TransCanada
In business to deliver

450 1st Street S.W.
Calgary, Alberta, Canada
T2P 5H1

Tel: (403) 920-5903
Fax: (403) 920-2357
Email:gord_toews@transcanada.com

December 13, 2013

All Customers
Other Interested Parties

Re: 2013 Annual Plan

NOVA Gas Transmission Ltd ("NGTL") has posted its 2013 Annual Plan on TransCanada Pipelines Limited's website at:

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

Customers and other interested parties are encouraged to communicate their suggestions and comments to NGTL regarding the development of the NGTL System 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
Commercial Services and System Design

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

The 2013 Annual Plan provides NOVA Gas Transmission Ltd.'s (NGTL's) customers and other interested parties an overview of potential NGTL System facilities that are expected to be applied for in the 2013/14 Gas Year. The 2013 Annual Plan describes NGTL's long-term outlook for receipts, deliveries, peak expected flows, design flow requirements and proposed facilities for the 2014/15 to 2018/19 Gas Years. This 2013 Annual Plan is based on NGTL's July 2013 Design Forecast of receipts and deliveries.

Since the release of the 2012 Annual Plan, TransCanada Pipelines Limited (TransCanada) has identified 17 NGTL 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 May 2013 and December 2014 and were initiated before issuance of this Annual Plan to accommodate the lead time required to meet the on-stream requirements.

NGTL provides commercial services under the NGTL Tariff using the combined assets of the NGTL System and the ATCO Pipelines (AP) System. NGTL follows facility planning processes to identify facilities required for the combined assets in the NGTL and AP footprints. For an overview of these processes, see the *Facilities Design Methodology* document. NGTL files facility applications with the National Energy Board (NEB) for facility additions on the NGTL System within the NGTL footprint. AP files facility applications with the Alberta Utilities Commission (AUC) for facility additions on the AP System within the AP footprint.

The facilities identified in this Annual Plan were presented to the TTFP Committee on October 22, 2013. New facilities proposed after issuance of this Annual Plan will be shown in the 2014 Facility Status Update, which can be accessed at http://www.transcanada.com/customerexpress/5250.html.

For the 17 facilities additions identified in the 2013 Annual Plan, see Table E-1.

Table E-1: Proposed Facilities Additions

Project Area	Proposed Facilities	Annual Plan Reference	Description	Target In-Service Date	Regulator	Capital Cost ($ Millions)
North and East	Vermillion Compressor Station (AP)	Chapter 2	3 MW Relocate	Nov 2014	AUC	14
Mainline	Medicine Hat Capacity Expansion Project	Chapter 2	1.2 km Connection, Meter Station, Control Valve, Pipe Modifications	Nov 2014	NEB	15
Mainline	North Branch Replacement (AP)	Chapter 2	3 km NPS 16	Nov 2014	AUC	7
Peace River	Cutbank River Lateral Loop No. 2 (Kakwa) Musreau Lake Lateral Loop No. 3	Chapter 3	12 km NPS 24 16 km NPS 24	Apr 2015	NEB	55
Peace River	Saddle Hills Compressor Modifications	Chapter 2	Bi-Directional Modifications	Nov 2015	NEB	10
Peace River	Alces River Compressor Modifications	Chapter 2	Bi-Directional Modifications	Nov 2015	NEB	10
North and East	Otter Lake Compressor Station	Chapter 2	28 MW Relocate	Nov 2015	NEB	100
North and East	Snipe Hills Compressor Station	Chapter 2	3.5 MW Relocate	Nov 2015	NEB	45
North and East	Inland Looping (AP)	Chapter 2	18 km NPS 20	Nov 2015	AUC	29
Peace River	North Montney Mainline (Aitken Creek Section)	Chapter 3	180 km NPS 42	Apr 2016	NEB	762
Peace River	Wolverine River Lateral Loop (Carmon Creek Pipeline Project)	Chapter 3	62 km NPS 20	Apr 2016	NEB	128
Peace River	North Montney Mainline (Kahta Section)	Chapter 3	125 km NPS 42	Apr 2017	NEB	530
Peace River	Groundbirch C/S (Bi-directional)	Chapter 2	30 MW	Apr 2017	NEB	103
Peace River	Saturn C/S	Chapter 2	15 MW	Apr 2017	NEB	70
Peace River	Saturn C/S – Unit 2	Chapter 2	15 MW	Apr 2019	NEB	63
Peace River	Aitken C/S	Chapter 2	15 MW	Apr 2019	NEB	72
Peace River	North Montney Mainline Meter Stations	Chapter 3	13 Receipt 1 Delivery 1 Storage	2016 to 2019	NEB	66
					Total	**2079**
Capital costs are in 2013 dollars and include AFUDC.						

The Snipe Hills Compressor is required to deliver incremental supply to the Cold Lake Area sales stations serving expanding steam-assisted gravity drainage (SAGD) projects.

The AP Vermillion Compressor Station is required to transport additional supply into the Lloydminster Area for growing industrial demand, as well as growing residential demand in the Greater Lloydminster Area.

The Medicine Hat Capacity Expansion project is required to transport additional supply into the Medicine Hat Design Area to meet additional demand in the area.

The AP North Branch replacement is proposed to transport additional supply into the Greater Calgary Area.

The Cutbank Area Looping is proposed to transport growing supply in the Lower Peace River Design Area.

The Otter Lake Compressor is required to transport growing Peace River Project Area supply in the North and East Project Area.

The Saddle Hills and Alces River Compressor Modifications are required to transport additional supply from the Peace River Project Area to meet additional demand in the North and East Project Area.

The AP Inland Looping project is required to transport additional supply into the greater Edmonton area to meet growing residential and industrial demand.

The North Montney Mainline (Aitken Creek and Kahta Sections) is proposed to connect a major new source of gas in an area known as North Montney.

The Wolverine Lateral Looping is required to provide additional capacity for a new oil sands project (the Carmon Creek Project) in the North of Bens Lake Design Area.
This 2013 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
- Appendix 3: System Map (expected in March 2014)

Electronic versions of the Annual Plan and the *Facilities Design Methodology* document can be accessed 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 the 2013 Annual Plan to:

- Darryn Rouillard, Manager, Mainline Planning West (403) 920-6341
- 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

1.0 DESIGN FORECAST

1.1 INTRODUCTION

This Annual Plan is based on the July 2013 Design Forecast of receipts and deliveries for the NGTL System. An overview of the July 2013 Design Forecast was presented at the October 22, 2013 TTFP meeting.

For information on forecasting methodology, see *Facilities Design Methodology*, Section 4.4: Design Forecast Methodology, which can be accessed at http://www.transcanada.com/customerexpress/871.html. This section describes:

- economic assumptions used in developing the 2013 Design Forecast
- receipts and deliveries for the NGTL System
- supply contribution, including winter withdrawal, from storage facilities used in design process

1.2 ECONOMIC ASSUMPTIONS

1.2.1 General Assumptions

The following assumptions, developed in May 2013, 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 by over 2.5 bcf/d from 2012 to 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 1.6 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

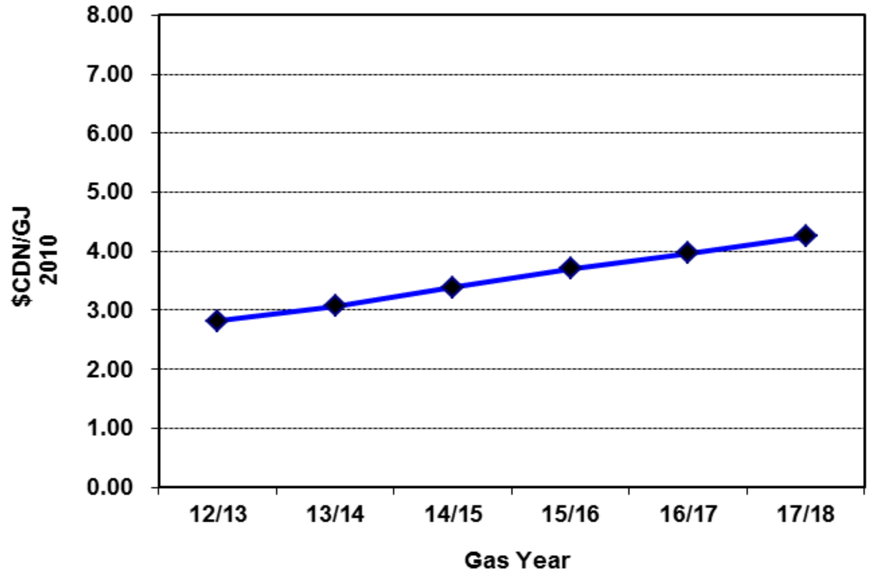
LNG exports from both the U.S. and Canada, with those from the U.S. beginning just after the middle of this decade and those from Canada beginning at the end of this decade.

- Because of weakness in natural gas demand from the slower pace of economic recovery and 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 toward an equilibrium price of $US 5.25/MMBtu in real 2010 $US by 2020.
- 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 made additional shale and tight gas resources 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, which represents the estimated price of natural gas at a point just before receipt onto the NGTL System. The gas price forecast, shown in Figure 1-1, was developed in January 2013 and reflects the general assumptions from Section 1.2.1.

Figure 1.1: NGTL Gas Price Forecast, Alberta Average Field Price



The Alberta Average Field Price fell to the lowest level in seventeen years during 2012, averaging just $2.01 Cdn/GJ in real 2010 $ for the year. Prices are forecast to rebound over the next few years, reaching $4.25 Cdn/GJ in terms of real 2010 $ by 2018. The long term equilibrium price of $4.72 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 in the NGTL System are forecasted to rise, primarily due to industrial demand in the oil sands sector. 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 has increased slightly compared to recent years, but is still not at previous levels due to changing market conditions and 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 NGTL System over the next 10 years. The forecasts were analyzed and compared with historical flow patterns at NGTL 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.

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 NGTL System. The Average Annual Delivery Forecast, for Gas Years 2013/14 through 2017/18 are listed by Delivery Type in Table 1-1 and further detailed by Project Area in Table 1-2.

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

Delivery Type	July 2013 Design Forecast ($10^6 m^3/d$)				
	2013/14	2014/15	2015/16	2016/17	2017/18
Export	158.4	168.4	171.1	176.8	182.4
Intra Basin	127.6	134.4	141.2	149.7	157.4
Total System	**286.0**	**302.8**	**312.3**	**326.5**	**339.8**
Delivery Type	**July 2013 Design Forecast (Bcf/d)**				
	2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Export	5.59	5.95	6.04	6.24	6.44
Intra Basin	4.50	4.74	4.99	5.28	5.56
Total System	**10.10**	**10.69**	**11.02**	**11.53**	**12.00**

Note: Totals have been rounded.
Volumes expressed as an average daily flow for each gas year, at 101.325 kPa and 15°C.

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

Project Area	July 2013 Design Forecast ($10^6m^3/d$)				
	2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Peace River	2.7	2.8	3.1	3.2	3.5
North and East	85.6	91.0	95.8	101.7	107.9
Mainline	37.3	38.5	40.2	42.8	43.9
Gas Taps	2.0	2.0	2.1	2.1	2.1
Total	**127.6**	**134.4**	**141.2**	**149.7**	**157.4**
Project Area	**July 2013 Design Forecast (Bcf/d)**				
	2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Peace River	0.10	0.10	0.11	0.11	0.12
North and East	3.02	3.21	3.38	3.59	3.81
Mainline	1.32	1.36	1.42	1.51	1.55
Gas Taps	0.07	0.07	0.07	0.07	0.07
Total	**4.50**	**4.74**	**4.99**	**5.28**	**5.56**

Note:
Totals have been rounded.
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 NGTL Delivery Points and are based on customer input, market conditions, firm transportation contracts and historical flows.

A summary of the July 2013 Design Forecast winter and summer Maximum Day Delivery by Project Area for Intra Basin 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 2013 Design Forecast ($10^6 m^3/d$)				
	2013/14	2014/15	2015/16	2016/17	2017/18
Peace River	9.5	9.7	10.2	10.3	10.6
North and East	139.8	149.3	157.0	168.1	179.0
Mainline	76.3	81.3	82.1	83.7	88.9
Gas Taps	4.0	4.1	4.1	4.1	4.2
Total	**229.6**	**244.4**	**253.4**	**266.2**	**282.7**
Project Area	**July 2013 Design Forecast (Bcf/d)**				
	2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Peace River	0.33	0.34	0.36	0.36	0.38
North and East	4.93	5.27	5.54	5.94	6.32
Mainline	2.69	2.87	2.90	2.95	3.14
Gas Taps	0.14	0.14	0.14	0.15	0.15
Total	**8.11**	**8.63**	**8.94**	**9.40**	**9.98**

Note:
Totals have been rounded.
Gas taps are located in all areas of the province.

Table 1-4: Summer Maximum Day Delivery Forecast

Project Area	July 2013 Design Forecast ($10^6 m^3/d$)				
	2013/14	2014/15	2015/16	2016/17	2017/18
Peace River	7.1	7.2	7.6	7.7	8.0
North and East	119.3	126.7	133.3	142.1	153.1
Mainline	53.7	55.2	56.6	59.1	60.5
Gas Taps	2.4	2.4	2.5	2.5	2.5
Total	**182.5**	**191.5**	**199.9**	**211.4**	**224.1**
Project Area	**July 2013 Design Forecast (Bcf/d)**				
	2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Peace River	0.25	0.25	0.27	0.27	0.28
North and East	4.21	4.47	4.70	5.02	5.41
Mainline	1.90	1.95	2.00	2.09	2.13
Gas Taps	0.09	0.09	0.09	0.09	0.09
Total	**6.44**	**6.76**	**7.06**	**7.46**	**7.91**

Note:
Totals have been rounded.
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. 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 from customers, to generate forecasts of future production. Factors such as e 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 NGTL System in the Peace River Project Area by the 2017/18 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 2013 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 was not included in the data presented in this section. For information pertaining to gas supply from Commercial Storage Facilities, see Section 1.6.

1.4.1 Average Receipt Forecast

The Average Receipt Forecast is the forecast aggregate receipts for the NGTL System for the 2013/14 through 2017/18 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 2013 Design Forecast ($10^6 m^3/d$)				
	2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Peace River	140.9	152.7	168.0	187.7	198.2
North and East	25.7	24.4	22.6	21.3	22.7
Mainline	117.0	118.1	115.7	112.6	111.3
Total	283.6	295.2	306.4	321.6	332.2
Project Area	**July 2013 Design Forecast (Bcf/d)**				
	2013/14	**2014/15**	**2015/16**	**2016/17**	**2017/18**
Peace River	4.97	5.39	5.93	6.63	7.00
North and East	0.91	0.86	0.80	0.75	0.80
Mainline	4.13	4.17	4.09	3.97	3.93
Total	10.01	10.42	10.81	11.35	11.73

Note:
Totals have been rounded.

1.5 SUPPLY DEMAND BALANCE

Supply received on to the NGTL 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

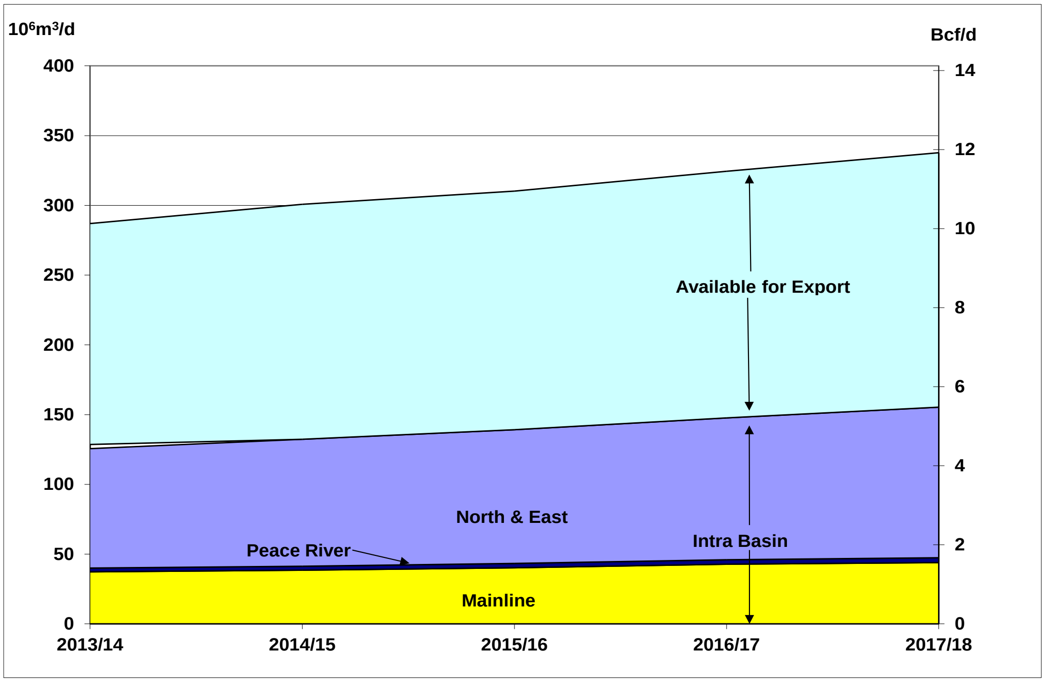
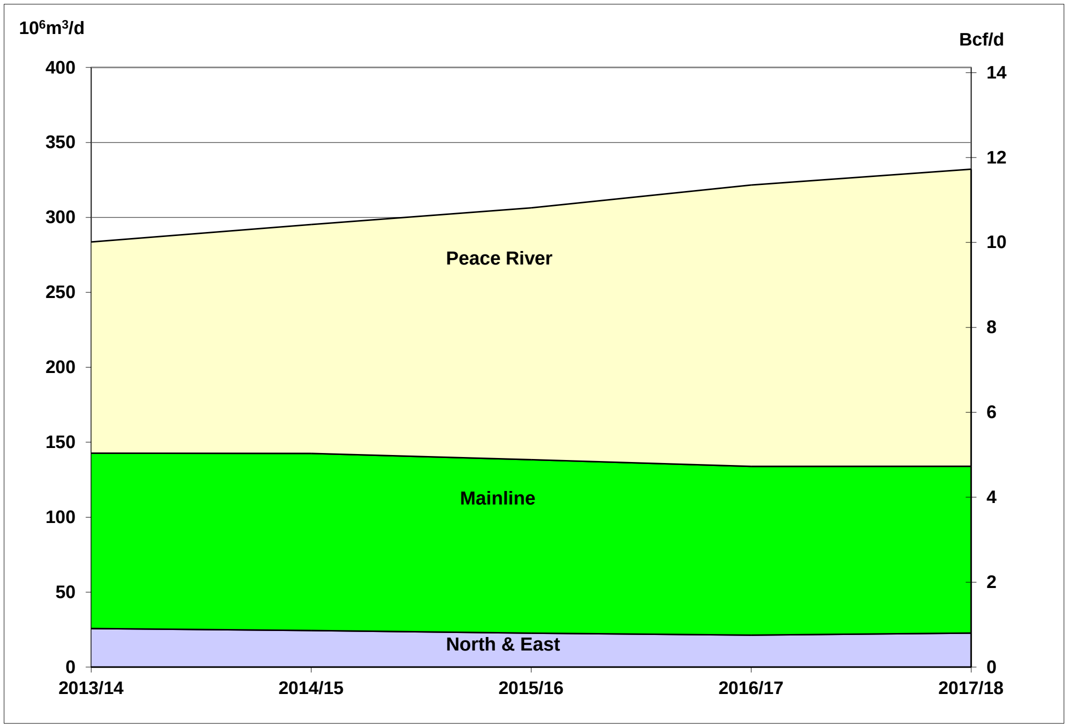


Figure 1-3: System Receipts by Project Area



1.6 STORAGE FACILITIES

1.6.1 Commercial Storage

There are nine commercial storage facilities connected to the NGTL System (AECO ‘C’, Big Eddy, Carbon, Chancellor, Crossfield East #2, January Creek, Rat Creek West, Severn Creek and Warwick Southeast Meter Stations). The total deliverability from Storage Facilities is significant, but actual maximum day receipts from storage are dependent on a number of factors, including market conditions, level of working gas in each storage facility, compression power at each storage facility and NGTL 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 for each Storage Facility 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 NGTL System for the winter season was 21.5 to 23.2 $10^6m^3/d$.

For the receipt meter capacity for each of the connected commercial storage facilities, see 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	2.9	0.10
Severn Creek	5.6	0.20
Warwick Southeast	6.1	0.22
Total	**177.9**	**6.29**

Note:
Storage is considered an interruptible supply source.
Totals have been rounded.

1.6.2 Peak Shaving Storage

The Fort Saskatchewan Salt Caverns are a peak shaving storage facility in the greater Edmonton area within the ATCO Pipeline footprint, in North of Bens Lake Design Area of the NGTL 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 depends on a number of factors, including market conditions, level of working gas, compression power at the storage facility and NGTL System operations.

For design purposes, a maximum withdrawal rate of 6500 $10^3m^3/d$ (230 MMcf/d) was used to meet the peak expected winter season delivery requirements.

2.0 DESIGN FLOW AND MAINLINE FACILITIES

2.1 INTRODUCTION

This section contains the proposed natural gas transportation mainline facilities as well as deactivation and decommissioning projects to be applied for on the NGTL System in the 2013/14 Gas Year to meet the design flow requirements. Included is information regarding size, routes, locations and cost estimates.

The design flow requirements are represented by peak expected flows and are presented for design areas where new mainline facilities are required. Peak expected flows are based on the July 2013 design forecast presented in Section 1, and were determined using the methodology described in *Facilities Design Methodology*, Section 3.5: Mainline Facilities Flow Determination. This document can be accessed at http://www.transcanada.com/customerexpress/871.html.

This section includes a comparison of historical flows to the peak expected flows. Additionally, the current design capability is shown for the Gas Year when facilities are required in 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.

An overview of the design peak expected flows, proposed facilities, and deactivation and decommissioning projects resulting from the July 2013 design forecast were presented at the TTFP meeting on October 22, 2013.

For a summary of the status of mainline facilities that have been proposed, applied for, under construction or placed in-service since the December 2012 Annual Plan, see Appendix 2: Facility Status Update.

2.2 PEACE RIVER PROJECT AREA

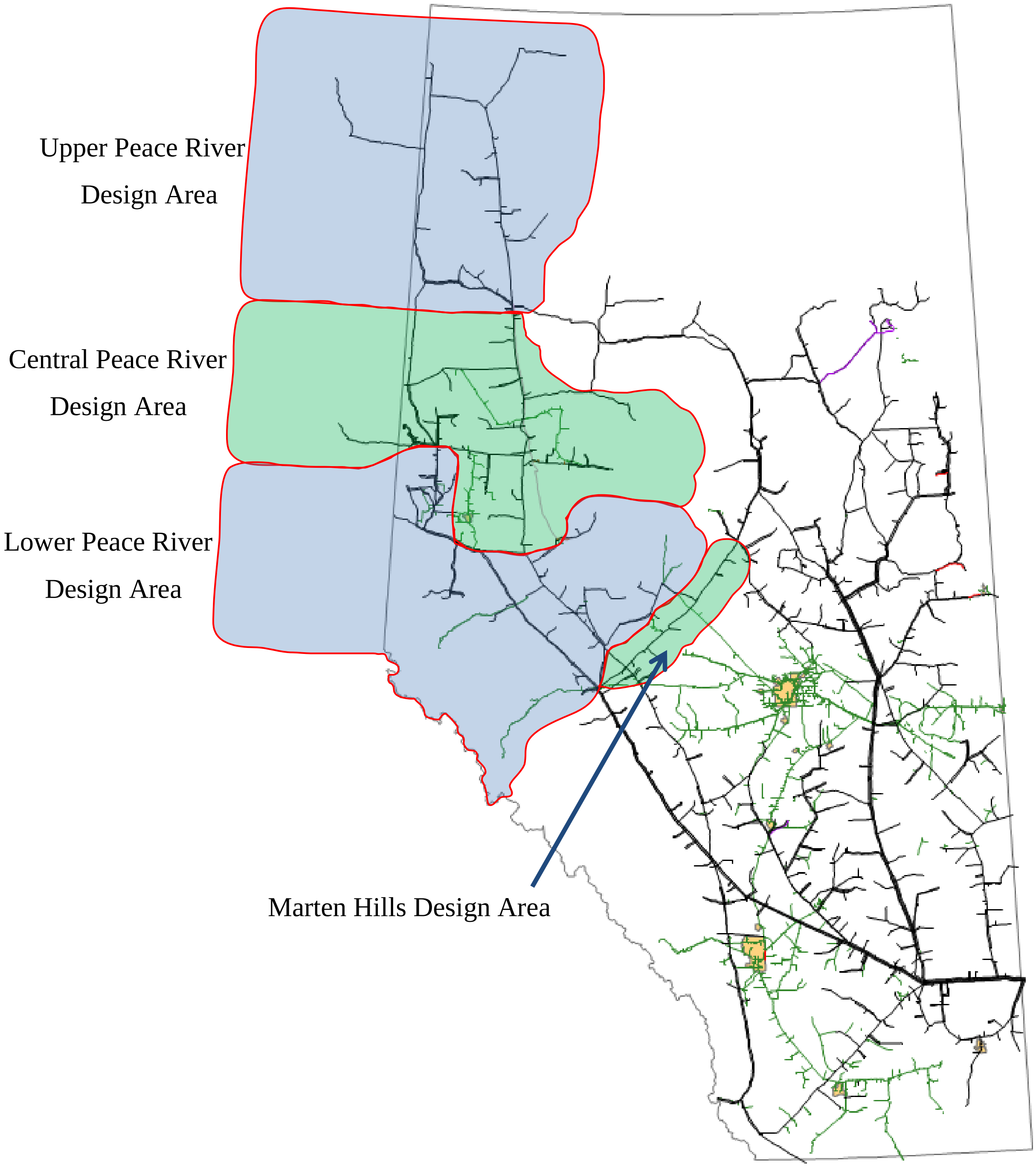
The Peace River Project Area (Figure 2-1) comprises the Upper Peace River, Central Peace River, Lower Peace River and Marten Hills design areas.

In the Peace River Project Area, the proposed facilities are required to transport growing receipts in the area to deliveries throughout the NGTL System. These facilities have been categorized two ways:

1. Supply-Triggered Facilities – Facilities triggered by peak expected supply flows in the Peace River Project Area exceeding the deliveries in the area and current capability to transport the excess gas out of the area (Peace River Project Area flow-through design condition).

2. Demand-Triggered Facilities – Facilities triggered by peak expected delivery flows in the North and East Project Area exceeding the supply in that area and current capability of the Peace River Project Area facilities to transport the required additional gas into the North and East Project Area (North and East Project Area flow-within design condition).

Figure 2-1: Peace River Project Area

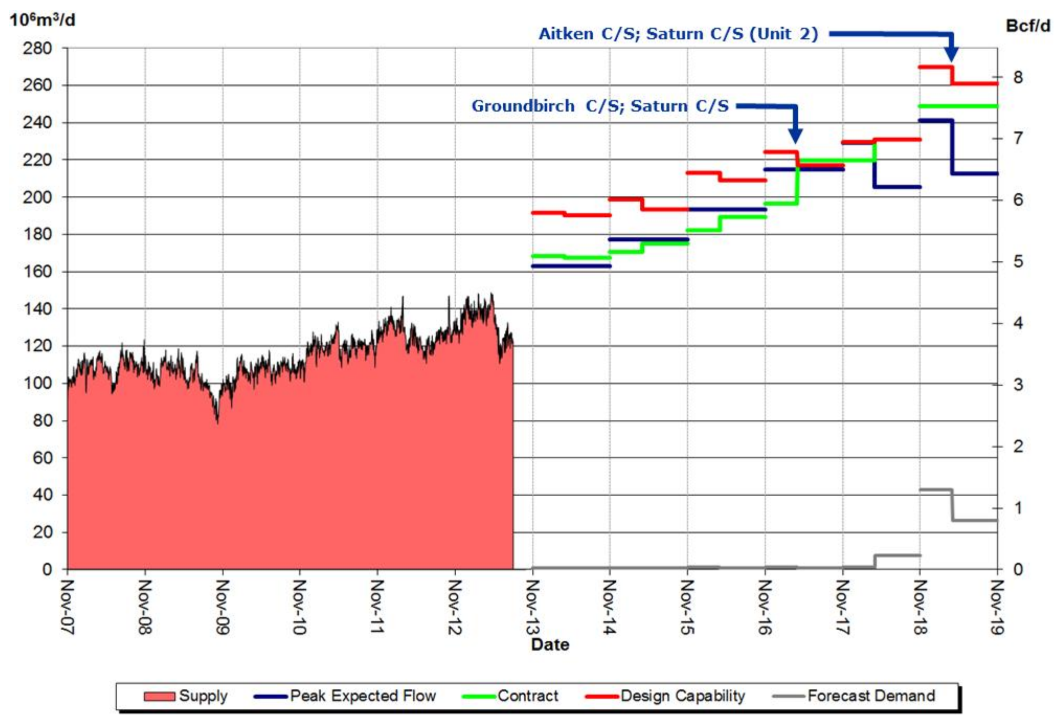


2.2.1 Design Flows – Supply-Triggered Facilities

The peak expected flow for the flow-through design condition in the Peace River Project Area is the net effect of the maximum local supply less minimum deliveries in the area. Continued supply growth will be accommodated by six proposed facilities that form the North Montney Mainline Facilities. The four North Montney Mainline compression facilities are described in this section. For a description of the two North Montney Mainline pipeline facilities, see Section 3.

Figure 2-2 shows historical flow, projected peak expected flow, contract levels and design capability for the Peace River Design Area. Peak expected flow is anticipated to rise throughout this forecast period, attributable primarily to a rise in B.C. shale gas supply.

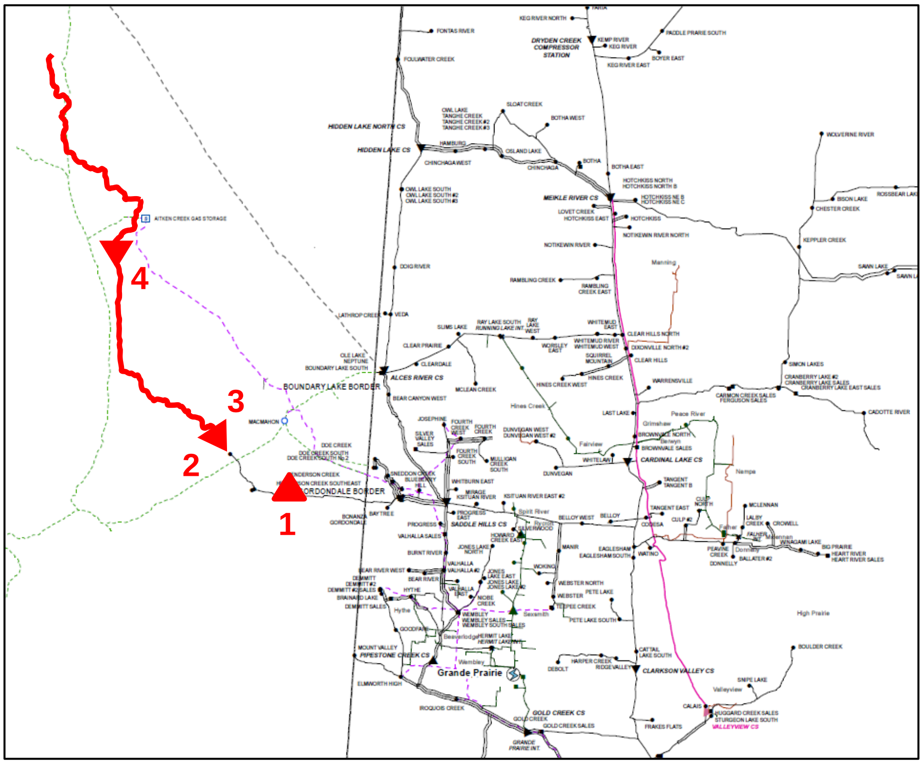
Figure 2-2: Peace River Project Area Design Chart – Supply Triggered Facilities



2.2.2 Proposed Supply-Triggered Facilities

Figure 2-3 shows the locations of the proposed facilities required to meet the design flow requirements of the flow-through design condition in the Peace River Project Area.

Figure 2-3: Peace River Project Area Map – Supply-Triggered Facilities



The application for these four proposed facilities was filed with the NEB on November 8, 2013, and the facilities are proposed to be in-service in 2017 through to 2019. For details on the proposed facilities, see Table 2-1 and for a description of the pipeline extension on which the Saturn and Aitken C/S are installed, see Section 3.2.

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

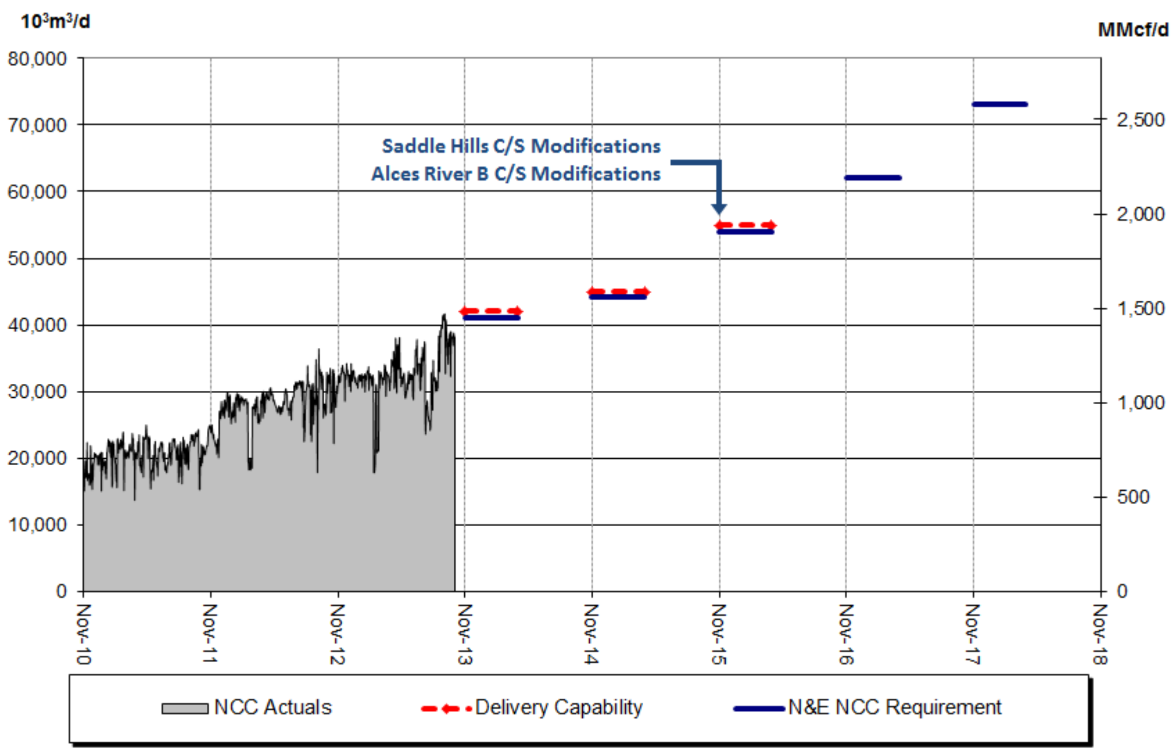
Map Location	Applied-For Facility	Description	Target In-Service Date	Forecast Cost ($Millions)
1	Groundbirch C/S (Bi-directional)	30 MW	Apr 2017	103
2	Saturn C/S	15 MW	Apr 2017	70
3	Saturn C/S – Unit 2	15 MW	Apr 2019	63
4	Aitken C/S	15 MW	Apr 2019	72
Capital costs are in 2013 dollars and include AFUDC.			**Total**	**308**

2.2.3 Design Flows – Demand-Triggered Facilities

The peak expected flow for the flow-within design condition is the net effect of maximum deliveries less the minimum available local supply in the area. Continued delivery growth in the North of Bens Lake Design Area will be accommodated by two proposed facilities in the North of Bens Lake Design Area (see Section 2.3) as well as two proposed facilities in the Peace River Design Area. The two facilities in the Peace River Design Area increase the delivery capacity of the North Central Corridor (NCC), to meet North and East delivery requirements.

Figure 2-4 shows historical flow, projected peak flow requirement and design capability of the NCC. The peak flow requirement was determined using aggregated FT delivery contracts in the North of Bens Lake Design Area.

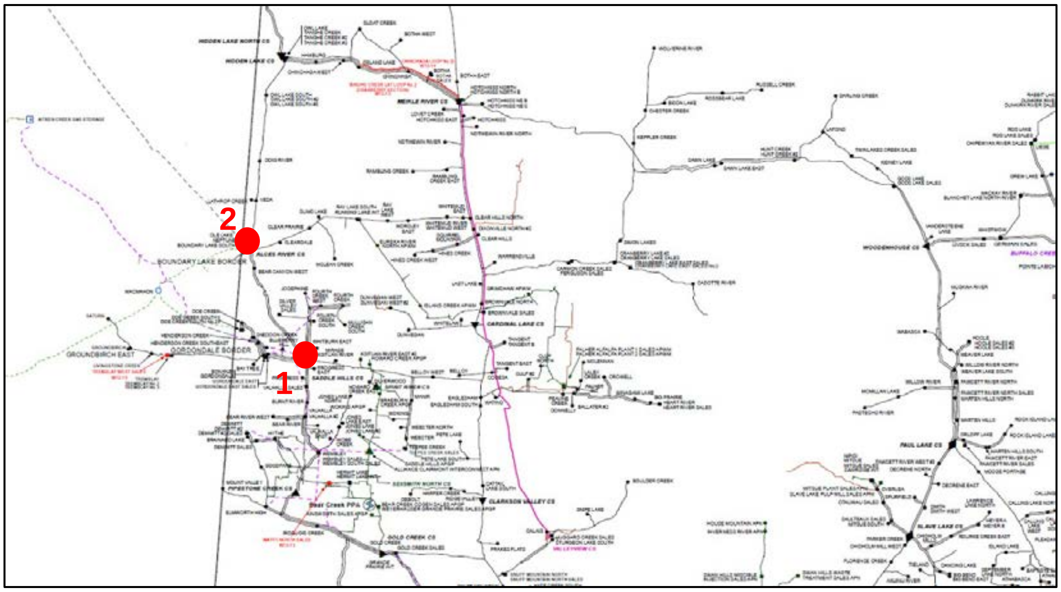
Figure 2-4: Peace River Project Area Map – Supply-Triggered Facilities



2.2.4 Proposed Demand Triggered Facilities

Figure 2-5 shows the locations of the proposed facilities in the Peace River Project Area that are required to meet the design flow requirements of the flow-within design condition in the North and East Project Area.

Figure 2-5: Peace River Project Area Map – Supply-Triggered Facilities



Applications for the two proposed facilities are expected to be filed with the NEB in 2014 and the facilities are proposed to be in-service in 2015. For details on each of the proposed facilities, see Table 2-2.

Table 2-2: Peace River Project Area – Demand-Triggered Facilities

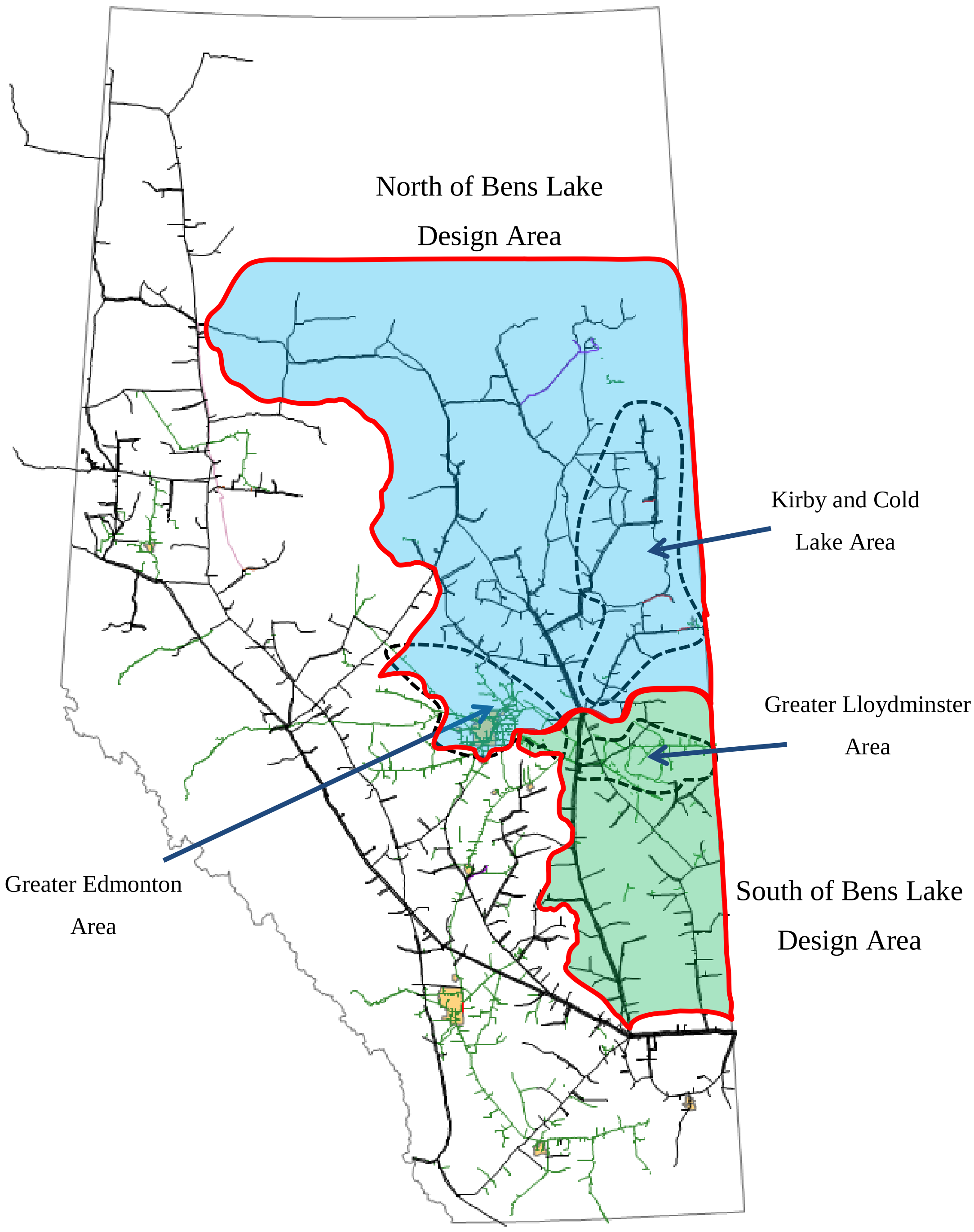
Map Location	Proposed Facility	Description	Target In-Service Date	Forecast Cost ($Millions)
1	Saddle Hills Compressor Modifications	Bi-Directional Modifications	Nov 2015	10
2	Alces River B Compressor Modifications	Bi-Directional Modifications	Nov 2015	10
Capital costs are in 2013 dollars and include AFUDC.			**Total**	**20**

2.3 NORTH AND EAST PROJECT AREA

The North and East Project Area (Figure 2-6) consists 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 required gas deliveries in the Kirby and Cold Lake, greater Edmonton and greater Lloydminster areas.

Figure 2-6: North and East Project Area

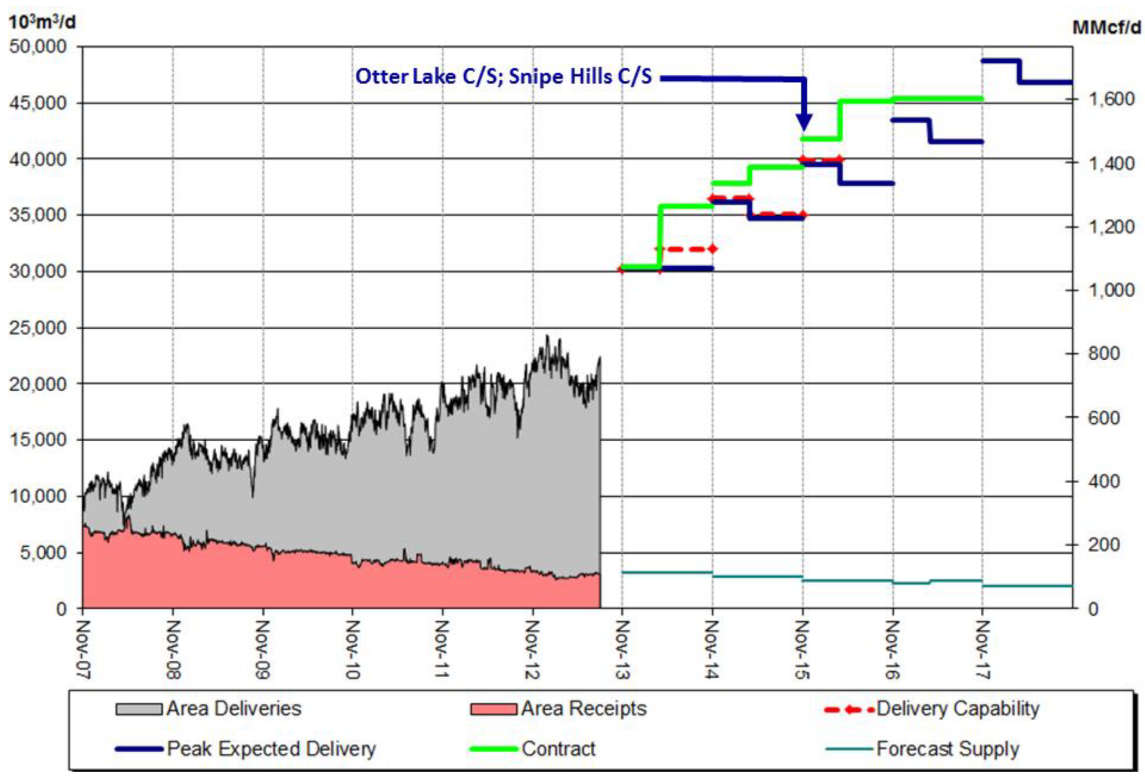


2.3.1 Design Flows – Kirby and Cold Lake Area

The peak expected flow for the flow-within design condition is the net effect of maximum deliveries less the minimum available local supply in the area. Continued delivery growth in the North of Bens Lake Design Area will be accommodated by two proposed facilities in the Peace River Design Area (see Section 2.2) as well as two proposed facilities in the North of Bens Lake Design Area.

Figure 2-7 shows historical actual flow, projected peak expected flow, contract levels and design capability for the Kirby and Cold Lake Area. Peak expected flow is anticipated to rise throughout this forecast period.

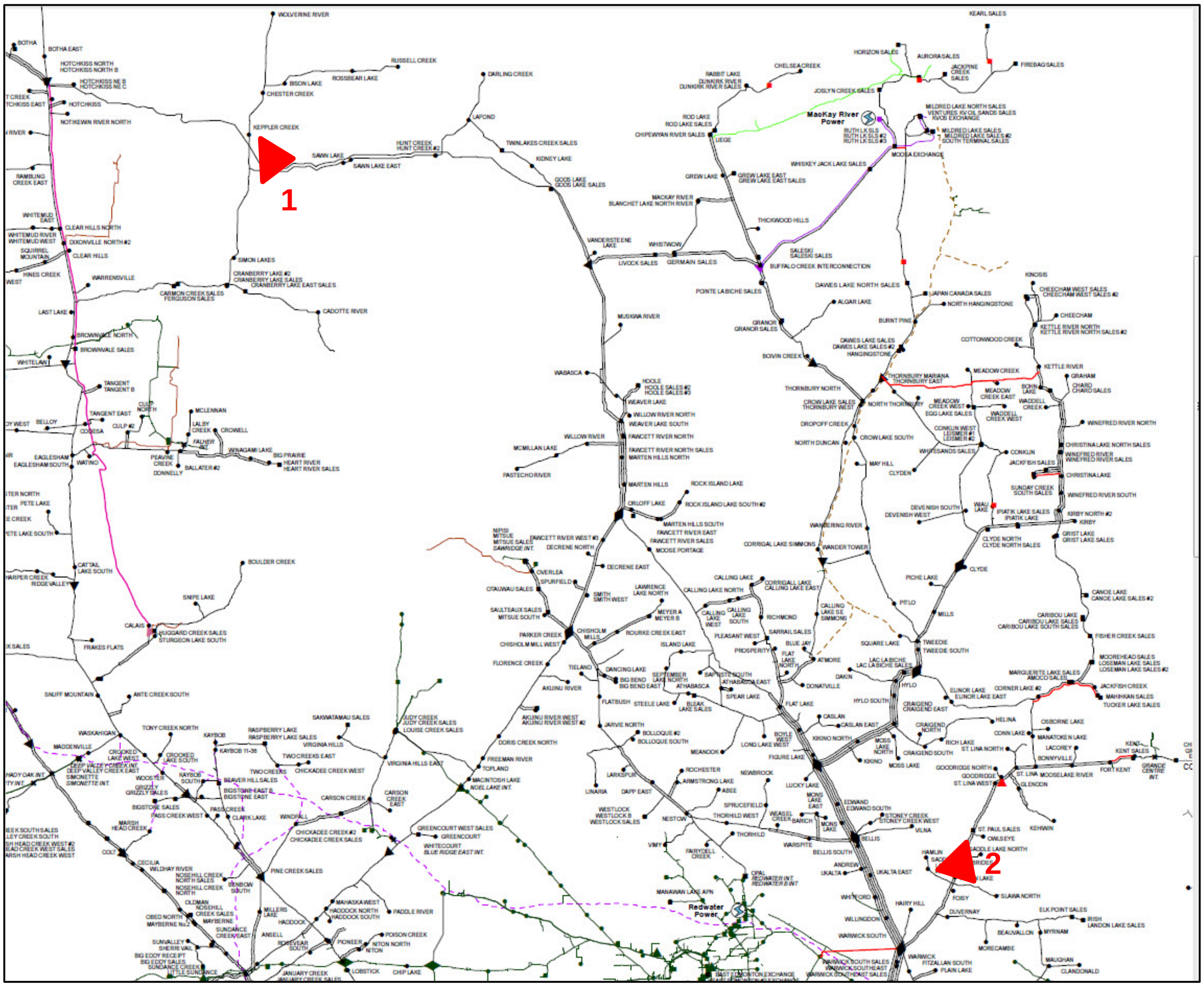
Figure 2-7: Kirby and Cold Lake Area Design Chart



2.3.2 Proposed Facilities – Kirby and Cold Lake Area

Figure 2-8 shows the location of the proposed facilities required to meet the design flow requirements of the Kirby and Cold Lake Area.

Figure 2-8: Kirby and Cold Lake Area Map – Proposed Facilities



Applications for the proposed facilities are expected to be filed with the NEB in 2014 and the facilities are proposed to be in-service in 2015. For details on the proposed facilities, see Table 2-3.

Table 2-3: Kirby and Cold Lake Area Proposed Facilities

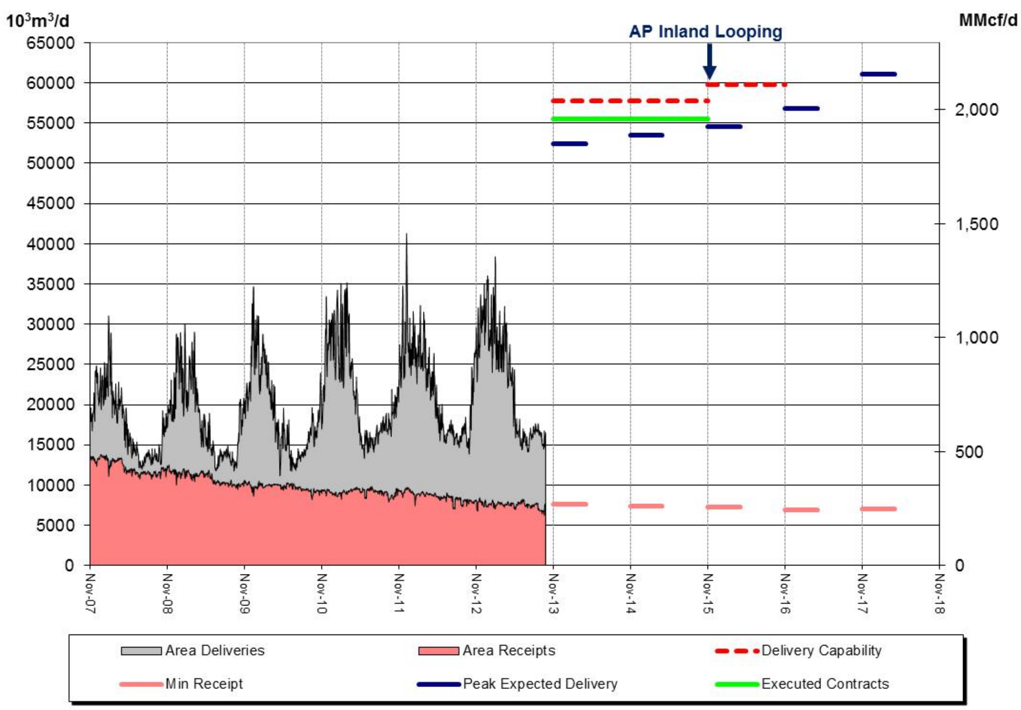
Map Location	Proposed Facility	Description	Target In-Service Date	Forecast Cost ($Millions)
1	Otter Lake Compressor Station	28 MW Relocate	Nov 2015	100
2	Snipe Hills Compressor Station	3.5 MW Relocate	Nov 2015	45
Capital costs are in 2013 dollars and include AFUDC.			**Total**	**145**

2.3.3 Design Flows – Greater Edmonton Area (ATCO Pipelines)

The peak expected flow for the flow-within design condition is the net effect of maximum deliveries less the minimum available local supply in the area. Continued delivery growth in the greater Edmonton area will be accommodated by one proposed facility.

Figure 2-9 shows historical actual flow, projected peak expected flow, contract levels and design capability for the greater Edmonton area. Peak expected flow is anticipated to rise throughout this forecast period.

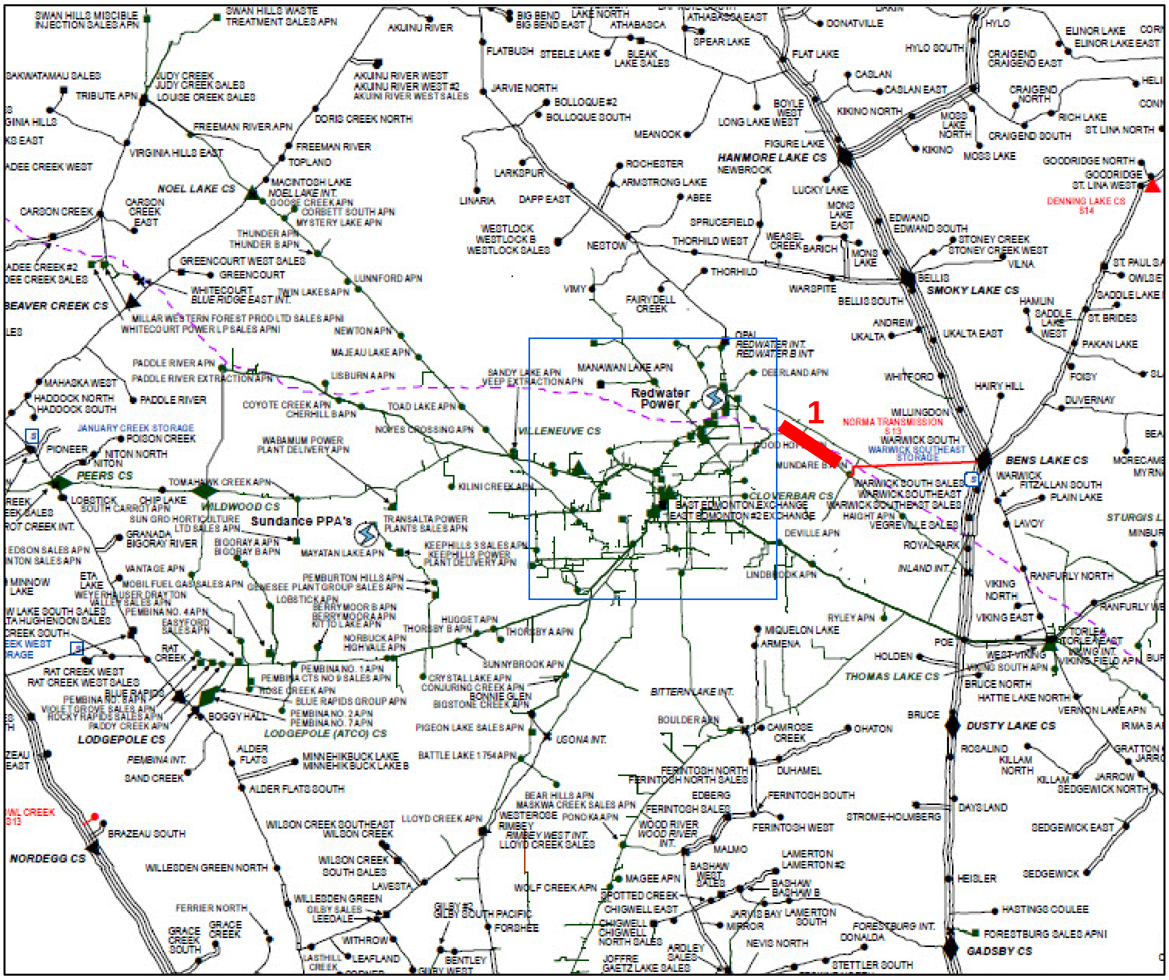
Figure 2-9: Greater Edmonton Area Design Chart



2.3.4 Proposed Facilities – Greater Edmonton Area (ATCO Pipelines)

Figure 2-10 shows the location of the proposed facility required to meet the design flow requirements of the greater Edmonton area.

Figure 2-10: Greater Edmonton Area Map – Proposed Facility



An application for the proposed facility is expected to be filed with the AUC in 2014 and the facility is proposed to be in-service in 2015. For details on the proposed facility, see Table 2-4.

Table 2-4: Greater Edmonton Area Proposed Facility

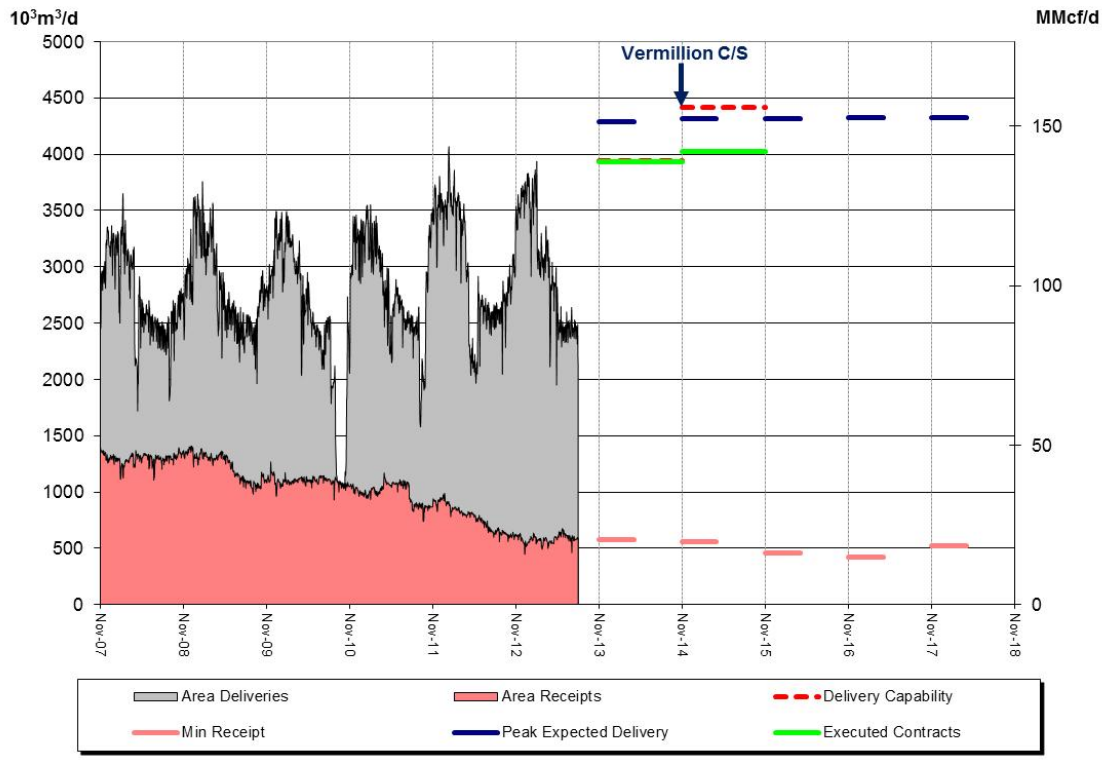
Map Location	Proposed Facility	Description	Target In-Service Date	Forecast Cost ($Millions)
1	Inland Looping	18 km NPS 20	Nov 2015	29
Capital costs are in 2013 dollars and include AFUDC.			**Total**	**29**

2.3.5 Design Flows – Greater Lloydminster Area (ATCO Pipelines)

The peak expected flow for the flow-within design condition is the net effect of maximum deliveries less the minimum available local supply in the area. Continued delivery growth in the greater Lloydminster area will be accommodated by one proposed facility.

Figure 2-11 shows historical actual flow, projected peak expected flow, contract levels and design capability for the greater Lloydminster area. Peak expected flow is anticipated to rise throughout this forecast period.

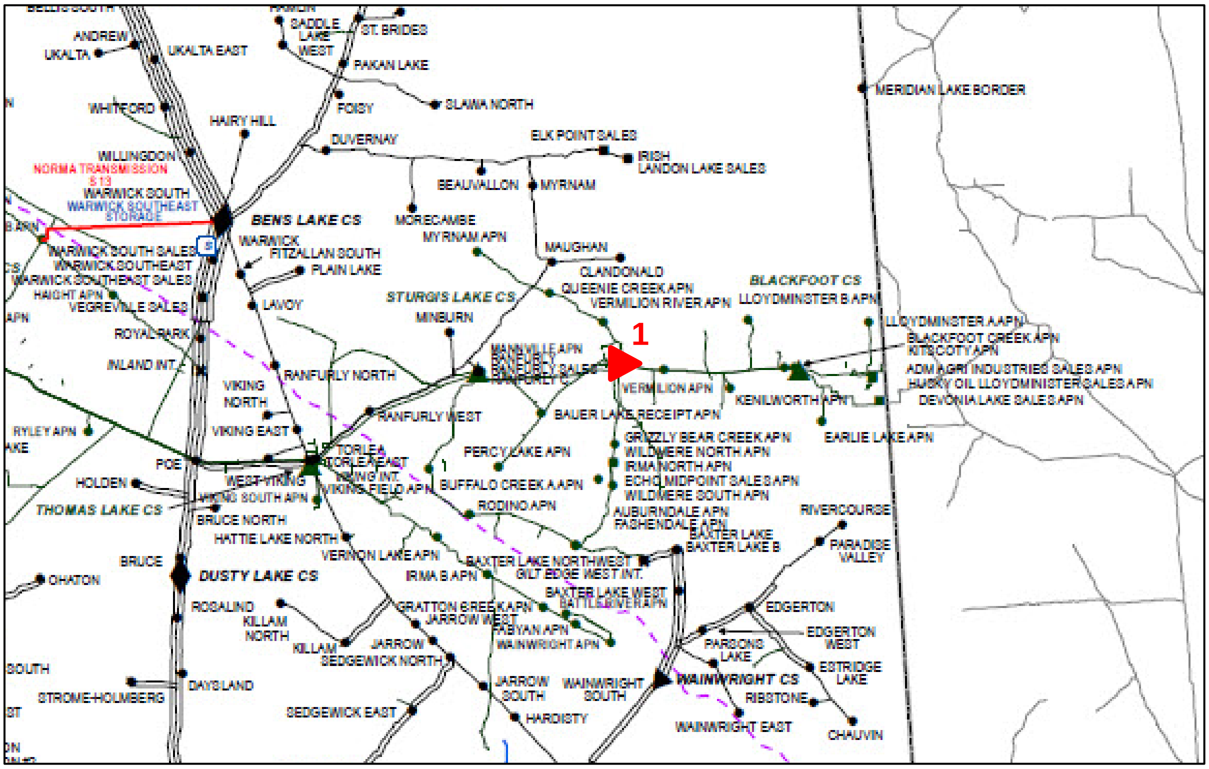
Figure 2-11: Greater Lloydminster Area Design Chart



2.3.6 Proposed Facilities – Greater Lloydminster Area (ATCO Pipelines)

Figure 2-12 shows the location of the proposed facility required to meet the design flow requirements of the greater Lloydminster area.

Figure 2-12: Greater Lloydminster Area Map – Proposed Facility



An application for the proposed facility is expected to be filed with the AUC in 2014 and the facility is proposed to be in-service in 2014. For details on the proposed facility, see Table 2-5.

Table 2-5: Greater Lloydminster Area Proposed Facility

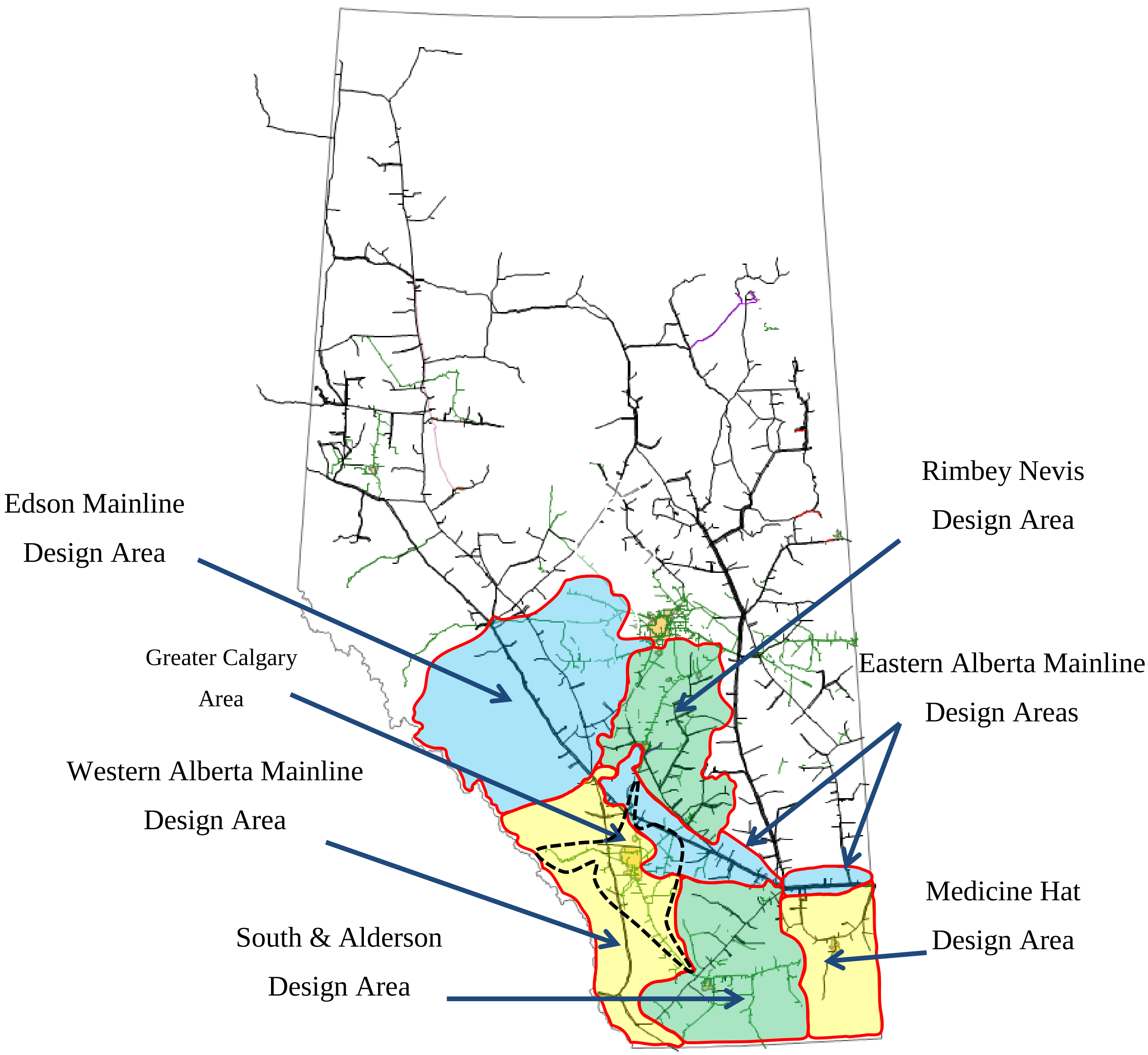
Map Location	Proposed Facility	Description	Target In-Service Date	Forecast Cost ($Millions)
1	Vermillion Compressor Station	3 MW Relocate	Nov 2014	14
Capital costs are in 2013 dollars and include AFUDC.			**Total**	**14**

2.4 MAINLINE PROJECT AREA

The Mainline Project Area comprises the Edson Mainline, Eastern Alberta Mainline, Western Alberta Mainline, Rimbey-Nevis, South and Alderson, and Medicine Hat Design Areas (see Figure 2-13).

In the Mainline Project Area, the proposed facilities are required to meet the required gas deliveries in the Medicine Hat Design Area and the greater Calgary area.

Figure 2-13: Mainline Project Area

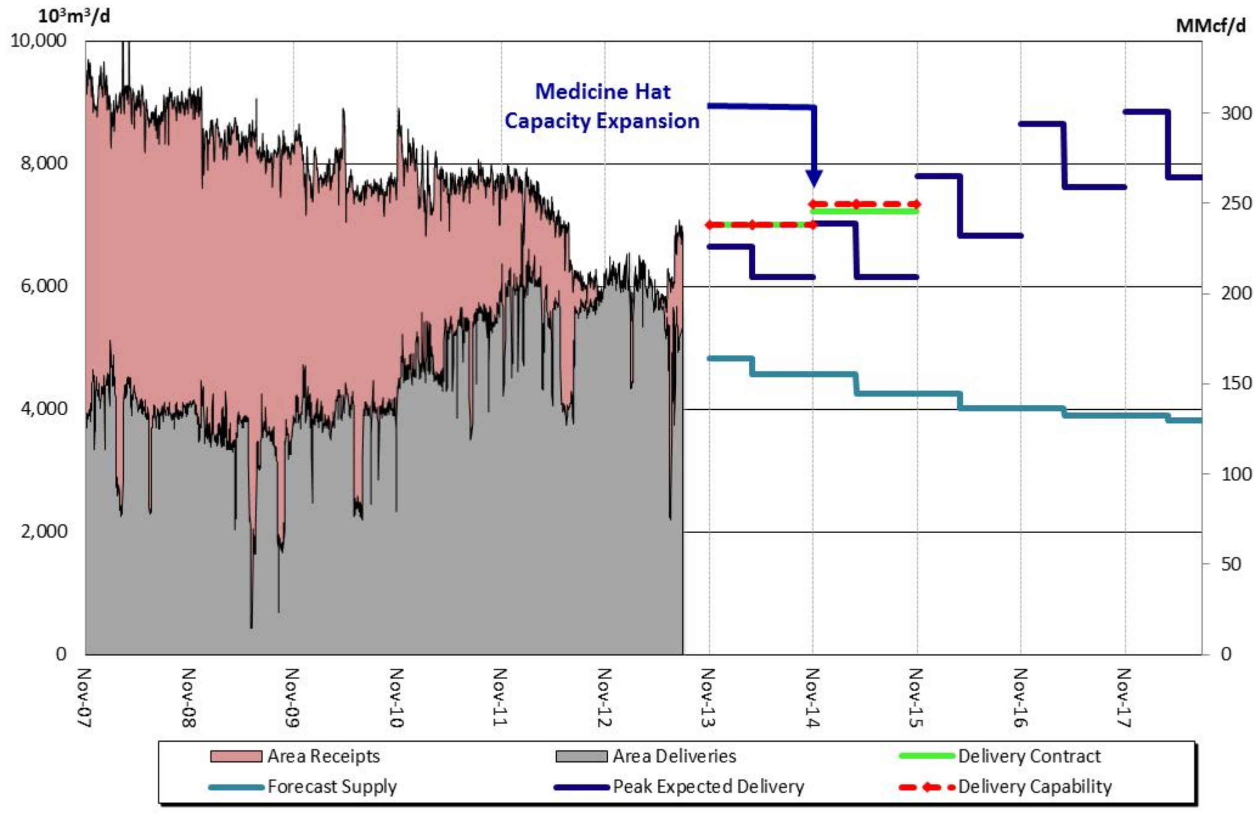


2.4.1 Design Flows – Medicine Hat Design Area

Peak expected flow for the flow-within design condition is the net effect of maximum deliveries less the minimum available local supply in the area. Continued delivery growth in the Medicine Hat Design Area will be accommodated by one proposed facility.

Figure 2-14 shows historical flow, projected peak expected flow, contract levels and design capability for the Medicine Hat Design Area. Peak expected flow is anticipated to rise throughout this forecast period.

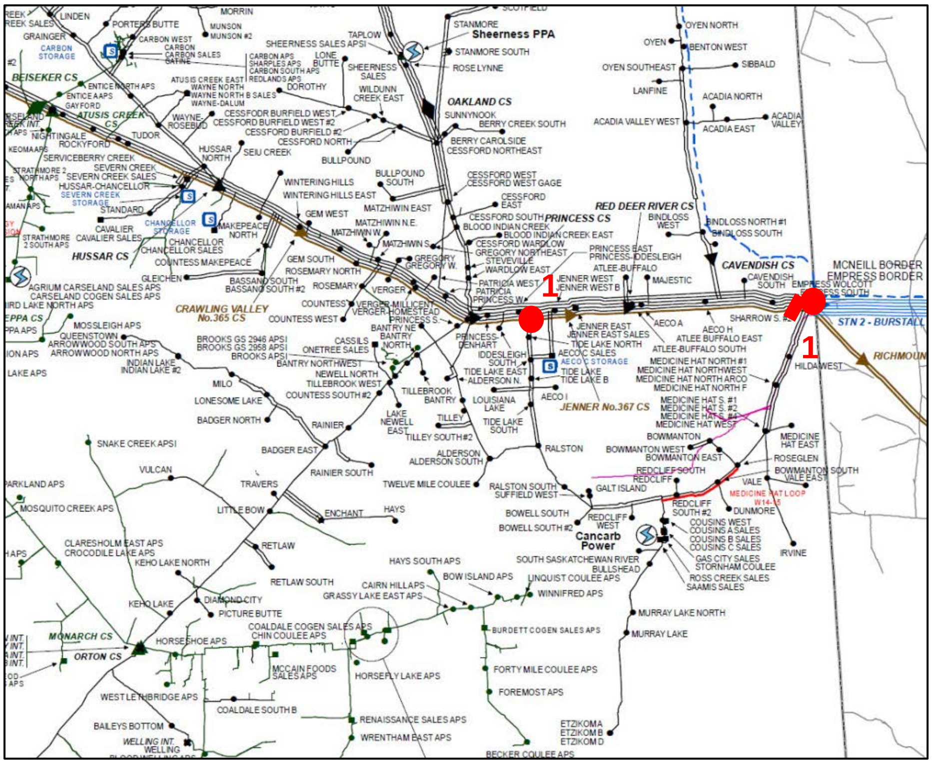
Figure 2-14: Medicine Hat Design Area Design Chart



2.4.2 Proposed Facilities – Medicine Hat Design Area

Figure 2-15 shows the location of the proposed facility required to meet the design flow requirements of the Medicine Hat Design Area.

Figure 2-15: Medicine Hat Design Area Map – Proposed Facility



An application for the proposed facility is expected to be filed with the NEB in 2014 and the facility is proposed to be in-service in 2014. For details on the proposed facility, see Table 2-6.

Table 2-6: Medicine Hat Design Area Proposed Facility

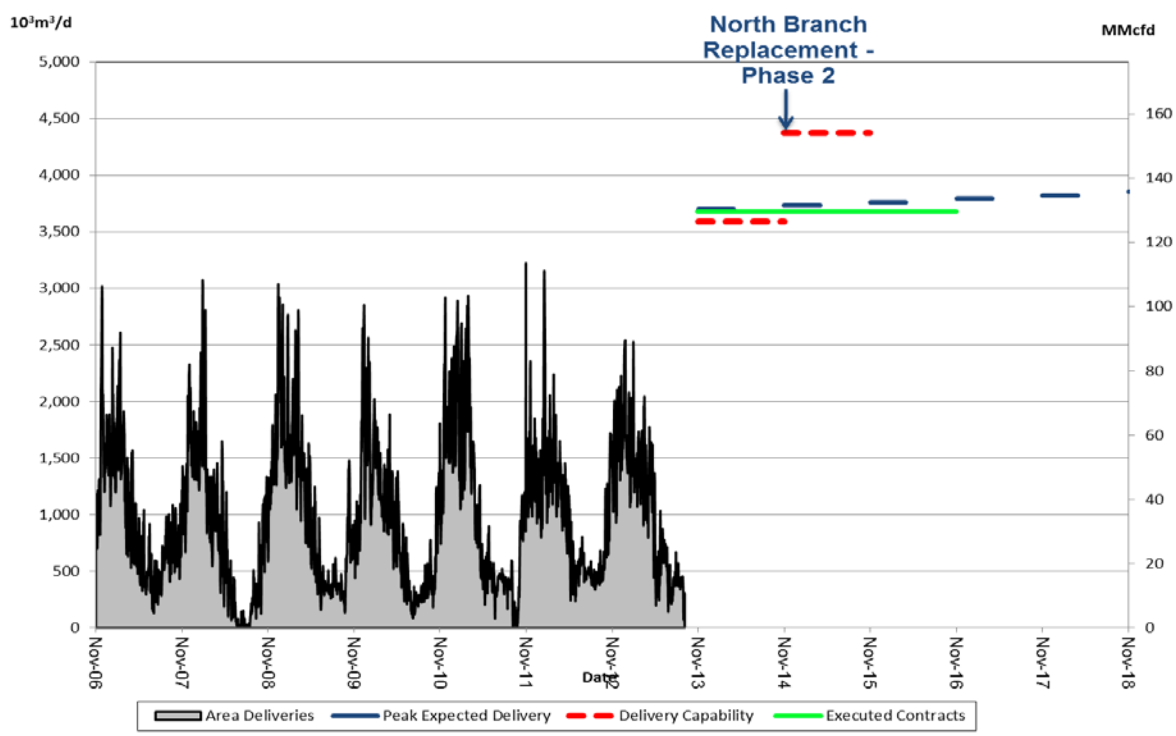
Map Location	Proposed Facility	Description	Target In-Service Date	Forecast Cost ($Millions)
1	Medicine Hat Capacity Expansion Project	1.2 km Connection, Meter Station, Control Valve, Pipe Modifications	Nov 2014	15
Capital costs are in 2013 dollars and include AFUDC.			**Total**	**15**

2.4.3 Design Flows – Greater Calgary Area (ATCO Pipelines)

Peak expected flow for the flow-within design condition is the net effect of maximum deliveries less the minimum available local supply in the area. Continued delivery growth, specifically on the Calgary North Branch, a delivery lateral in the northwest part of the city, will be accommodated by one proposed facility.

Figure 2-16 shows historical flow, projected peak expected flow, contract levels and design capability for the Calgary North Branch delivery lateral. Peak expected flow is anticipated to rise throughout this forecast period.

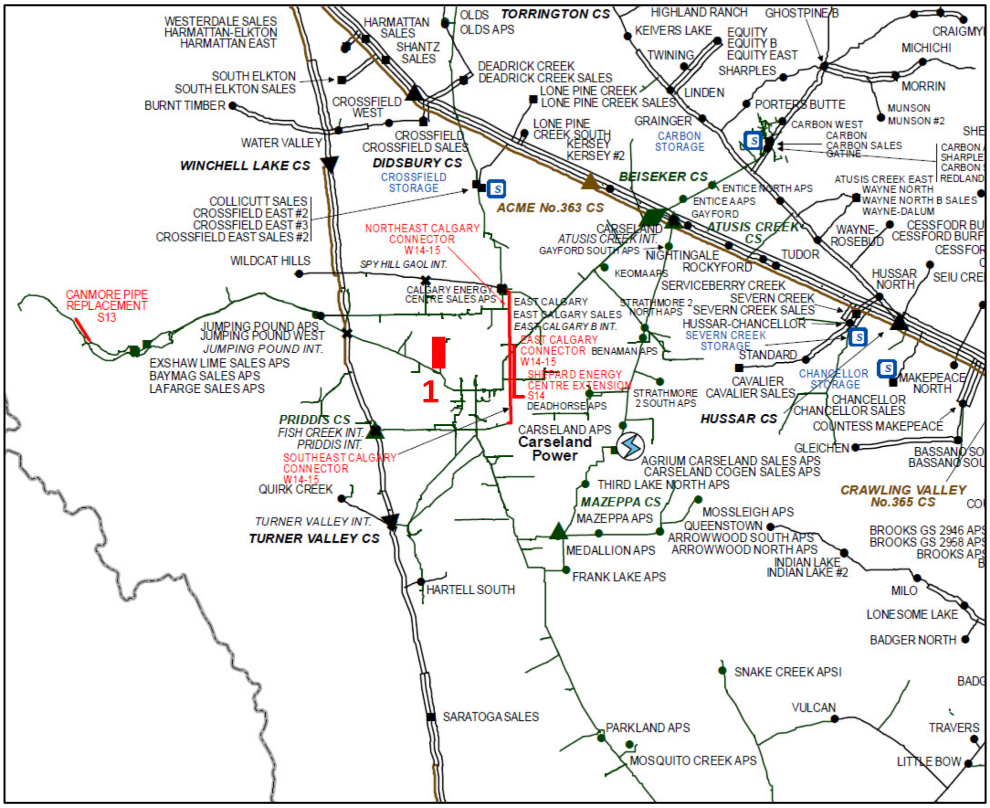
Figure 2-16: Calgary North Branch Delivery Lateral Design Chart



2.4.4 Proposed Facilities – Greater Calgary Area (ATCO Pipelines)

Figure 2-17 shows the location of the proposed facility required to meet the design flow requirements of the Calgary North Branch.

Figure 2-17: Greater Calgary Area Map – Proposed Facility



An application for the proposed facility is expected to be filed with the AUC in 2014 and the facility is proposed to be in-service in 2014. For details on the proposed facility, see Table 2-7.

Table 2-7: Greater Calgary Area Proposed Facility

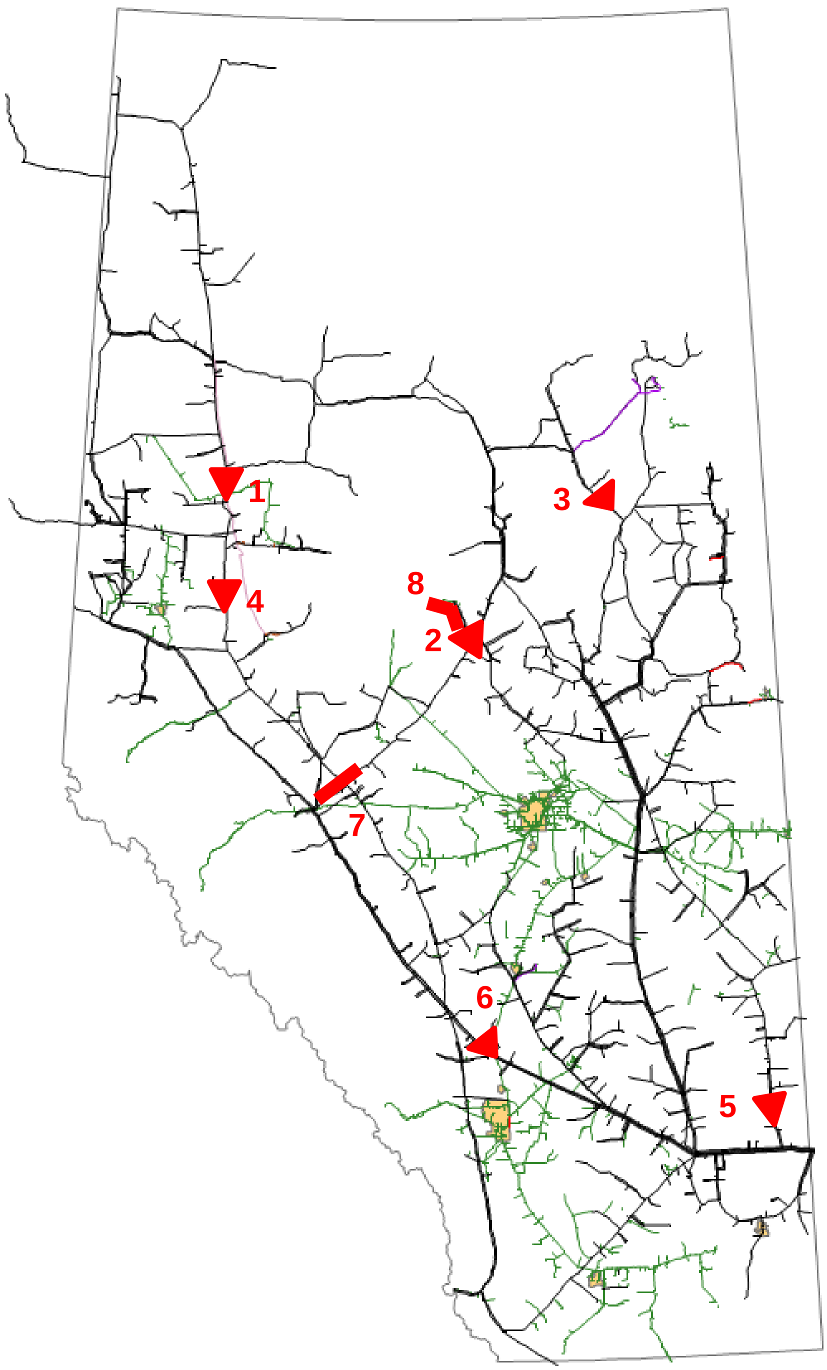
Map Location	Proposed Facility	Description	Target In-Service Date	Forecast Cost ($Millions)
1	North Branch Replacement	3 km NPS 16	Nov 2014	7
Capital costs are in 2013 dollars and include AFUDC.			**Total**	**7**

2.5 DEACTIVATION AND DECOMMISSIONING PROJECTS

Continual optimization of the changing NGTL System has identified a number of proposed facility deactivation and decommissioning projects. These facilities are no longer required to transport the design flow requirements.

Deactivation or decommissioning of these facilities is required to maintain regulatory compliance, avoid unnecessary capital spending, and reduce operating and maintenance expenses. For the locations of the proposed facility deactivation and decommissioning projects, see Figure 2-18.

Figure 2-18: Locations of Proposed Deactivation and Decommissioning Projects



The proposed projects are expected to be applied-for in the 2013/14 Gas Year and are proposed to be deactivated or decommissioned in 2014 through to 2015. For details on the proposed projects, see Table 2-8.

Table 2-8: Deactivation and Decommissioning Projects

Map Location	Proposed Compressor Project	Description	Target Date	Forecast Cost ($Millions)
1	Cardinal Lake	2 x 0.9 MW, 1.2 MW	Q1 2014	1.6
2	Slave Lake 1	1 MW	Q1 2014	1.7
3	Pelican Lake	3.3 MW	Q1 2014	2.4
4	Clarkson Valley	15.1 MW	Q1 2014	2.6
5	Cavendish	1.3 MW, 3 MW	Q2 2014	1.8
6	Didsbury	2 x 0.7 MW	Q2 2014	0.8
	Proposed Pipeline Project			
7	Marten Hills Extension	40 km NPS 20	Q3 2015	3.0
8	Mitsue Lateral Loop	13 km NPS 10 26 km NPS 8	TBD	3.1
Capital costs are in 2013 dollars and include AFUDC.			**Total**	**17.0**

3.0 EXTENSION FACILITIES, LATERAL LOOPS AND METER STATIONS

3.1 INTRODUCTION

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

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 *Gas Transportation Tariff of NOVA Gas Transmission Ltd.*, Appendix E: Criteria for Determining Primary Term.

For locations of the proposed extension facilities, lateral loops and meter stations, see Figure 3-1 and for facility details, see Table 3-1. These proposed facilities were presented at the TTFP meeting on October 22, 2013.

For a summary of the status of facilities that have been proposed, applied for, under construction or placed in-service since the 2012 Annual Plan, see Appendix 2: Facility Status Update.

Figure 3-1: Proposed Extensions, Lateral Loops and Meter Stations

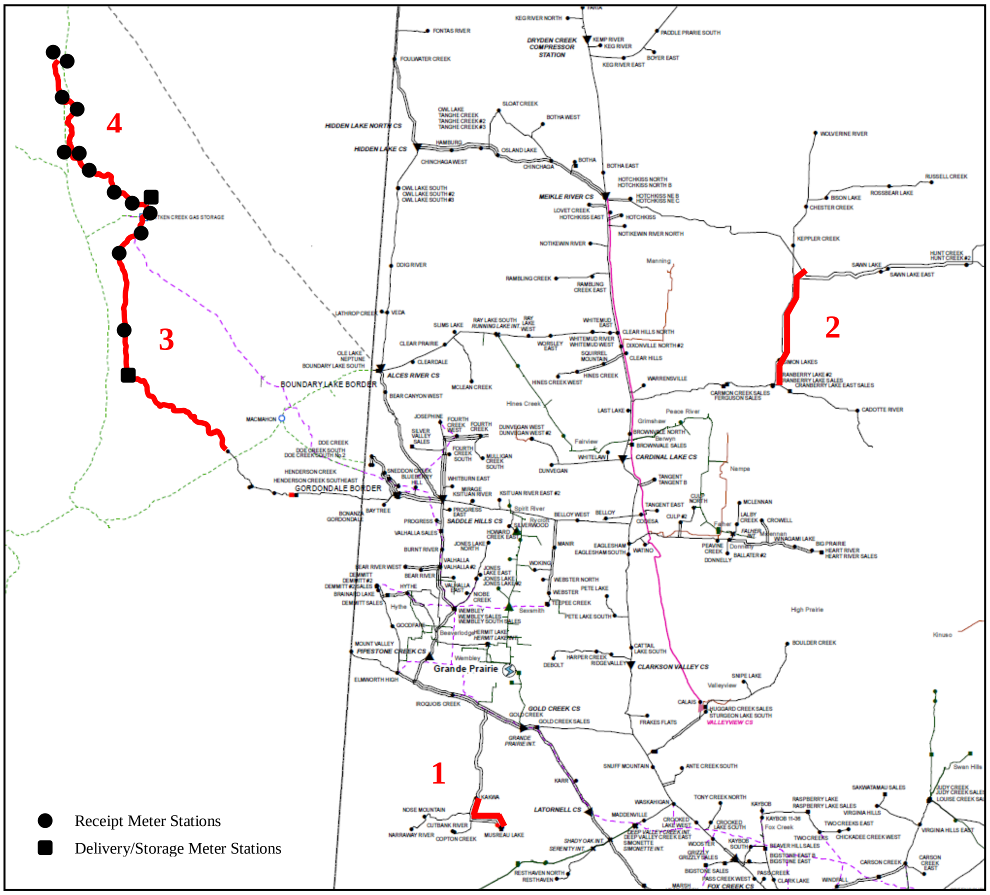


Table 3-1: Proposed Extensions, Lateral Loops and Meter Stations

Map Location	Proposed Facility	Description	Target In-Service Date	Forecast Cost ($Millions)
1	Cutbank River Lateral Loop No. 2 (Kakwa) Musreau Lake Lateral Loop No. 3	12 km NPS 24 16 km NPS 24	Apr 2015	55
2	Wolverine River Lateral Loop (Carmon Creek Pipeline Project)	62 km NPS 20[1]	Apr 2016	128
3	North Montney Mainline (Aitken Creek Section)	180 km NPS 42	Apr 2016	762
4	North Montney Mainline (Kahta Section)	125 km NPS 42	Apr 2017	530
	North Montney Mainline Meter Stations	13 Receipt 1 Delivery 1 Storage	2016 to 2019	66
Capital costs are in 2013 dollars and include AFUDC.			**TOTAL**	**1,541**

1. Pipe diameter has not been determined, forecast cost is based on NPS 20

3.2 FACILITY DESCRIPTION

Cutbank River Lateral Loop No. 2 (Kakwa Section) and Musreau Lake Lateral Loop No. 3

The Cutbank River Lateral Loop No. 2 (Kakwa Section) and Musreau Lake Lateral Loop No. 3 pipelines are required to meet incremental receipt contracts as a result of gas development in the Musreau Lake area. The target in-service date for the facilities is April 2015. The Section 58 facility application is scheduled to be filed with the NEB in April 2014.

Wolverine River Lateral Loop (Carmon Creek Pipeline Project)

The 62 km loop of the Wolverine River Lateral is required to provide additional capacity for incremental delivery contracts at the proposed Carmon Creek East Sales Meter Station for a proposed oil sands project in the area using thermal recovery methods. The pipeline loop diameter has not yet been finalized, but is anticipated to be up to NPS 24.

The target in-service date for the facility is April 1, 2016. The Carmon Creek Pipeline Project Description was filed with the NEB on November 15, 2013 and the Section 52 facility application is scheduled for NEB filing in March 2014.

North Montney Mainline (Aitken Creek and Kahta Sections)

The 180 km NPS 42 North Montney Mainline (Aitken Creek Section) and the 125 km NPS 42 North Montney Mainline (Kahta Section) extension facilities are required to accommodate receipt contract commitments along the North Montney supply fairway. The proposed extensions require associated compression facilities, which are described in Section 2.2.2. The target in-service dates for the extension facilities are April 2016 for the Aitken Creek Section and April 2017 for the Kahta Section.

The North Montney Project Description was filed with the NEB on August 6, 2013 and the Section 52 facility application was filed with the NEB on November 8, 2013. The NEB application also included 15 proposed meter stations:

- 4 receipt meter stations to be tied-in at various locations along the Aitken Creek Section
- 9 receipt meter stations to be tied-in at various locations along the Kahta Section
- 1 storage interconnect meter station to be tied-in at the north end of the Aitken Creek Section
- 1 delivery meter station to be tied-in at the south end of the Aitken Creek Section

Planned Meter Stations

Meter station projects are identified and planned to meet customer requests for service on an ongoing basis throughout the year. As new meter station projects are identified the TTFP will be informed and the new meter station projects will be included in the *2014 Facility Status Update*, which can be accessed at http://www.transcanada.com/customerexpress/871.html.

Appendix 1: Glossary of Terms

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 on to interpret NGTL's Gas Transportation Tariff or any Service Agreement. Capitalized terms not defined here are defined in NGTL's Gas Transportation Tariff.

Alberta Average Field Price

Average estimated price of natural gas (post processing) before receipt into the NGTL 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, 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 NGTL System at each receipt point.

Coincidental

Occurring at the same time.

Delivery Meter Station

A facility that measures gas volumes leaving the NGTL System.

Delivery Point

The point where gas might 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 NGTL System is divided into five delivery design areas used to facilitate delivery service within or between Delivery Design Areas:

- Northwest Alberta and Northeast BC Delivery Area
- Northeast Delivery Area
- Southwest Delivery Area
- Southeast Delivery Area
- Edmonton and Area Delivery Area

Demand Coincidence Factor

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

Design Area

The NGTL System is divided into three project areas – Peace River Project Area, North and East Project Area and Mainline Project Area. These project areas are subdivided into design and subdesign areas. This subdivision allows the system to be modelled in a way that best reflects the pattern of flows in each 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

Forecast of Peak Expected Flow required to be transported in a pipeline system considering design assumptions.

Design Forecast

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

Expansion Facilities

Facilities that will expand the existing NGTL 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 NGTL System.

Firm Transportation

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

Gas Year

A period beginning at 800 hours (08:00) Mountain Standard Time on the first day of November in any year and ending at 800 (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 NGTL System at Receipt Points or deliver gas off the NGTL 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.

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 expected to occur at a point or points on the NGTL System. For a design area or subdesign 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 NGTL System is divided into three project areas – Peace River Project Area, North and East Project Area and 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 area of the system. The Project Area could 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 NGTL System. The facilities in these areas include receipt meter stations and laterals.

Receipt Meter Station

A facility that measures gas volumes entering the NGTL System.

Receipt Point

The point on the NGTL System 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 NGTL System, and that is available to all customers.

Summer Season

The period starting 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 that includes qualifying a customer’s applications for service, designing additions to the system, sourcing all required facilities and installing facilities to meet firm transportation requests.

Winter Season

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

Appendix 2: 2013 Facility Status Update

This section describes the current status of facilities that were applied for, are under construction or have been placed on-stream since the 2012 Annual Plan was issued on December 14, 2012. Periodic updates are 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.

Table A2-1: Current Status of Facilities

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Aitken Creek Compressor Station	*15 MW Bi-directional*	*April 2019*	*Applied for Nov. 8 2013*	*October 22, 2013 TTFP Meeting*	*72*	*November*
Alces River Compressor Station Modifications	*Bi-directional Flow*	*November 2015*	*Proposed*	*October 22, 2013 TTFP Meeting*	*10*	*November*
Banff Loop Extension at Canmore (AP)	7 km NPS 6	4th qtr. 2013	Under construction	July 10, 2012 TTFP Notification	11.3	September
Bonanza Meter Station Upgrade	*2-1284U Ultrasonic Meter*	*February 2014*	*Applied for Oct. 15 2013*	*Oct. 1, 2013 TTFP Notification*	*3.0*	*November*
Bootis Hill Lateral Loop	5 km NPS 20	Feb. 2014	Project Cancelled[2]	Feb. 14/May 16 2012 TTFP Notification	24.3	April
Bootis Hill Meter Station Modifications	2-1280-4U Ultrasonic Meter	Feb. 2014	Project Cancelled	February 14, 2012 TTFP	2.2	April
Cardinal Lake Compressor Station Decommissioning – Units 1, 2 & 3	*2 – 0.8 MW units 1 – 1.2 MW unit*	*January 2014*	*Proposed*	*November 12, 2013 TTFP Notification*	*1.6*	*November*
Cavendish Compressor Station Decommissioning – Units 1 & 2	*1 – 1.3 MW unit 1 – 3 MW unit*	*Q2 2014*	*Proposed*	*October 22, 2013 TTFP Meeting*	*1.8*	*November*
Chinchaga Lateral Loop No. 3	33 km NPS 48	April 2014	*Under construction*	July 12/Sept 13, 2011 TTFP	140.7	*November*

[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.

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Clarkson Valley Compressor Station Decommissioning	*1 – 15.1 MW unit*	*Q1 2014*	*Proposed*	*October 22, 2013 TTFP Meeting*	*2.6*	*November*
Cutbank River Lateral Loop No. 2 (Kakwa Section)	*12 km NPS 24*	*April 2015*	*Proposed*	*October 22, 2013 TTFP Meeting*	*24.0*	*November*
Didsbury Compressor Station Decommissioning – Units 5 & 6	*2 – 0.7 MW unit*	*Q2 2014*	*Proposed*	*October 22, 2013 TTFP Meeting*	*0.8*	*November*
Divest Brazeau East Lateral & Pembina West Meter Station	3.8 km NPS 8		Sale Finalized Jan. 14 2013	June 12, 2012 TTFP Notification		January
Divest Hackett Lateral, Hackett Lateral Loop and Hackett Meter Station	2 – 6.5 km NPS 4	December 2013	*Sale Finalized Nov. 21 2013*	July 15, 2013 TTFP Notification	0.4	*November*
Decommission Alberta System Meter Stations and Associated Laterals	Flatbush Edward South Fourth Creek South Owlseye Oyen	3rd qtr. 2013	*Completed October 8, 2013*	June 7, 2012 TTFP Notification	1.7	*November*
Decommission Alces River Compressor Station – A Plant	3.3 MW	July 2013	Completed July 31, 2013	June 10, 2013 TTFP Notification	1.3	September
Decommission Beaver Creek Compressor Station – Units 1, 2, & 3	3 – 1 MW units	September 2013	*Completed September 18, 2013*	July 26, 2013 TTFP Notification	1.8	*November*
Decommission Bens Lake 'A' Compressor Station – Units 1, 2, 3 & 7	4 – 1 MW units	October 2013	*Completed October 27, 2013*	September 6, 2013 TTFP Notification	2.4	*November*
Decommission Nine NGTL System Meter Stations and Associated Laterals	Caslan Crossfield West Fawcett River Flat Lake North Keho Lake Meyer "A" & Meyer "B" Virginia Hills East Webster North	4th qtr. 2013	*Approved September 19, 2013*	May 8, 2013 TTFP Notification	2.2	*November*
Decommission Princess Compressor Station A – Units 1, 2, 3, 4 & 5	3 – 2.7 MW units 2 – 4.5 MW units	November 2013	Notification Filed August 26, 2013	August 12, 2013 TTFP Notification	2.2	September

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Denning Lake Compressor Station	3.5 MW	November 2014	*Approved Sept 25 2013*	November 20, 2012 TTFP June 7, 2013 TTFP Notification	34.7	*November*
East Calgary Connector (AP)	11 km NPS 30	*2015*	Proposed	July 12, 2011 TTFP	*41.8*	*November*
Grey Owl Creek Meter Station	660 Orifice Meter	November 2013	*In-service Oct. 31 2013*	May 3, 2013 TTFP Notification	*1.5* (less 0.2 CIAC)	*November*
Groundbirch Compressor Station	*30 MW Bi-directional*	*April 2017*	*Applied for Nov. 8 2013*	*October 22, 2013 TTFP Meeting*	*103*	*November*
Hangingstone Sales Meter Station	2-1280T Turbine Meter	*February 2014*	*Variance Application Nov. 1, 2013*	Aug. 20, 2012 TTFP Notification	*2.7*	*November*
Hanmore Lake Compressor Station Decommissioning – Units A1 & A2	*2 – 0.5 MW units*	*November 2013*	*Notification Filed October 21, 2013*	*October 7, 2013 TTFP Notification*	*1.5*	*November*
Hidden Lake North Compressor Station	15 MW	March 2013	In-service Mar. 19 2013	2010 Annual Plan	66.6	April
Horn River Mainline (HRML) Loop (Kyklo Creek Section)	29.1 km NPS 42	April 2013	In-service Mar. 30 2013	2010 Annual Plan	97.4	April
HRML (Komie North Section) & Fortune Creek M.S.	100 km NPS 36	April 2015	NEB recommends Certificate should not be approved Jan 30 2013	July 12/Sept 13, 2011 TTFP	227.3 2.5	February
HRML Loop (Townsoitoi Section)	27 km NPS 42	TBD	Proposed	July 12/Sept 13, 2011 TTFP	77.5	
Inland Looping (AP)	*18 km NPS 20*	*November 2015*	*Proposed*	*October 22, 2013 TTFP Meeting*	*29.0*	*November*
Leismer to Kettle River Crossover	79 km NPS 30	April 2013	In-service Apr. 26 2013	2010 and May 10, 2011 TTFP	149.9	June
Leming Lake Sales Lateral Loop	37 km NPS 20	April 2014	Approved Sept 13 2013	November 20, 2012 TTFP	61.0	September
Little Sundance Meter Station Upgrade	660-2 Orifice Meter	September 2013	*In-service Sep. 11 2013*	July 10, 2013 TTFP Notification	*1.5*	*November*
MacKay Sales Meter Station	2-860T Turbine Meter	December 2014	Applied for Sept 16 2013	June 10, 2013 TTFP Notification	1.6	September
Marten Hills Extension Decommissioning	*40 km NPS 20*	*Q3 2015*	*Proposed*	*October 22, 2013 TTFP Meeting*	*3.0*	*November*

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Medicine Hat Area Capacity Expansion Foothills Control Valve at Empress	EASML NPS 48 Loop #4 Modifications Tie-in / Control Valve / 2-1610 Ultrasonic Meter	November 2014	Proposed	*October 22, 2013 TTFP Meeting*	*15.2*	*November*
Minnehik Buck Lake & Minnehik Buck Lake B Meter Station Modifications and Minnehik Buck Lake Lateral Modifications	Sour Bottle & Sour Monitoring and shut-in facility	May 2013	In-service May 25 2013	April 5, 2013 TTFP Notification	*1.5*	*November*
Mitchell Creek Meter Station	2-1064U Ultrasonic Meter	December 2013	Approved Sept 13 2013	May 3, 2013 TTFP Notification	2.2	September
Mitsue Lateral Loop Decommissioning	*13 km NPS 10 26 km NPS 8*		*Proposed*	*October 22, 2013 TTFP Meeting*	*3.1*	*November*
Moody Creek Compressor Station	15 MW	January 2013	In-service Jan. 28 2013	2010 Annual Plan	54.6	March
Moosa Crossover	5 km NPS 20	April 2014	*Approved October 29 2013*	November 20, 2012 TTFP	12.6	*November*
Musreau Lake Lateral Loop No. 3	*16 km NPS 24*	*April 2015*	*Proposed*	*October 22, 2013 TTFP Meeting*	*31.0*	*November*
Musreau Lake West Meter Station	2-1284U Ultrasonic Meter	December 2013	*Approved November 5 2013*	August 6, 2013 TTFP Notification	3.2	*November*
Norma Transmission (AP) Norma Transmission (NGTL)	38 km NPS 20 3 km NPS 20	November 2013 November 2013	*In-service Oct. 24 2013* *In-service Oct. 22 2013*	July 10, 2012 TTFP Notification November 20, 2012 TTFP	52.0 8.4	*November* November
North Branch Replacement (AP)	*3 km NPS 16*	*November 2014*	*Proposed*	*October 22, 2013 TTFP Meeting*	*7.0*	*November*
North Montney Mainline (Aitken Creek Section) [3]	*180.9 km NPS 42*	*April 2016*	*Applied for Nov. 8 2013*	*October 22, 2013 TTFP Meeting*	*762*	*November*

[3] The North Montney Project was filed as a Section 52 application consisting of the following facilities: North Montney Mainline (Aitken Creek Section), North Montney Mainline (Kahta Section), Aitken Creek Compressor Station, Saturn Compressor Station, Groundbirch Compressor Station, 13 receipt meter stations, a bi-directional storage meter station (Aitken Creek Interconnect) and a delivery meter station (Mackie Creek Interconnection).

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
North Montney Mainline (Kahta Section)	*125 km NPS 42*	*April 2017*	*Applied for Nov. 8 2013*	*October 22, 2013 TTFP Meeting*	*530*	*November*
North Montney Mainline Meter Stations *Receipt Meter Stations:* *Kahta Creek* *Kahta Creek North* *Buckinghorse River* *Mason Creek* *Beatton River* *Lily* *Halfway River* *Blair Creek* *Aitken Creek West* *Aitken Creek East* *Gundy* *Kobes* *Altares* *Storage Meter Station:* *Aitken Creek Interconnect* *Delivery Meter Station:* *Mackie Creek Interconnection*	*2-1064U Ultrasonic Meters* *2-3020U Ultrasonic Meter* *2-3020U Ultrasonic Meter*	*April 2017* *January 2019* *April 2017* *January 2019* *April 2017* *April 2017* *April 2017* *April 2018* *January 2019* *April 2017* *April 2016* *January 2019* *April 2016* *April 2016* *January 2019*	*Applied for Nov. 8 2013*	*October 22, 2013 TTFP Meeting*	*66*	*November*
Northeast Calgary Connector (AP)	17 km NPS 24	*2015*	Proposed	2011 Annual Plan	*43.7*	*November*
Northwest Mainline Loop (Timberwolf Section)[4]	49.8 km NPS 48	April 2013	In-service Apr. 30 2013	2010 Annual Plan	202.2	June
NWML Loop (Pyramid Section)	30 km NPS 48	TBD	Proposed	July 12/Sept 13, 2011 TTFP	92.5	
Otter Lake Compressor Station	*28 MW*	*November 2015*	*Proposed*	*October 22, 2013 TTFP Meeting*	*100*	*November*
Peace River Mainline *Decommissioning / Abandonment* (Meikle River to Valleyview section)	266 km NPS 20 2.3 km NPS 4	*Q3 2015*	*Proposed*	*October 22, 2013 TTFP Meeting*	*13.7*	*November*

[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	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Peigan Trail Pipeline (AP)	8 km NPS 20	2016	Proposed	July 10, 2012 TTFP Notification	*32.5*	*November*
Pelican Lake Compressor Station Decommissioning – Unit 2	*1 – 3.3 MW unit*	*Q1 2014*	*Proposed*	*October 22, 2013 TTFP Meeting*	*2.4*	*November*
Resthaven Meter Station Upgrade	*2-1280-4U Ultrasonic Meter*	*August 2014*	*Applied for November 4 2013*	*Oct. 21, 2013 TTFP Notification*	*2.2*	*November*
Saddle Hills Compressor Station Modifications	*Bi-directional Flow*	*November 2015*	*Proposed*	*October 22, 2013 TTFP Meeting*	*10*	*November*
Saddle Lake Lateral Loop	12.1 km NPS 16	April 2014	*Under construction*	November 20, 2012 TTFP	19.7	*November*
Saturn Compressor Station	*15 MW Bi-directional*	*April 2017*	*Applied for Nov. 8 2013*	*October 22, 2013 TTFP Meeting*	*70*	*November*
Saturn Compressor Station – Unit 2	*15 MW Bi-directional*	*April 2019*	*Applied for Nov. 8 2013*	*October 22, 2013 TTFP Meeting*	*63*	*November*
Shepard Energy Centre Extension (AP)	15.8 km NPS 20, associated Delivery Station (2-1612T Turbine Meter) and associated system modifications	July 2014	Approved Aug. 14 2013 (AUC)	November 20, 2012 TTFP	71.8	September
Slave Lake Compressor Station Decommissioning – Unit 1	*1 – 1 MW unit*	*Q1 2014*	*Proposed*	*October 22, 2013 TTFP Meeting*	*1.7*	*November*
Snipe Hills Compressor Station	*3.5 MW*	*November 2015*	*Proposed*	*October 22, 2013 TTFP Meeting*	*45*	*November*
South Lateral Princess Control Valve	Pressure control valve station	November 2013	*In-service Nov. 16 2013*	August 1, 2013 TTFP Notification	5.9	*November*
Southeast Calgary Connector (AP)	11 km NPS 24	2014	Applied for	July 12, 2011 TTFP	*29.4*	*November*
Southwest Edmonton Connector (AP)	20 km NPS 20	2015	Proposed	July 10, 2012 TTFP Notification	*42.0*	*November*
Sunday Creek South Lateral Loop No. 3	12.8 km NPS 24	April 2014	Approved Aug. 13 2013	November 20, 2012 TTFP	31.0	September
Sunday Creek South Sales Meter Station	2-1280U Ultrasonic Meter	December 2012	In-service Dec. 11 2012	October 18, 2012 TTFP Notification	2.5	January
Tanghe Creek Lateral Loop No. 2 (Cranberry Section)	32.3 km NPS 48	April 2013	In-service Apr. 2 2013	2010 Annual Plan	117.7	April

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Upgrade Indus Pipeline System (AP)	20 km NPS 4	4th qtr. 2013	Approved Jul. 8 2013 (AUC)	July 10, 2012 TTFP Notification	8.4	September
Valleyview Compressor Station Decommissioning	*1 – 3 MW unit*	*Q2 2014*	*Proposed*	*October 22, 2013 TTFP Meeting*	*1.8*	*November*
Vermillion Compressor Station (AP)	*3.0 MW*	*November 2014*	*Proposed*	*October 22, 2013 TTFP Meeting*	*14.0*	*November*
Wapasu Creek Sales Meter Station	2 - 1280U Ultrasonic Meter	April 2013	In-service Apr. 1 2013	May 10, 2012 TTFP Notification	*2.9*	*November*
Wildhay River Meter Station Modifications	Sour Conversion and NPS 20 PTI	June 2013	In-service Aug. 8 2013	May 3, 2013 TTFP Notification	1.5 (100% CIAC)	September
Wolverine River Lateral Loop	*62 km NPS 20*	*April 2016*	*Project Description Filed November 15, 2013*	*October 22, 2013 TTFP Meeting*	*128.0*	*November*

Appendix 3: System Map

The System Map, including the 2013 Annual Plan facilities, is expected to be available in March 2014 and can be accessed at http://www.transcanada.com/customerexpress/5245.html.