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December 14, 2012

All Customers
Other Interested Parties

Re: 2012 Annual Plan

NOVA Gas Transmission Ltd ("NGTL") has posted its 2012 Annual Plan on TransCanada Pipelines Limited's website at:

http://www.transcanada.com/customerexpress/5193.html

Customers and other interested parties are encouraged to communicate their suggestions and comments to NGTL regarding the development and operation of the Alberta System and other related issues to me at (403) 920-5903.

Yours truly,
NOVA Gas Transmission Ltd.
a wholly owned subsidiary of TransCanada Pipelines Limited

Gord Toews
Director, System Design
System Design and Commercial Operations

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EXECUTIVE SUMMARY

The 2012 Annual Plan provides NOVA Gas Transmission Ltd.'s (NGTL's) Customers and other interested parties an overview of potential Alberta System facilities that are expected to be applied for in the 2013 calendar year. The Plan describes NGTL's long-term outlook for receipts, deliveries, peak expected flows, design flow requirements and proposed facilities for the 2013/14 and 2014/15 Gas Years. This Annual Plan is based on NGTL's July 2012 Design Forecast of receipts and deliveries.

Since the release of the 2011Annual Plan, TransCanada PipeLines Limited (TransCanada) has identified 28 Alberta System facility additions. NGTL's Tolls, Tariff, Facility and Procedures (TTFP) Committee has been notified of these facilities, and they are summarized in Appendix 2 – Facility Status Update. These projects have in-service dates between December 2012 and April 2015 and were initiated prior to the issuance of this Annual Plan to accommodate the lead time required to meet the on-stream requirements.

TransCanada follows facility planning processes to identify facilities required for the integrated Alberta System including both NGTL's and ATCO's Footprints. An overview of these processes is contained in the Facilities Design Methodology Document. NGTL files facility applications with the National Energy Board (NEB) for facility additions on the Alberta System within the "NGTL Footprint." ATCO Pipelines (AP) files facility applications with the Alberta Utilities Commission (AUC) for facility additions on the Alberta System within the ATCO Footprint.

The facilities identified in this Annual Plan were presented to the TTFP Committee on November 20, 2012. New facilities proposed after the issuance of this Annual Plan will be shown in the 2013 Facility Status Update, which can be accessed at http://www.transcanada.com/customerexpress/5194.html.

Eight facilities have been identified in the 2012 Annual Plan for the 2013/14 and 2014/15 Gas Years, as shown in Table E-1.

Table E-1: Proposed Facilities

Project Area	Proposed Facilities	Annual Plan Reference	Description	Target In-Service Date	Regulator	Capital Cost ($ Millions)
North and East	Leming Lake Sales Lateral Loop	Chapter 2	37 km NPS 20	Apr 2014	NEB	61.7
North and East	Moosa Crossover	Chapter 2	5 km NPS 20	Apr 2014	NEB	10.6
North and East	Saddle Lake Lateral Loop	Chapter 3	12 km NPS 16	Apr 2014	NEB	19.7
North and East	Denning Lake Compressor Station	Chapter 2	Relocation of 3.5 MW unit from Alces Compressor Station	Nov 2014	NEB	36.2
North and East	Sunday Creek South Lateral Loop No. 3	Chapter 3	13 km NPS 24	Apr 2014	NEB	31.0
Mainline	Medicine Hat Area Looping Foothills Control Valve at Empress	Chapter 2	27 km NPS 20 Tie-in / Control Valve	Nov 2014	NEB	38.0 4.0
AP	Shepard Energy Centre Extension	Chapter 2	14 km NPS 20, associated Delivery Station and associated system modifications	Jul 2014	AUC	59.5
					Total	**260.7**
Capital Costs are in 2012 dollars and include AFUDC						

The Leming Lake Sales Lateral Loop, Moosa Crossover, and Denning Lake Compressor Station projects are proposed to transport additional supply into the growing northeast Alberta demand as a result of increased Steam Assisted Gravity Drainage (SAGD) oil recovery operations.

The Saddle Lake Lateral Loop is required to provide additional capacity for incremental contracts at Kent Sales as well as increased export delivery requirements into Saskatchewan.

The Sunday Creek South Lateral Loop No.3 is required to deliver incremental gas to the Jackfish and Sunday Creek South Sales stations serving expanding SAGD projects in the area.

The Medicine Hat Area Looping and Foothills Control Valve at Empress Project are proposed to transport additional supply into the Medicine Hat area in order to overcome supply decreases, as well as, increased industrial and residential demand.

The Shepard Energy Centre project is proposed to transport additional supply into the Calgary area and to provide delivery to a gas-fired power plant currently under construction in South East Calgary.

This 2012 Annual Plan includes the following sections:

- Executive Summary;
- Chapter 1 – Design Forecast;
- Chapter 2 – Design Flow and Mainline Facilities;
- Chapter 3 – Extensions, Lateral Loops and Meter Stations;
- Appendix 1 – Glossary of Terms;
- Appendix 2 – Facility Status Update; and
- Appendix 3 – System Map (available in February 2013).

An electronic version of the Annual Plan and the Facilities Design Methodology Document can be accessed at TransCanada's website, located at:

http://www.transcanada.com/customerexpress/871.html

Customers and other interested parties are encouraged to communicate their suggestions, comments and questions to NGTL regarding this Annual Plan and other related issues. Please provide your comments to:

- Landen Stein, Manager, Customer Solutions (403) 920-5311;
- Karen Hill, Manager, Receipt and Delivery Forecasting (403) 920-5622;
- Gord Toews, Director, System Design (403) 920-5903; or
- Steve Emond, Vice President, System Design and Commercial Operations (403) 920-5979.

1.1 INTRODUCTION

This Annual Plan is based on the July 2012 Design Forecast of receipts and deliveries for the Alberta System. An overview of the July 2012 Design Forecast was presented at the November 20, 2012 TTFP meeting.

Information on forecasting methodology can be found in the Facilities Design Methodology Document Section 4.4 – Design Forecast Methodology which can be accessed online at:

http://www.transcanada.com/customerexpress/871.html

In this section, NGTL describes the:

- economic assumptions used in developing the 2012 Design Forecast;
- receipts and deliveries for the Alberta System; and
- supply contribution, including winter withdrawal, from Storage Facilities used in the design process.

1.2 ECONOMIC ASSUMPTIONS

1.2.1 General Assumptions

The following assumptions, developed in the TransCanada Strategic Outlook (TSO) January 2012, reflect broader trends in the North American economy and energy markets, and underlie the forecast of receipts and deliveries:

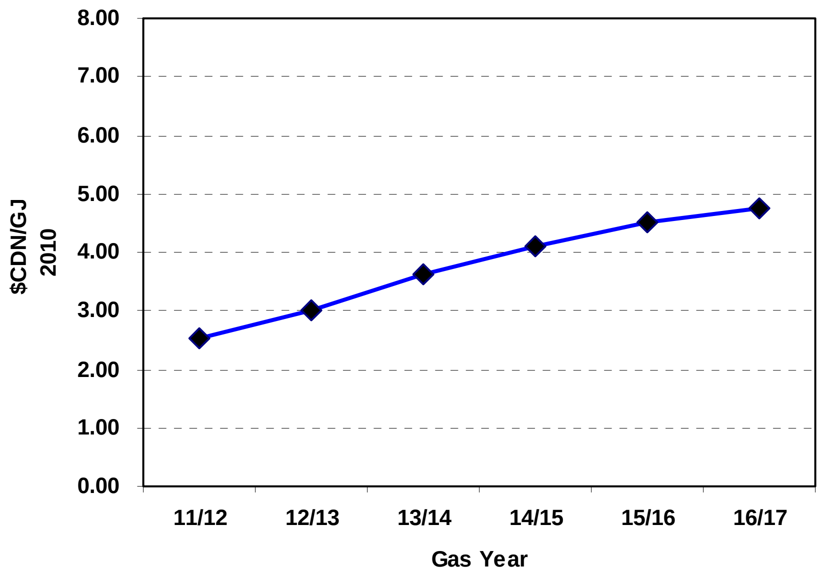
- North American natural gas demand will gradually increase to over 2.5 bcf/d by 2015 as the U.S. and Canadian economies recover. In the longer term, gas demand is expected to increase with continued economic and population growth in both the U.S. and Canada. U.S. gas demand growth is predominantly associated with gas-fired electricity generation. Canadian industrial gas demand is expected to increase by 1 bcf/d by 2020, driven primarily by the gas needs of the oil sands sector in Alberta.

- The North American market will be well supplied with domestic natural gas because of the strength in unconventional gas production, primarily shale gas. This strong supply growth is now expected to rise faster than the growth in gas demand, reducing the volume of imported liquefied natural gas (LNG) to minimum levels and fostering LNG exports from both the US and Canada beginning just after the middle of this decade.
- Because of weakness in natural gas demand from the slower pace of economic recovery and to the rapid expansion of shale gas supplies, short-term gas prices have been soft. NYMEX natural gas prices are forecast to recover over the next several years as the economy and gas demand improve. Higher prices will allow additional volumes of conventional gas to be produced, in conjunction with unconventional shale gas to meet market demands. The NYMEX gas price forecast rises from today's level towards an equilibrium price of $US 5.75/MMBtu in real 2010 $US.
- Currently, low gas prices are putting pressure on producers to be efficient and cost-effective. Recent drilling successes in many shale and tight gas plays have led to more fracture stages, higher initial production rates, and increases in the estimated ultimate recovery (EUR) per well, resulting in a lower cost per well for producers. These improvements have led to additional shale and tight gas resources being economic to produce in a low gas price environment, edging out higher cost conventional supply. However, even with strong growth in shale and tight gas production, there continues to be a need for a significant proportion of supply from conventional resources to meet North American gas demand requirements

1.2.2 Alberta Average Field Price

TransCanada's NYMEX gas price forecast was used to develop the Alberta Average Field Price (Alberta Reference Price), which represents the estimated price of natural gas at a point just prior to receipt onto the Alberta System. The gas price forecast, shown in Figure 1-1, was developed in January 2012 and reflects the general assumptions from Section 1.2.1.

Figure 1-1: NGTL Gas Price Forecast, Alberta Average Field Price



After reaching a low point of $2.52 Cdn/GJ in real 2010 $ in 2012, the Alberta Average Field Price is forecast to rebound over the next five years, reaching $4.76 Cdn/GJ in terms of real 2010 $ by 2017. The long term equilibrium price of $5.47 Cdn/GJ real 2010 $ is reached by 2020.

The gas price forecast affects the receipt and delivery forecast, and is used as input into the economic analysis for new facilities. The level of the gas price affects anticipated producer activity to support continuing production from connected supplies, connection of unconnected reserves, and the discovery and development of new reserves.

1.3 GAS DELIVERY FORECAST

Deliveries to markets within Alberta are forecast to rise, primarily due to industrial demand in the Oil Sands region. Gas demand from Oil Sands related projects is influenced by factors such as the amount of oil produced, the price of oil and gas, the process used to produce oil, and the technological improvements employed over time. At major Export Points, contract demand and throughput have declined over the past few years, as a result of changing market conditions and the ability of downstream markets to access alternative supply sources.

Several sources of information were considered in developing the gas delivery forecast. First, operators of downstream facilities such as connecting pipelines, local distribution companies (LDCs) and industrial plants were requested to provide a forecast of their maximum, average, and minimum requirements for deliveries from the Alberta System over the next ten years. The forecasts were analyzed and compared to historical flow patterns at Alberta Delivery Points. In cases where NGTL's analysis differed substantially from the operator's forecast, NGTL contacted the operator and either the operator's forecast was revised or NGTL adjusted its analysis. In cases where the operator did not provide a forecast, NGTL based its forecast on historical flows and growth rates for specific demand sectors.

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1.3.1 Average Annual Delivery Forecast

Forecast deliveries are expressed as an average daily flow. The Average Annual Delivery Forecast is the aggregate forecast deliveries for the Alberta System. The

Average Annual Delivery Forecast, for Gas Years 2012/13 through 2016/17 are listed by Delivery Point in Table 1-1 and further detailed by Project Area in Table 1-2.

Table 1-1: System Average Annual Delivery Forecast by Delivery Point

Delivery Point	July 2012 Design Forecast ($10^6 m^3/d$)				
	2012/13	2013/14	2014/15	2015/16	2016/17
Empress	76.7	83.0	91.6	102.8	111.1
McNeill	48.3	47.2	49.1	53.0	55.8
Alberta/B.C.	47.5	48.2	48.9	49.1	51.4
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Gordondale	0.0	0.0	0.0	0.0	0.0
Intra Alberta	122.5	128.3	134.7	140.8	145.6
Total System	**295.0**	**306.7**	**324.3**	**345.6**	**364.0**
Delivery Point	**July 2012 Design Forecast (Bcf/d)**				
	2012/13	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Empress	2.71	2.93	3.24	3.63	3.92
McNeill	1.71	1.67	1.73	1.87	1.97
Alberta/B.C.	1.68	1.70	1.73	1.73	1.81
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Gordondale	0.0	0.0	0.0	0.0	0.0
Intra Alberta	4.32	4.53	4.76	4.97	5.14
Total System	**10.41**	**10.83**	**11.45**	**12.20**	**12.85**

Note**:** Numbers may not add due to rounding.

Volumes expressed as an average daily flow for each gas year, at 101.325 kPa and 15°C.

Table 1-2: Alberta Deliveries – Average Annual Delivery Forecast by Project Area

Project Area	July 2012 Design Forecast ($10^6 m^3/d$)				
	2012/13	2013/14	2014/15	2015/16	2016/17
Peace River	2.5	2.6	2.7	2.9	3.0
North and East	83.2	88.9	93.7	97.9	102.3
Mainline	34.8	34.9	36.3	37.9	38.3
Gas Taps	2.0	2.0	2.0	2.1	2.1
Total Alberta	**122.5**	**128.3**	**134.7**	**140.8**	**145.6**
Project Area	**July 2012 Design Forecast (Bcf/d)**				
	2012/13	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Peace River	0.09	0.09	0.10	0.10	0.11
North and East	2.94	3.14	3.31	3.46	3.61
Mainline	1.23	1.23	1.28	1.34	1.35
Gas Taps	0.07	0.07	0.07	0.07	0.07
Total Alberta	**4.32**	**4.53**	**4.76**	**4.97**	**5.14**

Note: Numbers may not add due to rounding.
Volumes expressed as an average daily flow for each gas year.
Gas taps are located in all areas of the province.

1.3.2 Maximum Day Delivery Forecast

Peak deliveries (Maximum Day Delivery) are also forecast for the Alberta Delivery Points and are based on customer input, market conditions, firm transportation contracts and historical flows.

A summary of the July 2012 Design Forecast winter and summer Maximum Day Delivery by Project Area for Alberta Deliveries is provided in Table 1-3 for winter and Table 1-4 for summer.

Table 1-3: Winter Maximum Day Delivery Forecast

Project Area	July 2012 Design Forecast ($10^6m^3/d$)				
	2012/13	2013/14	2014/15	2015/16	2016/17
Peace River	8.3	8.4	8.6	8.8	9.0
North and East	133.5	142.4	150.9	156.9	166.5
Mainline	77.3	78.0	82.2	82.9	83.9
Gas Taps	4.0	4.0	4.1	4.1	4.1
Total Alberta	**223.1**	**232.8**	**245.8**	**252.8**	**263.6**
Project Area	**July 2012 Design Forecast (Bcf/d)**				
	2012/13	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Peace River	0.29	0.30	0.30	0.31	0.32
North and East	4.71	5.03	5.33	5.54	5.88
Mainline	2.73	2.75	2.90	2.93	2.96
Gas Taps	0.14	0.14	0.14	0.14	0.15
Total Alberta	**7.88**	**8.22**	**8.68**	**8.93**	**9.30**

Note: Numbers may not add due to rounding.

Gas taps are located in all areas of the province.

Table 1-4: Summer Maximum Day Delivery Forecast

Project Area	July 2012 Design Forecast ($10^6m^3/d$)				
	2012/13	2013/14	2014/15	2015/16	2016/17
Peace River	6.0	6.1	6.2	6.4	6.5
North and East	110.2	118.1	125.4	131.1	138.3
Mainline	55.0	59.6	59.8	60.2	60.9
Gas Taps	2.4	2.4	2.4	2.5	2.5
Total Alberta	**173.6**	**186.2**	**193.8**	**200.2**	**208.2**
Project Area	**July 2012 Design Forecast (Bcf/d)**				
	2012/13	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Peace River	0.21	0.21	0.22	0.23	0.23
North and East	3.89	4.17	4.43	4.63	4.88
Mainline	1.94	2.11	2.11	2.13	2.15
Gas Taps	0.08	0.09	0.09	0.09	0.09
Total Alberta	**6.13**	**6.57**	**6.84**	**7.07**	**7.35**

Note: Numbers may not add due to rounding.

Gas taps are located in all areas of the province.

1.4 RECEIPT FORECAST

NGTL develops its Receipt Forecast on an average annual basis that is based on two general approaches:

- For conventional production, NGTL typically uses an internal pool-based forecasting model that incorporates established reserve estimates and actual production records from government sources. For discovered resources, the model uses current production rates and reservoir modeling, supplemented by internal analysis to estimate future production. In order to estimate the future supply from undiscovered resources, NGTL bases its assessment on play and pool-based resource estimates.
- For unconventional resources such as shale gas, NGTL typically uses well-based forecasting methods and models, supplemented with information gathered from customers, to generate forecasts of future production. Factors such as the total number of drilling locations available, well production profiles, and pace of development are considered along with material and equipment availability, potential capital requirements, and access constraints when developing a forecast of supply.

Exploration activity focused on unconventional gas has resulted in an expectation of 2 bcf/d of incremental volumes of shale and tight gas entering the Alberta System in the Peace River Project Area by the 2016/17 Gas Year. Incremental shale and tight gas supply is expected to more than offset declines in production from connected established reserves, resulting in an increase in overall production levels in the WCSB over the next five years.

Three sources of gas supply used for the July 2012 Design Forecast are:

- Connected and Unconnected Reserves – supply from established conventional and unconventional reserves upstream of Receipt Points;
- Reserve Additions – supply from undiscovered resources, including conventional and unconventional resources; and
- Interconnections – supply from interconnections with other pipeline systems.

Gas supplied from storage facilities has not been included in the data presented in this section. Information pertaining to gas supply from Commercial Storage Facilities is contained in Section 1.6.

1.4.1 Average Receipt Forecast

The Average Receipt Forecast is the forecast aggregate receipts for the Alberta System for the 2012/13 through 2016/17 Gas Years. A summary of System Average Receipts by Gas Year and Project Area is expressed as an average daily flow and shown in Table 1-5.

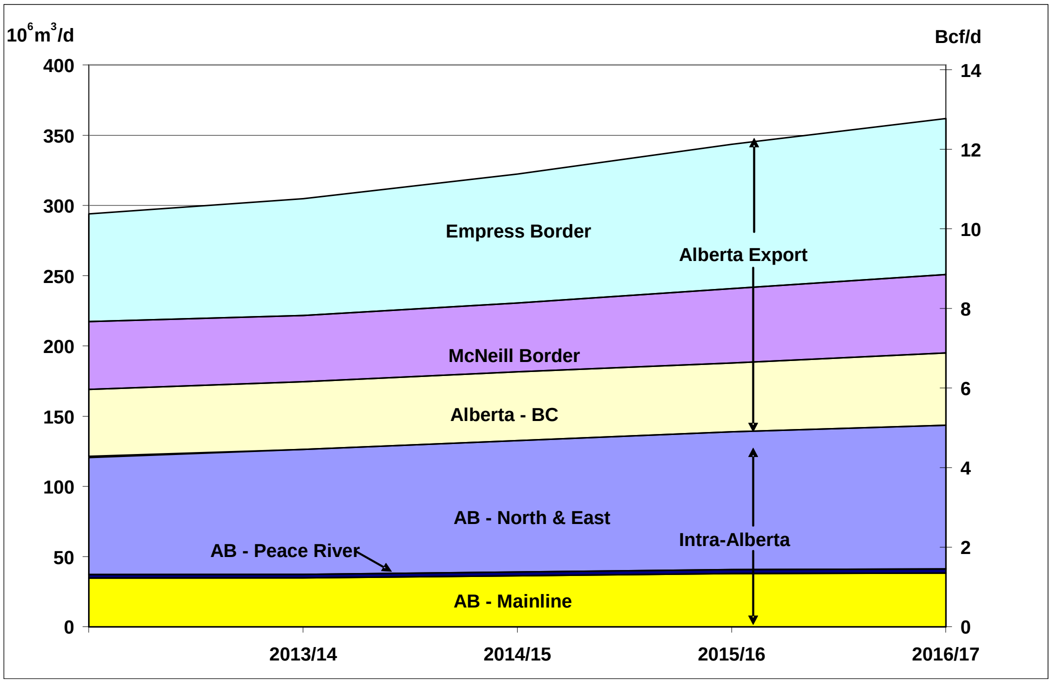
Table 1-5: System Average Receipts

Project Area	July 2012 Design Forecast ($10^6m^3/d$)				
	2012/13	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Peace River	146.1	155.5	167.7	183.0	200.1
North and East	26.9	26.5	25.7	27.7	29.7
Mainline	115.4	118.4	125.2	129.1	131.8
Total System	288.4	300.5	318.6	339.8	361.6
Project Area	**July 2012 Design Forecast (Bcf/d)**				
	2012/13	**2013/14**	**2014/15**	**2015/16**	**2016/17**
Peace River	5.16	5.49	5.92	6.46	7.07
North and East	0.95	0.94	0.91	0.98	1.05
Mainline	4.07	4.18	4.42	4.56	4.65
Total System	10.18	10.61	11.25	12.00	12.76
Note**:** Numbers may not add due to rounding.					

1.5 SUPPLY DEMAND BALANCE

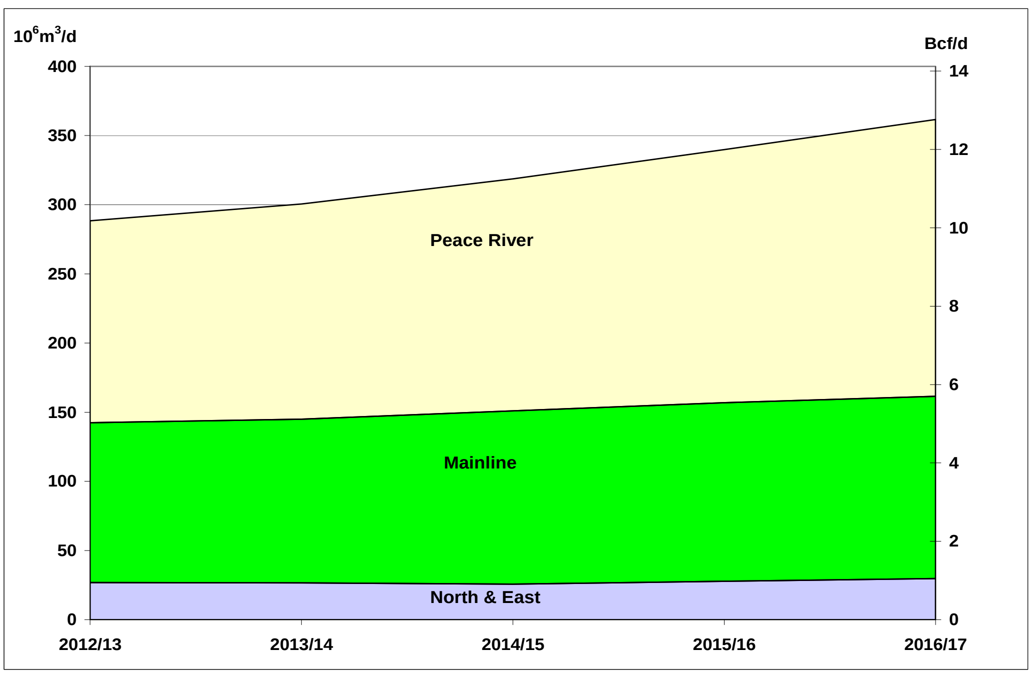
Supply received on to the Alberta System is balanced with System deliveries (net of gas in storage). System deliveries by destination are shown in Figure 1-2, while System receipts by Project Area are shown in Figure 1-3.

Figure 1-2: System Deliveries by Destination



Note: Gas taps are located in all areas of the province and included in Intra-Alberta

Figure 1-3: System Receipts by Project Area



1.6 STORAGE FACILITIES

1.6.1 Commercial Storage

There are eight commercial storage facilities connected to the Alberta System (AECO ‘C’, Big Eddy, Carbon, Chancellor, Crossfield East #2, January Creek, Severn Creek and Warwick Southeast Meter Stations). The total deliverability from Storage Facilities is significant, but actual maximum day receipts from storage are dependent upon a number of factors, including market conditions, the level of working gas in each storage facility, compression power at each storage facility, and Alberta System operations.

For design purposes, a supply contribution from Storage Facilities is used to meet peak day winter delivery requirements and provide for a better correlation between forecast design flow requirements and historical actual flows for the winter period. Historical withdrawals during recent winter periods at AECO ‘C’, Carbon, Crossfield East, Chancellor and Severn Creek were used to determine a reasonable expected rate of withdrawal for future winter seasons. The level of commercial storage withdrawal used in the design of the Alberta System for the winter season was 17.7 10^6m^3/d (630 MMcf/d), which is similar to the average winter withdrawal rate from these facilities.

The receipt meter capacity for each of the connected Commercial Storage Facilities is shown in Table 1-6.

Table 1-6: Receipt Meter Capacity from Commercial Storage Facilities

Storage Facility	Receipt Meter Capacity from Commercial Storage Facilities – 2012/13	
	$10^6m^3/d$	Bcf/d
AECO C	50.7	1.79
Big Eddy	35.4	1.25
Carbon	13.8	0.49
Chancellor	35.2	1.24
Crossfield East #2	14.1	0.50
January Creek	14.1	0.50
Rat Creek West	4.3	0.15
Severn Creek	5.6	0.20
Warwick Southeast	6.1	0.22
Total	**179.3**	**6.34**

Note:
Storage is currently considered as an interruptible supply source.
Numbers may not add due to rounding.

1.6.2 Peak Shaving Storage

The Fort Saskatchewan Salt Caverns comprise a peak shaving storage facility in the Greater Edmonton Area within the North of Bens Lake Design Area of the Alberta System. Similar to Commercial Storage Facilities, the total deliverability from the peak shaving Storage Facility is significant, but the actual maximum day receipt from storage is dependent upon a number of factors, including market conditions, the level of working gas, compression power at the storage facility, and Alberta System operations.

For design purposes, a maximum withdrawal rate of 6,500 $10^3m^3/d$ was used to meet the peak expected winter season delivery requirements.

2.1 INTRODUCTION

This section presents the proposed natural gas transportation mainline facilities to be applied for on the Alberta System in the 2013 calendar year to transport the design flow requirements. Included is information regarding size, routes, locations and cost estimates for the proposed facilities.

The design flow requirements are peak expected flows for each design area where new mainline facilities are required. Peak expected flows are based on the July 2012 design forecast presented in Section 1, and were determined using the methodology described in the Facilities Design Methodology Document, Section 3.5 – Mainline Facilities Flow Determination. This document can be accessed online at: http://www.transcanada.com/customerexpress/871.html

This section shows a comparison of historical flows for the 2007/08 Gas Year through to the 2011/12 Gas Year as well as the projected winter and summer peak expected flows to the 2016/17 Gas Year. Additionally, the current design capability is shown for the Gas Year when facilities are required within each applicable design area. Where there is a shortfall between peak expected flow and the existing design capability, a facility solution has been proposed. A facility application to the regulator for construction and operation is triggered by Firm Transportation (FT) contracts in excess of design capability and submitted to ensure the facility is in place in time to meet the FT requirements. Aggregated FT contract levels are also presented to indicate commercial underpinning of the proposed facilities.

A summary of the status of mainline facilities that have been applied for or placed in-service since the December 2011 Annual Plan is included in Appendix 2 – Facility Status Update.

2.2 NORTH AND EAST PROJECT AREA

The North and East Project Area (Figure 2-1) is comprised of the North of Bens Lake and South of Bens Lake Design Areas.

In the North and East Project Area, the proposed facilities are required to meet the gas deliveries in the North of Bens Lake Design Area, specifically in the Kirby and Cold Lake areas. Additional information on design flow conditions can be found in the Facility Design Methodology Document Section 3.5 – Mainline Facilities Flow Determination.

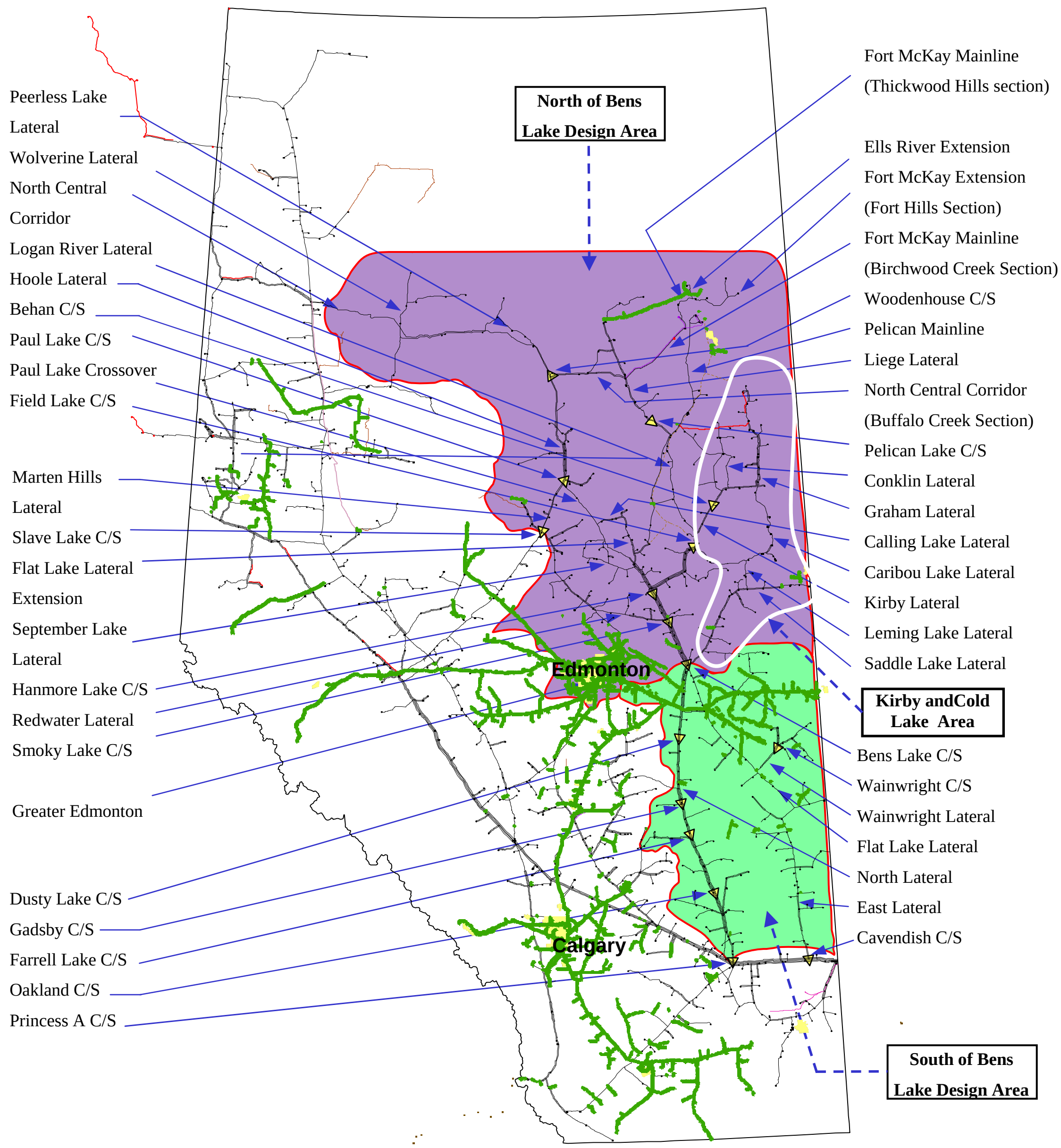

Peerless Lake Lateral
Wolverine Lateral
North Central Corridor
Logan River Lateral
Hoole Lateral
Behan C/S
Paul Lake C/S
Paul Lake Crossover
Field Lake C/S
Marten Hills Lateral
Slave Lake C/S
Flat Lake Lateral Extension
September Lake Lateral
Hanmore Lake C/S
Redwater Lateral
Smoky Lake C/S
Greater Edmonton
Dusty Lake C/S
Gadsby C/S
Farrell Lake C/S
Oakland C/S
Princess A C/S
North of Bens Lake Design Area
Fort McKay Mainline (Thickwood Hills section)
Ells River Extension
Fort McKay Extension (Fort Hills Section)
Fort McKay Mainline (Birchwood Creek Section)
Woodenhouse C/S
Pelican Mainline
Liege Lateral
North Central Corridor (Buffalo Creek Section)
Pelican Lake C/S
Conklin Lateral
Graham Lateral
Calling Lake Lateral
Caribou Lake Lateral
Kirby Lateral
Leming Lake Lateral
Saddle Lake Lateral
Kirby andCold Lake Area
Bens Lake C/S
Wainwright C/S
Wainwright Lateral
Flat Lake Lateral
North Lateral
East Lateral
Cavendish C/S
Edmonton
Calgary
South of Bens Lake Design Area

Figure 2-1: North and East Project Area

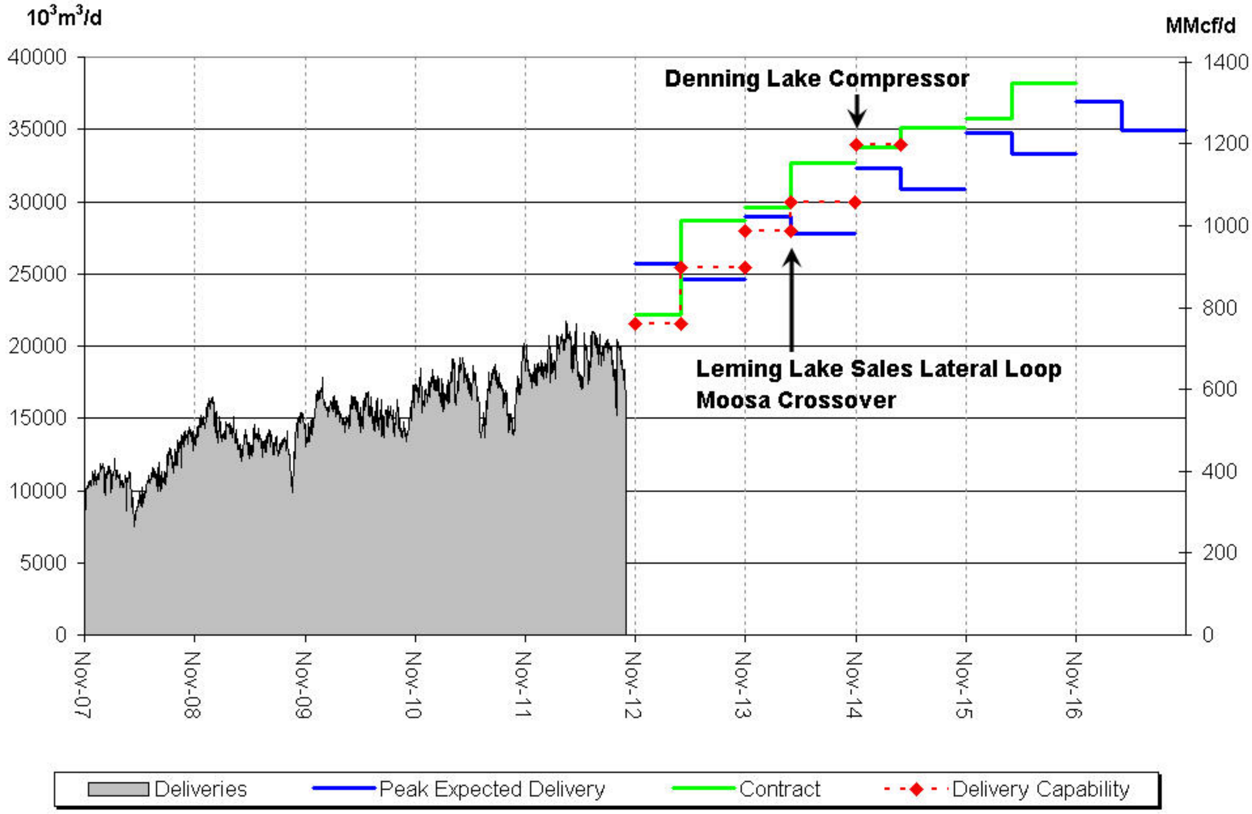
2.2.1 North of Bens Lake Design Area

2.2.1.1 Design Flows – Kirby and Cold Lake Area

Since deliveries in the North of Bens Lake Design Area are over twice the level of the area supply, the prevailing design condition for the North of Bens Lake Design Area is the flow within condition. The peak expected flow for the flow within design condition is equal to the maximum deliveries less the minimum available local supply within the area. Continued delivery growth, specifically in the Kirby and Cold Lake areas, will be accommodated by three proposed facilities.

Figure 2-2 provides historical actual deliveries, the projected peak delivery, the contract levels, and the delivery capability for the Kirby and Cold Lake areas. The peak expected flow is anticipated to rise throughout this forecast period.

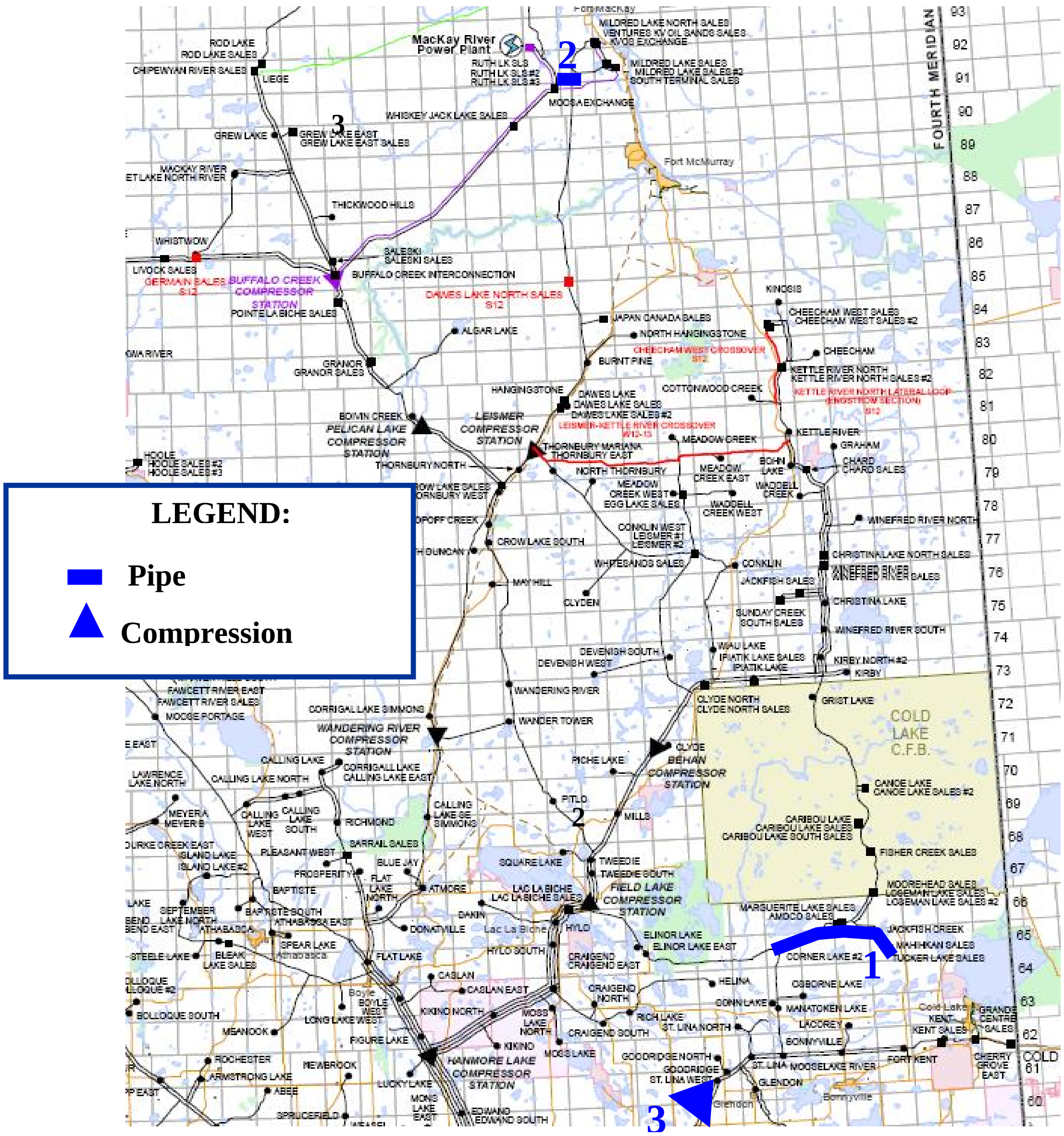
Figure 2-2: Deliveries / Peak Expected Deliveries / Contracts / Delivery Capability for the Kirby and Cold Lake Areas



2.2.1.2 Proposed Facilities – Kirby and Cold Lake Area

Figure 2-3 shows the locations of the proposed facilities required to meet the design flow requirements in the Kirby and Cold Lake areas.

Figure 2-3: Location of Proposed Facilities in Kirby and Cold Lake Areas



The three proposed facilities will be applied for in 2013 and are proposed to be in-service in 2014. Details on each of the proposed facilities are contained in Table 2-1.

Table 2-1: Kirby and Cold Lake Area Proposed Facilities

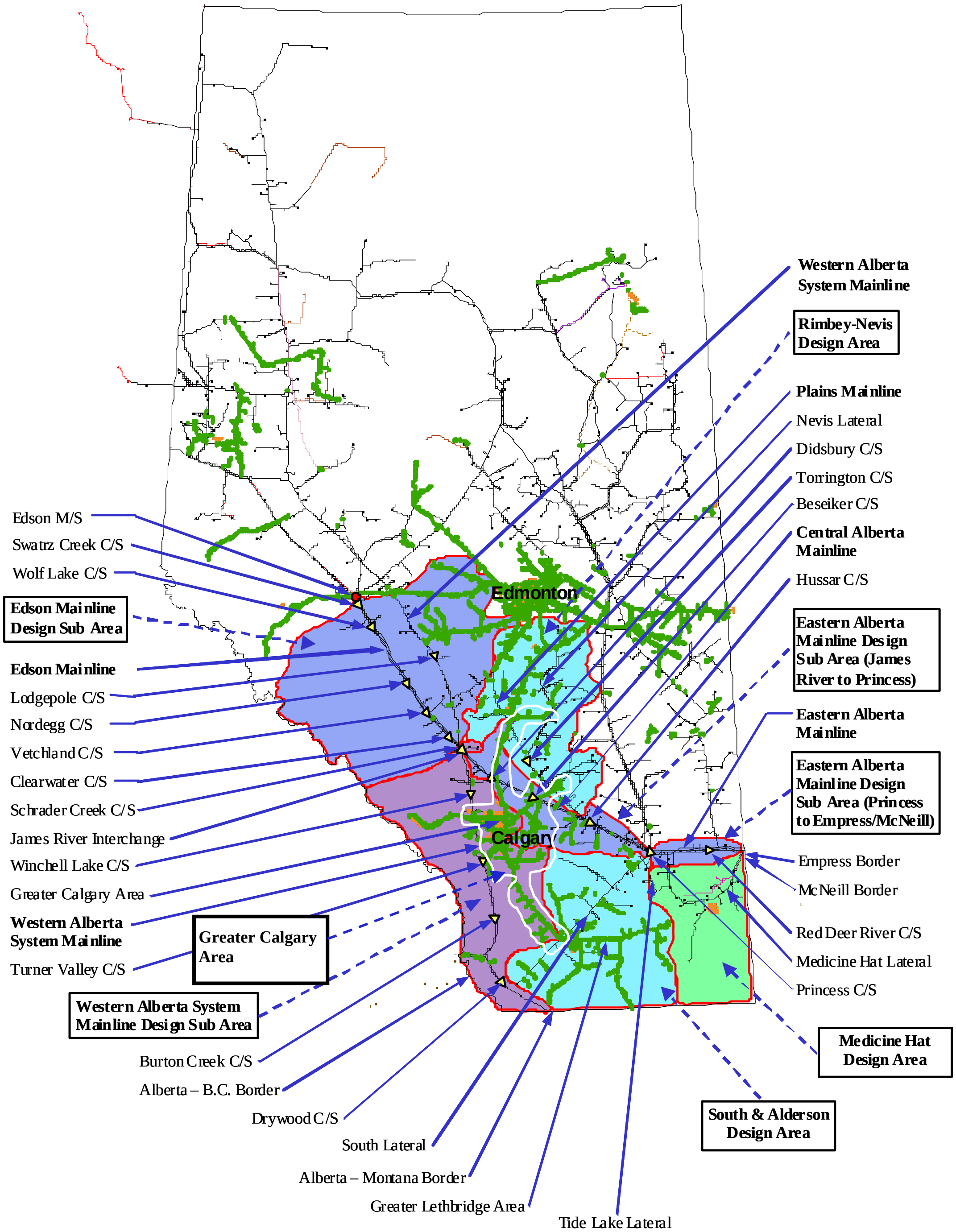
Map Location	Proposed Facility	Description	Target In-Service Date	Capital Cost ($Millions)
1	Leming Lake Sales Lateral Loop	37 km NPS 20	Apr 2014	61.7
2	Moosa Crossover	5 km NPS 20	Apr 2014	10.6
3	Denning Lake Compressor Station	Relocation of 3.5 MW unit from Alces Compressor Station	Nov 2014	36.2
Capital Costs are in 2012 dollars and include AFUDC.			**Total**	**108.5**

2.3 MAINLINE PROJECT AREA

The Mainline Project Area comprises the Mainline, Rimbey-Nevis, South and Alderson, and Medicine Hat Design Areas (see Figure 2-4).

In the Mainline Project Area, the proposed facilities are required to meet the gas deliveries in the Medicine Hat Design Area and the Greater Calgary Area. Additional information on design flow conditions can be found in the Facility Design Methodology Document Section 3.5 – Mainline Facilities Flow Determination.

Figure 2-4: Mainline Project Area



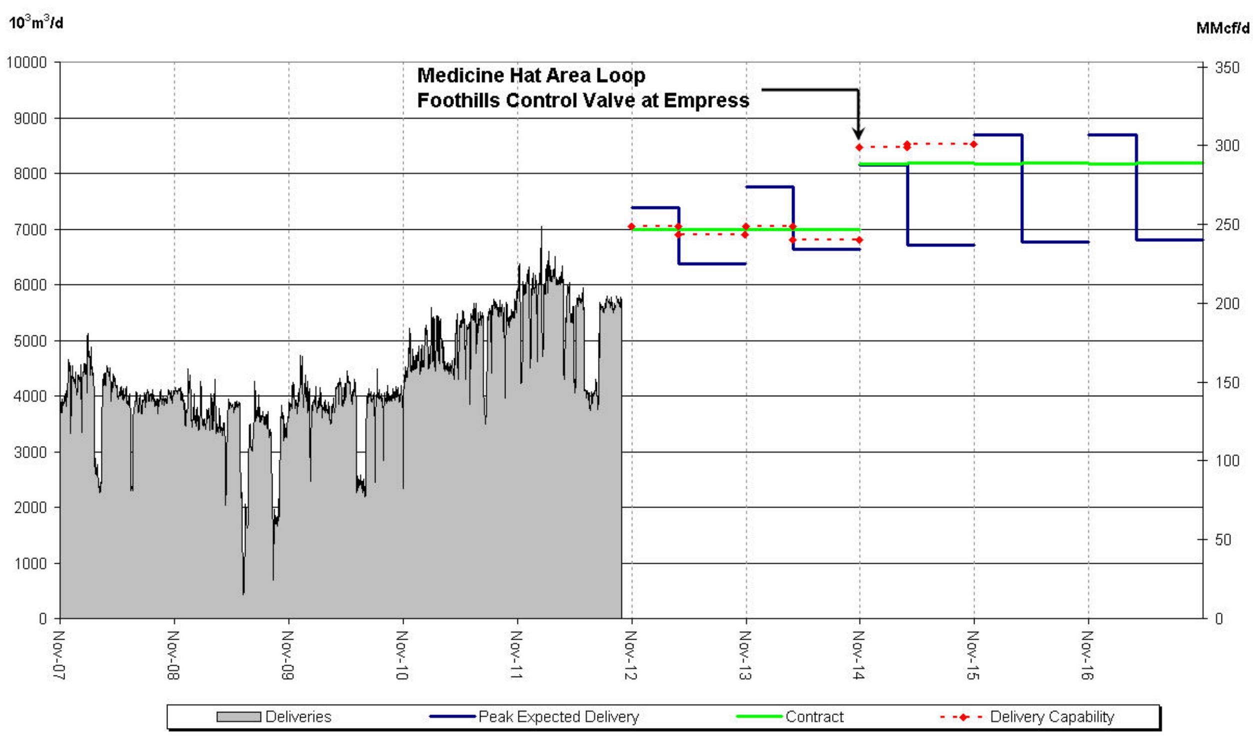
2.3.1 Medicine Hat Design Area

2.3.1.1 Design Flows – Medicine Hat Design Area

Demand growth in the Medicine Hat Design Area has caused area demands to exceed area supply. Consequently, the prevailing design condition for the Medicine Hat Area is the flow within condition. The peak expected flow for the flow within design condition is equal to the maximum deliveries less the minimum available local supply within the area. Continued delivery growth in this area will be accommodated by the proposed facilities.

Figure 2-5 provides historical actual deliveries, the projected peak delivery, the contract levels, and the delivery capability for the Medicine Hat Design Area. The peak expected flow is anticipated to rise throughout this forecast period.

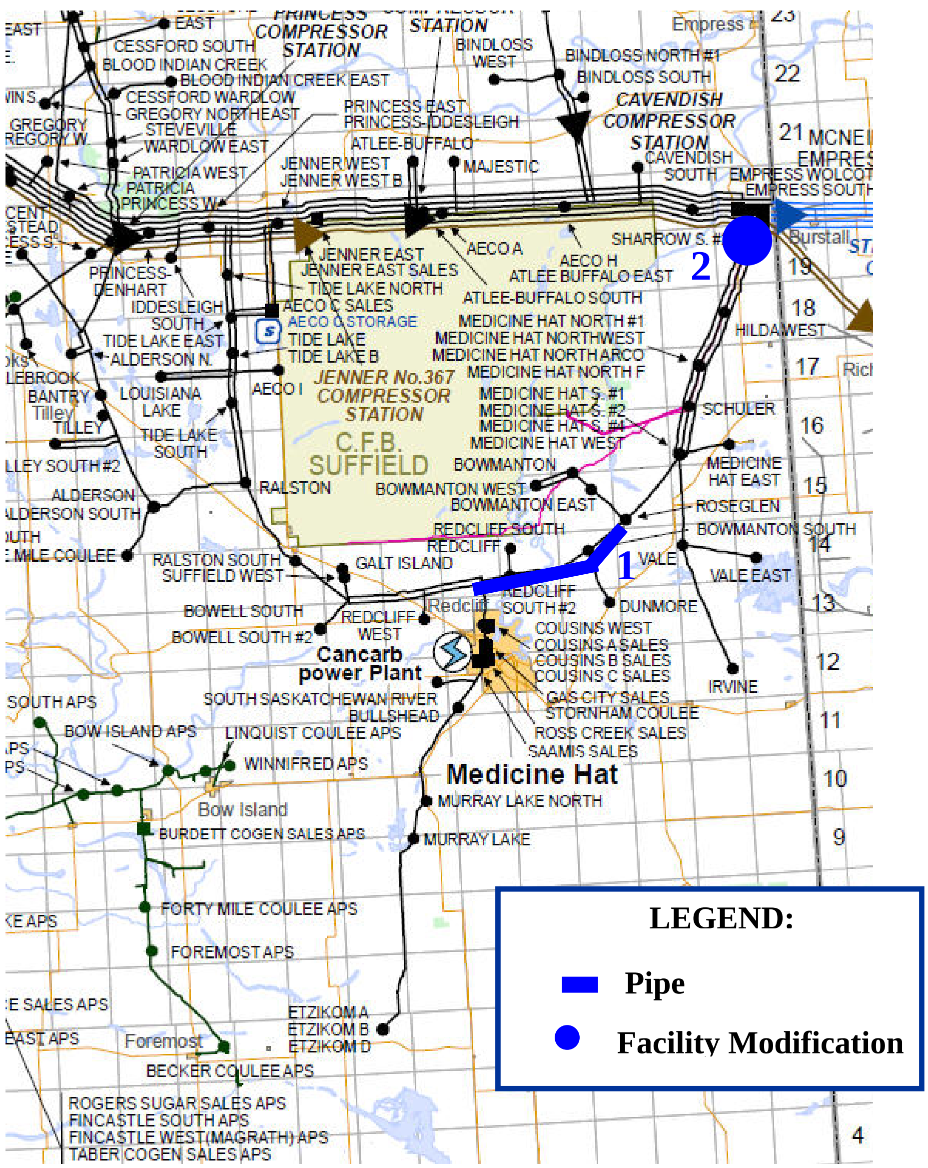
Figure 2-5: Deliveries / Peak Expected Deliveries / Contracts / Delivery Capability for the Medicine Hat Design Area



2.3.1.2 Proposed Facilities – Medicine Hat Design Area

Figure 2-6 shows the locations of the proposed facilities required to meet the design flow requirements in the Medicine Hat Design Area.

Figure 2-6: Location of Proposed Facilities in the Medicine Hat Design Area



The proposed facilities will be applied for in 2013 and are proposed to be in-service November 2014. Details on each of the proposed facilities are contained in Table 2-2.

Table 2-2: Medicine Hat Design Area Proposed Facilities

Map Location	Proposed Facility	Description	Target In-Service Date	Capital Cost ($Millions)
1	Medicine Hat Area Looping	27 km NPS 20	Nov 2014	38.0
2	Foothills Control Valve at Empress	Tie-in / Control Valve	Nov 2014	4.0
Capital Costs are in 2012 dollars and include AFUDC.			**Total**	**42.0**

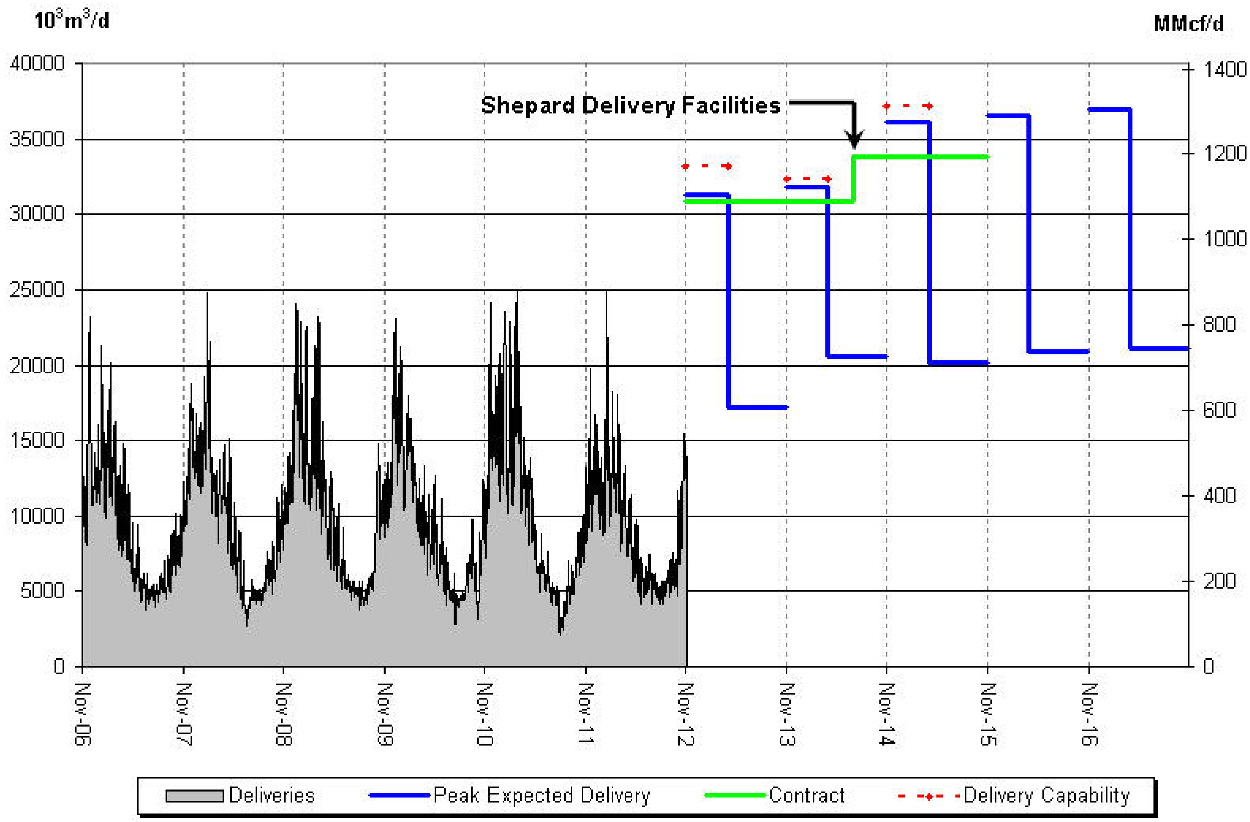
2.3.2 Western Alberta Mainline Design Sub Area

2.3.2.1 Design Flows – Greater Calgary Area (ATCO Pipelines Facilities)

Since winter season deliveries in the Greater Calgary Area are over twice the level of the area supply, the prevailing design condition for the Greater Calgary Area is the flow within condition. The peak expected flow for the flow within design condition is equal to the maximum deliveries less the minimum available local supply within the area. Continued delivery growth in the area, including a new natural gas fired power plant, will be accommodated by the proposed facilities.

Figure 2-7 provides historical actual deliveries, the projected peak delivery, the contract levels, and the delivery capability for the Greater Calgary Area. The peak expected flow is anticipated to rise throughout this forecast period.

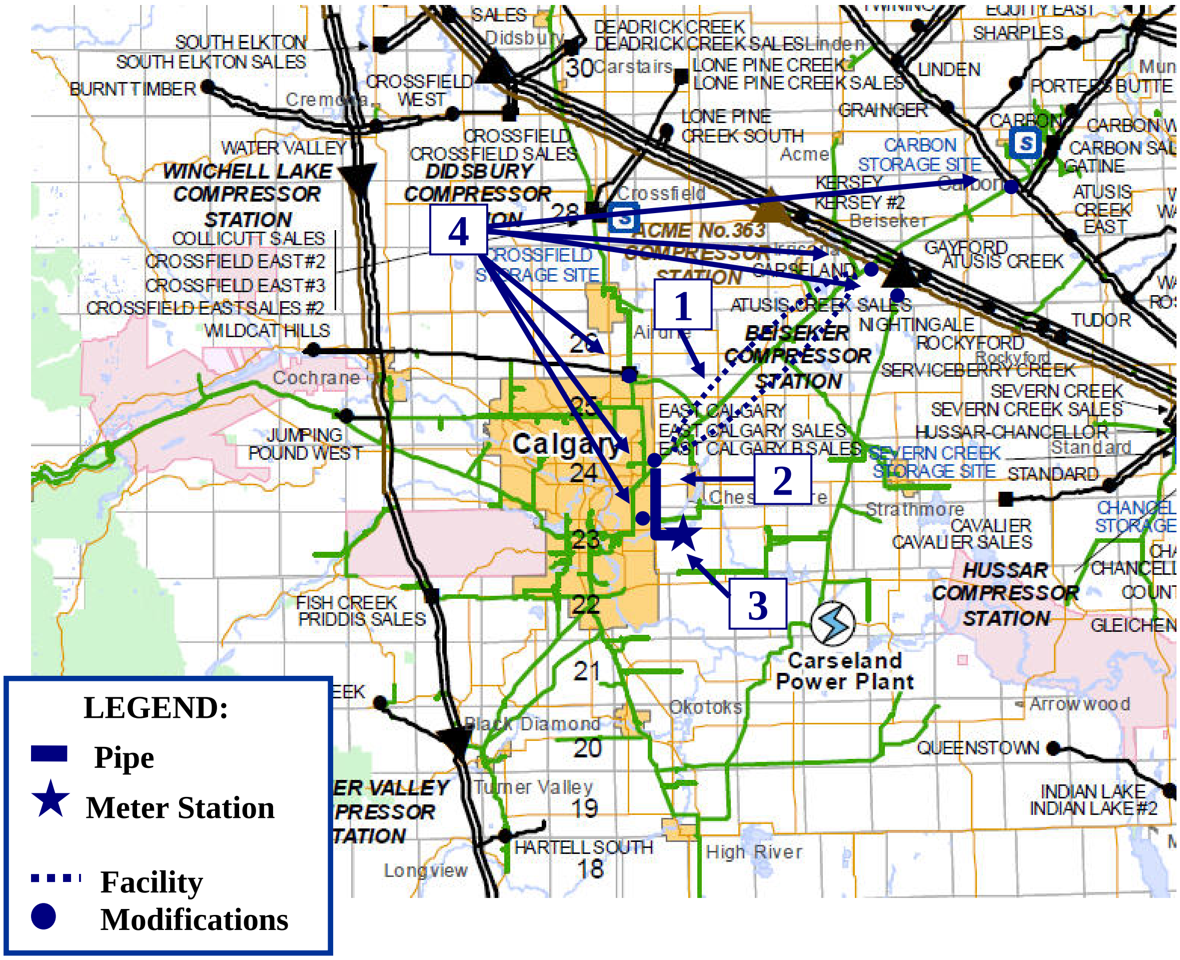
Figure 2-7: Deliveries / Peak Expected Deliveries / Contracts / Delivery Capability for the Greater Calgary Area



2.3.2.2 Proposed Facilities – Greater Calgary Area

Figure 2-8 shows the locations of the proposed facilities required to meet the design flow requirements in the Greater Calgary Area.

Figure 2-8: Location of Proposed Facilities in the Greater Calgary Area



These proposed facilities (referred to as the Shepard Energy Centre Extension) will be applied for by ATCO Pipelines to the Alberta Utilities Commission in 2013 and are proposed to be in-service July 2014. Details for each of the proposed facilities are contained in Table 2-3.

Table 2-3: Greater Calgary Area Proposed Facilities

Map Location	Proposed Facility	Description	Target In-Service Date	Capital Cost ($Millions)
1	Segregate Carbon Loop	Segregate Carbon Loop from Carbon Mainline	Jul 2014	0.5
2	Shepard Lateral	14 km NPS 20	Jul 2014	38
3	Shepard Delivery Station	Delivery station	Jul 2014	2
4	Additional Facility Modifications	Upgrades to increase area delivery capacity	Jul 2014	19
Capital Costs are in 2012 dollars and include AFUDC.			**Total**	**59.5**

3.1 SCOPE

This section presents an overview of the receipt and delivery meter stations, extension facilities and lateral loops that are required to meet customer requests for firm service.

New extensions, lateral loops and associated meter stations proposed after the 2012 Annual Plan is issued will be shown in the 2013 Facility Status Update. These facilities will be designed using the Transportation Design Process in Section 4 of the Facilities Design Methodology Document, which can be accessed online at:

http://www.transcanada.com/customerexpress/871.html

If mainline facilities are required, transportation service may be provided to Customers on an interruptible basis until the required mainline facilities are in service. If a Customer's request for service results in the addition of new or modified receipt meter stations the minimum term and minimum contractual obligation are determined in accordance with the economic criteria described in the *Criteria for Determining Primary Term* (Appendix E of the Alberta System Gas Transportation Tariff).

The proposed lateral loops are listed in Table 3.1 and shown on Figure 3.1. These proposed facilities were presented at the TTFP meeting held on November 20, 2012.

A summary of the status of the facilities that have been placed in-service or applied for since the issuance of the 2011 Annual Plan is included in Appendix 2 – Facility Status Update.

Figure 3.1
Proposed Lateral Loops

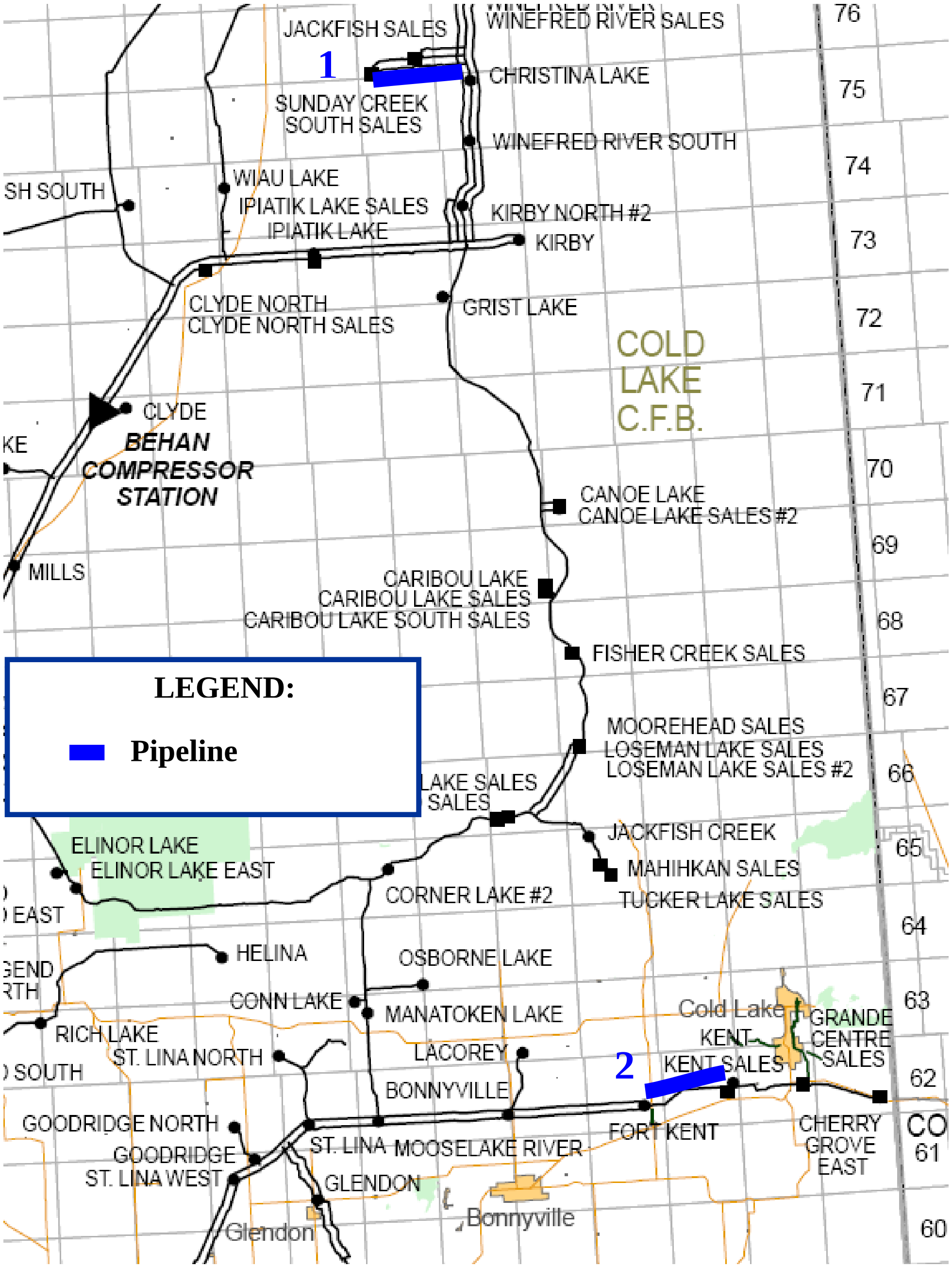


Table 3.1
Proposed Lateral Loops

Map Location	Proposed Facility	Description	Targeted In-Service Date	Capital Cost ($Millions)
1	Sunday Creek South Lateral Loop No. 3	13 km NPS 24	Apr 14	31.0
2	Saddle Lake Lateral Loop	12 km NPS 16	Apr 14	19.7
Capital Costs are in 2012 dollars and include AFUDC			**TOTAL**	**50.7**

3.2 FACILITY DESCRIPTION

Sunday Creek Lateral Loop No. 3

The 13 km NPS 24 Sunday Creek South Lateral Loop No. 3 is required to meet incremental delivery requirements to Jackfish Sales and Sunday Creek South Sales serving expanding SAGD projects in the area. The loop is required for November 1, 2014. Due to seasonal construction requirements it is targeted to be in-service April 1, 2014. The Section 58 facility application is planned to be filed with the NEB in March 2013.

Saddle Lake Lateral Loop

The 12 km NPS 16 loop of the Saddle Lake Lateral is required to provide additional capacity for incremental contracts at Kent Sales as well as increased export delivery requirements into Saskatchewan. The targeted in-service date is April 1, 2014. The NEB Section 58 application is expected to be filed in January 2013.

Appendix 1

The following definitions are provided to help the reader understand the Annual Plan. The definitions are not intended to be precise or exhaustive and have been simplified for ease of reference. These definitions should not be relied upon in interpreting NGTL's Gas Transportation Tariff or any Service Agreement. Capitalized terms not otherwise defined here are defined in NGTL's Gas Transportation Tariff. The defined terms in this Glossary of Terms might not be capitalized in their use throughout the Annual Plan.

Alberta Average Field Price

Average estimated price of natural gas (post processing) prior to receipt into the Alberta System. The Alberta Average Field Price is equivalent to the Alberta Reference Price (ARP).

Allowance for Funds Used During Construction (AFUDC)

The capitalization of financing costs incurred during construction of new facilities before the facilities are included in rate base.

Annual Plan

A document outlining NGTL's planned facility additions and major modifications.

Average Annual Delivery

The average day delivery determined for the period of one Gas Year. All forecast years are assumed to have 365 days.

Average Day Delivery

The average day delivery over a given period of time, determined by summing the total volumes delivered divided by the number of days in that period. It is determined for either a Delivery Point or an aggregation of Delivery Points.

Average Receipt Forecast

The forecast of average flows expected to be received onto the Alberta System at each receipt point.

Coincidental

Occurring at the same time.

Delivery Meter Station

A facility which measures gas volumes leaving the Alberta System.

Delivery Point

The point where gas may be delivered to Customer by Company under a Schedule of Service, which shall include but not be limited to Group 1 Delivery Point, Group 2 Delivery Point, Group 3 Delivery Point, Extraction Delivery Point and Storage Delivery Point.

Delivery Design Area

The Alberta System is divided into five delivery design areas used to facilitate the transfer of delivery service within or between Delivery Design Areas. The Delivery Design Areas are:

- Northwest Alberta and Northeast BC Delivery Area;
- Northeast Delivery Area;
- Southwest Delivery Area;
- Southeast Delivery area and
- Edmonton and Area Delivery Area.
-

Demand Coincidence Factor

A factor applied to adjust the system maximum and minimum day deliveries for all of the Group 1 and Group 2 Delivery Points within a design area to a value more indicative of the expected actual peak day deliveries.

Design Area

The Alberta System is divided into three project areas – Peace River Project Area, North and East Project Area, and the Mainline Project Area. These project areas are then divided into design and sub-design areas.

Dividing the system this way allows the system to be modelled in a way that best reflects the pattern of flows in each specific area of the system.

Design Capability

The maximum volume of gas that can be transported in a pipeline system considering design assumptions. Usually presented as a percentage of design flow requirements.

Design Flows

The forecast of Peak Expected Flow that is required to be transported in a pipeline system considering design assumptions.

Design Forecast

A forecast of the most current projection of receipts and deliveries over a five-year design horizon.

Expansion Facilities

Facilities that will expand the existing Alberta System to/from the point of Customer connection, including any pipeline loop of the existing system, metering and associated connection piping and system compression.

Extension Facilities

Facilities that connect new or incremental supply or markets to the Alberta System.

Firm Transportation

Service offered to Customers to receive gas onto the Alberta System at Receipt Points or deliver gas off of the Alberta System at Delivery Points with a high degree of reliability.

Gas Year

A period of time beginning at eight hundred hours (08:00) Mountain Standard Time on the first day of November in any year and ending at eight hundred hours (08:00) Mountain Standard Time on the first day of November of the next year.

Interruptible Transportation

Service offered to Customers to receive gas onto the Alberta System at Receipt Points or deliver gas off of the Alberta System at Delivery Points, provided capacity exists in the facilities, that is not required to provide firm transportation.

Lateral

A section of pipe that connects one or more Receipt or Delivery Points to the mainline.

Load / Capability Analysis

A statistical technique for comparing the available seasonal mainline capability in a design or design sub area with the expected range of seasonal loads or flows. The analysis provides a measure of both the probability of a service disruption, where load or flows exceed the available capability, and the expected magnitude of a service disruption.

Loop

The paralleling of an existing pipeline by another pipeline.

Mainline

A section of pipe, identified through application of the mainline system design assumptions, necessary to meet the aggregate requirements of all customers.

Maximum Day Delivery

The forecast maximum volume, included in the design, to be delivered to a Delivery Point.

Maximum Operating Pressure

The maximum operating pressure at which a pipeline is operated.

Minimum Day Delivery

The forecast minimum volume, included in the design, to be delivered to a Delivery Point.

NPS

Nominal pipe size, in inches.

Non-coincidental

Non-simultaneous occurrence.

Peak Expected Flow

The peak flow that is expected to occur at a point or points on the Alberta System. For a design area or sub design area, this is the coincidental peak of the aggregate flow. For a single receipt point, it is equivalent to field deliverability.

Project Area

For design purposes, the Alberta System is divided into three project areas – Peace River Project Area, North and East Project Area, and the Mainline Project Area.

Dividing the system this way allows the system to be modelled in a way that best reflects the pattern of flows in each specific area of the system. The Project Area may be amended from time to time by Company in consultation with the Tolls, Tariff, Facilities and Procedures (TTFP) Taskforce, provided Company has given six months notice of such amendment to its Customers.

Receipt Area

Areas where gas is received onto the Alberta System. The facilities in these areas include receipt meter stations and laterals.

Receipt Meter Station

A facility which measures gas volumes entering the Alberta System.

Receipt Point

The point in Alberta at which gas may be received from Customer by Company under a Schedule of Service.

Storage Facility

Any commercial facility where gas is stored, that is connected to the Alberta System, and that is available to all Customers.

Summer Season

The period commencing on April 1 and ending on October 31 of any calendar year.

System Average Receipts

The forecast of aggregate average receipts at all Receipt Points.

Transportation Design Process

The process which includes the qualifying of Customer’s applications for service, designing the additions to the system, sourcing all required facilities, and installing the facilities to meet firm transportation requests.

Winter Season

The period commencing on November 1 of any year and ending on March 31 of the following year.

Appendix 2

This section describes the current status of facilities that were applied for, are under construction or have been placed on-stream since the 2011 Annual Plan was issued on December 15, 2011. Periodic updates are being provided based on the level of activity occurring with respect to facilities. Facilities with (AP) after the project name refer to ATCO Pipelines footprint projects.

Applied-for Facilities	Description	Target In-Service Date	Status	Previous Annual Plan Reference	Forecast Cost [1] ($Millions)	Update Month
Banff Loop Extension at Canmore (AP)	7 km NPS 6	4th qtr. 2012	Proposed	July 10, 2012 TTFP Notification	11.3	July
Bens Lake C/S Modifications	Valves, Piping	April 2012	In service May 1 2012	December 13 2011 TTFP Notification	8.1	May
Berland River C/S Unit Addition	28 MW	September 2012	In-service September 18 2012	April 12, 2011 TTFP	71.6	October
Bootis Hill Lateral Loop	5 km NPS 20	Feb. 2014	NEB Rejected Application as deficient June 21 2012[2]	Feb. 14/May 16 2012 TTFP Notification	24.3	November
Bootis Hill Meter Station Modifications	2-1280-4U Ultrasonic Meter	Feb. 2014	NEB Rejected Application as deficient June 21 2012	February 14, 2012 TTFP	2.2	November
Divest Brazeau East Lateral & Pembina West Meter Station	3.8 km NPS 8		Approved Nov. 6 2012	June 12, 2012 TTFP Notification		November
Cabin Meter Station	2 - 2012U-8 Ultrasonic Meter	June 2012	In-service Aug 15 2012	2009	4.2	October
Cheecham West No. 2 Sales Meter Station Modifications	2 - 1610U Ultrasonic Meter	April 2012	In-service April 19 2012	June 2, 2011 TTFP Notification	2.6	May
Cheecham West Crossover	14 km NPS 20	April 2012	In-service Apr. 16 2012	April 12, 2011 TTFP	24.1	May
Chinchaga Lateral Loop No. 3	33 km NPS 48	April 2014	Applied for Oct. 14 2011[3]	July 12/Sept 13, 2011 TTFP	103.4	

[1] Forecast Cost is the applied for cost or the forecast cost to complete for facilities in-service.

[2] Bootis Hill Lateral Loop and Bootis Hill Meter Station Modifications were applied for in a single NEB Section 58 application.

[3] Chinchaga Lateral Loop No. 3, and HRML – Komie North Section were applied for in a single NEB Section 52 application.

Applied-for Facilities	Description	Target In-Service Date	Status	Previous Annual Plan Reference	Forecast Cost [1]($Millions)	Update Month
Cutbank River Lateral Loop (Red Rock Section)	10 km NPS 24	April 2012	In-service Apr. 11 2012	May 10, 2011 TTFP	26.6	May
Dawes Lake North Sales	2 – 640T Turbine Meter	October 2012	In-service Oct. 26 2012	April 13, 2012 TTFP Notification	1.2	November
Decommission Alberta System Meter Stations and Associated Laterals	Flatbush Edwand South Fourth Creek South Owlseye Oyen	4th qtr. 2012	Applied for July 19 2012	June 7, 2012 TTFP Notification	1.7	October
Denning Lake C/S	3.5 MW	November 2014	Proposed	November 20, 2012 TTFP	36.2	November
East Calgary Connector (AP)	11 km NPS 30	TBD	Proposed	July 12, 2011 TTFP	39.1	March
Germain Sales Meter Station	2 - 640T Turbine Meter	September 2012	In-service Aug. 29 2012	February 3, 2012 TTFP Notification	1.1	November
Gordondale Lateral Loop No. 2	24 km NPS 42	March 2012	In-service Mar. 17 2012	2010	55.3	May
Gordondale East Meter Station	882 Orifice Meter	May 2012	In-service June 5 2012	October 27, 2011 TTFP Notification	1.5	June
GPML Loop (Karr North and Nosehill Creek Sections)	16 km NPS 42 (Karr N.) 3.5 km NPS 42 (Nosehill Ck.)	April 2012	In-service Mar. 20 2012 Mar. 31 2012	2010	34.6 25.4	May
Groundbirch Mainline (Saturn Section) and Saturn Meter Station	24 km NPS 36	April 2012	In-service Apr. 1 2012	2010	44.2 3.5	May
Groundbirch East Meter Station	1212-4U Ultrasonic Meter	July 2012	In-service Nov. 23 2012	November 30, 2011 TTFP Notification	2.2	November
Hangingstone Sales Meter Station	2-1280T Turbine meter	May 1, 2013	Applied-for Sept. 7 2012	Aug. 20, 2012 TTFP Notification	1.9	October
Harmattan Straddle Plant Connections	NPS 24 tie-in	June 2012	In-service Sep. 10 2012	NA	CIAC	November
Hidden Lake North C/S	15 MW	January 2013	Under construction	2010	53.0	November
Horn River Mainline (HRML) Loop (Kyklo Creek Section)	29.1 km NPS 42	April 2013	Under construction	2010	81.2	November
Horn River Project (Ekwan & Cabin Section)	72 km NPS 36	May 2012	In-service Oct. 1, 2011 Apr. 23 2012	2009	64.0 168.6	May
HRML (Komie North Section) & Fortune Creek M.S.	100 km NPS 36	April 2015	Applied for Oct. 14 2011	July 12/Sept 13, 2011 TTFP	227.3 2.5	November
HRML Loop (Townsoitoi Section)	27 km NPS 42	TBD	Proposed	July 12/Sept 13, 2011 TTFP	77.5	

Applied-for Facilities	Description	Target In-Service Date	Status	Previous Annual Plan Reference	Forecast Cost [1]($Millions)	Update Month
Kettle River North Lateral Loop (Engstrom Section)	11.5 km NPS 24	April 2012	In-service Apr. 16 2012	April 12, 2011 TTFP	22.9	May
Komie East Extension	2.2 km NPS 24	May 2012	In-service Apr. 23 2012	2009	3.2	May
Komie East Meter Station	1010U-4 Ultrasonic Meter	June 2012	In-service June. 1, 2012	2009	2.3	July
Leismer to Kettle River Crossover	79 km NPS 30	April 2013	Under construction	2010 and May 10, 2011 TTFP	156.8	November
Leming Lake Sales Lateral Loop	37 km NPS 20	April 2014	Proposed	November 20, 2012 TTFP	61.7	November
Little Hay Creek Meter Station	442 Orifice Meter	June 2012	In-service June. 1, 2012	2009	1.8	July
Medicine Hat Area Looping Foothills Control Valve at Empress	27 km NPS 20 Tie-in / Control Valve	November 2014	Proposed	November 20, 2012 TTFP	38.0 4.0	November
Moody Creek C/S	15 MW	December 2012	Under construction	2010	57.1	November
Moosa Crossover	5 km NPS 20	April 2014	Proposed	November 20, 2012 TTFP	10.6	November
Musreau Lake Lateral Loop No. 2	16 km NPS 20	April 2012	In-service Apr. 4 2012	May 10, 2011 TTFP	23.4	May
Musreau Lake Meter Station Modifications	2 - 1610U Ultrasonic Meter	April 2012	In-service Mar. 25 2012	May 11, 2011 TTFP Notification	2.6	May
Norma Transmission (AP) Norma Transmission (NGTL)	34 km NPS 20 3 km NPS 20	November 2013 November 2013	Proposed Proposed	July 10, 2012 TTFP Notification November 20, 2012 TTFP	61.1 8.0	November November
Northeast Calgary Connector (AP)	17 km NPS 24	TBD	Proposed	2011	50.5	July
Northwest Edmonton Connector (AP)	16 km NPS 24	2nd qtr. 2012	In-service	July 12, 2011 TTFP	27.9	March
Northwest Mainline Loop (Timberwolf Section)[4]	49.8 km NPS 48	April 2013	Under construction	2010	153.6	November
NWML Loop (Pyramid Section	30 km NPS 48	TBD	Proposed	July 12/Sept 13, 2011 TTFP	92.5	

[4] The 2010 Annual Plan Chapter 2 included two sections of Northwest Mainline called Timberwolf and Sabbath sections. Since these were to be constructed together, both were combined under a single name – Timberwolf Section.

Applied-for Facilities	Description	Target In-Service Date	Status	Previous Annual Plan Reference	Forecast Cost [1]($Millions)	Update Month
Peace River Mainline & Valleyview C/S Decommissioning (Meikle River to Valleyview section)	266 km NPS 20 2.3 km NPS 4 2.9 MW	End of 2013	Applied-for Aug. 28 2012	2010	13.6	October
Peigan Trail Pipeline (AP)	8 km NPS 20	TBD	Proposed	July 10, 2012 TTFP Notification	39.5	July
Saddle Lake Lateral Loop	12.1 km NPS 16	April 2014	Proposed	November 20, 2012 TTFP	19.7	November
Shepard Energy Centre Extension (AP)	14 km NPS 20, associated Delivery Station (2-1612T Turbine Meter) and associated system modifications	July 2014	Proposed	November 20, 2012 TTFP	59.4	November
Sierra Meter Station	880U-4 Ultrasonic Meter	June 2012	In-service June 1, 2012	2009	3.0	July
Southeast Calgary Connector (AP)	11 km NPS 24	4th qtr. 2012	Applied for	July 12, 2011 TTFP	27.5	March
Southwest Edmonton Connector (AP)	20 km NPS 20	TBD	Proposed	July 10, 2012 TTFP Notification	39.5	July
Sunday Creek South Lateral Loop No. 3	12.7 km NPS 24	April 2014	Proposed	November 20, 2012 TTFP	31.0	November
Sunday Creek South Sales Meter Station	2-1280U Ultrasonic Meter	December 2012	Proposed	October 18, 2012 TTFP Notification	2.3	November
Torrington C/S Modifications	Valves/pipe mods.	November 2012	In-service Oct. 19 2012	2011 and May 28, 2012 TTFP Notification	7.6	October
Tanghe Creek Lateral Loop No. 2 (Cranberry Section)	32.3 km NPS 48	April 2013	Under construction	2010	89.2	November
Tanghe Creek Lateral Loop No. 2 (Sloat Creek Section)	38 km NPS 48	April 2012	In-service Apr. 6 2012	2010	106.0	May
Upgrade Indus Pipeline System (AP)	20 km NPS 4	4th qtr. 2012	Proposed	July 10, 2012 TTFP Notification	8.1	July
Wapasu Creek Sales Meter Station	2 - 1280U Ultrasonic Meter	April 2013	Approved Aug. 22 2012	May 10, 2012 TTFP Notification	3.5	October
Whiskey Jack Lake Sales Meter Station	2 - NPS 6 Turbine Meter	February 2012	In-Service February 15, 2012	June 13, 2011 TTFP Notification	1.2	March

Appendix 3

The System Map including the 2012 Annual Plan facilities will be available in February 2013 which can be accessed online at: http://www.transcanada.com/customerexpress/5193.html.