, the 20 largest represent about 80% of total estimated Alberta deliveries for the 2003/04 gas year. The Annual Plan indicates that, other than in urban areas where population and economic growth will drive residential and commercial gas demand higher, Alberta gas demand growth will occur mainly in conjunction with oil sands bitumen activity in the Fort McMurray area northeast of Edmonton. For example, in the Annual Plan, maximum winter day delivery requirements at the 20 largest sites are projected to grow by 11.8 Mm^3d (0.4 Bcfd) from 2002/03 to 2004/05 of which 8.8 Mm^3d (0.3 Bcfd) or 75% would be delivered to Mildred Lake near Fort McMurray. Oil sands bitumen production and upgrading (and related cogeneration) is increasing substantially and is expected to be a major driver of the Alberta economy for at least the next 10 to 20 years.

[18] NGTL's projected intra-Alberta deliveries reported in Table 5-1 are winter day peak delivery volumes. Consequently, these flows are not directly comparable to the daily Alberta demand and supply volumes discussed elsewhere in this report, which in most cases are annual averages.

Table 5-1: NGTL Winter Peak Day Delivery Forecast

	(Mm³d)		
	2002/03	**2004/05**	**2006/07**
Empress	102.83	114.16	119.83
McNeill	64.59	59.21	60.62
Total AB/Sask border	167.42	173.37	180.45
AB/Montana	1.13	0.57	0.57
AB/BC	84.70	81.30	87.25
Total border deliveries	253.26	255.24	268.27
Intra-AB delivery	89.52	103.12	115.30
Total	342.78	358.36	383.57

	(Bcfd)		
	2002/03	**2004/05**	**2006/07**
Empress	3.63	4.03	4.23
McNeill	2.28	2.09	2.14
Total AB/Sask border	5.91	6.12	6.37
AB/Montana	0.04	0.02	0.02
AB/BC	2.99	2.87	3.08
Total border deliveries	8.94	9.01	9.47
Intra-AB delivery	3.16	3.64	4.07
Total	12.10	12.65	13.54

Source: Nova Gas Transmission Ltd. December 2002 Annual Plan
(Converted to Mm^3d using NEB pressure base of 14.73 psi.)

The gradual northward and westward shift of new receipt volumes and changing volume requirements at existing and new delivery points, especially in the Fort McMurray oil sands area, have important implications for the future design of the Alberta gas gathering system. Because gas production is declining in the producing regions in eastern Alberta, NGTL's development strategy is heavily focused on opportunities to supply the growing oil sands gas requirements for process heat and cogeneration with gas from the northwest part of the province. Any excess flows from the northwest to the eastern part of the province would be available for export through Empress/McNeill via Princess on NGTL's East Leg.[19]

5.3 Implications for Intra-Alberta Pipeline Capacity and Tolls

This section examines the implications for the intra-Alberta gas transportation system of the delivery into Alberta of 34.0 Mm^3d (1.2 Bcfd) of Mackenzie Delta gas commencing in 2009. The Preliminary Information Package (PIP) provided to the NEB by the

[19] NGTL System Alberta border deliveries do not account for all of the gas exports from the WCSB region. The Alliance Pipeline accounts for about 10 % of total WCSB exports to eastern Canada and the U.S. on an average annual basis.

Mackenzie Pipeline Co-venturers indicated that the southern terminus of the Mackenzie Pipeline would be located south of the Alberta/NWT boundary, in the vicinity of Bootis Hill. Bootis Hill is currently the northern extremity of the part of the NGTL System that runs along the Alberta/British Columbia boundary in northwest Alberta. However, the current plan is to build the Mackenzie Pipeline only to the Alberta-NWT boundary. TransCanada will extend the NGTL System north to connect with the Pipeline at the boundary.

Such an extension would require several enhancements to the NGTL System. First, the system would need to be extended from its existing terminus at Bootis Hill to the Alberta/NWT border – a distance of 66 kilometers. In this regard various pipeline diameter and compression specifications are being evaluated. Second, pipeline section looping and pressure facility changes would likely be required on the section of the NGTL system that runs south from Bootis Hill to Zama Lake junction. Further, the section of the NGTL system that runs from Bootis Hill to Tanghe Creek would need to be enhanced. The cost of these enhancements was not estimated in this analysis.

Once Mackenzie Delta volumes enter the NGTL System, they can be transported to intra-Alberta delivery points and to the Alberta border export points via the West and East Legs of the System. Via the West Leg, the gas would be transported south from Bootis Hill to Gordondale and, from there, to numerous intra-Alberta points and to the British Columbia and Saskatchewan border export points. No capacity additions would be required to move Mackenzie volumes down the West Leg of the NGTL system south of Gordondale due to the spare capacity created when the 45.3 Mm^3d (1.6 Bcfd) Alliance Pipeline came into service. Including the spare capacity that existed prior to Alliance, there is currently considerable excess capacity available on the West Leg.

With gas production declining in eastern Alberta and demand increasing there due to the growth in oil sands bitumen processing requirements and other end uses, spare capacity on the NGTL System East Leg is also growing.[20] In this Study, we assumed that in the next three to five years NGTL would install new facilities to more directly link the gas-producing areas in northwest Alberta with regions in eastern Alberta where gas demand is increasing. Mackenzie Delta volumes in excess of the gas requirements in these regions could thus flow into the East Leg of the system for transportation to additional intra-Alberta delivery points and to the major Alberta/Saskatchewan border export delivery points at Empress and McNeill. In the absence of such facilities, the Mackenzie Delta volumes could flow down the West Leg of the NGTL system. As with

[20] The amount of slack capacity could be increased by the EUB's July 2003 decision to shut-in gas reserves in the Wabiskaw-McMurray part of the Athabasca Oil Sands Area. The Decision reflects the Board's concern that continued growth in gas production in the oil sands reserve areas could jeopardize potential bitumen recovery. As gas is extracted, the pressure in the gas pools declines, placing thermal recovery techniques such as steam assisted gravity drainage at risk. Current gas production in the Wabiskaw-McMurray area is about 7.1 Mm^3d (0.25 Bcfd).

the East Leg flows, the only enhancements needed to accommodate these incremental flows would be facilities required to receive the gas into the NGTL system.

Given the large incremental volume of gas from the Mackenzie Delta that would flow onto the NGTL system, and the short distance from Bootis Hill to the Alberta/NWT boundary, there would likely be a reduction in the NGTL tolls.

5.4 Export Pipeline Takeaway Capacity

This section discusses the potential impact of Mackenzie Delta gas production on the capacity of the pipelines that remove western Canadian gas to markets in eastern Canada and the United States. The basic question is whether the existing transmission capacity will be adequate to deliver projected total flows of gas from Alberta and the WCSB region as a whole to downstream markets when the Mackenzie Pipeline enters service.

In this analysis the WCSB is defined as British Columbia, Alberta, and Saskatchewan. The gas demand and supply outlook for the WCSB presented in Sections 3 and 4 indicates that gas consumption will grow throughout the forecast period while gas production in the region, including coalbed methane production, will plateau during the 2010 to 2020 period and subsequently decline. The projected changes in supply and demand are summarized in Table 5-2.

Table 5-2: Changes in WCSB Area Consumption and Production: Base Case
(Mm^3d and Bcfd)

	2002-2010			2010-2020			2020-2030		
Mm^3d	Demand	Production	Surplus	Demand	Production	Surplus	Demand	Production	Surplus
British Columbia	5.59	7.22	1.63	6.05	5.12	(0.93)	5.51	(10.32)	(15.83)
Alberta	21.50	3.57	(17.93)	19.17	(4.97)	(24.14)	17.31	(32.67)	(49.98)
Saskatchewan	2.02	1.24	(0.78)	2.72	1.01	(1.71)	2.56	(0.93)	(3.49)
WCSB Total	29.10	12.03	(17.07)	27.94	1.16	(26.78)	25.38	(43.93)	(69.31)
Bcfd	Demand	Production	Surplus	Demand	Production	Surplus	Demand	Production	Surplus
British Columbia	0.20	0.25	0.06	0.21	0.18	(0.03)	0.19	(0.36)	(0.56)
Alberta	0.76	0.13	(0.63)	0.68	(0.18)	(0.85)	0.61	(1.15)	(1.76)
Saskatchewan	0.07	0.04	(0.03)	0.10	0.04	(0.06)	0.09	(0.03)	(0.12)
WCSB Total	1.03	0.42	(0.60)	0.99	0.04	(0.95)	0.90	(1.55)	(2.45)

With regional demand increasing and production falling, gas exports from the WCSB would decline unless new supplies, such as Northern Frontier gas supplies, are introduced to the region. Since the potential drop in gas exports without Mackenzie Delta gas volumes is larger than the capacity of the proposed Pipeline, no additions to takeaway capacity will be required to accommodate the incremental exports made possible by the Mackenzie Delta volumes in the Base, Low Demand or Expansion Case scenarios.

This assessment was based on an examination of takeaway capacity on each of the five export corridors from the WCSB: (1) the Duke Energy British Columbia Gas Transmission and Williams Energy Northwest Pipeline corridor; (2) the NGTL/Foothills Pipe Lines Ltd., TransCanada British Columbia, and Gas Transmission Northwest Corporation (GTN) corridor; (3) the Alliance Pipeline corridor; (4) the Foothills East Leg and Northern Border Pipeline corridor; and (5) the NGTL System and the TransCanada Mainline corridor. Because the analysis indicated that no additions to WCSB takeaway capacity would be required except in the Alaska Case, the detailed review of the export corridor facilities and potential expansions is presented along with the results of the Alaskan Pipeline Sensitivity Case in Section 6.

Takeaway Capacity and Flows in the Base Case

Table 5-3 summarizes the capacity, projected flows, and capacity utilization of each of the five WCSB export corridors in the Base Case. As shown in the upper left hand portion of the Table, the total capacity available to transport WCSB gas to markets in eastern Canada and the U.S. Lower 48 is approximately 425.7 Mm^3d (15.1 Bcfd). In 2003, export flows along these five corridors were projected to average about 343.2 Mm^3d (12.1 Bcfd), which represented (approximately) the difference between expected average daily WCSB production of 484.4 Mm^3d (17.1 Bcfd) and average daily demand (including net storage injections) of 136.0 Mm^3d (4.8 Bcfd). In the Base Case, gas demand growth is projected to outpace gas supply growth in Alberta and the WCSB for all but the brief period following the onset of Mackenzie Delta gas deliveries in late 2009. As a consequence, WCSB exports are projected to decline for most of the forecast period. Further, the moderate increase in export volumes during the 2010-2020 period can clearly be accommodated by the existing takeaway capacity. Consequently, no pipeline constraints on WCSB exports are foreseen and no export pipeline facility expansions are required to accommodate the 34.0 Mm^3d (1.2 Bcfd) of gas delivered by the Mackenzie Pipeline.

Table 5-3: WCSB Export Pipeline Capacity, Projected Exports, Export Share, and Capacity Utilization (Base Case)

	(Mm^{3}d)				
Export Capacity	**2003**	**2010**	**2015**	**2020**	**2030**
Northwest Pipeline*	39.92	49.58	49.58	49.58	49.58
GTN*	77.05	77.05	77.05	77.05	77.05
Total West	**116.97**	**126.63**	**126.63**	**126.63**	**126.63**
Northern Border*	62.04	62.04	62.04	62.04	62.04
Alliance Pipeline*	43.54	43.54	43.54	43.54	43.54
TransCanada**	203.12	203.12	203.12	203.12	203.12
Total East	**308.70**	**308.70**	**308.70**	**308.70**	**308.70**
Total	**425.67**	**435.33**	**435.33**	**435.33**	**435.33**
Export Flows					
Northwest Pipeline*	28.61	29.12	32.97	32.32	21.95
GTN*	59.24	63.43	65.07	64.08	59.77
Total West	**87.85**	**92.55**	**98.05**	**96.40**	**81.73**
Northern Border*	60.28	60.31	60.82	60.96	35.52
Alliance Pipeline*	42.41	42.69	42.69	42.18	40.82
TransCanada**	152.66	171.47	160.14	136.37	112.44
Total East	**255.35**	**274.48**	**263.65**	**239.52**	**188.78**
Total	**343.20**	**367.03**	**361.70**	**335.92**	**270.51**
Export Shares					
Northwest Pipeline*	8.3%	7.9%	9.1%	9.6%	8.1%
GTN*	17.3%	17.3%	18.0%	19.1%	22.1%
Total West	**25.6%**	**25.2%**	**27.1%**	**28.7%**	**30.2%**
Northern Border*	17.6%	16.4%	16.8%	18.1%	13.1%
Alliance Pipeline*	12.4%	11.6%	11.8%	12.6%	15.1%
TransCanada**	44.5%	46.7%	44.3%	40.6%	41.6%
Total East	**74.4%**	**74.8%**	**72.9%**	**71.3%**	**69.8%**
Capacity Utilization					
Northwest Pipeline*	71.7%	58.7%	66.5%	65.2%	44.3%
GTN*	76.9%	82.3%	84.4%	83.2%	77.6%
Northern Border*	97.2%	97.2%	98.0%	98.3%	57.3%
Alliance Pipeline*	97.4%	98.0%	98.0%	96.9%	93.8%
TransCanada**	75.2%	84.4%	78.8%	67.1%	55.4%
Total	**80.6%**	**84.3%**	**83.1%**	**77.2%**	**62.1%**

	(Bcfd)				
Export Capacity	**2003**	**2010**	**2015**	**2020**	**2030**
Northwest Pipeline*	1.41	1.75	1.75	1.75	1.75
GTN*	2.72	2.72	2.72	2.72	2.72
Total West	**4.13**	**4.47**	**4.47**	**4.47**	**4.47**
Northern Border*	2.19	2.19	2.19	2.19	2.19
Alliance Pipeline*	1.54	1.54	1.54	1.54	1.54
TransCanada**	7.17	7.17	7.17	7.17	7.17
Total East	**10.90**	**10.90**	**10.90**	**10.90**	**10.90**
Total	**15.03**	**15.37**	**15.37**	**15.37**	**15.37**
Export Flows					
Northwest Pipeline*	1.01	1.03	1.16	1.14	0.78
GTN*	2.09	2.24	2.30	2.26	2.11
Total West	**3.10**	**3.27**	**3.46**	**3.40**	**2.89**
Northern Border*	2.13	2.13	2.15	2.15	1.25
Alliance Pipeline*	1.50	1.51	1.51	1.49	1.44
TransCanada**	5.39	6.05	5.65	4.81	3.97
Total East	**9.01**	**9.69**	**9.31**	**8.46**	**6.66**
Total	**12.12**	**12.96**	**12.77**	**11.86**	**9.55**

*At U.S. border **At Man./Sask. border

Direction of Export Flows

Table 5-4 summarizes WCSB export flows from 2009 through 2011, which coincides with the first three years of Mackenzie Pipeline deliveries. In the Base Case, flows along each of the corridors except TransCanada and GTN remain quite stable after 2009. Flows on GTN increase by about 3.7 Mm^3d (0.1 Bcfd) or 5% initially and then remain steady, while export flows on TransCanada's Mainline increase by about 25.3 Mm^3d (0.9 Bcfd) in 2010 and then fall back by about 6.0 Mm^3d (0.2 Bcfd).

Table 5-4. Base Case: Impact of Mackenzie Valley Pipeline on WCSB Export Flows

	(Mm^3d)			
Export Corridor	**2008**	**2009**	**2010**	**2011**
Northwest Pipeline*	29.75	28.95	29.12	27.76
GTN*	59.77	59.77	63.43	63.46
Total West	89.80	88.73	92.55	90.93
Northern Border*	60.28	60.31	60.31	60.23
Alliance Pipeline*	42.49	42.46	42.69	42.78
TransCanada**	146.46	146.18	171.47	165.44
Total East	249.58	248.95	274.48	268.27
Total	339.09	337.68	367.03	359.49

	(Bcfd)			
Export Corridor	**2008**	**2009**	**2010**	**2011**
Northwest Pipeline*	1.05	1.02	1.03	0.98
GTN*	2.11	2.11	2.24	2.24
Total West	*3.17*	*3.13*	*3.27*	*3.21*
Northern Border*	2.13	2.13	2.13	2.13
Alliance Pipeline*	1.50	1.50	1.51	1.51
TransCanada**	5.17	5.16	6.05	5.84
Total East	8.81	8.79	9.69	9.47
Total	11.97	11.92	12.96	12.69

*At U.S. border **At Man./Sask. border

As indicated in Table 5-3, the east-west distribution of WCSB exports is quite stable during the 2003 to 2010 period. In the Base Case, westward flows to the Pacific Northwest and California increase about 5% from 2003 to 2010, mainly due to a 7% increase in flows on the GTN corridor. Most of the 23.8 Mm^3d (0.8 Bcfd) increase in

WCSB exports during this period is on the TransCanada system at the Saskatchewan/Manitoba border. However, the increase does not occur until 2010 when Mackenzie Delta gas becomes available. Until then, flows on the TransCanada Mainline at the Saskatchewan-Manitoba border tend to gradually decline.

From 2010 to 2020, export flows to the West increase by about 4% in response to growing demand in California and the Pacific Northwest although total WCSB exports slip by 31.1 Mm^3d (1.1 Bcfd) as a result of increased Alberta demand and declining WCSB production.[21] The net result is that the western share of total exports rises from 25% to about 29%, while the eastern share drops from 75% to 71%.

During the final ten years of the forecast period, both eastward and westward export flows decline due to declining deliverability in the WCSB. However, the drop in the eastward flows is much greater in absolute and percentage terms. As a consequence, the share of west-bound gas exports increases further. This reflects the strong growth of gas demand in California and the State's closer proximity to Western Canada, compared to the Midwestern and Northeastern United States.

Throughout the entire forecast period the most stability occurs on the GTN and Alliance Pipeline corridors where export flows in 2030 are within 4% of the estimated 2003 flows. Flows on the Northwest Pipeline and TransCanada WCSB export corridors decline by 23% and 26%, respectively, from 2003 to 2030. Flows on Northern Border Pipeline are expected to weaken by 41% during this period.

Toll Implications

The stable flows along the WCSB export corridors, forecast in the Base Case through 2010, indicate that no expansions to the takeaway capacities of pipelines receiving gas for export from the region are likely to be required. Absent expansions, pipeline rate bases would tend to decline due to depreciation. In general, therefore, no increases in tolls are anticipated to result from the onset of Mackenzie Delta gas deliveries to Alberta. In fact, in some cases increased flows and firm transportation contract revenue could lead to toll reductions. In summary, the toll impacts of the Mackenzie Delta volumes for shippers on the WCSB export pipelines are likely to be neutral or positive (i.e. reduction in tolls) during the first 21 years of the Pipeline's operation (to 2030).

[21] Strong demand growth in the Lower 48 states indicates that the decline in exports is not the consequence of sluggish demand there.

6 SENSITIVITY ANALYSIS

This section presents the results of the three sensitivity cases examined in the Study. The cases were conducted to test the impacts of alternative assumptions on the capacity of the Pipeline, growth in Canadian and U.S. gas demand, and the potential construction of an Alaskan gas pipeline on the market need for gas from the Mackenzie Delta.

6.1 Mackenzie Pipeline Expansion Case

This Case assumes that the delivery capacity of the Mackenzie Pipeline is expanded to 42.5 Mm^3d (1.5 Bcfd) in November 2015 and 51.0 Mm^3d (1.8 Bcfd) in November 2020. The expansions are accomplished by adding compression along the Pipeline. All other assumptions are also the same as in the Base Case. Table 6-1 provides a comparison of gas demand, production, and LNG imports for the Mackenzie Expansion and Base Cases.

The increase in Mackenzie Delta volumes enabled by the Mackenzie Pipeline expansions increases total Canadian gas supply by 1.4% in 2016 and 2.9% in 2021. In the same years, total supply in Canada and the U.S. Lower 48 increases by 0.4% and 0.8%, respectively.

Table 6-2 indicates the changes in gas export flows and pipeline utilization between the Mackenzie Expansion and Base Cases. The initial 8.5 Mm^3d (0.3 Bcfd) expansion results in an increase in WCSB exports of 7.3 Mm^3d (0.3 Bcfd) in 2016 and an increase of 1.2 Mm^3d (0.04 Bcfd) in Alberta gas consumption. Following the second expansion, WCSB exports are 14.4 Mm^3d (0.5 Bcfd) greater than in the Base Case in 2021. The increase in export flows compared with the Base Case remains roughly constant for the remainder of the forecast period. As the increase in gas deliveries is relatively small, no additions to WCSB export pipeline capacity would be required.

In 2016 and 2021, most of the increase in exports is expected to flow along TransCanada. In subsequent years, the increase is shared between TransCanada and Northern Border.

Given the outlook for minimal growth in Alberta gas production for the next ten years followed by declining production thereafter, there would be sufficient capacity on the NGTL System to facilitate the incremental flow of Mackenzie Delta gas to Alberta border export points in the Expansion Case. In the Mackenzie Expansion Case the percentage increase in costs is expected to be no larger than the increase in transportation volumes. Consequently, no increases in NGTL pipeline tolls are expected.

Table 6-1: Comparison of Mackenzie Expansion and Base Case Forecasts

	(Mm^{3}d)					
	2009	2010	2015	2020	2025	2030
Gas Consumption						
Mackenzie Expansion Case						
Canada	284.0	294.7	323.5	348.9	369.2	397.9
U.S. Lower 48	1901.0	1957.2	2177.8	2340.1	2376.3	2423.9
Total	2185.0	2251.9	2501.3	2689.0	2745.5	2821.8
Mackenzie Base Case						
Canada	284.0	294.7	323.4	347.8	366.1	395.0
U.S. Lower 48	1901.0	1957.2	2177.8	2336.1	2365.1	2413.2
Total	2185.0	2251.9	2501.2	2683.9	2731.2	2808.2
Expansion Minus Base Case						
Canada	0.0	0.0	0.1	1.1	3.1	2.9
U.S. Lower 48	0.0	0.0	0.0	4.0	11.2	10.7
Total	0.0	0.0	0.1	5.1	14.3	13.5
% Difference	0.0%	0.0%	0.0%	0.2%	0.5%	0.5%
Gas Production						
Mackenzie Expansion Case						
Canada	525.9	555.7	589.2	594.6	597.0	577.2
U.S. Lower 48	1531.7	1543.3	1587.6	1591.3	1568.2	1511.5
Total	2057.6	2099.0	2176.8	2185.9	2165.2	2088.7
Mackenzie Base Case						
Canada	525.9	555.7	587.7	586.3	580.4	560.1
U.S. Lower 48	1531.7	1543.3	1587.6	1593.0	1571.8	1516.0
Total	2057.6	2099.0	2175.4	2179.2	2152.2	2076.1
Expansion Minus Base Case						
Canada	0.0	0.0	1.4	8.4	16.5	17.1
U.S. Lower 48	0.0	0.0	0.0	-1.7	-3.6	-4.5
Total	0.0	0.0	1.4	6.7	12.9	12.7
% Difference	0.0%	0.0%	0.1%	0.3%	0.6%	0.6%
Lower 48 LNG Imports						
Mackenzie Expansion Case	169.9	201.1	378.9	540.3	633.8	758.4
Mackenzie Base Case	169.9	201.1	378.9	540.3	633.8	758.4
Difference	0.0	0.0	0.0	0.0	0.0	0.0
% Difference	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	(Bcfd)					
	2009	2010	2015	2020	2025	2030
Gas Consumption						
Canada	10.0	10.4	11.4	12.3	13.0	14.0
U.S. Lower 48	67.1	69.1	76.9	82.6	83.9	85.6
Total	77.1	79.5	88.3	94.9	96.9	99.6
Mackenzie Base Case						
Canada	10.0	10.4	11.4	12.3	12.9	13.9
U.S. Lower 48	67.1	69.1	76.9	82.5	83.5	85.2
Total	77.1	79.5	88.3	94.7	96.4	99.1
Expansion Minus Base Case						
Canada	0.0	0.0	0.0	0.0	0.1	0.1
U.S. Lower 48	0.0	0.0	0.0	0.1	0.4	0.4
Total	0.0	0.0	0.0	0.2	0.5	0.5
% Difference	0.0%	0.0%	0.0%	0.2%	0.5%	0.5%
Gas Production						
Mackenzie Expansion Case						
Canada	18.6	19.6	20.8	21.0	21.1	20.4
U.S. Lower 48	54.1	54.5	56.0	56.2	55.4	53.4
Total	72.6	74.1	76.8	77.2	76.4	73.7
Mackenzie Base Case						
Canada	18.6	19.6	20.7	20.7	20.5	19.8
U.S. Lower 48	54.1	54.5	56.0	56.2	55.5	53.5
Total	72.6	74.1	76.8	76.9	76.0	73.3
Expansion Minus Base Case						
Canada	0.0	0.0	0.1	0.3	0.6	0.6
U.S. Lower 48	0.0	0.0	0.0	-0.1	-0.1	-0.2
Total	0.0	0.0	0.1	0.2	0.5	0.4
% Difference	0.0%	0.0%	0.1%	0.3%	0.6%	0.6%
Lower 48 LNG Imports						
Mackenzie Expansion Case	6.0	7.1	13.4	19.1	22.4	26.8
Mackenzie Base Case	6.0	7.1	13.4	19.1	22.4	26.8
Difference	0.0	0.0	0.0	0.0	0.0	0.0
% Difference	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Table 6-2: WCSB Export Pipeline Capacity, Exports, Export Share and Capacity Utilization - Mackenzie Expansion Case: Differences from Base Case

	(Mm^{3}d)		
	2016	2021	2026
Export Flows			
Northwest Pipeline*	0.42	0.91	1.05
GTN*	0.48	0.74	1.10
Total West	0.91	1.64	2.15
Northern Border*	0.00	0.28	5.33
Alliance Pipeline*	0.00	0.48	0.34
TransCanada**	6.43	11.95	6.88
Total East	6.43	12.72	12.55
Total	7.34	14.36	14.70
Export Shares***			
Northwest Pipeline*	-0.1	-0.2	-0.1
GTN*	-0.2	-0.6	-0.6
Total West	-0.3	-0.8	-0.7
Northern Border*	-0.3	-0.7	0.9
Alliance Pipeline*	-0.2	-0.4	-0.5
TransCanada**	0.9	1.8	0.4
Total East	0.3	0.8	0.7
Capacity Utilization*****			
Northwest Pipeline*	0.9	1.8	2.1
GTN*	0.6	1.0	1.4
Northern Border*	0.0	0.5	8.6
Alliance Pipeline*	0.0	1.1	0.8
TransCanada**	3.2	5.9	3.4
Total	0.0	3.3	3.4
	(Bcfd)		
Export Flows			
Northwest Pipeline*	0.02	0.03	0.04
GTN*	0.02	0.03	0.04
Total West	0.03	0.06	0.08
Northern Border*	0.00	0.01	0.19
Alliance Pipeline*	0.00	0.02	0.01
TransCanada**	0.23	0.42	0.24
Total East	0.23	0.45	0.44
Total	0.26	0.51	0.52

* At U.S. border
** At Saskatchewan-Manitoba border
*** Change in percent share
**** Change in the capacity utilization rate percentage

6.2 Low Demand Sensitivity Case

To test the impacts of the Mackenzie Pipeline under less favorable market conditions, a Low Gas Demand Sensitivity Case was conducted assuming that economic growth in both Canada and the United States is 0.5 percentage points slower (about 18% less) than in the Base Case. This reduces GDP growth in Canada and the United States to 2.1% and 2.3% per annum, respectively. The decrease in economic activity builds over time. In 2010, the Canadian and U.S. economies are about 4% smaller than in the Base Case. The difference from the Base case grows to 6% by 2015, 8% by 2020, and 13% by 2030.

Figure 6-1: Reduction in Canadian & U.S. Lower 48 Gas Demand from Base Case

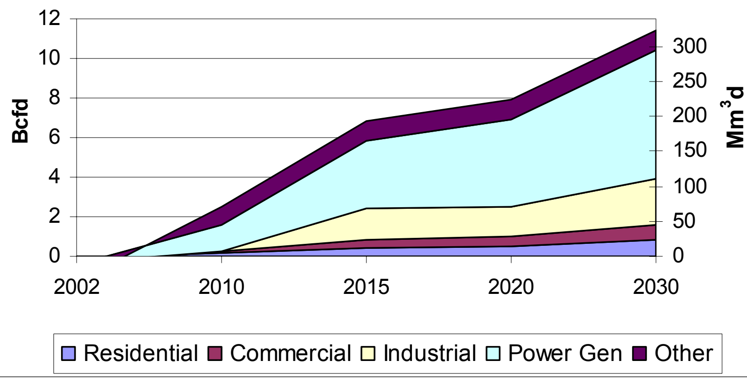


Figure 6-1 shows the impact of lower GDP growth on the various end-use sectors. Table 6-3 presents the forecast of gas demand under the Low Demand Case assumptions.

By 2030, total gas demand in Canada and the U.S. Lower 48 is projected to be 323.0 Mm³d (11.4 Bcfd) or 11% lower than in the Base Case. Over 60% of the reduction occurs in the power generation sector, where combined gas demand is forecast to be 183.4 Mm³d (6.5 Bcfd) or 23% lower than in the Base Case. The forecast mainly reflects the slower growth in electricity consumption in both nations, which reduces gas demand. The industrial sector is also negatively affected by the slowdown in economic growth as reflected in an 8% reduction in industrial gas demand in Canada and the U.S. Lower 48 compared with the Base Case. Owing to the prominence of resource-based industries, industrial demand is especially hard-hit in Canada, falling 21% below Base Case levels.

Table 6-3: Low Case Gas Consumption Forecast

	Mm³d					Bcfd				
	2002	2010	2015	2020	2030	2002	2010	2015	2020	2030
US L48 & Can. Total	1,938.7	2,217.8	2,347.0	2,500.2	2,528.4	68.4	78.3	82.9	88.3	89.3
Residential	421.4	483.2	494.7	515.3	552.6	14.9	17.1	17.5	18.2	19.5
Commercial	275.9	319.8	328.6	351.6	383.4	9.7	11.3	11.6	12.4	13.5
Industrial	704.6	700.6	691.4	734.5	794.8	24.9	24.7	24.4	25.9	28.1
Power Generation	359.9	522.6	633.4	697.9	606.0	12.7	18.4	22.4	24.6	21.4
Other	176.8	191.5	198.9	200.8	191.7	6.2	6.8	7.0	7.1	6.8
Canada Total	242.4	288.6	303.6	321.1	343.3	8.6	10.2	10.7	11.3	12.1
Residential	49.0	53.6	55.8	58.9	64.0	1.7	1.9	2.0	2.1	2.3
Commercial	33.6	37.1	38.0	40.6	44.0	1.2	1.3	1.3	1.4	1.6
Industrial	83.9	101.6	106.2	112.0	113.3	3.0	3.6	3.7	4.0	4.0
Power Generation	27.1	44.8	50.2	56.9	72.9	1.0	1.6	1.8	2.0	2.6
Other	48.7	51.5	53.3	14.3	49.2	1.7	1.8	1.9	0.5	1.7
U.S. Lower 48 Total	1,696.3	1,929.2	2,043.5	2,179.1	2,185.1	59.9	68.1	72.1	76.9	77.1
Residential	372.3	429.6	439.0	456.4	488.7	13.1	15.2	15.5	16.1	17.2
Commercial	242.3	282.8	290.6	311.1	339.4	8.6	10.0	10.3	11.0	12.0
Industrial	620.7	599.0	585.2	622.6	681.4	21.9	21.1	20.7	22.0	24.1
Power Generation	332.8	477.8	583.2	641.0	533.1	11.7	16.9	20.6	22.6	18.8
Other	128.1	140.0	145.5	148.1	142.5	4.5	4.9	5.1	5.2	5.0
	Low Demand Case Minus Base Case Consumption									
	2002	2010	2015	2020	2030	2002	2010	2015	2020	2030
US L48 & Can. Total	-35.0	-71.2	-192.5	-223.2	-323.0	-1.2	-2.5	-6.8	-7.9	-11.4
Residential	-1.4	-3.5	-11.7	-14.3	-23.0	0.0	-0.1	-0.4	-0.5	-0.8
Commercial	-2.0	-2.7	-12.6	-13.9	-21.2	-0.1	-0.1	-0.4	-0.5	-0.7
Industrial	-5.8	-1.9	-43.2	-42.1	-66.3	-0.2	-0.1	-1.5	-1.5	-2.3
Power Generation	-2.5	-36.9	-98.1	-126.6	-183.4	-0.1	-1.3	-3.5	-4.5	-6.5
Other	-23.3	-26.2	-26.8	-26.3	-29.0	-0.8	-0.9	-0.9	-0.9	-1.0
Canada Total	0.0	-6.1	-19.9	-26.7	-51.7	0.0	-0.2	-0.7	-0.9	-1.8
Residential	0.0	-0.2	-1.1	-1.3	-2.3	0.0	0.0	0.0	0.0	-0.1
Commercial	0.0	0.0	-1.2	-1.2	-2.0	0.0	0.0	0.0	0.0	-0.1
Industrial	0.0	-4.2	-13.7	-18.6	-30.0	0.0	-0.1	-0.5	-0.7	-1.1
Power Generation	0.0	-0.8	-3.0	-5.4	-16.4	0.0	0.0	-0.1	-0.2	-0.6
Other	0.0	-0.8	-0.8	-38.6	-0.9	0.0	0.0	0.0	-1.4	0.0
U.S. Lower 48 Total	-35.0	-65.1	-172.6	-196.5	-271.3	-1.2	-2.3	-6.1	-6.9	-9.6
Residential	-1.4	-3.3	-10.5	-13.0	-20.6	0.0	-0.1	-0.4	-0.5	-0.7
Commercial	-2.0	-2.7	-11.4	-12.7	-19.2	-0.1	-0.1	-0.4	-0.4	-0.7
Industrial	-5.8	2.3	-29.5	-23.5	-36.3	-0.2	0.1	-1.0	-0.8	-1.3
Power Generation	-2.6	-36.0	-95.1	-121.2	-167.0	-0.1	-1.3	-3.4	-4.3	-5.9
Other	-23.3	-25.4	-26.1	-26.1	-28.1	-0.8	-0.9	-0.9	-0.9	-1.0
	Percent Change									
	2002	2010	2015	2020	2030	2002	2010	2015	2020	2030
US L48 & Can. Total	-2%	-3%	-8%	-8%	-11%	-2%	-3%	-8%	-8%	-11%
Residential	0%	-1%	-2%	-3%	-4%	0%	-1%	-2%	-3%	-4%
Commercial	-1%	-1%	-4%	-4%	-5%	-1%	-1%	-4%	-4%	-5%
Industrial	-1%	0%	-6%	-5%	-8%	-1%	0%	-6%	-5%	-8%
Power Generation	-1%	-7%	-13%	-15%	-23%	-1%	-7%	-13%	-15%	-23%
Other	-12%	-12%	-12%	-12%	-13%	-12%	-12%	-12%	-12%	-13%
Canada Total	0%	-2%	-6%	-8%	-13%	0%	-2%	-6%	-8%	-13%
Residential	0%	0%	-2%	-2%	-4%	0%	0%	-2%	-2%	-4%
Commercial	0%	0%	-3%	-3%	-4%	0%	0%	-3%	-3%	-4%
Industrial	0%	-4%	-11%	-14%	-21%	0%	-4%	-11%	-14%	-21%
Power Generation	0%	-2%	-6%	-9%	-18%	0%	-2%	-6%	-9%	-18%
Other	0%	-2%	-1%	-73%	-2%	0%	-2%	-1%	-73%	-2%
U.S. Lower 48 Total	-2%	-3%	-8%	-8%	-11%	-2%	-3%	-8%	-8%	-11%
Residential	0%	-1%	-2%	-3%	-4%	0%	-1%	-2%	-3%	-4%
Commercial	-1%	-1%	-4%	-4%	-5%	-1%	-1%	-4%	-4%	-5%
Industrial	-1%	0%	-5%	-4%	-5%	-1%	0%	-5%	-4%	-5%
Power Generation	-1%	-7%	-14%	-16%	-24%	-1%	-7%	-14%	-16%	-24%
Other	-15%	-15%	-15%	-15%	-16%	-15%	-15%	-15%	-15%	-16%

Table 6-4 presents a comparison of forecast gas production and LNG imports in the Low Demand and Base Cases. At the lower demand levels, natural gas markets will clearly not support all of the growth in LNG import capacity that is projected to occur beyond 2007 in the Base Case. Thus, while existing expansion projects are expected to proceed, LNG developers are projected to scale back plans for further expanding existing terminals and building new ones. As a result, the overall volume of LNG imports declines. In the Low Demand Case forecast, LNG imports into the U.S. Lower 48 are projected to reach 528.0 Mm^3d (18.6 Bcfd) in 2030, 230.5 Mm^3d (8.1 Bcfd) or 30% less than in the Base Case. Approximately two-thirds of the reduction reflects the cancellation or scaling back of plans for new import terminal capacity. In the Low Demand Case, LNG is forecasted to supply 23% of U.S. Lower 48 gas consumption in 2030, versus 31% in the Base Case.

Gas production in Canada and the United States is also forecasted to decline from Base Case levels. As shown in Table 6-4, annual gas production in Canada is expected to be 5.4 Mm^3d to 10.0 Mm^3d (0.2 Bcfd to 0.4 Bcfd) lower than in the Base Case while U.S. Lower 48 gas production is between 6.7 Mm^3d and 43.4 Mm^3d (0.2 Bcfd to 1.5 Bcfd) lower than in the Base Case. The combination of reduced LNG imports and lower gas production brings gas supply into balance with gas demand in the Low Demand Case.

Figure 6-2 compares forecast U.S. Lower 48 LNG imports in the Base Case and the Low Demand Case.

Figure 6-2: Lower 48 LNG Imports: Low Demand vs. Base Case

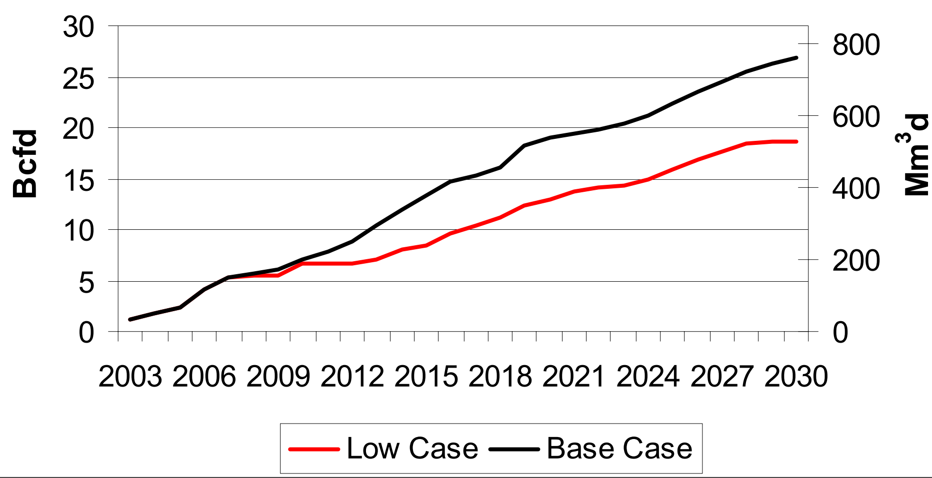


Table 6-4: Comparison of Low Demand and Base Case Forecasts						
	(Mm^{3}d)					
Gas Production	**2009**	**2010**	**2015**	**2020**	**2025**	**2030**
Low Demand Case						
Canada	520.5	548.2	577.7	578.5	572.6	551.9
U.S. Lower 48	1,520.4	1,528.9	1,580.9	1,584.6	1,548.7	1,472.6
Total	2,040.9	2,077.1	2,158.6	2,163.1	2,121.3	2,024.5
Mackenzie Base Case						
Canada	525.9	555.7	587.7	586.3	580.4	560.1
U.S. Lower 48	1,531.7	1,543.3	1,587.6	1,593.0	1,571.8	1,516.0
Total	2,057.6	2,099.0	2,175.4	2,179.2	2,152.2	2,076.1
Low Demand Minus Base Case						
Canada	-5.4	-7.5	-10.0	-7.8	-7.8	-8.1
U.S. Lower 48	-11.4	-14.4	-6.7	-8.4	-23.1	-43.4
Total	-16.7	-21.8	-16.7	-16.2	-30.9	-51.5
% Difference	-0.8%	-1.0%	-0.8%	-0.7%	-1.4%	-2.5%
Lower 48 LNG Imports						
Low Demand Case	155.8	186.9	236.5	369.3	448.7	528.0
Mackenzie Base Case	169.9	201.1	378.9	540.3	633.8	758.4
Difference	-14.2	-14.2	-142.4	-171.0	-185.1	-230.5
% Difference	-8.3%	-7.0%	-37.6%	-31.6%	-29.2%	-30.4%
	(Bcfd)					
Gas Production	**2009**	**2010**	**2015**	**2020**	**2025**	**2030**
Low Demand Case						
Canada	18.4	19.4	20.4	20.4	20.2	19.5
U.S. Lower 48	53.7	54.0	55.8	55.9	54.7	52.0
Total	72.0	73.3	76.2	76.4	74.9	71.5
Mackenzie Base Case						
Canada	18.6	19.6	20.7	20.7	20.5	19.8
U.S. Lower 48	54.1	54.5	56.0	56.2	55.5	53.5
Total	72.6	74.1	76.8	76.9	76.0	73.3
Low Demand Minus Base Case						
Canada	-0.2	-0.3	-0.4	-0.3	-0.3	-0.3
U.S. Lower 48	-0.4	-0.5	-0.2	-0.3	-0.8	-1.5
Total	-0.6	-0.8	-0.6	-0.6	-1.1	-1.8
% Difference	-0.8%	-1.0%	-0.8%	-0.7%	-1.4%	-2.5%
Lower 48 LNG Imports						
Low Demand Case	5.5	6.6	8.3	13.0	15.8	18.6
Mackenzie Base Case	6.0	7.1	13.4	19.1	22.4	26.8
Difference	(0.5)	(0.5)	(5.0)	(6.0)	(6.5)	(8.1)
% Difference	-8.3%	-7.0%	-37.6%	-31.6%	-29.2%	-30.4%

The Low Demand case analysis indicates that the Mackenzie Delta will still provide an important source of incremental gas supplies to Canadian and U.S. markets even if natural gas demand grows substantially less than expected in the Base Case. Despite the lower economic growth, gas demand is still projected to increase substantially between 2002 and the start of the Mackenzie Pipeline in 2009. Gas production continues to expand at a lower rate than gas demand, and significant increases in "frontier gas supplies" are still required to balance supply and demand. The anticipated favorable performance of the Pipeline under such adverse market conditions buttresses the basic conclusion of this Study, i.e. that there is market need for the Mackenzie Pipeline during the forecast period.

Because demand growth is less robust in the Low Demand Case than in the Base Case, it follows that no reinforcements of either the NGTL System or the export pipelines taking gas from the WCSB are required.

Table 6-5 presents the changes in export flows, capacities, and capacity utilization rates between the Low Demand Case and the Base Case. Total export flows and flows on the various export corridors are essentially the same as in the Base Case until about 2015. Thereafter, exports are slightly greater than in the Base Case because the reduction in WCSB demand exceeds the fall in production. In addition, investments in LNG facilities in the United States are assumed to fall, increasing the U.S. need for imports of Canadian gas.

Table 6-5: Export Shares and Capacity Utilization, Low Demand Case: Differences from Base Case

(Mm³d)	2010	2015	2020	2030
Export Flows				
Northwest Pipeline*	0.14	-0.14	0.23	10.40
GTN*	0.59	0.23	-0.03	5.47
Total West	0.74	0.08	0.20	15.86
Northern Border*	0.03	-0.06	0.37	15.58
Alliance Pipeline*	0.00	0.00	0.37	0.11
TransCanada**	-3.85	1.44	9.26	-4.96
Total East	-3.82	1.39	10.00	10.74
Total	-3.09	1.47	10.20	26.60
Export Shares* **				
Northwest Pipeline*	0.1	-0.1	-0.2	2.8
GTN*	0.3	0.0	-0.6	-0.1
Total West	0.4	-0.1	-0.8	2.6
Northern Border*	0.1	-0.1	-0.4	4.1
Alliance Pipeline*	0.1	0.0	-0.3	-1.3
TransCanada**	-0.7	0.2	1.5	-5.4
Total East	-0.4	0.1	0.8	-2.6
Capacity Utilization** **				
Northwest Pipeline*	0.3	-0.3	0.5	21.0
GTN*	0.8	0.3	0.0	7.1
Northern Border*	0.0	-0.1	0.6	25.1
Alliance Pipeline*	0.0	0.0	0.8	0.3
TransCanada**	-1.9	0.7	4.6	-2.4
Total	-0.7	0.3	2.3	6.1

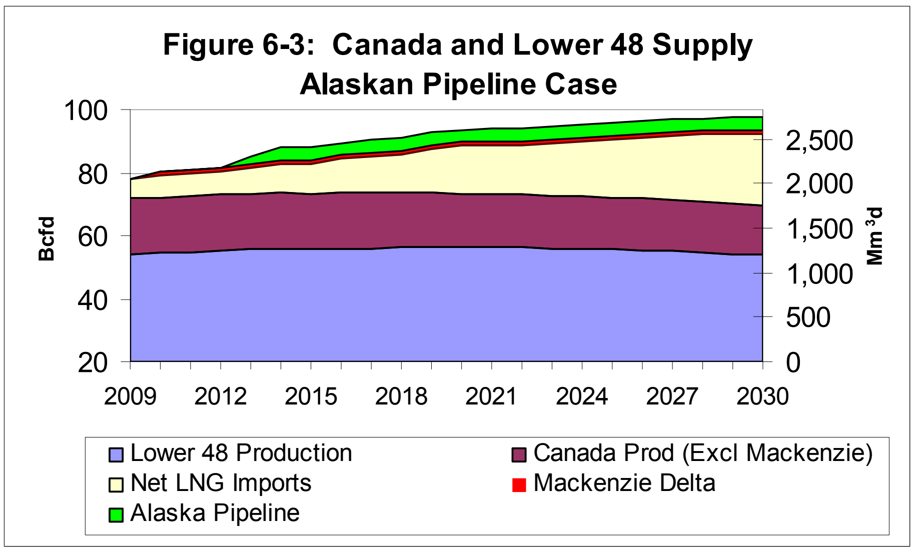
(Bcfd)	2010	2015	2020	2030
Export Flows				
Northwest Pipeline*	0.01	-0.01	0.01	0.37
GTN*	0.02	0.01	0.00	0.19
Total West	0.03	0.00	0.01	0.56
Northern Border*	0.00	0.00	0.01	0.55
Alliance Pipeline*	0.00	0.00	0.01	0.00
TransCanada**	-0.14	0.05	0.33	-0.18
Total East	-0.14	0.05	0.35	0.38
Total	-0.11	0.05	0.36	0.94

*At U.S. border
** At Saskatchewan-Manitoba border
*** Change in percent share
**** Change in the capacity utilization rate percentage

6.3 Alaskan Pipeline Sensitivity Case

In this Case, an Alaskan pipeline is assumed to begin delivering 70.8 Mm^3d (2.5 Bcfd) of gas from the North Slope of Alaska to Alberta in January 2013, and to increase deliveries to 113.3 Mm^3d (4.0 Bcfd) in 2014 through additional compression. As in the Base Case, a 34.0 Mm^3d (1.2 Bcfd) Mackenzie Pipeline begins operation in the fourth quarter of 2009. The Alaskan pipeline is assumed to follow the Southern or Alaskan Highway route to a terminus near Boundary Lake, Alberta, where the gas is delivered into TransCanada, Alliance, and other pipeline systems. No dedicated facilities downstream of Boundary Lake are assumed to be built as part of the Alaskan pipeline project.

Figure 6-3 shows the total supply of gas to Canada and U.S. Lower 48 markets in the Alaska Case. From 2014 to 2030, gas deliveries from the Mackenzie Delta and Alaska are projected to account for about 4% of total gas supply in Canada and the U.S. Lower 48. Table 6-6 compares forecasts of consumption, production, and LNG imports in the Alaska and Base Cases.



In anticipation of the construction of the Alaskan pipeline, LNG developers are assumed to scale back plans for expanding existing LNG import terminals and constructing new terminals. Thus, while overall LNG import capacity continues to increase over current levels, the amount of LNG capacity added by 2015 is an estimated 111.3 Mm^3d (3.9 Bcfd) or 29% less than in the Base Case. Further, the increase in total Canadian and U.S. Lower 48 gas production is less in the Alaskan Sensitivity Case than in the Base Case. The net result is that gas markets remain closely balanced despite the additional volumes of northern frontier gas.

Table 6-6: Comparison of Alaskan Pipeline and Base Case Forecasts

	(Mm^{3}d)					
Gas Consumption	**2009**	**2010**	**2015**	**2020**	**2025**	**2030**
Alaska Case						
Canada	284.0	294.7	326.2	347.1	373.7	388.7
U.S. Lower 48	1901.0	1957.2	2168.7	2313.1	2373.9	2396.0
Total	2185.0	2251.9	2494.9	2660.3	2747.6	2784.7
Mackenzie Base Case						
Canada	284.0	294.7	323.4	347.8	366.1	395.0
U.S. Lower 48	1901.0	1957.2	2177.8	2336.1	2365.1	2413.2
Total	2185.0	2251.9	2501.2	2683.9	2731.2	2808.2
Alaska Minus Base Case						
Canada	0.0	0.0	2.8	-0.7	7.7	-6.3
U.S. Lower 48	0.0	0.0	-9.1	-23.0	8.8	-17.2
Total	0.0	0.0	-6.3	-23.6	16.4	-23.5
% Difference	0.0%	0.0%	-0.3%	-0.9%	0.6%	-0.8%
Gas Production						
Alaska Case						
Canada	525.9	555.7	575.0	571.1	564.9	543.4
U.S. Lower 48	1531.7	1543.3	1581.0	1592.9	1580.4	1525.6
Total	2057.6	2099.0	2156.0	2163.9	2145.3	2069.0
Mackenzie Base Case						
Canada	525.9	555.7	587.7	586.3	580.4	560.1
U.S. Lower 48	1531.7	1543.3	1587.6	1593.0	1571.8	1516.0
Total	2057.6	2099.0	2175.4	2179.2	2152.2	2076.1
Alaska Minus Base Case						
Canada	0.0	0.0	-12.7	-15.2	-15.5	-16.6
U.S. Lower 48	0.0	0.0	-6.7	-0.1	8.6	9.6
Total	0.0	0.0	-19.4	-15.3	-6.9	-7.0
% Difference	0.0%	0.0%	-0.9%	-0.7%	-0.3%	-0.3%
Lower 48 LNG Imports						
Alaska Case	169.9	201.1	267.6	428.8	522.3	647.0
Mackenzie Base Case	169.9	201.1	378.9	540.3	633.8	758.4
Difference	0.0	0.0	-111.3	-111.5	-111.5	-111.5
% Difference	0.0%	0.0%	-29.4%	-20.6%	-17.6%	-14.7%
	(Bcfd)					
Gas Consumption	**2009**	**2010**	**2015**	**2020**	**2025**	**2030**
Alaska Case						
Canada	10.0	10.4	11.5	12.3	13.2	13.7
U.S. Lower 48	67.1	69.1	76.6	81.7	83.8	84.6
Total	77.1	79.5	88.1	93.9	97.0	98.3
Mackenzie Base Case						
Canada	10.0	10.4	11.4	12.3	12.9	13.9
U.S. Lower 48	67.1	69.1	76.9	82.5	83.5	85.2
Total	77.1	79.5	88.3	94.7	96.4	99.1
Alaska Minus Base Case						
Canada	0.0	0.0	0.1	0.0	0.3	-0.2
U.S. Lower 48	0.0	0.0	-0.3	-0.8	0.3	-0.6
Total	0.0	0.0	-0.2	-0.8	0.6	-0.8
% Difference	0.0%	0.0%	-0.3%	-0.9%	0.6%	-0.8%
Gas Production						
Alaska Case						
Canada	18.6	19.6	20.3	20.2	19.9	19.2
U.S. Lower 48	54.1	54.5	55.8	56.2	55.8	53.9
Total	72.6	74.1	76.1	76.4	75.7	73.0
Mackenzie Base Case						
Canada	18.6	19.6	20.7	20.7	20.5	19.8
U.S. Lower 48	54.1	54.5	56.0	56.2	55.5	53.5
Total	72.6	74.1	76.8	76.9	76.0	73.3
Alaska Minus Base Case						
Canada	0.0	0.0	-0.4	-0.5	-0.5	-0.6
U.S. Lower 48	0.0	0.0	-0.2	0.0	0.3	0.3
Total	0.0	0.0	-0.7	-0.5	-0.2	-0.2
% Difference	0.0%	0.0%	-0.9%	-0.7%	-0.3%	-0.3%
Lower 48 LNG Imports						
Alaska Case	6.0	7.1	9.4	15.1	18.4	22.8
Mackenzie Base Case	6.0	7.1	13.4	19.1	22.4	26.8
Difference	0.0	0.0	(3.9)	(3.9)	(3.9)	(3.9)
% Difference	0.0%	0.0%	-29.4%	-20.6%	-17.6%	-14.7%

The onset of Alaskan gas deliveries will not alter the fundamental mismatch between ever-increasing gas demand and sluggish gas production growth observed in this Study. Moreover, while large in absolute terms, deliveries of Alaskan gas would still represent less than a 5% increase in supply to the overall Canadian and U.S. Lower 48 gas market, which is projected to require 2,501.4 Mm^3d (88.3 Bcfd) of gas in 2015 and 2,808.5 Mm^3d (99.1 Bcfd) in 2030. The ability of the marketplace to absorb both new sources of northern frontier gas is a strong indication of the need for the Mackenzie Pipeline during the forecast period.

Infrastructure Implications of an Alaskan Pipeline

From the foregoing discussion it is clear that WCSB takeaway capacity would need to be expanded in order to accommodate the increased exports that an Alaskan pipeline would produce. For analytical purposes the required increase in export capacity was estimated to be 85.0 Mm^3d (3.0 Bcfd). This was allocated pro-rata across all of the WCSB export corridors in proportion to their respective shares of total export capacity in 2003. The analysis further assumed that the additions would be made in a timely and orderly manner so as to avoid major bottlenecks.

To provide insights into potential enhancements, a brief overview of the WCSB export corridor facilities and some of the available expansion options is provided below. The implications of the Alaska Pipeline sensitivity with respect to export flows, WCSB export pipeline capacity, and capacity utilization rates, including comparisons to the Base Case, are then discussed.

Northwest Pipeline Corridor

Northwest Pipeline receives Western Canadian gas from Duke Energy Gas Transmission British Columbia (DEGT) at the international border at Huntingdon, British Columbia/Sumas, Washington (Huntingdon/Sumas) and delivers the gas to export markets in the Pacific Northwest and California. DEGT currently has the capacity to deliver about 51.0 Mm^3d (1.8 Bcfd) into Northwest Pipeline at Huntingdon/Sumas.

In January 2003 DEGT received approval from the NEB to expand the capacity of its Southern Mainline by 5.7 Mm^3d (0.2 Bcfd) at a capital cost of approximately Cdn. $270 million. The approved facilities include 42-inch pipeline loops at eight compression stations and upgrading of compression capacity at four locations. However, DEGT has subsequently reduced the size of the planned expansion, lowered its capital cost to Cdn. $50 million, and deferred construction until shipper demand warrants. In the interim, DEGT expects to meet customers' firm transportation requirements by a combination of additional compression at the Hope, B.C. compressor station and 3.8 Mm^3d (0.1 Bcfd) of capacity that was to become available from Station 2 to Sumas on November 1, 2003 as a result of the annual capacity renewal process (after allowance for re-contracting). Following the renewal process, DEGT will have about 56.7 Mm^3d (2.0 Bcfd) of contractible capacity to the Huntingdon/Sumas border crossing. When the remaining enhancements approved by the NEB in January 2003 are built, total capacity at the international border will be about 59.5 Mm^{3}d (2.1 Bcfd). Southern Mainline capacity could ultimately be doubled, if necessary, since DEGT has the ability (and rights of way) to loop the entire 30- and 36-inch system with a 42-inch high pressure (1,440 psi) pipe all the way from Station 2 (south of Tumbler Ridge) to Huntingdon if the supply is available and if Northwest Pipeline provides matching takeaway capacity at Sumas. Some engineering difficulties would probably be encountered in the Coquihalla Valley, but looping in that section could be avoided by adding compression at the southern end of the DEGT system.

Northwest Pipeline, which receives gas from DEGT at Huntingdon/Sumas, is a major gas transmission artery in the Pacific Northwest with 3,932 miles of pipeline, 43 compressor stations, and design capacity of 82.2 Mm^{3}d (2.9 Bcfd).[22] The pipeline transports Rocky Mountain and San Juan Basin gas to Washington, Oregon, and other markets in the Western United States. It also interconnects with the GTN system at Stanfield, Oregon.

In the Base Case analysis, export flows at Huntingdon/Sumas are expected to average 28.3 Mm^{3}d (1.0 Bcfd) in 2003. The analysis indicates that no additional capacity will be required in the near future to accommodate incremental exports of gas from the WCSB. Nor does the outlook for British Columbia gas production suggest the need for additional facilities to transport B.C. sourced gas to the U.S. at Huntingdon/Sumas. Should additional expansion be required in the future, DEGT sources indicated that the Evergreen expansion is typical of the types of improvements that could be made and the likely cost.

GTN Corridor

The Foothills Pipe Lines System was built in the early 1980s as the "Southern Pre-build" of the proposed Alaska Natural Gas Transportation System. Foothills' intra-Alberta capacity is contracted to the NGTL Alberta gathering and delivery system and the costs are incorporated in the NGTL toll. The West Leg of the Foothills System currently has about 31.1 Mm^{3}d (1.1 Bcfd) of firm export delivery capacity. This Leg runs from Caroline, Alberta to Kingsgate, British Columbia where most of the gas is delivered into the Gas Transmission Northwest Corporation (GTN) system for delivery to the U.S.

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[22] The total includes the Evergreen Expansion completed in October 2003. Approved by the FERC in 2001, the Evergreen expansion was designed to provide 7.8 Mm^{3}d (0.3 Bcfd) of incremental firm service to five power generation customers in Washington State by the installation of 28 miles of looping and several new compression units at a total cost of US $240 million of which US $197 million was for north-south flow enhancement. Because not all of the planned power generation plants have been built, excess capacity on the line during the next few years is greater than previously anticipated.

Pacific Northwest and California. [23] The remaining volumes are delivered to B.C. Gas (now Terasen) Pipeline system on a seasonal basis.

The TransCanada "B.C. System" (formerly Alberta Natural Gas) also transports gas from the Alberta/British Columbia border to Kingsgate. The combined export capacity of the Foothills West Leg and the TransCanada B.C. Systems at the international border at Kingsgate is approximately 85.0 Mm^{3}d (3.0 Bcfd). The GTN system has matching receipt capacity on the U.S. side of the border. GTN's system traverses northern Idaho, southeastern Washington, and central Oregon before terminating at the Oregon-California border near Malin. GTN interconnects with various U.S. pipelines including Northwest Pipeline at Spokane and Palouse, Washington and at Stanfield, Oregon and with Tuscarora Gas Transmission at Malin, Oregon.

The GTN system primarily transports WCSB gas but also receives some domestic U.S. production. Of the total capacity of 82.2 Mm^{3}d (2.9 Bcfd), over 59.5 Mm^{3}d (2.1 Bcfd) can be delivered to California, and up to 28.3 Mm^{3}d (1.0 Bcfd) to the Pacific Northwest -- although typical deliveries to the latter region are in the 0.7 Bcfd range.

In the Base Case, gas flows along GTN are forecast to average about 59.5 Mm^{3}d (2.1 Bcfd) in 2003. GTN does not currently plan to significantly expand their facilities. In fact, because 2002 capacity has turned out to be sufficient to meet present requirements, GTN has postponed implementation of its planned 2003 expansion until such time as it becomes necessary. Moreover, because capacity at NGTL's Alberta/British Columbia export delivery point is limited by the receipt capacity of GTN, NGTL did not include any plans to expand its Western Alberta Mainline Sub Area in its December 2002 Annual Plan.

The Base Case analysis indicated that no capacity additions are required on GTN to facilitate the projected increase in WCSB exports after 2009-2010. However, it is likely that some additional capacity would be required to accommodate the flow of Alaska gas. GTN indicated that their expansion options and costs would be similar to those outlined in their 2003 expansion proposal.

Northern Border Corridor

The firm capacity of the East Leg of the NGTL/Foothills system, which runs from Caroline, Alberta to Monchy, Saskatchewan, is about 62.3 Mm^{3}d (2.2 Bcfd). Shippers on the East Leg of Foothills pay the NGTL export delivery charge at the Alberta/Saskatchewan border and the Foothills tariff for transportation from Empress to Monchy.

[23] The Pacific Gas Transmission or PG & E Gas Transmission Northwest Corporation has been renamed Gas Transmission Northwest Corporation or "GTN" in abbreviated form.

Northern Border Pipeline (NBPL) connects with the Foothills East Leg near the international border at Monchy, Saskatchewan/Morgan, Montana and then travels 1,249 miles to North Hayden, Indiana. NBPL is a general partnership 70% owned by Northern Border Partners Limited Partnership and 30% by TC Pipelines Limited partnership.

Together, the Foothills East Leg and NBPL constitute what is referred to in this report as the Northern Border export corridor. In 2002 the corridor accounted for about 20% of total WCSB gas exports to the United States. The Base Case analysis indicates that this system will maintain its current average capacity utilization rate (98%) until at least 2020. In the subsequent ten years, NBPL could have difficulty maintaining such a high utilization rate, as the supply of gas available for export from the WCSB shrinks due to declining WCSB production and increased intra-Alberta gas demand,

There are currently no plans to expand either the Foothills East leg or the NBPL system. However, both legs of Foothills could be expanded to market needs. The combined capacity of the East and West legs, currently 93.5 Mm^3d (3.3 Bcfd), could be expanded by up to 28.3 Mm^3d (1.0 Bcfd) through initial looping. With further looping and additional compression, Foothills could potentially add another 42.5 Mm^3d (1.5 Bcfd) in capacity, with the East/West leg distribution being a function of shipper requirements. If capacity of 70.8 Mm^3d (2.5 Bcfd) were added it is likely that the tolling would be about the same as for the existing system. NBPL's throughput capacity could also be increased in accordance with market requirements.

Alliance Pipeline

The Alliance Pipeline was designed to transport liquids-rich gas from northeastern British Columbia and northwestern Alberta under high pressure directly to the Chicago market area. The capital cost of the system (Cdn. $4.6 Billion) was divided about equally between the Canadian and U.S. sections. It is designed to deliver up to 37.5 Mm^3d (1.325 Bcfd) on a firm basis at a maximum pressure of 1740 psi plus authorized overrun service (AOS) equal to 16% of that amount. On an average basis, AOS has been running close to 5.9 Mm^3d (0.2 Bcfd) or 16% of authorized firm service since the pipeline was commissioned in November 2000. AOS has frequently exceeded this level in the first nine months of 2003. For example, in January and February of 2003, delivered throughput averaged 47.9 Mm^3d (1.7 Bcfd), with AOS equal to 28% of the firm service amount.

The mainline portion of the system that runs from Gordondale, Alberta to Joliet, Illinois, is 2,988 kilometers long. The Canadian export point is Elmore, Saskatchewan; the U.S. import point is near Sherwood, North Dakota. The Canadian portion of the mainline has 339 kilometers of 42-inch pipeline and 120 kilometers of 36-inch pipeline. The U.S. portion has 1,429 kilometers of 36-inch pipe and 7 delivery points: Aux Sable Liquid Products, Nicor Gas, NGPL, Midwestern Gas, Peoples Gas, ANR and Vector Pipeline.

The Alliance Pipeline is not yet fully compressed. This provides a relatively low cost option for expansion. In fact, Alliance could readily add 11.3 Mm^3d to 14.2 Mm^3d (0.4 Bcfd to 0.5 Bcfd) of capacity by adding compression. The cost of increasing capacity by 14.2 Mm^3d (0.5 Bcfd) via infill compression would likely be in the Cdn. $600 -700 million range, with the total cost depending to a large extent on the location(s) where the additional pressure is needed - influenced, for example, by where an Alaskan pipeline would tie into Alliance.

Alliance will undoubtedly consider various partial and full looping possibilities once the low-cost infill compression option has been implemented or if adding compression becomes unattractive because of the fuel cost. As with any other pipeline, market conditions and opportunities will determine whether any looping is undertaken by Alliance, and when.

TransCanada Corridor

The TransCanada export corridor consists of NGTL's intra-Alberta gas transmission facilities to Empress and McNeill and the portions of the TransCanada Mainline from these border points to Manitoba, Ontario, Minnesota, and beyond. As Manitoba has virtually no gas production, the province is essentially dependent on imports to meet gas requirements. For practical purposes, therefore, where the TransCanada Mainline crosses the Saskatchewan/Manitoba boundary is considered to be a point of export from the WCSB. Except for the relatively small amount of gas consumed in Manitoba, gas flowing across this boundary is bound for markets in Ontario, Quebec and the U.S. Northeast or for the U.S. Midwest via Emerson, Manitoba.

There are currently no plans to increase the capacity of the NGTL system to deliver incremental gas volumes from Princess to the Empress and McNeill border points in NGTL's Eastern Alberta Mainline Design Sub Area. There has been considerable surplus capacity on the system since the start-up of Alliance in late 2000 reduced firm transportation commitments out of Empress and McNeill on the TransCanada Mainline. Actual flows increased slightly in the 2001/02 season as shippers made greater use of interruptible service at the Empress delivery point. However, NGTL currently estimates that flow volumes from Princess to Empress/McNeill in the next several years could be at least 28 Mm^3d (1.0 Bcfd) lower than in the 2001/02 season.

Similarly, because of the capacity created when Alliance began service, there are no plans to increase the capacity of the TransCanada Mainline from the Alberta/Saskatchewan border to Manitoba. The present capacity of the TransCanada Mainline at this point, 203.1 Mm^3d (7.2 Bcfd), is more than sufficient given the annual average flow rates of 147.3 Mm^3d (5.2 Bcfd) to 153.0 Mm^3d (5.4 Bcfd) indicated in the Base Case from 2003 until 2010. Even with the higher export flows between 2010 and 2018, there is still likely to be slack capacity on the Mainline, and therefore no need for expansion during this period. In contrast, the existing takeaway capacity from the WCSB will clearly need to be expanded in the Alaskan Pipeline case when 70.8 Mm^3d to 113.3 Mm^3d (2.5 Bcfd to 4.0 Bcfd) of additional northern frontier gas begins flowing into Alberta.

WCSB Export Implications
Table 6-7 compares WCSB export pipeline capacity and export flows in the Alaskan Pipeline and Base Case analyses. As shown in the first column, in the Alaskan Case WCSB takeaway capacity is increased by 76.5 Mm^3d (2.7 Bcfd) in 2013 and by an additional 8.5 Mm^3d (0.3 Bcfd) in 2014. The capacity is pro-rated across the existing export pipelines as follows: 11.3 Mm^3d (0.4 Bcfd) of capacity is added on the Northwest Pipeline corridor, 8.5 Mm^3d (0.3 Bcfd) on Alliance, 17.0 Mm^3d (0.6 Bcfd) on GTN, and 39.7 Mm^3d (1.4 Bcfd) on the TransCanada Mainline in 2013, and Northern Border capacity is increased by 8.5 Mm^3d (0.3 Bcfd) in 2014.

These expansions boost WCSB export capacity enough to accommodate flows of Alaskan gas without major bottlenecks. With gas demand in Western Canada expected to continue to grow, and gas production projected to decline after 2016, no further additions to takeaway capacity are required.

Table 6-7: Alaskan Case, Comparison of Export Flows and Pipeline Capacity with Base Case

	(Mm^{3}d)									
	2013		2014		2015		2020		2030	
	Alaska	Base	Alaska	Base	Alaska	Base	Alaska	Base	Alaska	Base
Export Flows										
Northwest Pipeline*	38.41	32.18	41.87	32.55	42.46	32.97	42.10	32.32	33.80	21.95
GTN*	77.28	65.04	81.30	64.84	82.12	65.07	80.68	64.08	68.36	59.77
Total West	115.69	97.22	123.17	97.39	124.59	98.05	122.78	96.40	102.15	81.73
Northern Border*	60.79	60.68	69.12	60.91	69.04	60.82	68.73	60.96	67.56	35.52
Alliance Pipeline*	51.02	42.69	51.02	42.69	51.02	42.69	51.02	42.18	49.72	40.82
TransCanada**	196.43	159.07	213.34	161.27	210.40	160.14	182.46	136.37	145.55	112.44
Total East	308.24	262.44	333.48	264.87	330.45	263.65	302.21	239.52	262.83	188.78
Total	423.94	359.66	456.66	362.27	455.04	361.70	424.99	335.92	364.99	270.51
Export Capacity										
Northwest Pipeline*	60.91	49.58	60.91	49.58	60.91	49.58	60.91	49.58	60.91	49.58
GTN*	94.05	77.05	94.05	77.05	94.05	77.05	94.05	77.05	94.05	77.05
Northern Border*	62.04	62.04	70.54	62.04	70.54	62.04	70.54	62.04	70.54	62.04
Alliance Pipeline*	52.04	43.54	52.04	43.54	52.04	43.54	52.04	43.54	52.04	43.54
TransCanada**	242.78	203.12	242.78	203.12	242.78	203.12	242.78	203.12	242.78	203.12
Total	511.81	435.33	520.31	435.41	520.31	435.33	520.31	435.33	520.31	435.33

	(Bcfd)									
	2013		2014		2015		2020		2030	
	Alaska	Base	Alaska	Base	Alaska	Base	Alaska	Base	Alaska	Base
Export Flows										
Northwest Pipeline*	1.36	1.14	1.48	1.15	1.50	1.16	1.49	1.14	1.19	0.78
GTN*	2.73	2.30	2.87	2.29	2.90	2.30	2.85	2.26	2.41	2.11
Total West	4.08	3.43	4.35	3.44	4.40	3.46	4.33	3.40	3.61	2.89
Northern Border*	2.15	2.14	2.44	2.15	2.44	2.15	2.43	2.15	2.39	1.25
Alliance Pipeline*	1.80	1.51	1.80	1.51	1.80	1.51	1.80	1.49	1.76	1.44
TransCanada**	6.93	5.62	7.53	5.69	7.43	5.65	6.44	4.81	5.14	3.97
Total East	10.88	9.26	11.77	9.35	11.67	9.31	10.67	8.46	9.28	6.66
Total	14.97	12.70	16.12	12.79	16.06	12.77	15.00	11.86	12.88	9.55
Export Capacity										
Northwest Pipeline*	2.15	1.75	2.15	1.75	2.15	1.75	2.15	1.75	2.15	1.75
GTN*	3.32	2.72	3.32	2.72	3.32	2.72	3.32	2.72	3.32	2.72
Northern Border*	2.19	2.19	2.49	2.19	2.49	2.19	2.49	2.19	2.49	2.19
Alliance Pipeline*	1.84	1.54	1.84	1.54	1.84	1.54	1.84	1.54	1.84	1.54
TransCanada**	8.57	7.17	8.57	7.17	8.57	7.17	8.57	7.17	8.57	7.17
Total	18.07	15.37	18.37	15.37	18.37	15.37	18.37	15.37	18.37	15.37

* At U.S. border ** At the Sask./ Man. border

Spurred by the inflows of Alaska gas and the additions to takeaway capacity, gas exports from the WCSB increase to about 433.9 Mm^{3}d (15.0 Bcfd) in 2013 versus 359.7 Mm^{3}d (12.7 Bcfd) in the Base Case. In that year, expansion to Northwest Pipeline and GTN boost exports to the Pacific Northwest and California by about 18.5 Mm^{3}d (0.7 Bcfd) over the Base Case level. At the same time, expansion of TransCanada Mainline capacity raises flows to eastern Canada and the U.S. Midwest by about 45.8 Mm^{3}d (1.6 Bcfd) over the Base Case. In 2014, when the flow of Alaskan gas into Alberta increases to 113.3 Mm^{3}d (4.0 Bcfd), gas flows into the Pacific Northwest and California from the WCSB average 25.8 Mm^{3}d (0.9 Bcfd) greater than in the Base Case, while eastward bound exports via Alliance, Northern Border and TransCanada are about 68.6 Mm^{3}d (2.4 Bcfd) greater. As a result, total exports from the WCSB are indicated to reach 456.7 Mm^{3}d (16.1 Bcfd) in 2014 in the Alaska Case or about 94.4 Mm^{3}d (3.3 Bcfd) more than in the Base Case. During the remainder of the forecast period, exports from the WCSB are generally 87.8 Mm^{3}d to 93.5 Mm^{3}d (3.1 Bcfd to 3.3 Bcfd) above Base Case levels.

Table 6-8 highlights the differences between the export capacities, flows, and capacity utilization rates projected in the Alaskan Pipeline and Base Cases. Given that the additional takeaway capacity added in the Alaskan Case was allocated pro-rata based on the current capacities of the various corridors, their respective market shares remain approximately the same as in the Base Case. However, the large increase in capacity assumed to occur on the TransCanada Mainline allows it to increase volumes at the expense of the other pipelines heading east. TransCanada's capacity utilization rate also improves more than that of the other transporters.

The impact of the Alaskan gas on NGTL system tolls for domestic and export shippers will depend, among other things, on the portion of the incremental flows removed from Alberta via the Alliance Pipeline and where the gas is received. The assumed allocation of incremental takeaway capacity implies that less than 10% of the gas delivered to Alberta from Alaska will flow on the Alliance Pipeline. This would mean that about 65.2 Mm^{3}d (2.3 Bcfd) of Alaskan gas would utilize the NGTL system in 2013 and 99.2 Mm^{3}d (3.5 Bcfd) in 2014 and beyond.

A detailed engineering analysis of the pipeline and compression enhancements required on the NGTL system in the Alaska Case and the costs that would be involved was beyond the scope of the Study. However, given the large increase in projected gas flows, it is reasonable to assume that the resulting revenue increases could at least offset the costs of the required system improvements. As a result, no increases in tolls are anticipated.

Table 6-8: WCSB Export Pipeline Capacity, Projected Exports, Export Share, and Capacity Utilization
Alaskan Case: Differences from Mackenzie Base Case

	2013	2014	2015	2020	2030
(Mm³d)					
Export Capacity					
Northwest Pipeline*	11.33	11.33	11.33	11.33	11.33
GTN*	17.00	17.00	17.00	17.00	17.00
Northern Border*	0.00	8.50	8.50	8.50	8.50
Alliance Pipeline*	8.50	8.50	8.50	8.50	8.50
TransCanada**	39.66	39.66	39.66	39.66	39.66
Total	76.49	84.99	84.99	84.99	84.99
Export Flows					
Northwest Pipeline*	6.23	9.32	9.49	9.77	11.84
GTN*	12.24	16.46	17.05	16.60	8.58
Total West	18.47	25.78	26.54	26.37	20.42
Northern Border*	0.11	8.22	8.22	7.76	32.04
Alliance Pipeline*	8.33	8.33	8.33	8.84	8.90
TransCanada**	37.37	52.07	50.25	46.09	33.12
Total East	45.81	68.61	66.80	62.69	74.05
Total	64.28	94.39	93.34	89.07	94.48
Export Shares* **					
Northwest Pipeline*	0.11	0.18	0.22	0.28	1.14
GTN*	0.15	-0.10	0.06	-0.09	-3.37
Total West	0.26	0.09	0.27	0.19	-2.22
Northern Border*	-2.53	-1.68	-1.64	-1.98	5.38
Alliance Pipeline*	0.17	-0.61	-0.59	-0.55	-1.47
TransCanada**	2.11	2.20	1.96	2.34	-1.69
Total East	-0.26	-0.09	-0.27	-0.19	2.22
Capacity Utilization****					
Northwest Pipeline*	-1.85	3.09	3.21	3.92	11.20
GTN*	-2.24	2.29	2.87	2.62	-4.89
Northern Border*	0.18	-0.18	-0.17	-0.84	38.52
Alliance Pipeline*	-0.01	-0.01	-0.01	1.16	1.78
TransCanada**	2.60	8.48	7.82	8.02	4.60
All of the above	0.21	4.57	4.37	4.51	8.01
(Bcfd)					
Export Capacity					
Northwest Pipeline*	0.40	0.40	0.40	0.40	0.40
GTN*	0.60	0.60	0.60	0.60	0.60
Northern Border*	0.00	0.30	0.30	0.30	0.30
Alliance Pipeline*	0.30	0.30	0.30	0.30	0.30
TransCanada**	1.40	1.40	1.40	1.40	1.40
Total	2.70	3.00	3.00	3.00	3.00
Export Flows					
Northwest Pipeline*	0.22	0.33	0.34	0.35	0.42
GTN*	0.43	0.58	0.60	0.59	0.30
Total West	0.65	0.91	0.94	0.93	0.72
Northern Border*	0.00	0.29	0.29	0.27	1.13
Alliance Pipeline*	0.29	0.29	0.29	0.31	0.31
TransCanada**	1.32	1.84	1.77	1.63	1.17
Total East	1.62	2.42	2.36	2.21	2.61
Total	2.27	3.33	3.30	3.14	3.34

*At U.S. border
**At Man./Sask. border
*** Change in percent share
**** Change in the capacity utilization rate percentage

7 CONCLUSIONS

The fundamental conclusion of this Study is that natural gas markets in Canada and the U.S. Lower 48 States will support construction of a 34.0 Mm^3d (1.2 Bcfd) pipeline to deliver Mackenzie Delta gas to Alberta in the 2009 timeframe, as well as possible expansions of the Pipeline in the 2015 and 2020 timeframes. The need for the Mackenzie Valley Pipeline reflects a series of factors including:

- The outlook for continued growth in gas demand in Canada and the U.S. Lower 48 States prior to the Pipeline's start date and throughout the study period. In addition to the steady growth in residential and commercial consumption, the favorable demand outlook reflects the expectation that gas usage for electric power generation will continue to expand at a robust pace in Canada and the U.S., particularly during the 2003 to 2020 period. The growing gas requirements of the Alberta oil sands industry are another major component of gas demand growth. The growth in gas demand is a consistent factor in all scenarios examined, including the Low Demand case.

- The projected inability of traditional gas producing basins in Canada and the U.S. Lower 48 states to keep pace with the anticipated growth in gas demand.

Further, the analysis indicated that there is sufficient capacity on the intra-Alberta gas transmission system and on the major pipelines that export gas from the WCSB to accommodate anticipated deliveries of gas from the Mackenzie Delta during the study period. The intra-Alberta transmission system is adequate to handle Mackenzie Delta flows in all the cases examined, including the scenario that assumes an Alaskan gas pipeline is built in the mid 2010s. In this latter case, a modest increase in export pipeline takeaway capacity is required to accommodate the increase in WCSB exports facilitated by the onset of Alaskan gas deliveries in this timeframe. Even in this case, however, it would appear that a large investment in gas transmission infrastructure would not be required to facilitate the movement of gas to intra-Alberta delivery or export points or to accommodate increased export volumes from the WCSB.

Although the market environment for the proposed Mackenzie Pipeline is expected to be very positive under the Base Case assumptions, development of the project is nonetheless subject to risks and uncertainties to the Co-Venturers. Principal risks and uncertainties include the following:

- Slower development of heavy oil and oil sands bitumen production in Alberta, or greater use of coal for meeting projected fuel requirements could reduce regional gas demand and hence the ability of the Alberta market to absorb as much Mackenzie Delta gas production.

- More rapid expansion of gas production in general could meet a larger share of future gas demand.

- Accelerated development of coalbed methane gas production in the WCSB could cause the region's gas production to grow more rapidly than expected, with similar effects.

- Measures selected to implement the Kyoto Agreement could have a substantial impact on both conventional and non-conventional oil and gas production costs in the WCSB and reduce investments in new oil sands bitumen production facilities for a time, reducing gas demand.

- Increased gas production in Alberta, especially if coupled with markedly slower growth in oil sands gas demand, could raise pipeline utilization in Alberta and on the major export pipelines from Alberta to downstream markets. Higher utilization of existing capacity could reduce the amount of spare capacity available to deliver Mackenzie Delta production to major markets.

- Overbuilding of LNG capacity could lessen the capacity of U.S. and Canadian markets to absorb Mackenzie Delta volumes and lower gas prices throughout North America.

- Increases in the price of gas relative to oil and coal could encourage more rapid development of lower cost energy supplies (e.g. coal), perhaps facilitated by technological breakthroughs.

- Changes in energy policy in Canada and the United States could promote alternative energy sources and thereby reduce the market's capacity to absorb Mackenzie Delta gas production. Particularly important initiatives include the renewed focus on nuclear power and the promotion of cleaner coal-combustion technologies. If these initiatives are realized, gas-fired power generation and North American gas demand for electric generation could be lower than expected.