Canadian Energy Research Institute

Capacity of the Western Canada Natural Gas Pipeline System

SUMMARY REPORT

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Study No. 113 – Summary Report
ISBN 1-896091-67-9

Purchased by the State of Alaska

November 2006

CANADIAN ENERGY RESEARCH INSTITUTE

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November 2006
Printed in Canada

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CHAPTER 1
INTRODUCTION

The performance of the pipeline system in Western Canada is a critical issue for the North American natural gas marketplace over the next decade, as additional supplies from within the Western Canada Sedimentary Basin (WCSB) and from Canadian and US northern frontiers transit the area.

The study is motivated by the expected changes in the regional distribution of gas production within Western Canada, and by the introduction of new gas flows from northern sources—the Mackenzie Delta and the North Slope of Alaska. These changes are expected to have significant impacts on pipeline capacity utilization within and from Western Canada. Pipeline capacity utilization will also be impacted by changes in deliveries to accommodate increased gas requirements for planned oil sands projects in northeastern Alberta. Alternative scenarios will consider the timing and sequencing of volumes of natural gas entering or bypassing the Canadian pipeline systems from a variety of potential supply sources.

This summary consists of four chapters. Chapter 2 provides background information for this study, more specifically a description of the future supply potential from British Columbia and Alberta. This chapter also includes a supply forecast for the WCSB basin that is used in the methodology. Chapter 3 describes the existing export pipelines that remove gas from Alberta and British Columbia, followed by a brief description of the Mackenzie Valley and Alaska Highway pipelines. Chapter 4 outlines briefly the methodology and the possible flow scenarios for transporting Alaska gas volumes to the Chicago area.

CHAPTER 2
BACKGROUND

Before determining how much new capacity will be needed to handle increased volumes, the study must first forecast the production from conventional and unconventional resources for Alberta and British Columbia, as well as determine the future flow rates in the various sections of the existing pipeline system. The following sections describe the current situation for pipelines, production volumes, demand requirements and export obligations for BC and Alberta.

2.1 British Columbia Gas Supply

British Columbia is included in this study because of the variable size of the export flow volumes moving to Alberta now and in the future. The BC provincial demand and export volumes at Huntington determine the flow rate on the Westcoast Energy transmission system between northeast BC and the lower mainland. The residual volume would flow east to connect with the TransCanada pipeline system in northwest Alberta. Future new well connection profiles, LNG imports and export potential to the United States have an impact on volumes that can move east to Alberta and potentially could have an effect on the spare capacity in TCPL's Alberta and eastern mainline systems when the Alaska gas volumes come on stream.

British Columbia, the second largest supplier of natural gas in Canada, has continued to expand its production level from two to three bcf/day over a 10 year period (1994 to 2004). British Columbia is uniquely positioned to access the Pacific Northwest and California markets by means of the export connection at Huntington, British Columbia. At the same time, British Columbia can access eastern Canada, the US mid-continent and Atlantic export markets by utilizing the interconnecting pipelines with Alberta. For this study, the potential flow into Alberta was taken to be the annual provincial production plus imports from the Yukon and Kitimat (LNG) minus the provincial demand and an estimate of the Huntington export volume. The residual volume would either deliver directly, or by volume displacement, to the Alberta interconnecting pipelines. This interconnecting flow volume would connect with the TransCanada pipeline system (TCPL Alberta) in northwest Alberta for transport to eastern delivery points.

The following paragraphs, which describe the current and recent history of the natural gas pipeline industry in British Columbia, were derived from the NEB document entitled "The British Columbia Natural Gas Market, An Overview and Assessment" (April 2004), and other publications and data elements from the British Columbia Oil and Gas Commission.

Prior to 2000, the British Columbia pipeline system consisted of a single major pipeline, owned by Westcoast Energy, that connected the northeast BC supply area with the lower mainland market (Vancouver) and the United States export market (Washington, Oregon and California). Smaller connections at Boundary Lake and Gordondale permitted gas to flow eastward to Alberta connecting with the TCPL Alberta pipeline system. The Gordondale pipeline is bidirectional and permits Westcoast to either deliver or receive gas supplies from Alberta. In recent years, several smaller pipelines have been constructed to connect gas fields in British Columbia along the

Alberta/British Columbia border, specifically to move gas into the Western Peace River pipeline system in Alberta.

These connections permit BC gas to connect with the eastern Canadian markets as well as the West North Central (WNC), East North Central (ENC), Pacific Northwest (PAC) and California markets in the United States. The largest of these border pipelines includes the CNRL pipeline that originates in the Ladyfern area, capacity 680 mmcf/day (19,100 e^3m^3/day) and the Ekwan pipeline that connects the Sierra area, capacity 418 mmcf/day (11,800 e^3m^3/day). In total these pipelines have a capacity of 1700 mmcf/day (49,700 e^3m^3/day) but to date the maximum volume transported to Alberta has been 845 mmcf/day (23,800 e^3m^3/day). The Alliance pipeline system was constructed in 2000 to transport primarily liquid rich Alberta gas to the Chicago market; however, this pipeline also connects with supplies in British Columbia and is capable of transporting 500 mmcf/day (14,087 e^3m^3/day) out of the province.

LNG has been proposed at two locations in British Columbia, Kitimat and Prince Rupert. Pacific Northern Gas Ltd. and Kitimat LNG Inc. have formed a partnership for the purpose of developing the natural gas transmission pipeline system to connect the Kitimat LNG terminal with Westcoast Energy's mainline. This connection will give Kitimat access to the North American gas markets either by direct flow to the BC lower mainland and the Pacific Northwest part of the US or by displacement flow moving BC conventional supply to Alberta and on to eastern or US markets. The Prince Rupert LNG supply, when constructed, appears to be directed to local markets on the BC coast and Vancouver Island and will not affect the gas transmission pipeline systems.

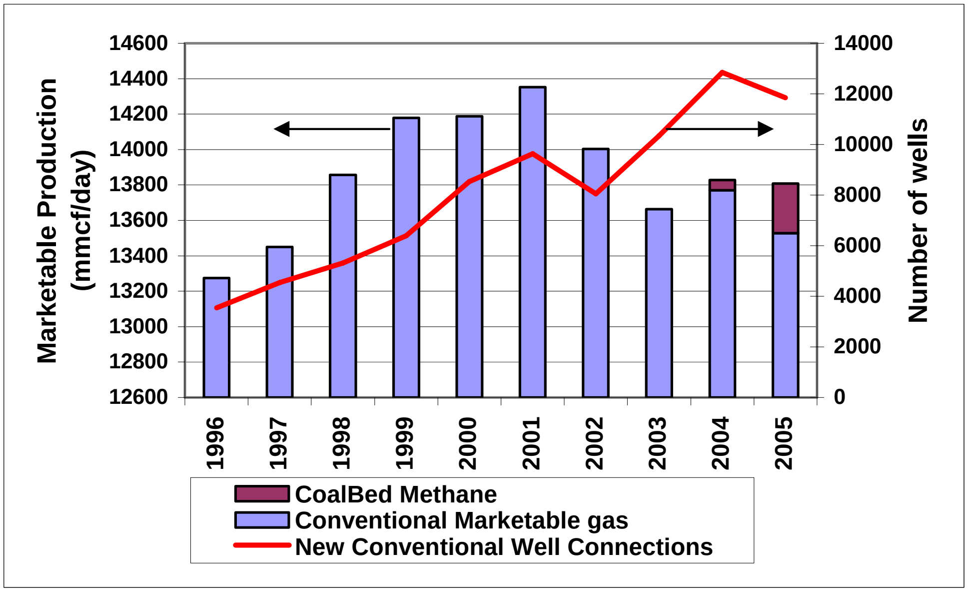
2.2 Alberta Gas Supply

Alberta is the main producer of natural gas in Canada, accounting for 81 percent of total production. Of this percentage, 12 percent is used in Alberta, 33 percent in eastern Canada and 55 percent is exported to the United States.

Alberta's raw gas production for 2005 was approximately 5.9 tcf (168,326,700 e^3m^3) or 16,357 mmcf/day (460,840 e^3m^3/day). Of this value, 1.54 tcf is utilized in Alberta for enhanced oil recovery projects, flaring, fuel and plant shrinkage. Added to this, 0.33 tcf (9,414,870 e^3m^3) or 915 mmcf/day (25,780 e^3m^3/day) was imported from British Columbia. Approximately 0.8 tcf (22,774,200 e3m3) or 2,213 mmcf/day (62,350 e^3m^3/day) is consumed in Alberta (not including the straddle plants) while 3.8 tcf (108,960,150 e^3m^3) or 10,588 mmcf/day (298,306 e^3m^3/day) is exported out of the province.

Figure 2.1 shows that marketable gas production (raw gas minus re-injection, minus flared, minus field fuel and minus field plant shrinkage) from Alberta peaked in 2001. This peak was partially due to the Alliance pipeline system coming on stream and partially due to the number of new well connections as a result of increased market prices.

Figure 2.1
Alberta Marketable Gas Production and New Well Connections



The marginal set back in new well connections in 2002 was a result of the market price falling back to the four dollar level (Canadian dollars per gigajoule). The subsequent years (2003 and 2004) show the gas well connections in Alberta expanding at a rate of 25 percent per year, again driven by increased market prices. However, the resulting increase in production from conventional gas resources was only marginal when compared to the number of well connections. Part of the reason for the declining production is the fact that the drilling focus has been heavily weighted towards the shallow gas plays in the southeastern part of the province. The attraction to this area of the province is the low risk, low cost drilling and easy connection to the transmission system. The downside to this attraction is that the wells that are being connected have lower initial production rates and decline faster than the historical gas connections. This, coupled with the decline in production from existing wells, has caused the decline in conventional production from the province.

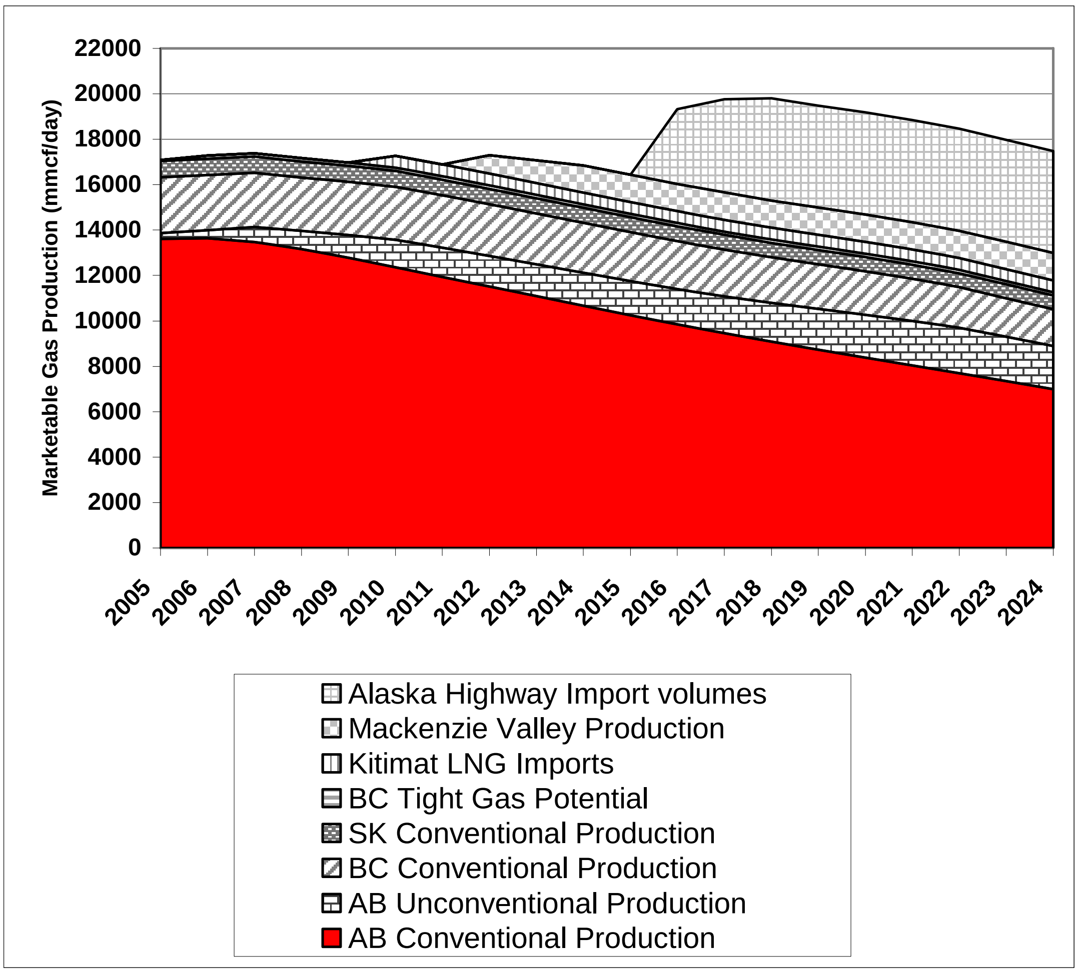
Figure 2.1 also indicates that deliveries from the basin remained relatively stable as a result of increased production from coalbed methane (CBM). In 2005, approximately 3,200 wells were connected for CBM production, resulting in an additional average production rate of 280 mmcf/day. CBM production continues to grow and TCPL anticipates that CBM production will grow to 1500 mmcf/day by 2015 and 1,900 mmcf/d by 2020.[1]

[1] TCPL, Canadian Mainline Throughput Study, Keystone Pipeline Transfer Application, June 2006.

2.3 WCSB Supply Forecast

Figure 2.2 details the base case supply forecast for the WCSB including British Columbia, Alberta, and Saskatchewan and appends the estimated production forecast for the Mackenzie Valley, Kitimat LNG and Alaska Highway. The Alberta and British Columbia conventional production forecasts are derived from the procedure outlined in Chapter 4. The unconventional (CBM) production forecast was taken from the base case used in TCPL's Keystone application.[2] The Saskatchewan production forecast was taken from the NEB 2003 supply and demand outlook.[3] The Mackenzie Valley gas forecast was taken from the Wright Mansell report on the Mackenzie Valley Pipeline.[4]

Figure 2.2
Western Canada Gas Production Forecast
(including Mackenzie Valley and Alaska Highway production)



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[2] Ibid.
[3] NEB, Canada's Energy Future: Scenarios for Supply and Demand to 2025, July 2003.
[4] Wright Mansell Research Ltd, An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Gas, 2004.

CHAPTER 3
WESTERN CANADA EXPORT AND FRONTIER PIPLINES

The existing pipeline infrastructure in Western Canada (Alberta and British Columbia) has an average annual export capacity of 14,890 mmcf/day (419,500 e^3m^3/day)[5] for the design year 2005/2006. Based on individual pipeline performance numbers, the non consecutive peak day flow level is approximately 16,090 mmcf/day (453,300 e^3m^3/day). Figure 3.1 details the break down of this basin capacity into the contributing pipelines that export natural gas out of Alberta and British Columbia for deliveries to eastern Canada and the United States.

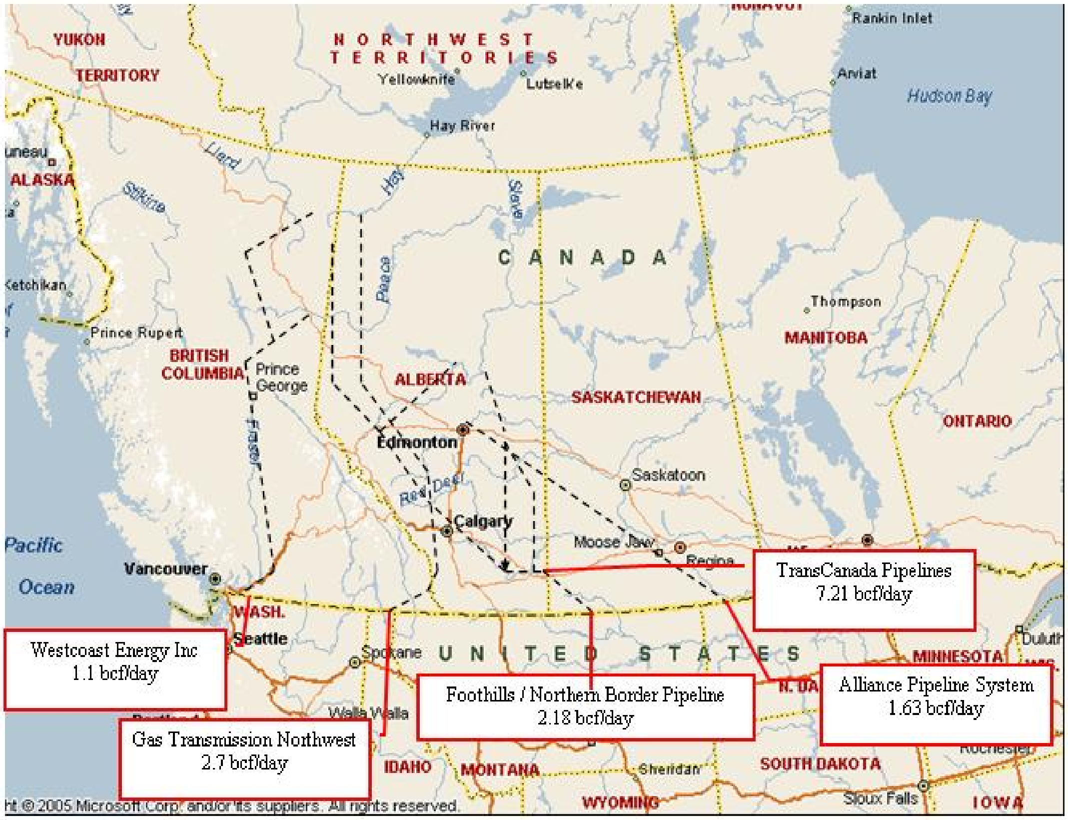
Export deliveries for the Alliance Pipeline and the Foothills/Northern Border Pipeline have historically been close to the capacity of each pipeline. This situation is a result of the long term firm service contracts backing the pipeline that date back to the original construction period. The Alliance pipeline contract obligations extend to 2015 with the possibility of a five year extension (2015-2020) that must be committed to by 2010. The Northern Border Pipeline contracts are currently coming to completion (2005/2006) and it is assumed that flow movement on this pipeline will tend to be more predominately of the interruptible type as in the case of TCPL East.

Gas Transmission Northwest, Westcoast Energy and TCPL East have seen declining deliveries in volumes since 1999. This is partially due to a consumer response to higher prices, an increased industrial usage of natural gas in the Alberta oil sands area and to declining production from conventional gas resources in the Western Canada Sedimentary Basin (WCSB).

Alberta currently accounts for 81 percent of the total Canadian gas production with British Columbia the next largest supplier at 13 percent. Alberta's *annual average production* of marketable natural gas peaked in 2001 at 14,353 mmcf/day (404,381 e^3m^3/day), and has declined to its current 2005 level of 13,527 mmcf/day (381,110 e^3m^3/day),[6] which represents an annual decline of 1.5 percent. With two of the export pipelines maintaining their delivery levels, coupled with the declining basin production and increasing Alberta usage, the result has been an annual average border delivery for Gas Transmission Northwest to decline by 4.6 percent per year and TCPL East to decline by 3 percent per year since 2000.

[5] TCPL, Canadian Mainline Throughput Study, Appendix G, 2006.
[6] EUB, EIB-ST98-2006, Alberta's Energy Reserves 2005 and Supply/Demand Outlook.

Figure 3.1
Current Export Capacity by Pipeline



3.1 Gas Transmission Northwest

The Gas Transmission Northwest Pipeline, also known as the GTN System, transports gas from the Canada/US border near Kingsgate, British Columbia to the Oregon/California border, where it interconnects with the Pacific Gas and Electric Company at Malin, California.

Alberta is the primary source for gas supply for the GTN system, but requires a connection with the TCPL BC System in order to access the Alberta portion of the WCSB basin. TCPL Alberta delivers gas to the TCPL BC System at a point on the Alberta/British Columbia border near Coleman, Alberta. With the exception of gas sourced from the deep southwest portion of the province, almost all of the gas passes through the Cochrane straddle plant where natural gas liquids are removed before leaving the province for delivery to the Pacific Northwest and California markets.

The pipeline is 614 miles in length (Kingsgate to Malin), made up of one 36 inch and one 42 inch pipe that run parallel to each other, with 12 compressor stations utilizing 29 gas turbines ranging from 10 megawatts to 23 megawatts of power. The GTN System has a capacity of 2,760 mmcf/day (77,760 e^3m^3/day) from Kingsgate, and delivers 1,975 mmcf/day (55,645 e^3m^3/day) to the California border. The average daily volume for 2005 was 65 percent of capacity. There currently is no expansion projects anticipated for the GTN system, as it is currently under utilized. If the situation presented itself where additional volumes were required to be transported, the capacity could be increased by adding additional loop and compression. A 500 mmcf/day (14,085 e^3m^3/day) increase would require approximately 60 miles of 36 inch loop pipe and ten additional gas turbines at existing compressor sites. A 1,000 mmcf/day (28,174 e^3m^3/day) would require 275 miles of 36 inch loop and thirteen additional gas turbines.

3.2 Foothills/Northern Border Pipeline

The Foothills/Northern Border Pipeline system, also referred to as the NBPL System, transports gas from the Canada/US border near Monchy, Saskatchewan to Iowa, Illinois and Indiana, where it interconnects with several interstate pipelines. Alberta is the primary source for gas supply for the NBPL system which connects to the WCSB by way of the Foothills Alberta pipeline system and the Foothills Saskatchewan pipeline system. The entire pipeline system, including the Foothills pipeline segments in Canada, is 1,654 miles in length extending from James River, Alberta to North Hayden, Indiana. The pipeline is configured with a combination of 42 inch and 36 inch pipe with 22 compressor stations utilizing 24 gas turbines with the predominate size being 26 megawatt units. The NBPL System has a capacity of 2,180 mmcf/day (61,420 e^3m^3/day) from Monchy, Saskatchewan and delivers 2,220 mmcf/day (62,545 e^3m^3/day) to locations between Ventura, Iowa and North Hayden, Indiana. Gas volumes from the Williston Basin in North Dakota make up the difference between the Alberta supply and the transported volume. Average daily volume for 2005 was 95 percent of capacity.

There currently is no expansion projects indicated for the NBPL System but this pipeline system could be expanded to carry additional volumes of Alaska gas when it becomes available. A 500 mmcf/day (14,085 e^3m^3/day) increase would require approximately 305 miles of 42 inch loop and four additional gas turbines at existing compressor sites. A 1,000 mmcf/day increase (28,174 e^3m^3/day) would require 585 miles of 42 inch loop and five additional gas turbines. The addition of a complete 42 inch loop and expanding each station with the addition of 29 megawatt gas turbines would more than double the capacity to 4,450 mmcf/day (125,375 e^3m^3/day).

3.3 Alliance Pipeline System

The Alliance Pipeline system transports rich natural gas from northeastern British Columbia and northwestern Alberta through Saskatchewan, North Dakota, Minnesota, and Iowa to its terminus at Aux Sable, Illinois. The pipeline is 1,984 miles in length (Aitken Creek, British Columbia to Aux Sable, Illinois), made up of 42 inch and 36 inch pipe with 14 compressor stations utilizing 15 gas turbines with the predominate size being 23 megawatt units. The receipt capacity of the pipeline is 1,630 mmcf/day (46,485 e^3m^3/day) with 1,610 mmcf/day crossing the Canada/US border and 1,570 mmcf/day (43,670 e^3m^3/day) delivered to the terminus.

Completely looping the existing pipeline system from Fort Saskatchewan, Alberta to the Illinois terminal with 36 inch loop and constructing the twelve intermediate compressor stations (23 megawatt gas turbines) would increase the capacity to 3,500 mmcf/day (98,609 e^3m^3/day).

Adding a second 23 megawatt gas turbine to each station would further increase the capacity to 4,475 mmcf/day (126,080 e^3m^3/day). Utilizing a 48 inch loop instead of the 36 inch loop, a fully powered system (two units per station) would result in a capacity of 6,264 mmcf/day (176,480 e^3m^3/day).

3.4 TransCanada Eastern Mainline

The TransCanada Eastern Mainline, also referred to as TCPL East, transports gas from Empress, Alberta, which is situated on the Alberta/Saskatchewan border, through Saskatchewan and Manitoba to a point south of Winnipeg, Manitoba. At this point, 30 percent of the gas is directed south to connect with the Great Lakes Transmission Pipeline while the remaining 70 percent is directed to the TCPL Central system for delivery to Ontario, Quebec and the eastern export points into the United States. The current receipt capacity is 7,210 mmcf/day (203,130 e^3m^3/day) and the 2005 average daily flow level was 5,315 mmcf/day (149,745 e^3m^3/day) which equates to a 74 percent load factor.

TCPL has applied to convert the original 34 inch pipeline from gas service to oil service as part of their Keystone pipeline project. Removing this pipe from gas service would effectively reduce the capacity to 6,695 mmcf/day (188,625 e^3m^3/day), which would still leave approximately 1,300 mmcf/day of spare capacity in 2005. As a result of the forecasted dwindling supplies, the base case indicates that this spare capacity will increase to 1,785, 1,950, 2,200 and 2,470 mmcf/day for the years 2016 to 2019, respectively.

3.5 Westcoast Energy Pipeline

The Westcoast Energy transmission pipeline gathers gas from northeast British Columbia, primarily from the Fort St. John and Fort Nelson areas, and transports it south to Vancouver, the lower mainland portion of British Columbia and the export point at Huntingdon, British Columbia. The southern mainline, which is that portion of the system that starts where the gathering pipelines from Fort St. John and Fort Nelson join together and terminates at the Huntington export point, has a current capacity of 2,085 mmcf/day (58,742 e^3m^3/day). Average daily volume for 2005 was 82 percent of capacity. This study has assumed that the LNG terminal at Kitimat, British Columbia will be constructed with 130 mmcf/day of the 550 mmcf/day average send out volume being directed to the export markets in Washington and Oregon. The remaining 420 mmcf/day will move east through Alberta to the eastern markets by means of volume displacement.

3.6 The Mackenzie Valley Pipeline

The Mackenzie Valley Pipeline is assumed to start production in 2012 with an initial flow rate of 820 mmcf/day (23,270 e^3m^3/day), growing to 1,200 mmcf/day (33,810 e^3m^3/day) by the third operating year and maintaining that level for 13 years to the end of the forecast. The 761 mile (1,224 kilometer), 30 inch pipeline with four stations and one heater station will have an annual average capacity of 1,295 mmcf/day (36,490 e^3m^3/day) receipt volume and 1,275 mmcf/day

(35,920 e^3m^3/day) delivered volume to the Northwest Territories/Alberta border. This production volume will be supported by the three anchor fields in the Mackenzie Delta, Niglintgak, Parsons Lake, and Taglu, plus several smaller discoveries which are assumed to be available for production in 2012. Natural gas liquids production for the first six years of the project is expected to be in the range of 13,000 barrels/day. These assumptions correspond to Case Number 2 in the 2004 update to the Economic Impacts of the Mackenzie Valley Pipeline prepared by Wright Mansell Research Ltd.[7]

The Mackenzie Valley Pipeline can be expanded to handle 1,600 mmcf/day (45,080 e^3m^3/day) by adding four additional intermediate stations, and 1,950 mmcf/day (54,940 e^3m^3/day) by doubling the number of units at each of the eight compressor sites.

3.7 TCPL Alberta Integrated System

Figure 3.2 details two expansion options for the Alberta integrated pipeline system proposed by TransCanada (TCPL Alberta) to handle the volumes associated with the Mackenzie Valley pipeline. Route "A" indicates that, if constructed by TCPL, the North Central Corridor (NCC), connecting the Upper Peace River area with the Upper Bens Lake area, will handle some, or all, of the Upper Peace River (Alberta) volumes plus some, or all, of the Mackenzie Valley gas volumes. Route "B" will carry the Mackenzie Valley gas volumes south through the existing pipeline system for delivery to the export markets.

The requirement for the construction of the NCC is based on three design considerations:

1. The growth in gas supply in the Peace River area, reducing the requirement for additional facilities that would otherwise be necessary downstream of the Peace River area.

2. The growth in deliveries to the Fort McMurray area.

3. Minimize the fuel gas requirements associated with the Alberta integrated system.

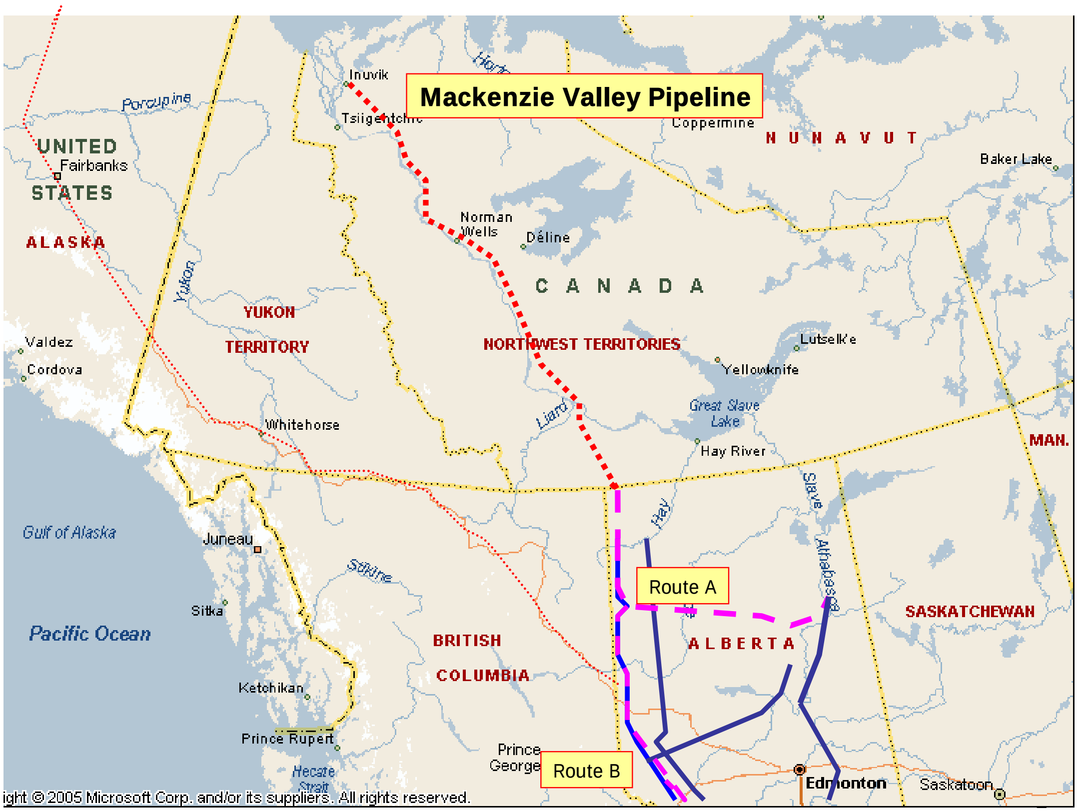
This study assumes the NCC will be constructed to handle 700 mmcf/day (19,720 e^3m^3/day) which eliminates the need for additional facilities in the Lower Peace River and Edson Mainline sub areas.

The demand for gas in the Fort McMurray area is such that, in addition to the NCC volumes, the gas supply from the Fort McMurray, Bens Lake and North lateral areas plus additional volumes sourced from the eastern Alberta mainline (reversal of the North Lateral at the Princess compressor site) would be required. Constructing the NCC to handle larger volumes would permit the Bens Lake / North Lateral areas to continue flowing south to Princess, but this would result in

[7] Wright Mansell Research Ltd, An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Development, August 2004.

the utilization factor to decrease for the Lower Peace River, Edson and James River to Princess areas.

Figure 3.2
Mackenzie Valley Pipeline



The Inuvik area gas plant is expected to recover 90 percent of the "pentanes plus" and 50 percent of the butanes. The ethane and propane volumes, plus the residual of the butanes and pentanes, will remain in the gas stream for delivery to the TCPL Alberta integrated pipeline system at the Alberta/Northwest Territories border. Assuming that these volumes flow south and eventually reach the James River crossover point, additional liquids would be extracted at both the Empress straddle plant facility and the Cochrane straddle plant facility.

Volumes of gas that are transported through the NCC facility will not be processed by a straddle plant, resulting in lost liquid volumes. This study has assumed that marketable gas volumes from the Upper Peace River and eastern side of the Central Peace River areas will be directed to the NCC corridor, thus allowing the Mackenzie Valley volumes to flow south connecting with the existing straddle plants at Cochrane and Empress.

The current cost estimate is based on baseline 2002 Canadian dollar estimates taken from the COLTKBR Mackenzie Gas Project cost estimate report[8]. From these baseline numbers, appropriate escalation factors were applied to labor and materials to arrive at a 2004 estimate. This estimate was then compared against the Wright Mansell Research report,[9] which indicated the pipeline portion of the project, based on project sponsors input, would be $3.5 billion (2004 Canadian dollars).

In August 2006, Imperial Oil Ltd. indicated that the cost of the project had jumped in expected cost and, although Imperial did not give any particulars, it is assumed that materials have increased in cost by 20 percent and labor by 30 percent. Taking these factors into account, the cost estimate for the gas pipeline portion of the Mackenzie Valley development would be approximately $4.377 billion (2006 Canadian dollars). The liquids pipeline from Inuvik to Norman Wells to handle the recovered liquids would add an additional $0.7 billion (2006 Canadian dollars).

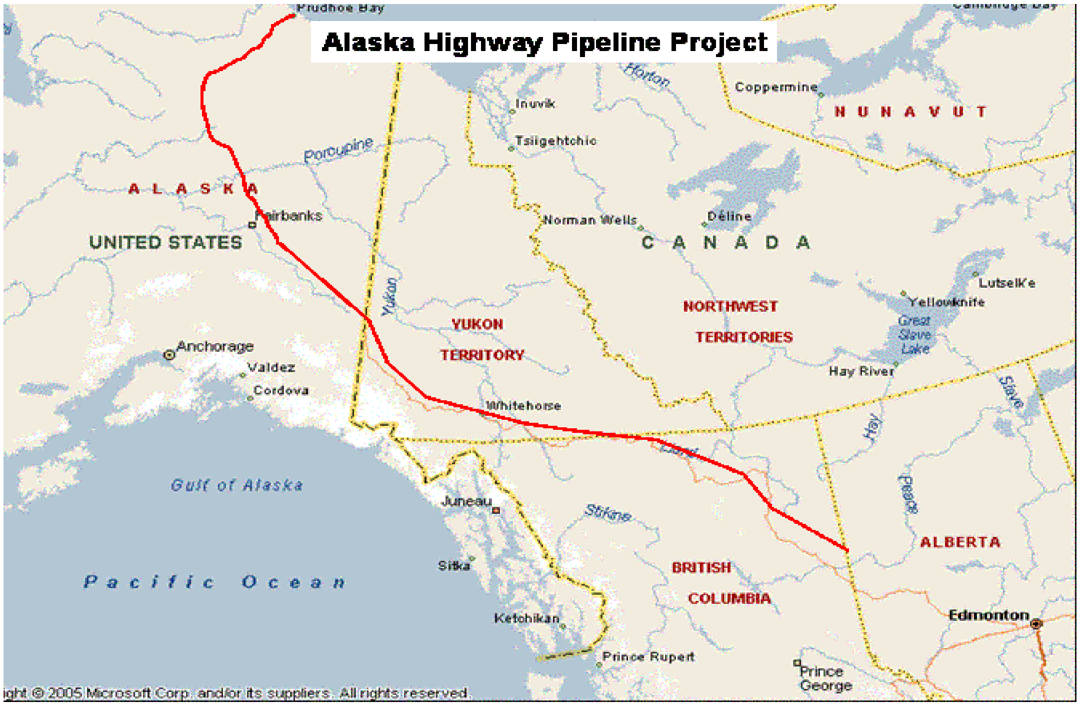
3.8 The Alaska Highway Pipeline

For the purpose of this study, the Alaska Highway Pipeline is assumed to start production in 2016 with an initial flow rate of 3,300 mmcf/day (92,974 e^3m^3/day) growing to 4,500 mmcf/day (126,780 e^3m^3/day) in year 3 and maintaining that volume out past the forecast period (see Figure 3.3). There is speculation that the Prudhoe Bay fields are capable of delivering 6,000 mmcf/day (169,045 e^3m^3/day). The pipeline route is comprised of 745 miles (1,200 kilometers) of pipe within the state of Alaska and 940 miles (1,512 kilometers) within the Yukon Territory and the province of British Columbia, connecting to the TCPL Alberta System at Boundary Lake on the border between Alberta and British Columbia.

[8] COLTKBR, Detailed System Optimization, Mackenzie Gas Project, December 2003

[9] Wright Mansell Research Ltd, An Evaluation of the Economic Impacts Associated with the Mackenzie Valley Gas Pipeline and Mackenzie Delta Gas, 2004.

Figure 3.3
Alaska Highway Pipeline and WCSB export Pipelines



The current design of the pipeline is centered on using either a 48 inch (1,220 millimeter) diameter or a 52 inch (1,320 millimeter) diameter pipeline. The study has assumed that a unit size equivalent to the LM2500 gas turbine will be used on the pipeline with multiple units at each station. Actual compressor station locations, site elevations and compressor unit sizes will indicate the resultant pipeline capacity but, for this study, utilizing the LM2500 gas turbine (2 units per station with chillers in permafrost areas) with 120 mile spacing, a 48 inch pipeline will yield an annual average capacity of approximately 4,750 mmcf/day (133,825 e^3m^3/day) receipt volume and 4,625 mmcf/day (130,300 e^3m^3/day) delivered to Boundary Lake. Under this design, the capacity with four units per station would be approximately 5,850 mmcf/day (164,800 e^3m^3/day) receipt volume and 5,810 mmcf/day (163,690 e^3m^3/day) delivered to Boundary Lake.

As previously indicated, the economic merits of constructing a new straddle plant facility at Fort Saskatchewan compared to mixing gas streams with Alberta volumes and utilizing the existing facilities was not considered as part of this study.

CHAPTER 4
METHODOLOGY AND SCENARIOS

Chapter 4 discusses briefly the methodology used in this study to determine a supply forecast for the WCSB basin in general and Alberta in particular.

4.1 Model Methodology

As previously mentioned, the primary objective of this study is to determine the amount of spare capacity that currently exists and to estimate the amount of spare capacity that might exist in the future for the pipelines that export gas from the two western provinces (GTN, Alliance, NBPL, Westcoast and TCPL east), and the transmission pipelines that operate within the two western provinces (Alliance, Westcoast and TCPL Alberta).

TCPL Alberta, Westcoast Energy and Alliance pipelines operate pipelines that gather gas from supply areas within Alberta and British Columbia. The amount of spare capacity within these provincial pipeline systems will vary from area to area as a result of the changing natural gas supply and demand patterns in the future. In order to estimate these changing supply patterns, CERI first divided the physical pipeline systems into 36 "Pipeline Influence Areas" (PIA) and then developed a computer model to estimate the future deliverability potential for each area. The elements that contribute to the pipeline area performance and resulting capacity determinations are as follows:

- The geographical layout of the intra provincial pipeline systems.
- The number of new well connections per year.
- The initial production rates for new well connections by area.
- The rate of decline in existing production rates by area.
- The rate of decline for new well connections for each year after connection.
- New supply forecasts (LNG, Mackenzie Valley Gas, and Alaska Highway Gas).
- The provincial demand for natural gas and the potential for change in that demand as a result of efficiency changes (oil sands purchase gas requirements).
- Export obligations.

Due to the amount of detail, these elements are not discussed in this summary. However, the main report includes details of the pipeline influence areas, as well as new well connection forecasts, initial production rate forecasts, CBM marketable gas forecasts and demand for natural gas forecasts (including a section on oil sands demand).

The following sections discuss the base case and the four scenarios outlined in this study. Sensitivities are not included in this summary.

4.2 Base Case Pipeline Simulation

In the Base Case, recorded production data for the year 2004 was assigned to one of the 37 pipeline influence areas that were used to represent the pipeline systems for British Columbia and Alberta. New well connections were forecasted for four cases (low case, base case, growth case and high case), with the base case adopting the view point of a flat well connection profile for the next 15 years. The remaining three cases reflect a pessimistic, continued growth and optimistic view point to new well connections. These cases are used to determine the sensitivity of new well connections on pipeline flow volumes.

This flat profile, of 12,000 new well connections for Alberta, was adopted from the EUB ST98-2006 document (2005 to 2015) and extended to the year 2020. The same assumption was applied to the British Columbia portion of the basin at a rate of 1,100 new well connections per year. New well connections for Alberta have grown from 8,200 wells in 2002, 10,655 wells in 2003, and 13,244 wells in 2004, to approximately 12,000 wells in 2005. New well connections for British Columbia for the years 2002 to 2005 have been 493, 804, 1,070 and 1,163.

Initial productivity flow rates, existing production decline rates and future well connection decline rates were calculated based on historic production values. Flow volumes in the various sections were compared against pipeline design information for the purpose of history matching the simulation program. A history match factor was applied to the initial production rates in order to calibrate the start year of the forecast to actual recorded volumes for 2005 and further calibrated to an estimate of the 2006 production levels (January to October, extrapolated to December).

Figure 4.1 compares the border deliveries for seven specified years against the current indicated capacity (“Capacity”), plus any additional capacity that has been proposed (“Add Capacity”), minus any capacity reductions ("Rem Capacity") as in the case of the TCPL Keystone project.

The vertical axis on the left side of the diagram relates to the current capacity of the pipeline area and is indicated as the boxed area spanning the individual bars. The vertical axis on the right side of the diagram indicates the average daily rate (mmcf/day) and relates to the individual vertical bars that represent a series of years (2006, 2012, 2014, 2016, 2018, 2019, and 2020) for the simulation.

Figure 4.1 indicates that deliveries by the Alliance pipeline are constant at 1,630 mmcf/day (45,925 e^3m^3/day), while the Northern Border, Gas Transmission Northwest (TCPL West Design Area) and TCPL East are declining as a result of declines in the basin projected supply. By 2016, TCPL East will be operating at 73 percent utilization assuming the Keystone project proceeds with the conversion of the 34 inch pipeline from Empress to Winnipeg. If this project were not to proceed, the utilization factor would drop to 67 percent.

Figure 4.1
WCSB Export Pipeline
Base Case Border Deliveries versus Export Capacity

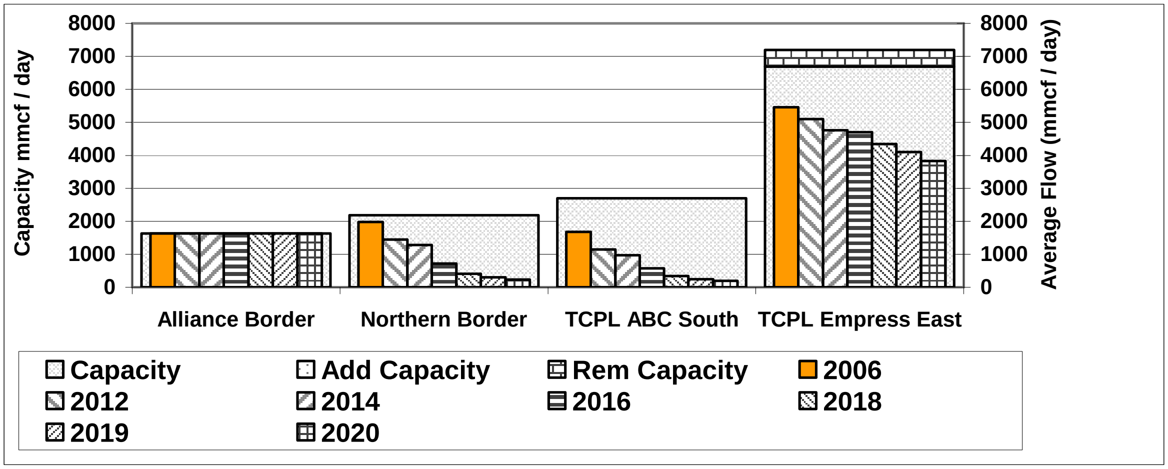


Figure 4.2 compares the selected design area deliveries for seven specified years against the current indicated capacity of the section. The Base Case has assumed that the NCC is constructed to transport 700 mmcf/day, which is sufficient to just negate any facility requirements in the Lower Peace River and Edson sub design areas. The Upper Peace area requires 600 mmcf/day of additional capacity to handle the projected new volumes originating from the area.

Figure 4.2
Base Case Section Volumes and Capacities (Alberta Northwest)

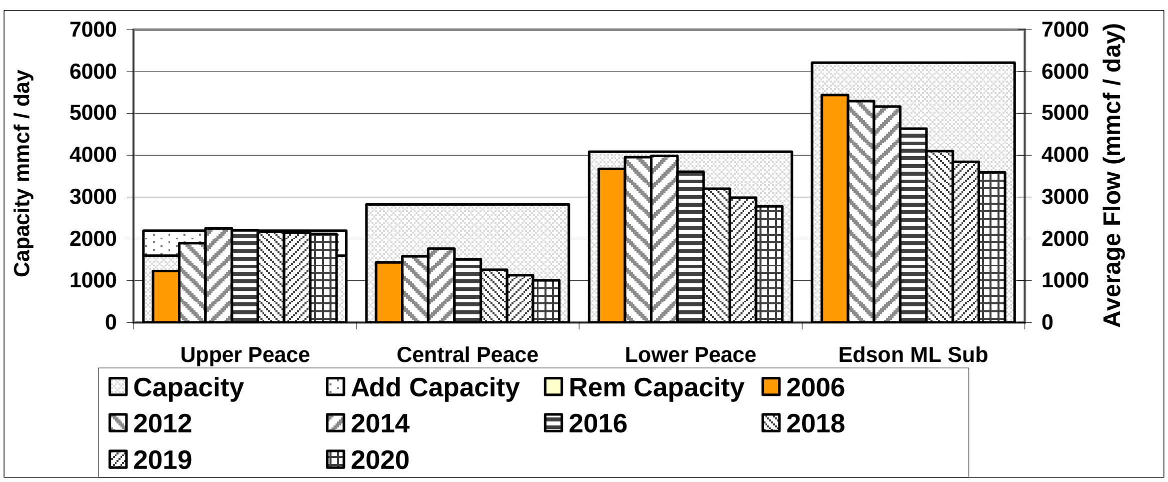


Figure 4.3 examines four sections in the southern part of Alberta between the James River crossover and the western and eastern border points. The James River to Princess area reflects a less dramatic decline over time primarily as a result of the new supplies originating from the northwest part of the province, whereas the Princess to Empress section is indicating a more

dramatic decline as a result of increasing volumes flowing north to Bens Lake and away from the Empress export point.

The base case indicates that the spare capacity for the Princess to Empress section (Figure 4.3) of the TCPL Alberta System in the years 2016 through 2018 will be 3,300 mmcf/day, 3,600 mmcf/day and 3,970 mmcf/day, respectively. The section between Empress and Winnipeg (Figure 4.3), for the same years will have spare capacities of 2,490 mmcf/day, 2,640 mmcf/day and 2,860 mmcf/day. The Northern Border Pipeline (Figure 4.1) will have spare capacities of 1,460 mmcf/day, 1,640 mmcf/day and 1,775 mmcf/day.

Figure 4.3
Base Case Section Volumes and Capacities (Alberta Southeast)

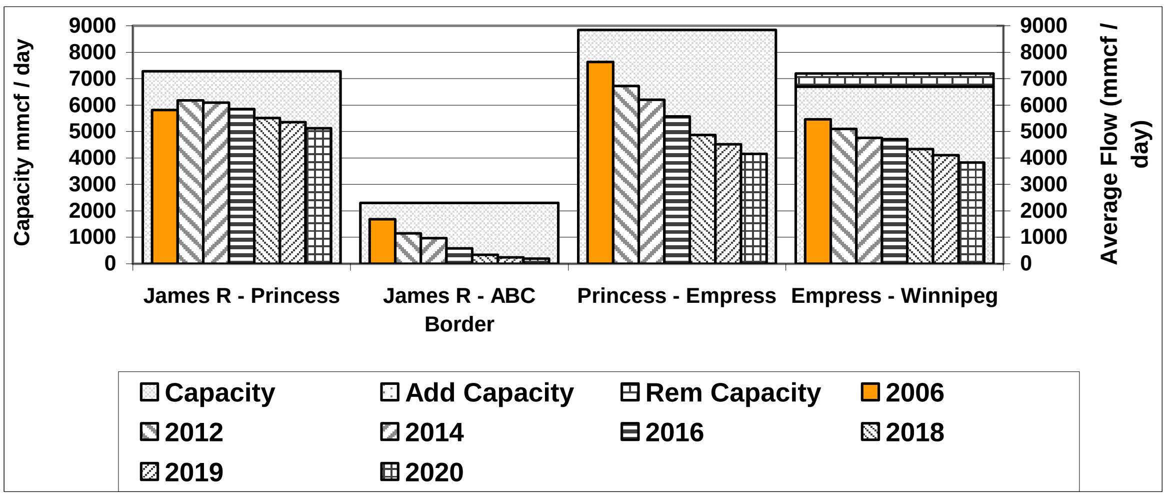
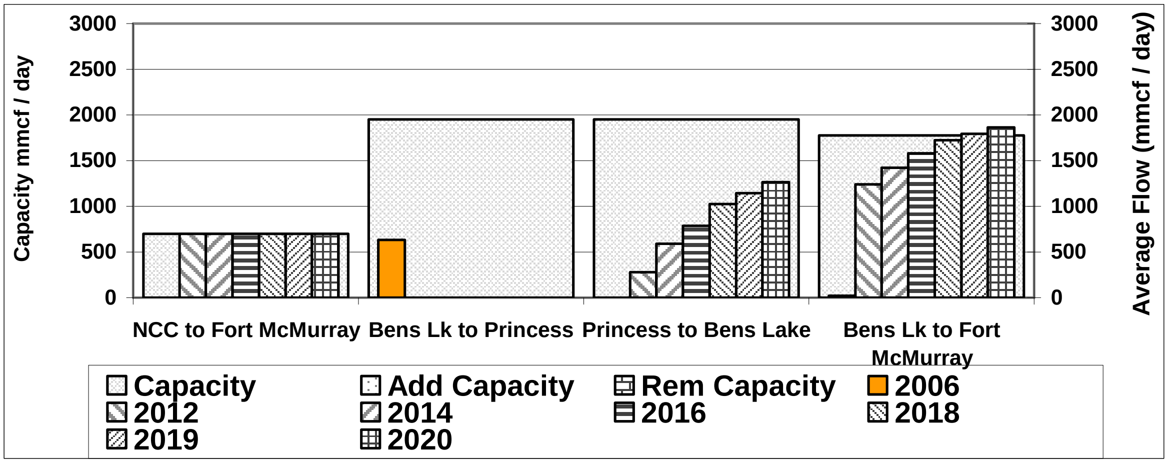


Figure 4.4 demonstrates the flow volumes into and out of the Fort McMurray area as a result of increased natural gas requirements. The NCC connector to the Upper Bens Lake area shows the 700 mmcf/day assumed flow from the Peace River area. The current flow direction for Bens Lake to Princess is south towards the Princess compressor station, but by 2012, the flow direction reverses and supply volumes from Princess are transported north to the Upper Bens Lake area.

In the Base Case, the border deliveries to TCPL East drop from 5,768 mmcf/day (162,510 e^3m^3/day) in 2006 to 3,850 mmcf/day (108,500 e^3m^3/day) in 2020. As indicated previously, this assumes the deliveries to the other border points continue to decline (with the exception of the Alliance pipeline) as the basin production declines.

Figure 4.4
Base Case Section Volumes and Capacities (Fort McMurray)

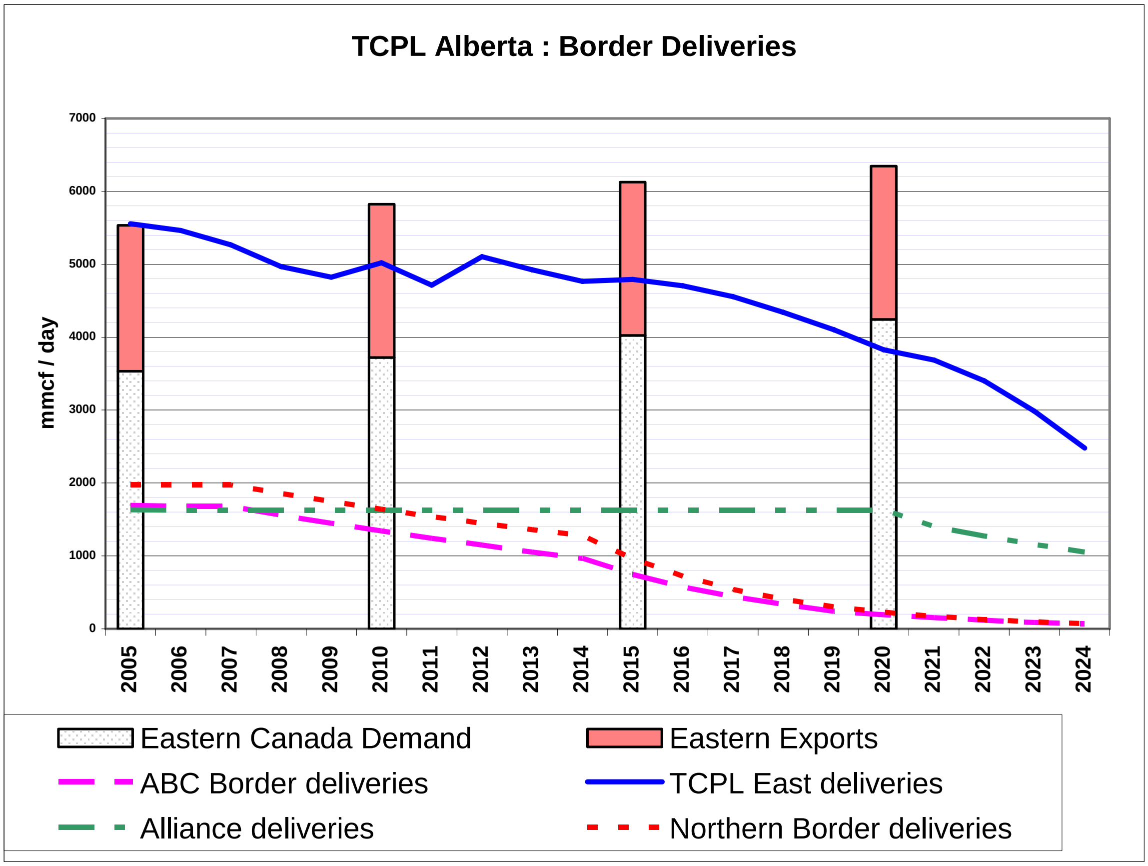


In Figure 4.5, the TCPL East delivery is compared against the Canadian demand east of Alberta[10] and the volumes delivered to the eastern export points connecting with The Great Lakes Transmission Company, Portland Natural Gas Pipeline Company, Iroquois Pipeline Company and the St. Clair River interchange. To demonstrate the change in export potential, the solid portion of the vertical bar in Figure 4.5 represents the 2005 actual export volume. Export volumes for the GTN pipeline, Alliance pipeline and Northern Border pipeline are shown on the graph for reference purposes but are not directly related to the TCPL East deliveries versus the eastern demand.

Figure 4.5 indicates that gas supply for the export market in the United States will fall by 40 percent in 2010, 60 percent by 2015 and 100 percent by 2020. This decline is reflected in the deliveries to the eastern export points (connected to TCPL East), the Northern Border export at Monchy, Saskatchewan and the Gas Transmission Northwest export at Kingsgate, British Columbia. This base case situation has not accounted for the potential LNG supplies entering Quebec, increased supplies from the Sable Island Offshore Energy Project or Compressed Natural Gas supplies from the Grand Banks, all of which would reduce the Canadian demand supplied by the WCSB. Market pressures and new LNG supplies from the Gulf of Mexico would also tend to level out this situation

[10] NEB, Canada's Energy Future: Scenarios for Supply and Demand to 2025, July 2003.

Figure 4.5
TCPL East Canadian Demand and Export Potential

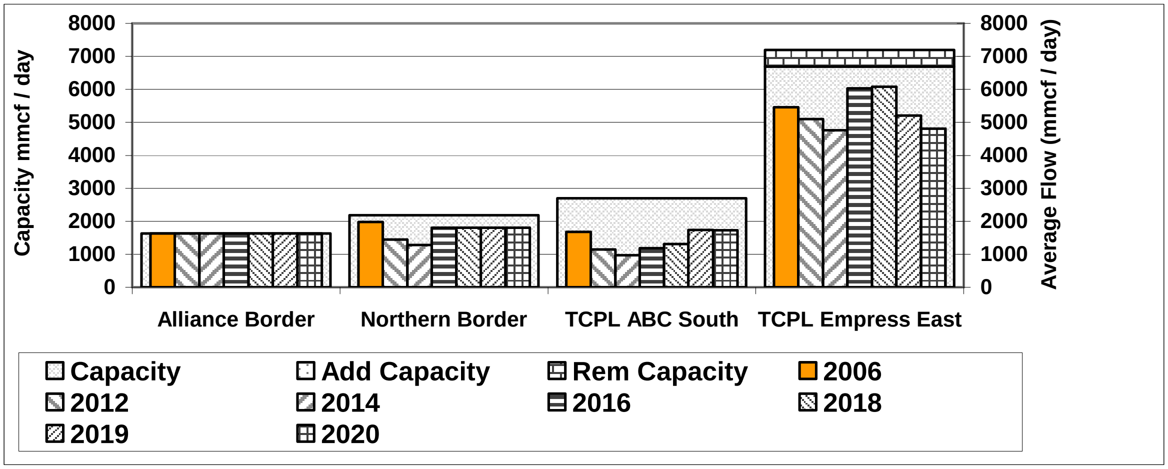


4.3 Scenario #1: Alaska Gas Transported on TCPL Integrated System Without North Central Corridor Expansion

Scenario #1 assumes that Alaska gas will connect to the TCPL Alberta system at Boundary Lake, Alberta, where it will be mixed with Alberta gas streams. The combined stream will be transported to James River where some of the gas will head south to be processed at the Cochrane straddle plant and the rest will head east in the TCPL Alberta mainline and Foothills Alberta mainline to be processed at the Empress straddle plant. This scenario measures the effect on the mainline systems as a result of not expanding the North Central Corridor.

Figure 4.6 shows the effect on border deliveries as a result of Alaska Gas being transported on TCPL's Alberta System without expanding the North Central Corridor. This scenario allows the border delivery for Gas Transmission Northwest to recover to their 2005 delivery levels while the NBPL and TCPL East also recover to a 90 percent load factor. This assumes the Keystone project reduces the capability for the Empress to Winnipeg section to 6,695 mmcf/day.

Figure 4.6
Scenario #1 (Utilizing TCPL Integrated System)
Border Deliveries versus Export Capacity



Figures 4.7 and 4.8 indicate that the Central Peace, Lower Peace, Edson Sub Design, and James River to Princess areas, would need to be expanded to handle the incremental flow volumes. Spare capacity in these sections would be utilized and facilities would need to be added or modified to handle an additional 2,900 mmcf/day for the Central Peace River area, 3,500 mmcf/day for the Lower Peace River area, 2,250 mmcf/day for the Edson to James River area and 1500 mmcf/day for the James River to Princess area. The Princess to Empress and Empress to Winnipeg sections would have sufficient spare capacity to handle the increased flow.

Scenario #1 requires extensive expansion of the Boundary Lake to Princess sections of the TCPL Alberta system and requires a flow reversal in the Bens Lake to Princess section in order to meet the Fort McMurray demand. Scenario #2 investigates the expansion of the North Central Corridor as a more efficient method of handling flows on the integrated system.

Figure 4.7
Scenario #1 (Utilizing TCPL Integrated System)
Section Volumes and Capacities (Alberta Northwest)

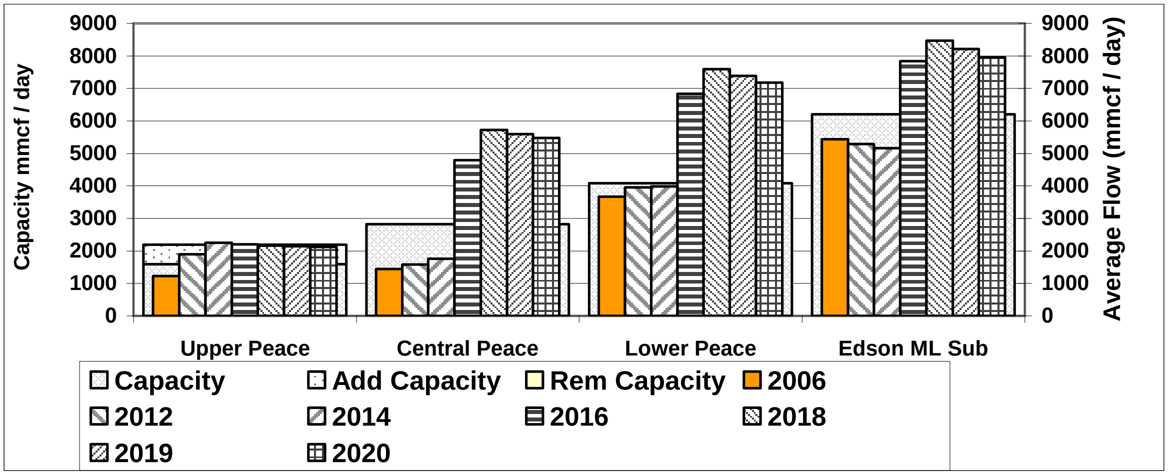


Figure 4.8
Scenario #1 (Utilizing TCPL Integrated System)
Section Volumes and Capacities (Alberta Southeast)

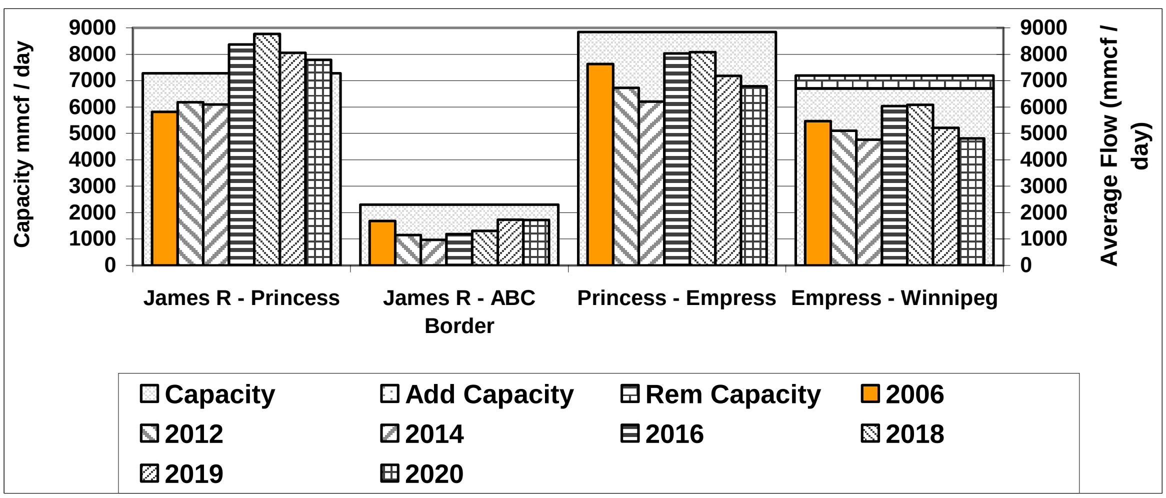
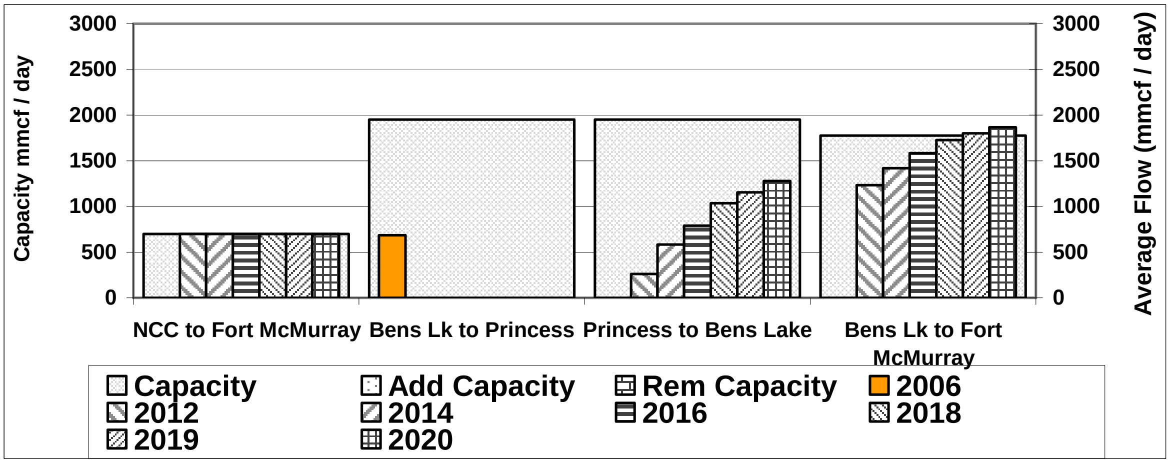


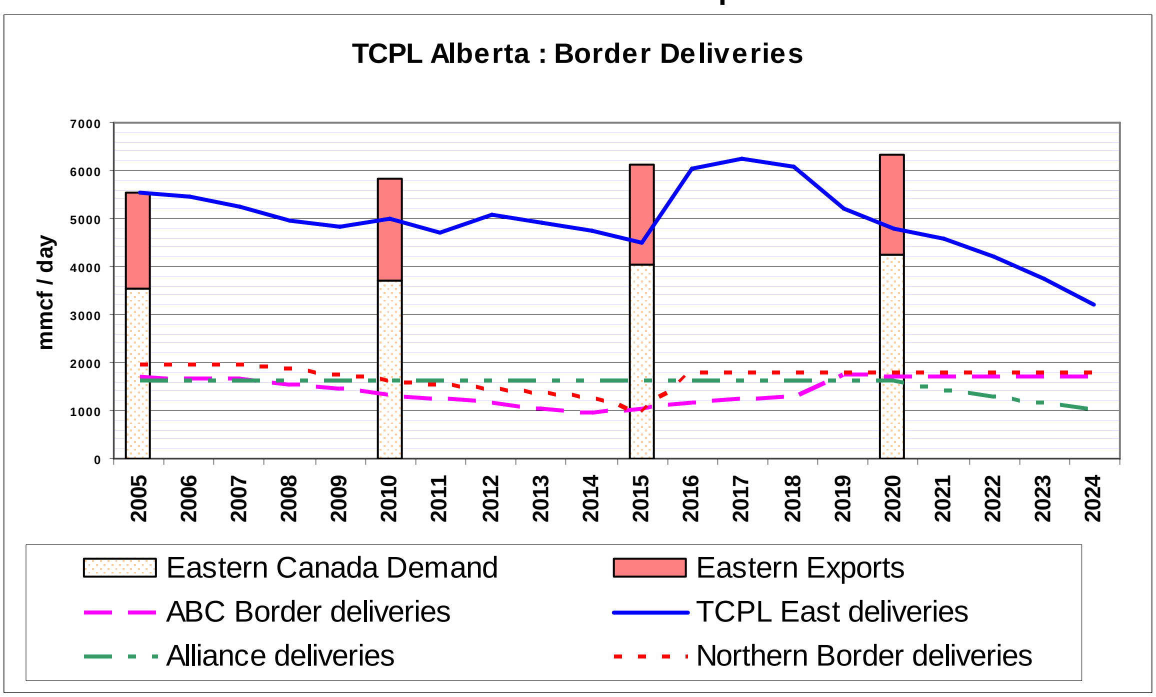
Figure 4.9 shows that the flow direction from Bens Lake to Princess must reverse, resulting in the flow of gas being transferred from the mainline (Princess Compressor station) north to the Bens Lake area and ultimately to Fort McMurray.

Figure 4.9
Scenario # 1 (Utilizing TCPL Integrated System)
Section Volumes and Capacities (Fort McMurray)



In Figure 4.10, the deliveries to the Gas Transmission Northwest and Northern Border Pipelines are held at the 2005 level until 2007 followed by a 6 percent decline until the Alaska volumes are connected to the system. Some of the Alaska volumes have been allocated to the GTN pipeline system under the assumption that deliveries to the California market will gradually recover to the 2005 level. The Northern Border Pipeline and the TCPL East pipeline are assumed to share the transportation of the residual Alaska volumes with each pipeline operating at a 90 percent load factor in the initial years.

Figure 4.10
TCPL East Canadian Demand and Export Potential



4.4 Scenario #2: Alaska Gas Transported on TCPL Integrated System With North Central Corridor Expansion

Scenario #2 assumes that Alaska gas will connect to the TCPL Alberta system at Boundary Lake, Alberta where it will be mixed with Alberta gas streams. The combined stream will be transported to James River, where some of the gas will head south to be processed at the Cochrane straddle plant, and the rest will head east in the TCPL Alberta mainline and Foothills Alberta mainline to be processed at the Empress straddle plant.

This scenario examines the effect on the TCPL Alberta System if the North Central Corridor is expanded to handle a volume of 2300 mmcf/day thereby reducing the mainline facility requirements south of the Peace River area and offering a better utilization of the Bens Lake south to Princess lateral.

This scenario effectively takes all the gas from the Upper Peace area, Central Peace area and Mackenzie Valley and directs the flow towards the Upper Bens Lake area with some of the residual volumes flowing south and reconnecting with the mainline at Princess and on to Empress, where liquids can be removed from the stream. The volumes of gas delivered within the Upper Bens Lake area will not have liquids recovered from the marketable gas stream.

The NCC pipeline will transport all the gas from the Upper Peace and Central Peace areas (north of Boundary Lake lateral) and the Mackenzie Gas over to the Upper Bens Lake area, which results in the Central Peace area carrying almost the total volume of Alaska gas in 2018. Expansion of the NCC connector would involve two intermediate compressor stations and a second 30 inch loop line to handle the 2,300 mmcf/day flow volume. Expanding the NCC to this level eliminates any new facility additions downstream of James River (Figure 4.13) and minimizes the facility additions on the Edson Sub Design area (Figure 4.12). The Edson Sub Design area can handle the increased volume through the addition of one intermediate station on the Swartz Creek to Clearwater loop line.

The existing pipeline in the Central Peace and the Lower Peace area would need to be expanded and/or reconfigured to handle an increased volume (Figure 4.12). The facilities required would include the addition of 134 miles of 48 inch pipe, 119 miles of 36 inch pipe, five 23 megawatt compressor additions and a new compressor station near Wembley, Alberta.

Figure 4.11 shows the effect on border deliveries as a result of Alaska Gas being transported on TCPL's Alberta System. This scenario allows the border delivery for Gas Transmission Northwest to recover to their 2005 delivery levels while the NBPL and TCPL East also recover to a 90 percent load factor. This assumes the Keystone project reduces the capability for the Empress to Winnipeg section to 6,695 mmcf/day.

The James River to Princess, Princess to Empress, and Empress to Winnipeg has sufficient spare capacity to handle the increased flow (Figure 4.13).

Figure 4.11
Scenario #2 Expanded NCC (Utilizing TCPL Integrated System)
Border Deliveries versus Export Capacity (Alberta Northwest)

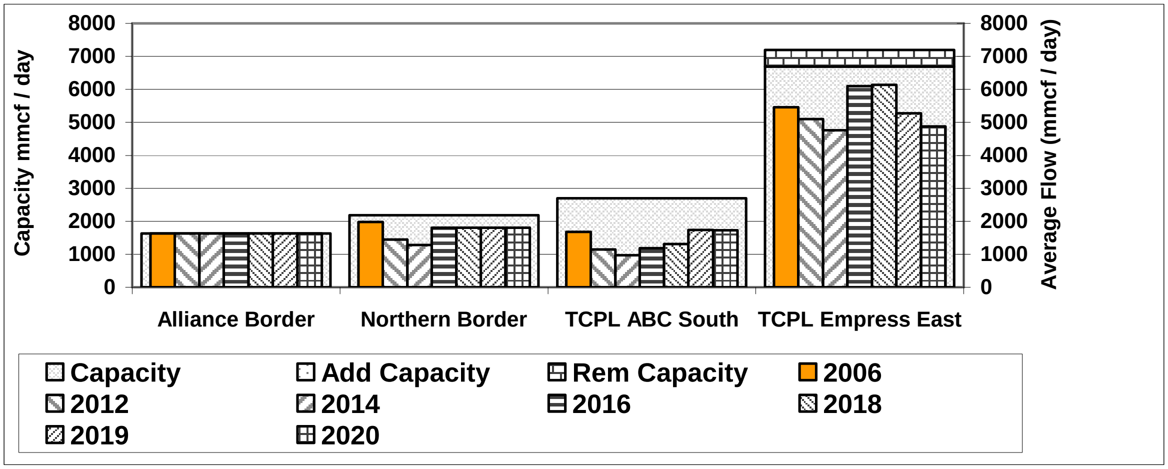
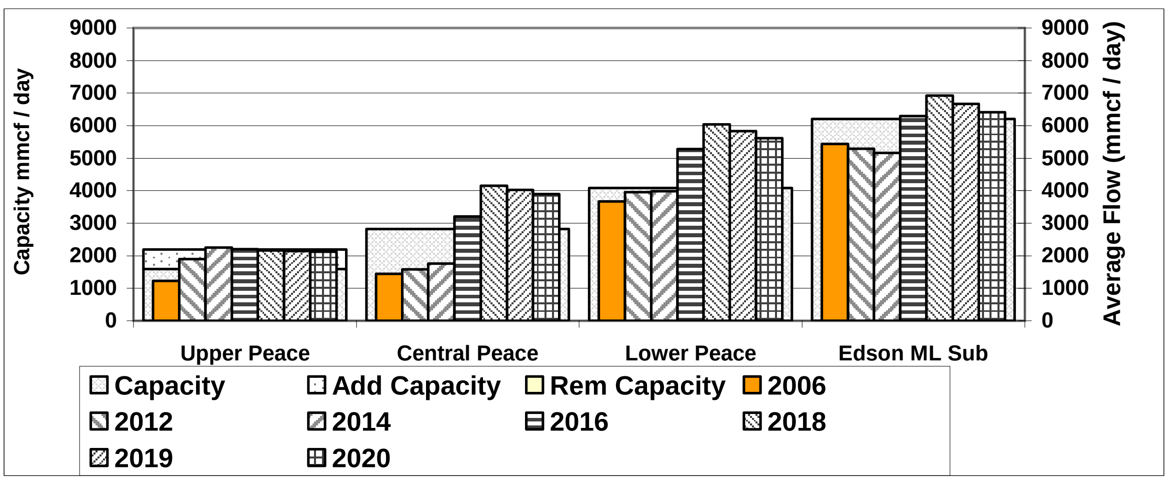


Figure 4.12
Scenario #2 (Utilizing TCPL Integrated System)
Section Volumes and Capacities (Alberta Northwest)



As in Scenario #1, the utilization rate for the Empress to Winnipeg section approaches 90 percent after accounting for the reduced capacity of the Keystone project.

Figure 4.13
Scenario #2 Expanded NCC (Utilizing TCPL Integrated System)
Section Volumes and Capacities (Alberta Southeast)

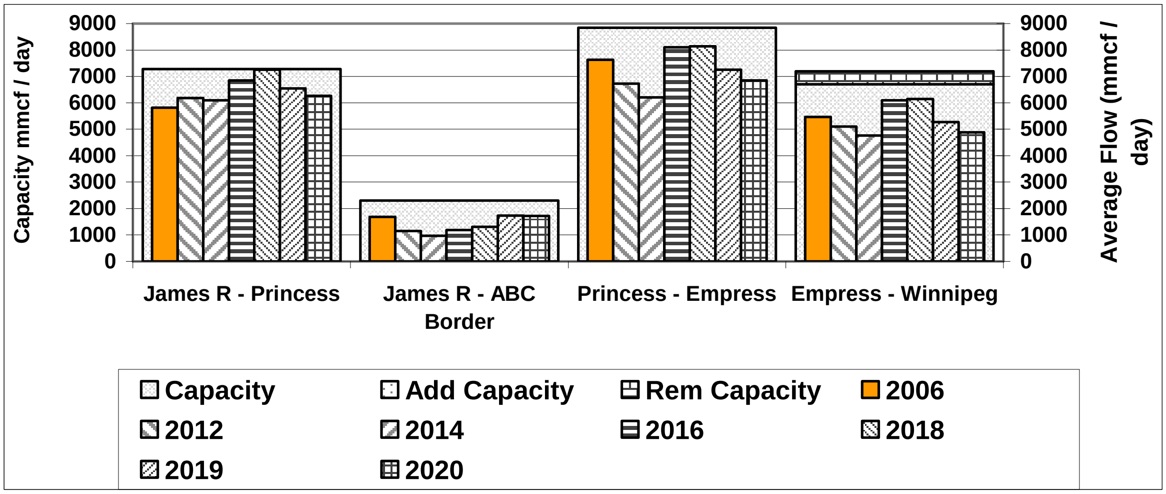
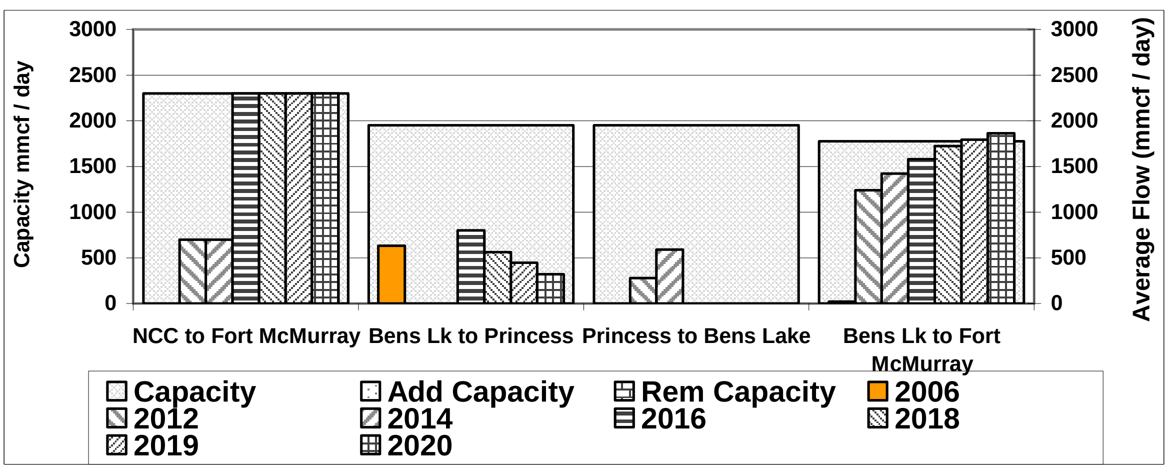


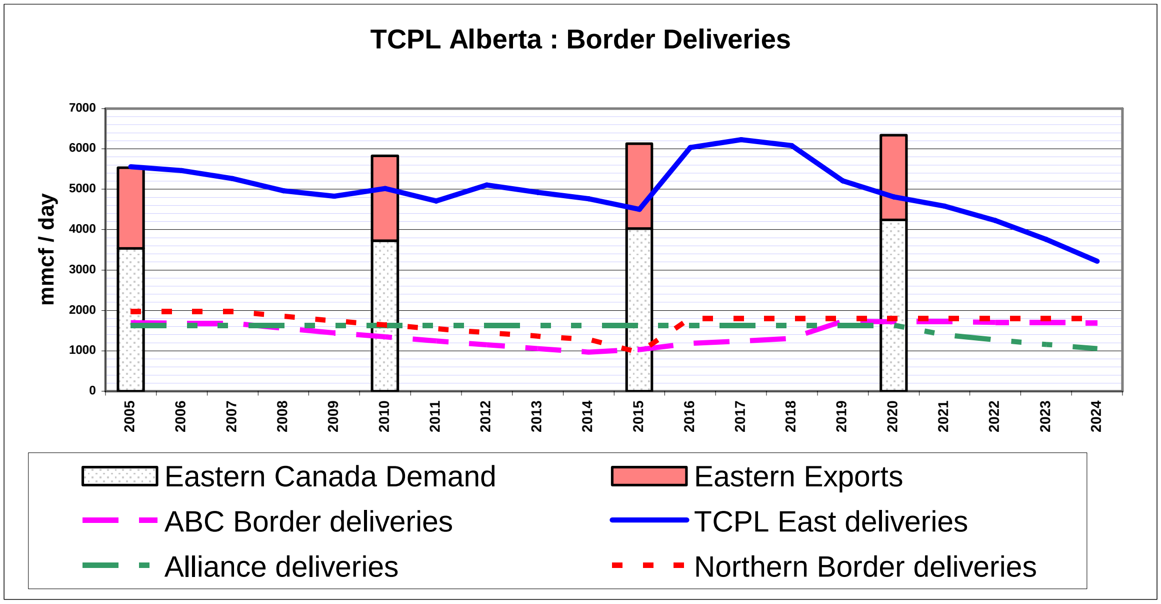
Figure 4.14 indicates that flows on the Bens Lake to Princess lateral will return to their normal south flow direction following expansion of the North Central Corridor.

Figure 4.14
Scenario # 2 Expanded NCC (Utilizing TCPL Integrated System)
Section Volumes and Capacities (Fort McMurray)



In Figure 4.15, the deliveries to the Gas Transmission Northwest and Northern Border Pipelines are held at the 2005 level until 2007 followed by a 6 percent decline until the Alaska volumes are connected to the system. At this point in time deliveries to these markets are assumed to partially recover. Some of the Alaska volumes have been allocated to the GTN pipeline system under the assumption that deliveries to the California market will gradually recover to the 2005 level. The Northern Border Pipeline and the TCPL East pipeline are assumed to share the transportation of the residual Alaska volumes with each pipeline operating at a 90 percent load factor in the initial years.

Figure 4.15
TCPL East Canadian Demand and Export Potential



4.4 Scenario #3: Alaska Gas Transported on TCPL Integrated System and Alliance Pipeline System

Scenario #3 assumes that the Alaska gas will follow two different paths in order to get to market. The Alliance pipeline has a current capacity of 1,630 mmcf/day (46,485 e^3m^3/day) from Fort Saskatchewan to Aux Sable, Illinois. The addition of twelve intermediate compressor stations and adding a complete 36 inch loop would boost the pipeline capacity to 3,500 mmcf/day (100,720 e^3m^3/day). In addition, a connector pipeline (355 miles of 36 inch loop with 2 compressor stations each with a single LM2500 unit) would need to be constructed from Boundary Lake to Fort Saskatchewan to deliver 1,875 mmcf/day to the start of the expanded Alliance pipeline. This connector pipeline is assumed to operate at 2500 pounds per square inch. Construction of a straddle plant at Fort Saskatchewan could be economic based on the liquids available.

After accounting for the volumes transferred to Alliance, the remaining gas would be transported on the TCPL system south to James River. In order to eliminate the need for additional facilities on the Lower Peace and Edson sub area, this scenario assumes the NCC will be expanded to handle 1,700 mmcf/day. Expansion of the NCC to this level eliminates the need for additional facilities in the Central Peace River area coupled with minor additions in the Lower Peace River area. An expansion to the Lower Peace River area (Figure 4.17) in the form of completing the loop down stream of Gold Creek, coupled with power additions at three of the compressor stations, will increase the capacity to handle the Alaska volumes.

Figure 4.16 shows that with the increased flow on the Alliance System, coupled with the recovered deliveries to the GTN and Northern Border pipelines, the utilization of the TCPL system downstream of James River continues to decline.

Figure 4.16
Scenario #3 (TCPL/Alliance Transportation)
Border Deliveries versus Export Capacity

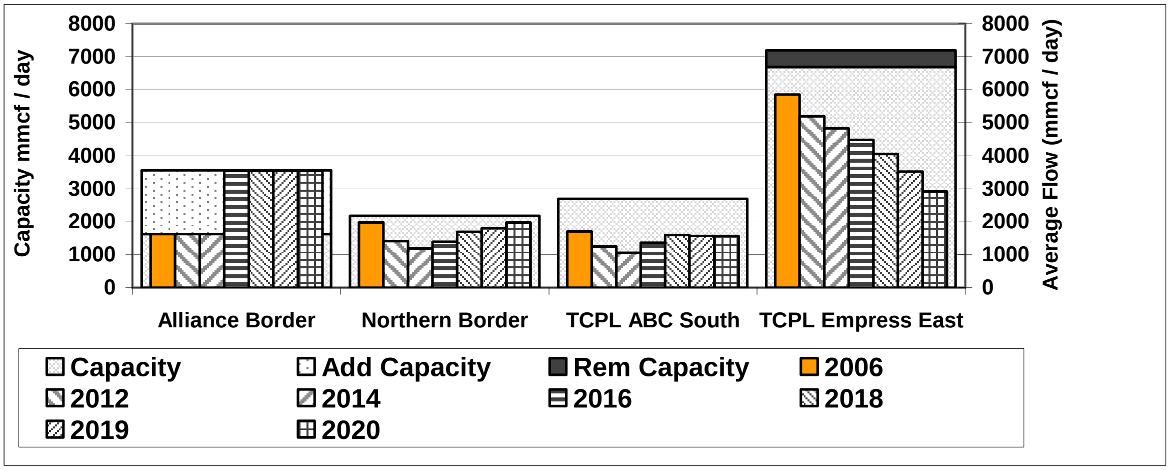
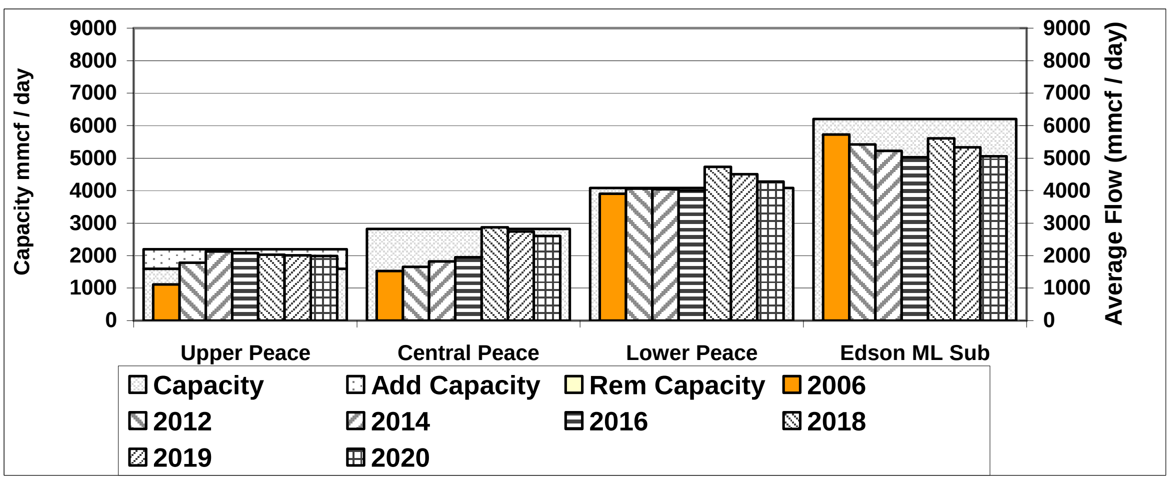


Figure 4.17
Scenario #3 (TCPL/Alliance Transportation)
Section Volumes and Capacities (Alberta Northwest)



With the exception of the facilities mentioned above for the Lower Peace River area, the Alaska volumes can be handled by the existing mainline facilities between Gold Creek, Alberta (exit of the Lower Peace River area) and Winnipeg (Figure 4.18)

Figure 4.18
Scenario #3 (TCPL/Alliance Transportation)
Section Volumes and Capacities (Alberta Southeast)

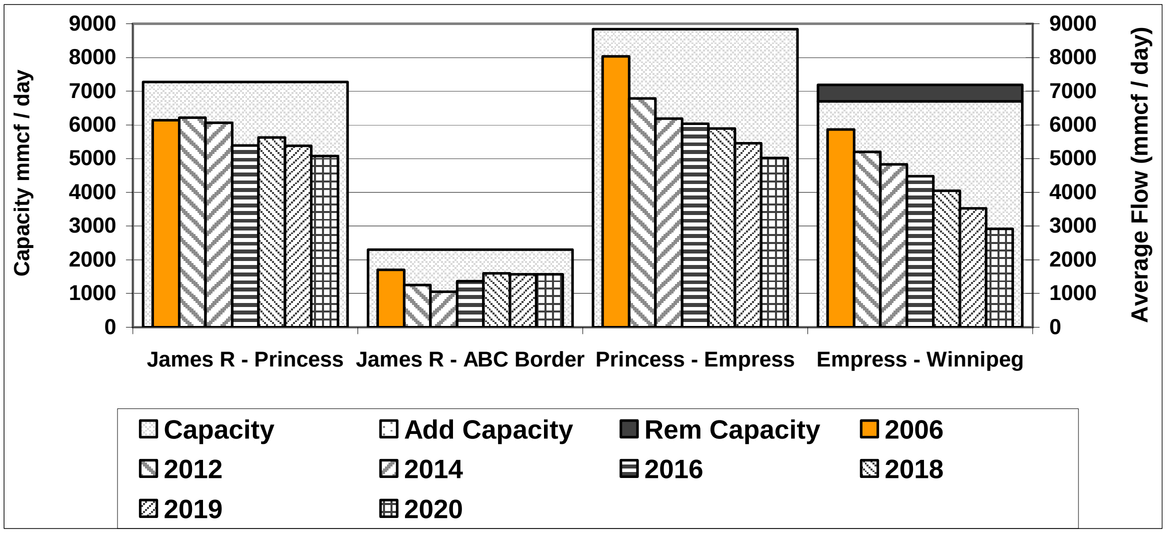
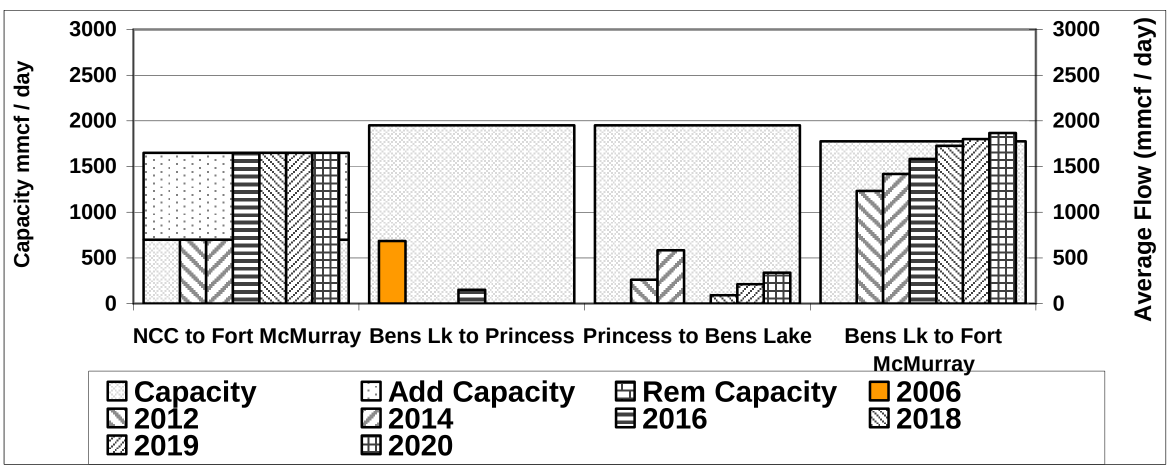


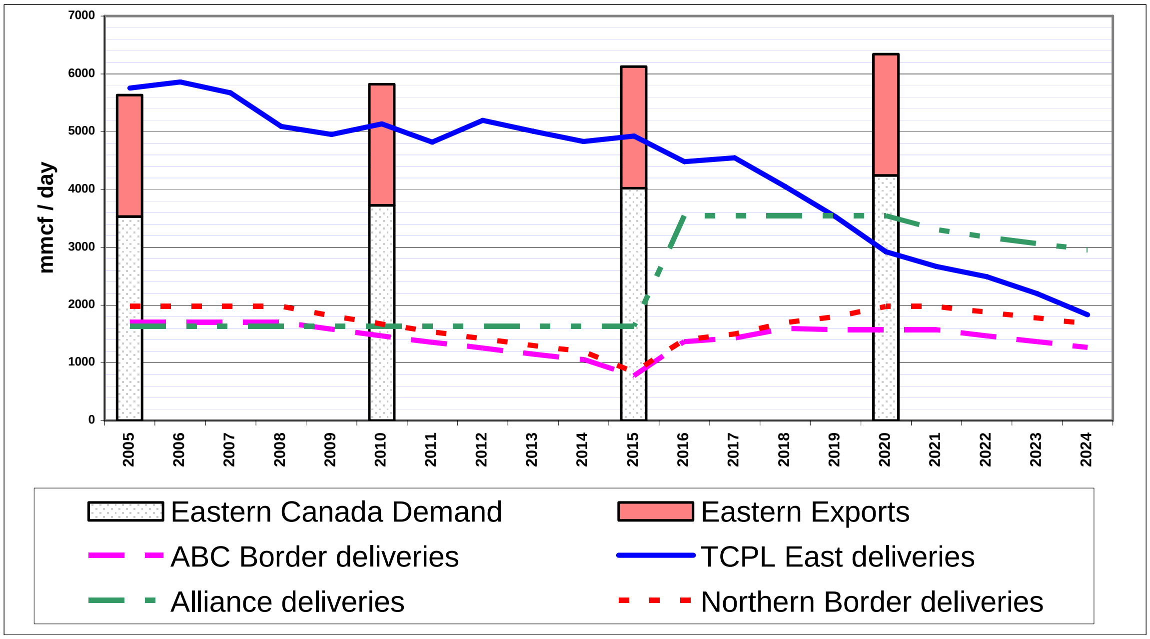
Figure 4.19 shows the expansion of the NCC to handle a flow of 1,700 mmcf/day.

Figure 4.19
Scenario #3 (TCPL/Alliance Transportation)
Section Volumes and Capacities (Fort McMurray)



In 2018, the Alaska volumes are split, with 1,890 mmcf/day allocated to the Alliance Pipeline, 1,300 mmcf/day to the GTN system and 1,200 mmcf/day to the NBP system (Figure 4.20). This scenario indicates that by 2019 the deliveries to the TCPL East system would fall short of the forecasted Canadian demand. In reality, market pressures would result in additional volumes being transported by TCPL into Ontario and Quebec and less volumes in Northern Border going to Chicago.

Figure 4.20
Scenario #3 (TCPL/Alliance Transportation)

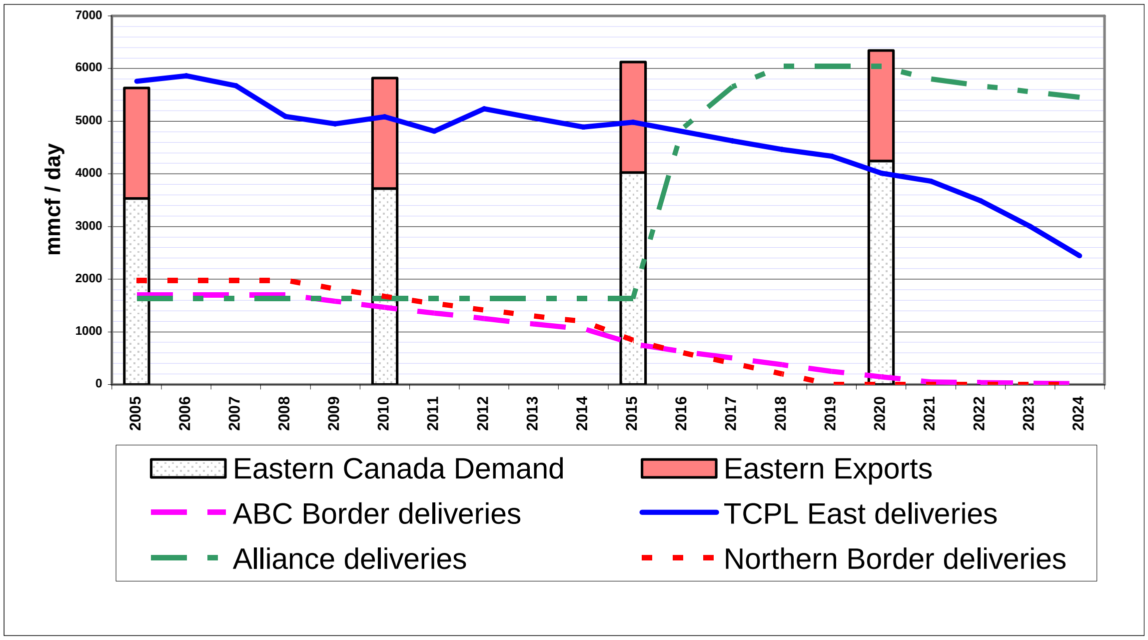


4.6 Scenario #4: Alaska Gas Transported on the Alliance Pipeline System

Scenario #4 assumes the total Alaska volume would be transported on an expanded Alliance Pipeline. This scenario also assumes that the GTN deliveries to the California market will not recover to their 2005 level requiring the California market to be supplied by LNG imports and mid continent gas supplies. The Northern Border pipeline is assumed not to recover from declining basin deliveries and residual supplies are directed towards eastern Canadian demand (Figure 4.21).

The addition of twelve intermediate compressor stations, adding a complete 48 inch loop (1,505 miles) and expanding 24 stations with the addition of a 29 megawatt compressor would boost the pipeline capacity to 6,264 mmcf/day (176,480 e^3m^3/day). In addition, a connector pipeline (355 miles) of 42 inch loop with 2 compressor stations, each with twin 25 megawatt gas turbines, would need to be constructed from Boundary Lake to Fort Saskatchewan. This connector pipeline is assumed to operate at 2,500 pounds per square inch. Construction of a straddle plant at Fort Saskatchewan could be economic based on the liquids available.

Figure 4.21
Scenario #4 (Alaska Volumes to Alliance 48 inch Capacity)



CHAPTER 5
NOTES ON KEY ASSUMPTIONS

This chapter is intended to briefly identify issues surrounding some of the key assumptions used in the study and to detail the reasons for arriving at a specific position.

Some of the issues described below could not be analyzed because of the lack of detailed information. In these situations, a reasonable assumption was adopted. In other situations, the subject matter was outside the scope of the study and thus not analyzed. And finally, in some situations external information was used to assist in arriving at a reasonable assumption.

5.1 Consideration of Heavier Hydrocarbon Gas Streams on Existing Pipelines

This study has assumed that the compositional makeup of the Alaskan gas stream will have no effect on the integrity of the existing pipeline systems that gather and export natural gas from Alberta and British Columbia.

The point of contention here is the belief that, in the event of a pipeline rupture, a “rich gas” stream may contribute to “Dynamic Fracture Propagation” (DFP) in pipeline systems where the toughness of the steel is insufficient to arrest the crack. The question is directed at the existing pipeline systems that developed over time where the degree of toughness can be different from section to section and mainline to loop lines.

“Pipelines could contain defects introduced during steel and pipe making, and pipeline construction. Although significant pre-service defects are very rare in recently constructed pipelines, that initial defect population could expand as pipelines continue service, due to defects introduced by outside forces, including mechanical damage defects, or defects that nucleate and grow in service. Such defects may be blunt (for example due to corrosion) or sharp (for example due to stress corrosion cracking or effects of hydrogen embrittlement).”[11]

In the unlikely event of a failure of a high pressure gas pipeline, the rupture allows the gas to exhaust, which establishes a decompression front propagating away from the origin limited by the acoustic velocity of the gas. If the acoustic velocity is less than the velocity of the fracture front, the result can lead to a running fracture or a DFP. For a gas, the de-compositional behavior depends on its operating pressure, temperature, composition and more importantly the amount of heavier hydrocarbon elements. For a pipeline, the velocity of a propagating fracture is a function of the stress in the pipeline and the ability of the steel to resist a ductile-fracture or its degree of toughness.

The Alaska Highway gas volume could be directed towards Fort Saskatchewan, Alberta and onto Chicago by way of the Alliance Pipeline System, or the stream could enter the TCPL Alberta

[11] Fracture Propagation Control in Onshore Transmission Pipelines, Onshore Pipeline Technology Conference, Istanbul, December 1998, Brian N Leis and Robert J. Eiber.

integrated system where it will be mixed with Alberta conventional gas streams for transportation to the Alberta border points to connect with Canadian domestic and US export pipelines. The Alliance pipeline was constructed to provide a Charpy-vee notch (CVN) toughness of approximately 200 joules at 1,178 BTU's per cubic foot whereas pipelines constructed prior to 1997 provide a CVN toughness of approximately 100 joules at 1,050 BTU's per cubic foot. The assumption that the hydrocarbon composition of Alaskan gas will not affect the integrity of the existing pipeline systems is based on the following:

- The Peace River section of the TCPL Alberta system currently receives gas with a hydrocarbon makeup similar to that of the Alaska gas. Alberta conventional gas entering the pipeline system north of Boundary Lake has an average ethane content of 6.0 percent as compared to the 6.3 percent for the Alaskan gas, and a propane content of 1.8 percent as compared to 2.4 percent for the Alaskan gas. Alberta conventional gas entering the TCPL Alberta system south of Gold Creek has ethane and propane contents greater than the Alaskan gas. The mixing of these gas streams will not significantly alter the compositional make up of the existing gas stream.

- Prior to the construction of the Alliance Pipeline, the composition of gas streams entering the TCPL Alberta System in the Kaybob and Deep Basin areas contained ethane and propane compositions in excess of 12 percent and 6 percent, respectively. Most of these gas streams are now carried on the Alliance pipeline.

- In the event the North Central Corridor is constructed and results in gas volumes from the Peace River area being transported to the Upper Bens Lake area, the Alaska gas will be diluted only minimally by conventional sources. However, the compositional makeup of the Alaskan gas is not significantly different than the composition that the pipeline is currently being exposed to.

- Detailed information regarding the type of steel (yield stress, thickness and toughness) used in the various sections of the TCPL Alberta system was not available for this study, thus limiting the ability to investigate this subject in more detail.

5.2 Pressure Constraints on the TCPL Alberta System

This study has assumed that the operating pressure of the Alaska Pipeline System will not be a problem at the Boundary Lake connection.

The Alaska Highway Pipeline is proposed to operate with a maximum operating pressure (MOP) of 2,500 pounds per square inch. At Boundary Lake, the pressure of the gas stream will be approximately 1,900 pounds per square inch (based on a flow volume of 4,500 mmcf/day) as a result of the last station on the BC section being situated 120 miles upstream from Boundary Lake. The TCPL Alberta system has a maximum operating pressure of 1,200 pounds per square inch at the point where the Alaska pipeline will interconnect. The following assumptions have been made with regard to pressure considerations at Boundary Lake:

- If the majority of the gas stream is directed to the Fort Saskatchewan connection with the Alliance pipeline then the connector pipeline between these two points will be designed to operate at 2,500 pounds per square inch and any volumes of gas directed to the TCPL Alberta System will need to be pressure regulated down to 1,200 pounds per square inch.

- If the majority of the gas stream is directed to the TCPL Alberta system, then the discharge pressure at the last upstream compressor station will be set to yield a pressure of 1,200 pounds per square inch at Boundary Lake. Any residual gas going to Fort Saskatchewan will require a compressor station at Boundary Lake to boost the pressure to 1,750 pounds per square inch to match the operating pressure of the Alliance Pipeline.

5.3 Potential Impact of a Straddle Plant at Fort Saskatchewan, Alberta

The relative economics of constructing a new straddle plant at Fort Saskatchewan compared to utilizing the existing plants at Empress and Cochrane were not accounted for in this study because they are considered outside the scope.

If Alaska gas volumes enter the TCPL Alberta pipeline system, the liquids contained within the gas stream will be removed either by the Empress or Cochrane straddle plant operations. The combined capacity of the five Empress Plant operations is 8,700 mmcf/day (245,110 e^3m^3/day); while the Cochrane facility will have a capacity of 2,500 mmcf/day (70,435 e^3m^3/day) after the cryogenic train number four comes online in 2008. Scenario #1 which accounted for all of the Alaskan gas being transported on the TCPL Alberta system resulted in a flow at Empress of 8,011 mmcf/day, and at Cochrane a flow level of 1,650 mmcf/day, which is still below the plant capacity levels. Under the scenario where the California market does not take the gas from the Gas Transmission Northwest system, these volumes would be redirected to flow eastward, resulting in the flow volume at Empress exceeding the plant capacity by 3 percent.

If gas volumes are directed to the Fort Saskatchewan area, the assumption is made that a new straddle plant operation will be constructed to remove the liquids prior to the flow entering the Alliance pipeline. The assumption is also made that, if a significant portion of the Alaska volumes are directed to Fort Saskatchewan, then the connector pipeline will operate at 2,500 pounds per square inch and the inlet pressure to the straddle plant will be in the order of 1,900 pounds per square inch with the exit pressure matching the Alliance line pressure at that point. If a smaller quantity of gas is directed to Fort Saskatchewan then the connector pipeline will operate at 1,750 pounds per square inch and the inlet pressure to the plant will be approximately 1,240 pounds per square inch.

5.4 Kitimat LNG Terminal

This study has included the Kitimat LNG terminal as part of the base case and has assumed an operational load factor of 85 percent.

The Kitimat LNG terminal to be located at Emsley Cove, British Columbia has been proposed to be developed with a send out capacity of 620 mmcf/day (17,470 e^3m^3/day). The projected on stream date is 2009. Kitimat LNG has received its provincial and federal environmental permit and can now proceed with development of the project. Gas supply for the terminal will come from an Australian company.

In July of 2006, Kitimat LNG Inc. entered into a partnership with Pacific Trails Pipelines for the purpose of developing the natural gas transmission pipeline system to connect the LNG terminal to Westcoast Energy's pipeline system at Summit Lake, British Columbia. This pipeline connection will give Kitimat LNG access to the lower mainland of BC, and the export markets of Washington, Oregon and California.

5.5 California Demand Considerations

This study has assumed that volumes of gas transported on the GTN system will decrease as production from the WCSB basin decreases and will recover when the Alaska gas enters the markets starting in 2016.

Figure 5.1 details the potential deficiency in the California market as a result of declining supplies from Alberta that are connected to the Gas Transmission Northwest pipeline. This deficiency will exist even after accounting for new LNG imports from Mexico, new LNG imports directly into California, increased deliveries from the proposed Kitimat LNG terminal and assuming the US interstate pipelines all operate at their capacity levels.

What is not accounted for in this assumption is the potential for new supplies of gas from Wyoming entering the California market in addition to flows moving to the Illinois market area. The Rockies Express Pipeline was originally designed to transport gas from Sweetwater, Wyoming to Illinois, Indiana and Ohio, and is projected to be on stream in 2008. However, the Overthrust Expansion Project is intended to connect the Sweetwater area to the existing Kern River Gas Transmission System. This means that the Wyoming gas will have access to the California market (assuming Kern River is expanded to handle the volumes) and could displace Alberta gas as the WCSB basin declines. This could result in the flow volumes on the GTN system not recovering to the 2005 level as assumed. Should this transpire, these volumes would be directed towards TCPL East.

Figure 5.1
Pacific Northwest and California Supply/Demand Balance

					2005 tcf/yr	2010 tcf/yr	2015 tcf/yr	2020 tcf/yr
Pacific Northwest								
	Supply		Gas Transmission NorthWest Pipeline	1	0.65	0.53	0.28	0.06
			Northwest Pipeline Corp (Rockies)	2	0.04	0.04	0.04	0.04
			Northwest Pipeline Corp (Sumas)	3	0.28	0.32	0.36	0.41
			Increase Supply (Sumas)	4	0.00	0.02	0.06	0.06
			Incerase Supply (Kitimat LNG)	5	0.00	0.06	0.06	0.06
			Pacific Northwest Demand (EIA estimate)		0.50	0.56	0.60	0.67
	Balance		Surplus (+) / Deficiency (-)		0.48	0.41	0.20	-0.04
	Comments	1	GTN receipts at Kingsgate					
		2	NWP deliveries from Rockies					
		3	Westcoast Energy will increase exports at 2.5% per year into the I5 corridor					
		4	Assumed new exports volumes at Sumas					
		5	Assumed Kitimat LNG export volumes					
California								
	Supply		California local Supply		0.34	0.38	0.36	0.36
			GTN residual supply to California		0.48	0.41	0.20	-0.04
			Kern River Pipeline Supply	6	0.45	0.45	0.45	0.45
			TransWestern Pipeline Supply	6	0.87	0.87	0.87	0.87
			El Paso Pipeline Supply	6	0.25	0.25	0.25	0.25
			LNG imports to California	7	0.00	0.00	0.31	0.31
			LNG imports from Mexico	8	0.00	0.16	0.31	0.47
	Demand		California Demand (EIA estimate)		2.39	2.71	2.90	3.24
			Surplus		0.00	0.00	0.00	0.00
			Deficiency		0.00	0.19	0.15	0.57
	Comments	6	Mid continent Pipes into the California market assumed to remain at current levels					
		7	California LNG terminal (85% LF)					
		8	LNG (Costa Azul) assumed delivery to California (50% volume) plus a second term					

5.6 North Central Corridor Design Capacity

The North Central Corridor (NCC) is a connector pipeline that TCPL has proposed to construct in the northern part of the province in order to efficiently move natural gas from the Peace River area to the Upper Bens Lake area for the purpose of supplying the oil sands development near Fort McMurray. TCPL has indicated that it is more economical from a fuel usage point of view to move gas east to the Bens Lake area and south to Princess, than it is to maximize (and possibly expand) the Peace River to James River to Princess mainline.

This study did not have sufficient details to examine and compare fuel requirements for the two routes. As a result, the size of the NCC connector (volume to be transported) was established for each scenario as the quantity of gas required to maximize the flow in the Peace River to Princess (via James River) pipeline sections with minimal or no facility expansions in these areas. The size of the connector was further limited to the volumes of gas in the Upper Peace River and Central Peace River areas above the Boundary Lake Lateral.

As a result of these considerations, the NCC was sized to handle a volume of 700 mmcf/day (in the base case), which eliminates the need for additional facilities in the Lower Peace River and Edson Mainline areas. Additional facilities down stream of James River would not be required because of the available spare capacity. In Scenario #2, the NCC would need to be expanded to handle 2,300 mmcf/day. In Scenario #3, the NCC would need to be expanded to handle 1,700 mmcf/day.

These flow levels should be considered minimum volumes as larger capacities for the NCC might prove to be more economic as a result of greater fuel savings.

5.7 Alliance Pipeline Future Contracts

Volumes of gas that flow on the Alliance Pipeline are associated with contractual obligations that have a primary term that extends out to 2015. There is an automatic extension to these contracts for an additional 5 years unless the contractor exercises a “Notice of Termination” available in 2010. For this study, the assumption has been made that the Alliance pipeline will remain full out to 2020, followed by a prorated share of the basin decline after that point. This assumption is based on the following:

- Alliance receives its gas from areas of Alberta and British Columbia (PIA areas 13, 15, 14, 16, and 34) where 20 percent of the 2005 drilling took place with an average initial production rate of 715 mmcf/day.
- The Western Plains area of Alberta contains approximately 37 percent[12] of the total yet-to-be-established reserves for Alberta. The Alliance receipt areas access the north half of this area which, from a geological point of view, may be more prolific.

[12] EUB, ST98-2006, Alberta’s Energy Reserves 2005 and Supply/Demand Outlook, 2006.

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