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December 15, 2014

All Customers
Other Interested Parties

Re: 2014 Annual Plan

NOVA Gas Transmission Ltd ("NGTL") has posted its 2014 Annual Plan on TransCanada Pipelines Limited's website at:

http://www.transcanada.com/customerexpress/5328.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 & System Design

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EXECUTIVE SUMMARY

The 2014 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 2014/15 Gas Year. The 2014 Annual Plan describes NGTL's long-term outlook for receipts, deliveries, peak expected flows, design flow requirements and proposed facilities for the 2015/16 to 2016/17 Gas Years. This 2014 Annual Plan is based on NGTL's June 2014 Design Forecast of receipts and deliveries.

Since the release of the 2013 Annual Plan, TransCanada Pipelines Limited (TransCanada) has identified 20 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 August 2014 and April 2016 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 30, 2014. New facilities proposed after issuance of this Annual Plan will be shown in the *2015 Facility Status Update*, which can be accessed at http://www.transcanada.com/customerexpress/871.html.

For the 21 facilities additions identified in the 2014 Annual Plan, see Table E-1.

Table E-1: Proposed Facilities Additions / Deactivation and Decommissioning Projects

Project Area	Proposed Facilities	Annual Plan Reference	Description	Target In-Service Date	Regulator	Capital Cost ($ Millions)
Peace River	Alces River C/S Modifications	Chapter 2	Bi-Directional Modifications	Nov 2015	NEB	10
Peace River	Saddle Hills C/S Modifications	Chapter 2	Bi-Directional Modifications	Nov 2015	NEB	10
North and East	Woodenhouse Coolers	Chapter 2		Nov 2015	NEB	25
Mainline	Pembina Looping - Phase 1 (AP)	Chapter 2	5 km NPS 24	Nov 2015	AUC	9
Peace River	Cutbank River Lateral Loop No. 2 (Pinto Creek Section) plus Musreau Lake North Receipt Meter Station	Chapter 3	32 km NPS 24	Apr 2016	NEB	92
North and East	McDermott Extension plus Calumet River Sales & Calumet River No.2 Sales Meter Stations	Chapter 3	8 km NPS 20	Apr 2016	NEB	44
Peace River	Simonette Lateral Loop plus Simonette East Receipt Meter Station	Chapter 3	22 km NPS 24	Apr 2016	NEB	84
Peace River	Meikle River D C/S	Chapter 2	33 MW	Nov 2016	NEB	136
North and East	Goodfish Compressor Station	Chapter 2	30 MW	Nov 2016	NEB	135
North and East	Inland Looping (AP)	Chapter 2	18 km NPS 20	Nov 2016	AUC	29
Mainline	Pembina Looping - Phase 2 (AP)	Chapter 2	17 km NPS 24	Nov 2016	AUC	31
Peace River	Alces River C/S Unit Addition	Chapter 2	15 MW	Apr 2017	NEB	79
Peace River	Grande Prairie Mainline Loop #2 (McLeod)	Chapter 2	37 km NPS 48	Apr 2017	NEB	207
Peace River	Hidden Lake North C/S Unit Addition	Chapter 2	15 MW	Apr 2017	NEB	78
Peace River	Northwest Mainline Loop (Bear Canyon)	Chapter 2	27 km NPS 36	Apr 2017	NEB	110
Peace River	Northwest Mainline Loop (Boundary Lake)	Chapter 2	91 km NPS 36	Apr 2017	NEB	384
North and East	Kettle River Lateral Loop (Christina River)	Chapter 2	20 km NPS 24	Apr 2017	NEB	77
North and East	Liege Lateral Loop No.2 (Pelican Lake)	Chapter 2	56 km NPS 30	Apr 2017	NEB	215
North and East	Otter Lake CS Unit Addition	Chapter 2	30 MW	Apr 2017	NEB	115

North and East	South Kirby Expansion Project	Chapter 2	42 km NPS 24	Apr 2017	NEB	137
North and East	Woodenhouse CS Unit Addition	Chapter 2	30 MW	Apr 2017	NEB	136
Mainline	Suffield Lateral Loop	Chapter 2	27 km NPS 20	Nov 2016	NEB	50
	Deactivation and Decommissioning Projects	Chapter 2	2 Compressor Projects 5 Pipeline Projects	2015	NEB	34
					Total	**2227**

The Alces River and Saddle Hills modifications, Woodenhouse coolers, Meikle River, Goodfish, Alces, Hidden Lake North, Otter Lake, and Woodenhouse compressor additions, McLeod, Bear Canyon, Boundary Lake, Christina River, and Pelican Lake pipeline loops are required to transport additional supply from the Peace River Project Area to meet additional system demand, primarily in the North and East Project Area.

The Pembina Phase 1, Phase 2, and Inland pipeline loops are required to transport additional supply into the Greater Edmonton Area to meet growing residential and industrial demand.

The Cutbank River Lateral Loop No. 2 (Pinto Creek Section) plus Musreau Lake North Receipt Meter Station and the Simonette Lateral Loop plus Simonette East Receipt Meter Station are required to transport growing supply in the Lower Peace River Design Area.

The McDermott Extension plus Calumet River Sales & Calumet River No.2 Sales Meter Stations are required to transport additional supply to accommodate oil sands demand.

The South Kirby Expansion Project is required to transport additional supply into the North of Bens Lake Design Area to meet growing oil sands demand.

The Suffield Lateral Loop is required to transport additional supply into the Medicine Hat Design Area to address receipt decline and continue to meet demand in the area.

This 2014 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 2014 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 June 2014 Design Forecast of receipts and deliveries for the NGTL System. An overview of the June 2014 Design Forecast was presented at the October 30, 2014 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 2014 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 early 2014, reflect broader trends in the North American economy and energy markets, and underlie the forecast of receipts and deliveries:

- Over the next several years, North American natural gas demand will gradually increase 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 broadly based, increasing in the electricity generation and industrial sectors as well as for LNG exports. Canadian industrial gas demand is expected to be 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 at moderate prices because of the strength in unconventional gas production, primarily

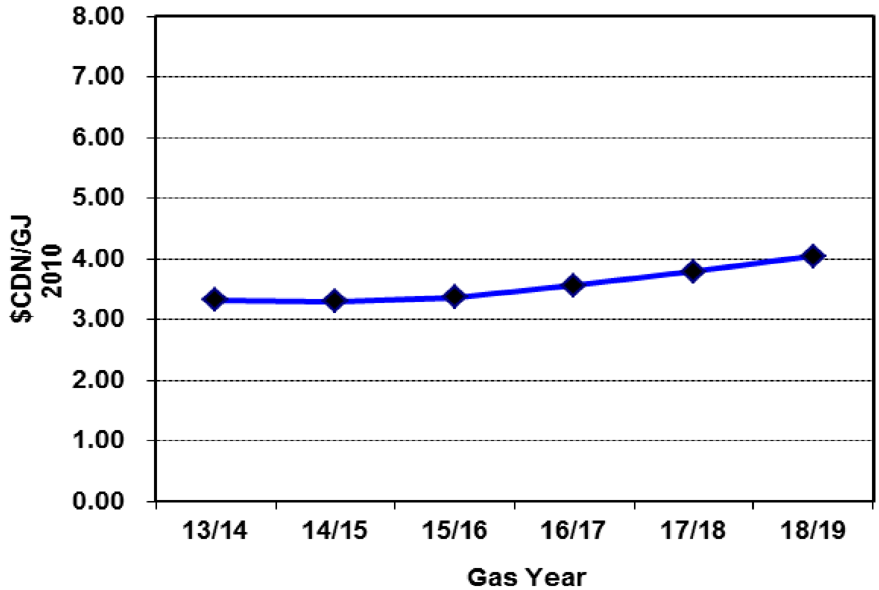
shale gas. The size of the North American natural gas resource base has expanded dramatically over the past few years, assuring many decades of moderate cost gas supplies for domestic users. The resource base is now so extensive that numerous LNG export projects are being developed in both the U.S. and Canada. Those in the U.S. will begin just after the middle of the decade and those from Canada beginning at the end of this decade. These projects will serve as a substantial source of incremental demand and help balance the ongoing rapid growth in gas supply.

- Recent short-term gas prices have been soft because of weakness in natural gas demand due to the slow pace of economic recovery as well as the rapid expansion of shale gas supplies. 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 gradually rises from today's level toward an equilibrium price of $US 4.80/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 Average Field Price

TransCanada's NYMEX gas price forecast was used to develop the 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 2014 and reflects the general assumptions from Section 1.2.1.

Figure 1.1: Average Field Price



The Average Field Price during 2013 rebounded over 30% from the seventeen year low seen during 2012, averaging $2.69 Cdn/GJ in real 2010 $ for the year. The Average Field Price is forecast to rebound along with the NYMEX price, reaching the long term equilibrium price of $4.21 Cdn/GJ real $2010 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 2014/15 through 2018/19 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

	June 2014 Design Forecast ($10^6 m^3/d$)				
Delivery Type	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Export	167.3	159.0	159.4	160.9	171.7
Intra Basin	138.1	144.9	152.5	160.8	167.7
Total System	**305.4**	**303.9**	**311.9**	**321.7**	**339.4**
	June 2014 Design Forecast (Bcf/d)				
Delivery Type	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Export	5.90	5.61	5.63	5.68	6.06
Intra Basin	4.88	5.12	5.38	5.68	5.92
Total System	**10.78**	**10.73**	**11.01**	**11.36**	**11.98**
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	June 2014 Design Forecast ($10^6 m^3$/d)				
	2014/15	2015/16	2016/17	2017/18	2018/19
Peace River	2.5	2.7	2.8	3.1	3.8
North and East	92.3	98.0	103.6	110.4	115.5
Mainline	41.0	42.0	43.8	45.0	46.0
Gas Taps	2.2	2.2	2.2	2.3	2.3
Total	**138.1**	**144.9**	**152.5**	**160.8**	**167.7**
Project Area	**June 2014 Design Forecast (Bcf/d)**				
	2014/15	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Peace River	0.09	0.10	0.10	0.11	0.14
North and East	3.26	3.46	3.66	3.90	4.08
Mainline	1.45	1.48	1.55	1.59	1.62
Gas Taps	0.08	0.08	0.08	0.08	0.08
Total	**4.88**	**5.12**	**5.38**	**5.68**	**5.92**

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 system.

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 June 2014 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	June 2014 Design Forecast ($10^6m^3/d$)				
	2014/15	2015/16	2016/17	2017/18	2018/19
Peace River	13.1	15.6	17.0	19.0	19.8
North and East	160.7	176.3	188.0	205.9	216.9
Mainline	79.6	80.5	83.4	86.4	91.8
Gas Taps	4.5	4.6	4.6	4.6	4.6
Total	**258.0**	**277.0**	**292.9**	**316.0**	**333.1**
Project Area	**June 2014 Design Forecast (Bcf/d)**				
	2014/15	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Peace River	0.46	0.55	0.60	0.67	0.70
North and East	5.67	6.22	6.64	7.27	7.66
Mainline	2.81	2.84	2.94	3.05	3.24
Gas Taps	0.16	0.16	0.16	0.16	0.16
Total	**9.11**	**9.78**	**10.34**	**11.15**	**11.76**

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

Table 1-4: Summer Maximum Day Delivery Forecast

Project Area	June 2014 Design Forecast ($10^6m^3/d$)				
	2014/15	2015/16	2016/17	2017/18	2018/19
Peace River	10.9	13.0	14.2	16.0	16.7
North and East	133.6	149.4	159.5	174.5	184.1
Mainline	62.5	63.6	65.9	68.7	73.3
Gas Taps	3.6	3.6	3.6	3.6	3.6
Total	**210.6**	**229.7**	**243.2**	**262.8**	**277.6**
Project Area	**June 2014 Design Forecast (Bcf/d)**				
	2014/15	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Peace River	0.38	0.46	0.50	0.56	0.59
North and East	4.72	5.28	5.63	6.16	6.50
Mainline	2.21	2.25	2.33	2.43	2.59
Gas Taps	0.13	0.13	0.13	0.13	0.13
Total	**7.31**	**7.98**	**8.46**	**9.15**	**9.67**

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

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 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 over 2.5 bcf/d of incremental volumes of shale and tight gas entering the NGTL System in the Peace River Project Area by the 2018/19 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 June 2014 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 2014/15 through 2018/19 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	June 2014 Design Forecast ($10^6m^3/d$)				
	2014/15	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Peace River	167.8	178.4	193.1	211.0	239.3
North and East	19.7	16.5	14.8	13.9	12.8
Mainline	115.0	103.8	97.8	93.4	87.1
Total	302.4	298.6	305.7	318.2	339.2
Project Area	**June 2014 Design Forecast (Bcf/d)**				
	2014/15	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Peace River	5.92	6.30	6.82	7.45	8.45
North and East	0.70	0.58	0.52	0.49	0.45
Mainline	4.06	3.66	3.45	3.30	3.08
Total	10.68	10.54	10.79	11.23	11.97

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

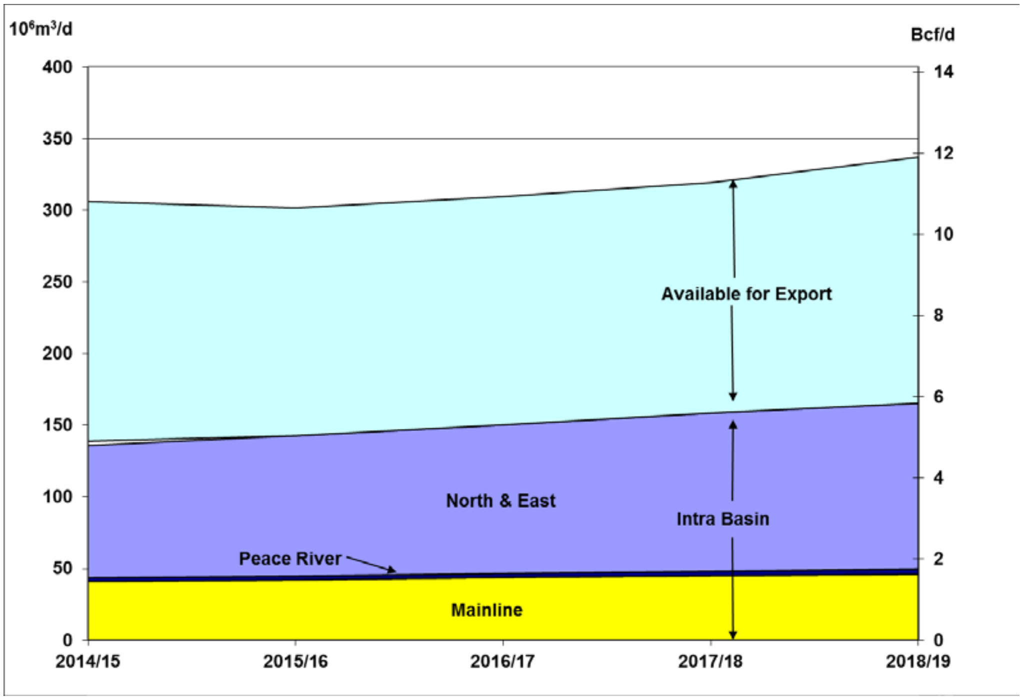
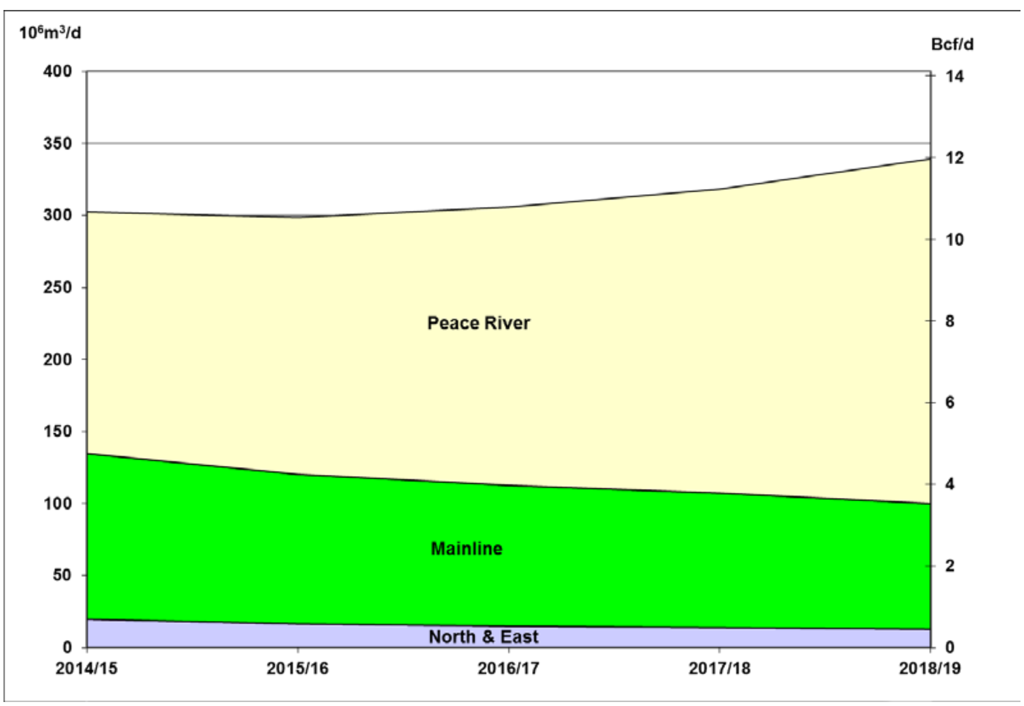


Figure 1-3: System Receipts by Project Area



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 24.2 to 30.9 $10^6 m^3/d$.

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 – 2013/14	
	$10^6m^3/d$	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 FLOWS 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 2014/15 Gas Year to meet the design flow requirements. Included is information regarding size, routes, locations and cost estimates.

The design flows are presented for design areas where new mainline facilities are required. Design flows are based on the June 2014 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 design 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 design 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 flows, proposed facilities, and deactivation and decommissioning projects resulting from the June 2014 design forecast were presented at the TTFP meeting on October 30, 2014.

For a summary of the status of mainline facilities that have been proposed, applied for, under construction or placed in-service since the December 2013 Annual Plan, see Appendix 2: Facility Status Update.

2.2 PEACE RIVER PROJECT AREA

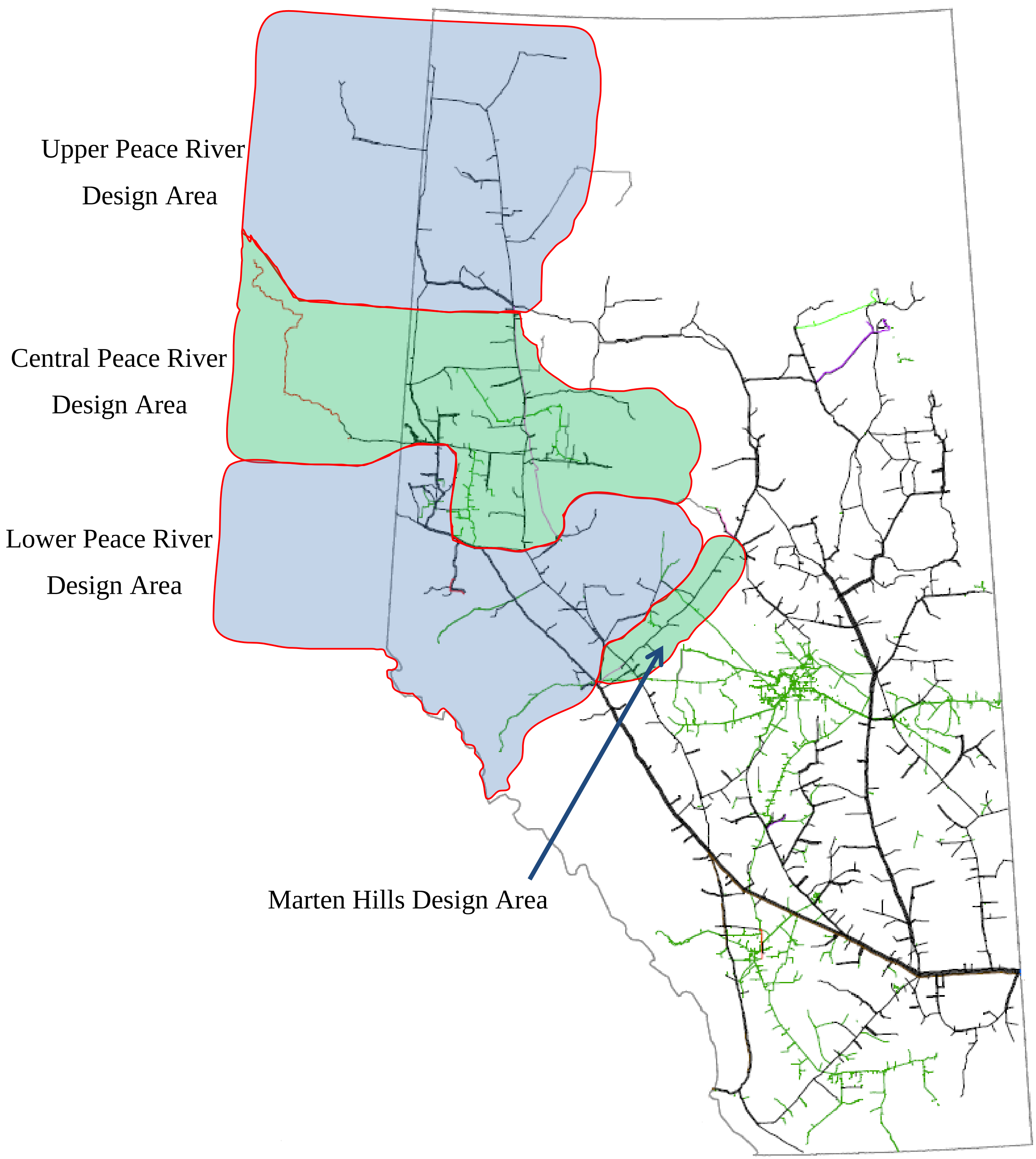
The Peace River Project Area (Figure 2-1) comprises the Upper Peace River, Central Peace River, Lower Peace River and Marten Hills design areas.

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 will handle two design conditions:

1. Flow-Through – When receipts are at a maximum and deliveries are at a minimum in the Peace River Project Area. Facilities must be capable of transporting the excess gas out of the area to deliveries throughout the system.

2. Flow-Within – When receipts are at a minimum and deliveries are at a maximum in the Peace River Project Area. Facilities must be capable of meeting local delivery requirements and be able to transport the gas required to meet deliveries in the North and East Project Area.

Figure 2-1: Peace River Project Area

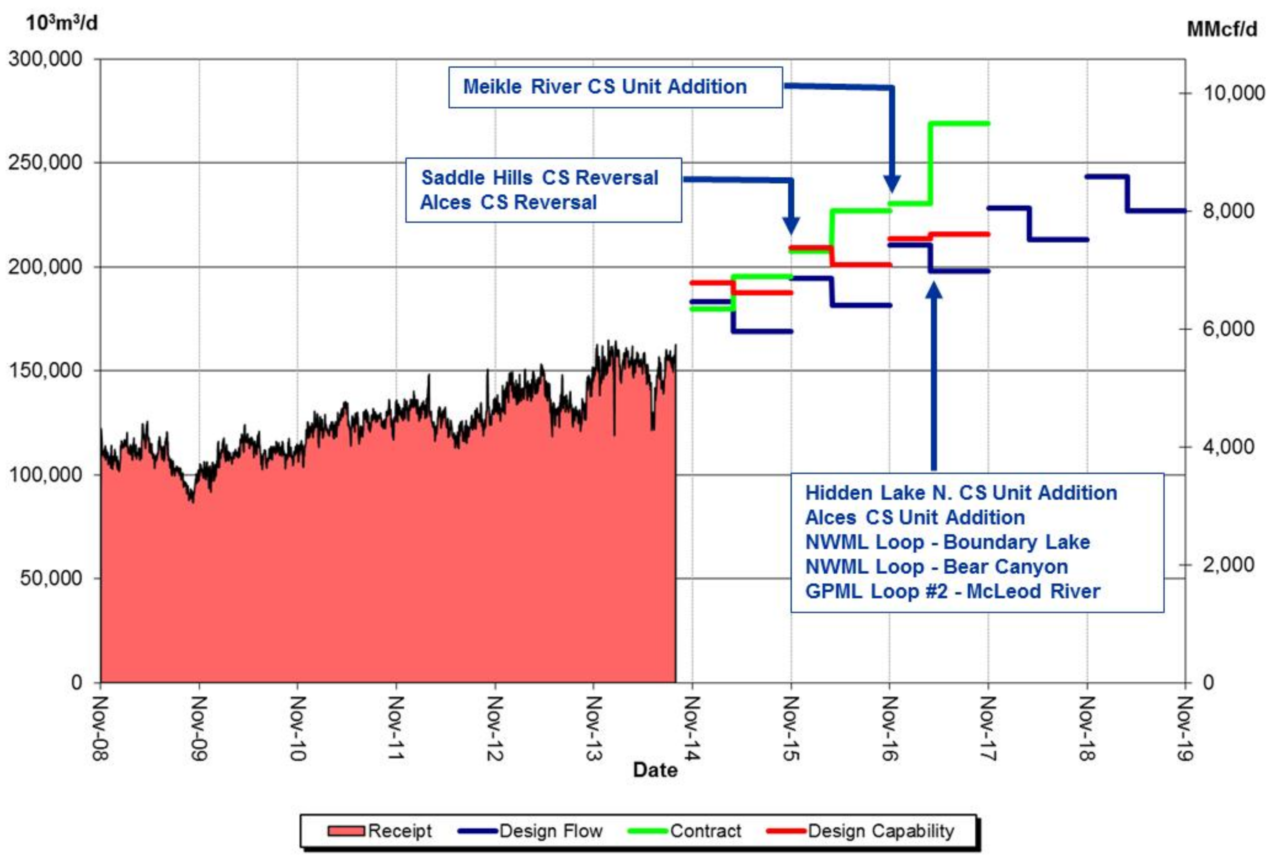


2.2.1 Design Flows

The design flows for the flow-through design condition in the Peace River Project Area are the net effect of the maximum local receipts less minimum deliveries in the area. Continued receipt growth will be accommodated by eight proposed facilities.

Figure 2-2 shows historical receipts, receipt design flow, contract levels and design capability for the Peace River Design Area (Upper, Central, and Lower). Receipt design flow rises throughout this forecast period, attributable primarily to increasing B.C. shale receipts.

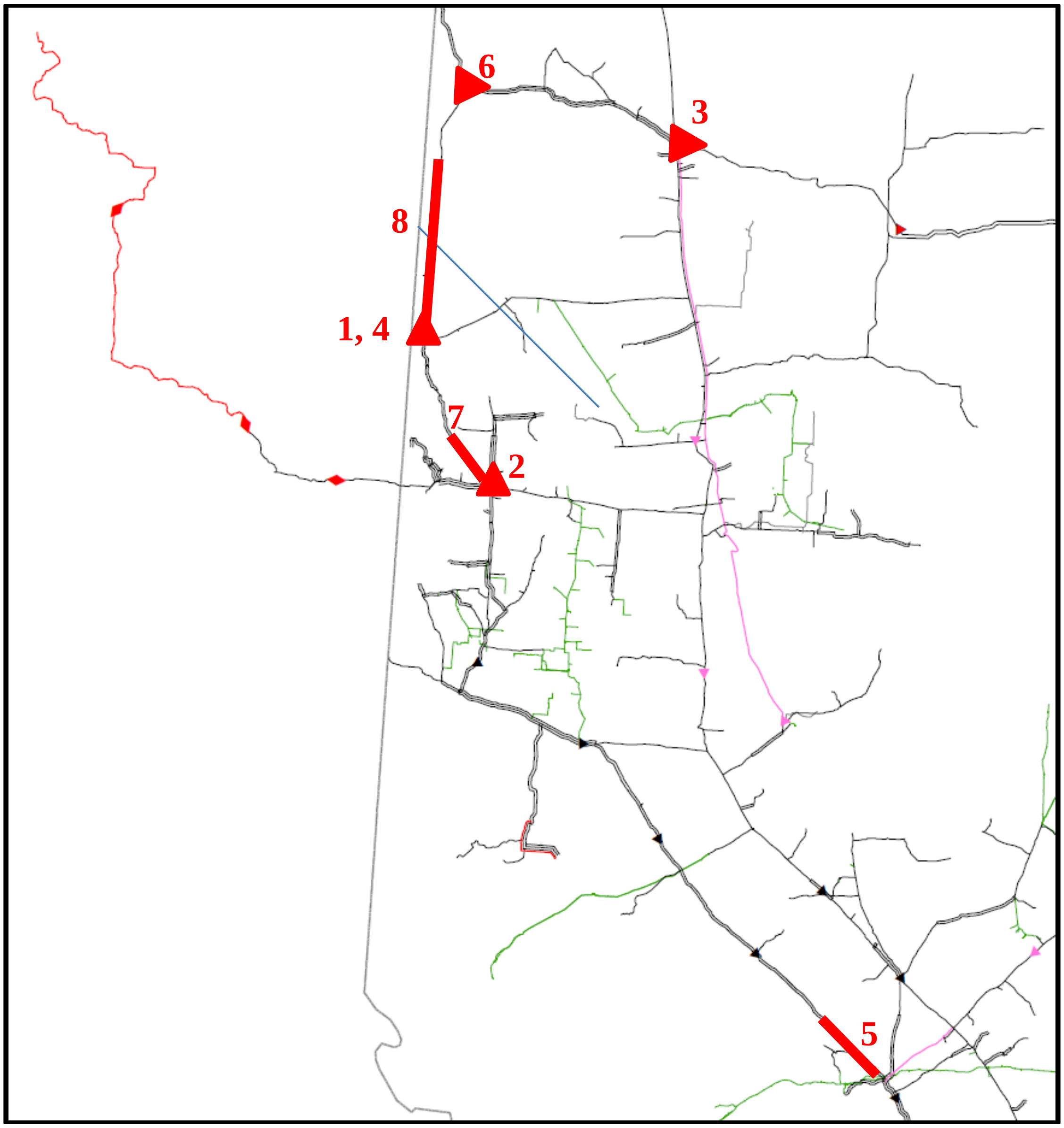
Figure 2-2: Peace River Area Design Chart



2.2.2 Proposed 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 – Proposed Facilities



Applications for the proposed facilities are expected to be filed with the NEB in gas year 2014/2015 and the facilities are proposed to be in-service in 2015 through to 2017. For details on each of the proposed facilities, see Table 2-1.

Table 2-1: Peace River Area Project Area Proposed Facilities

Map Location	Applied-For Facility	Description	Target In-Service Date	Forecast Cost ($Millions)
1	Alces River C/S Modifications	Bi-Directional Modifications	Nov 2015	10

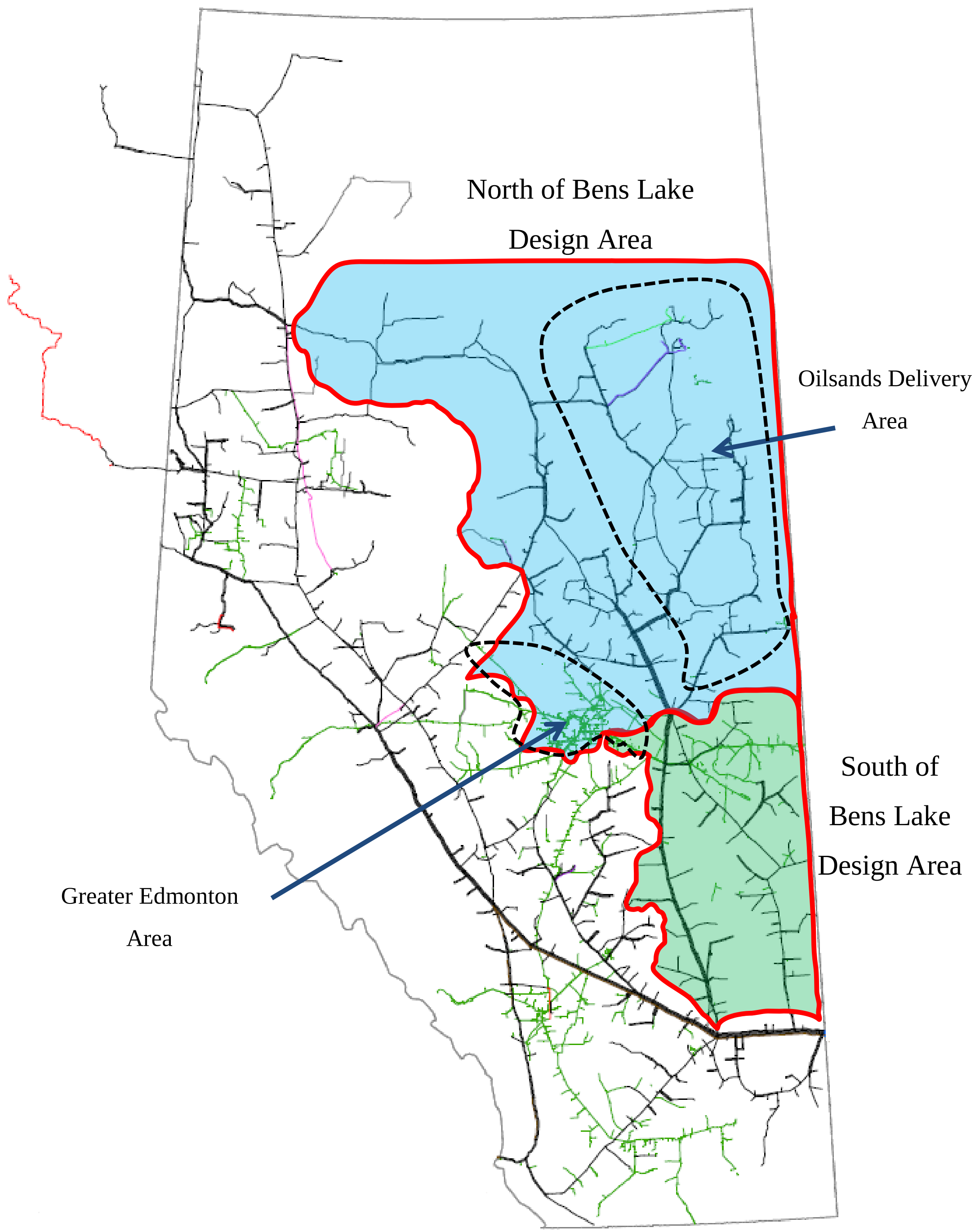
Map Location	Applied-For Facility	Description	Target In-Service Date	Forecast Cost ($Millions)
2	Saddle Hills C/S Modifications	Bi-Directional Modifications	Nov 2015	10
3	Meikle River D C/S	33 MW	Nov 2016	136
4	Alces River C/S Unit Addition	15 MW	Apr 2017	79
5	Grande Prairie Mainline Loop #2 (McLeod)	37 km NPS 48	Apr 2017	207
6	Hidden Lake North C/S Unit Addition	15 MW	Apr 2017	78
7	Northwest Mainline Loop (Bear Canyon)	27 km NPS 36	Apr 2017	110
8	Northwest Mainline Loop (Boundary Lake)	91 km NPS 36	Apr 2017	384
			Total	**1,014**

2.3 NORTH AND EAST PROJECT AREA

The North and East Project Area (Figure 2-4) 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 Oilsands Delivery and Greater Edmonton areas.

Figure 2-4: North and East Project Area

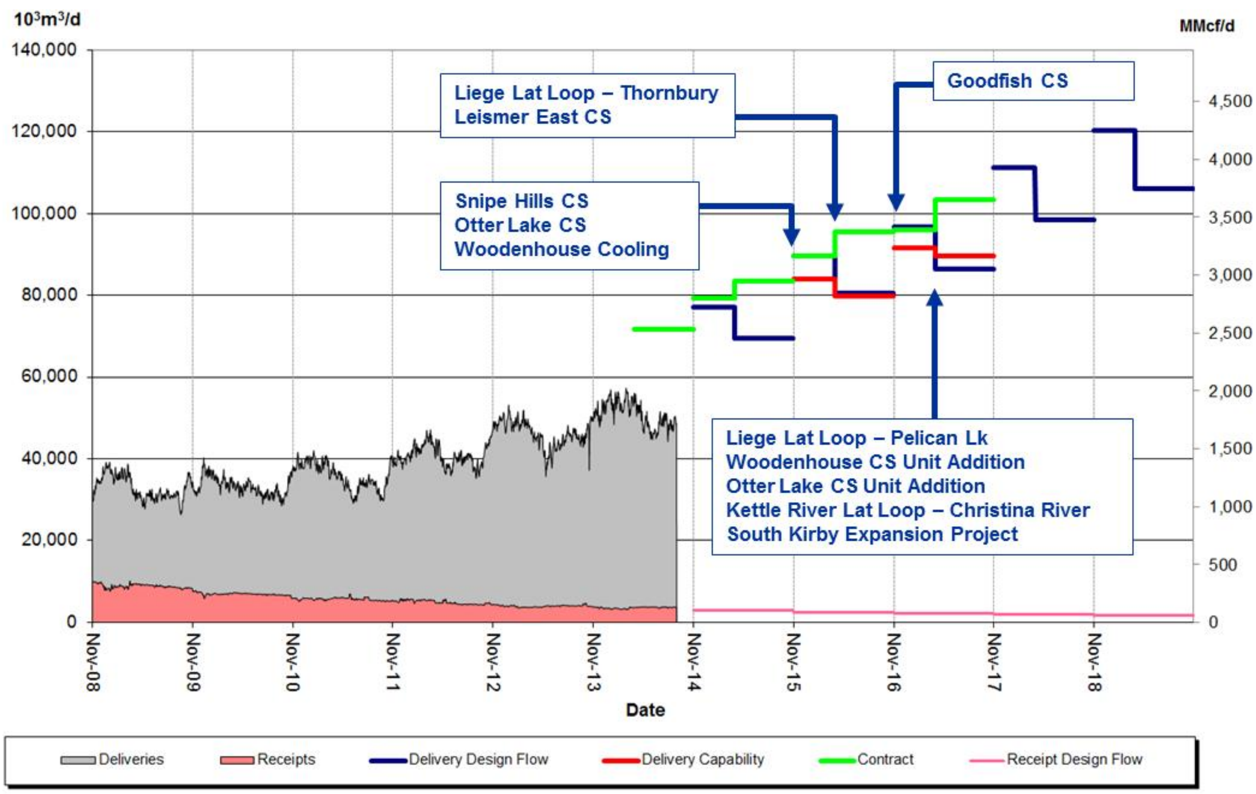


2.3.1 Design Flows – Oilsands Delivery Area

The design flows for the flow-within design condition in the Oilsands Delivery Area are the net effect of maximum deliveries less the minimum available local receipts in the area. Continued delivery growth will be accommodated by seven proposed facilities.

Figure 2-5 shows historical flows, design flows, contract levels and design capability for the Oilsands Delivery Area. Delivery design flow rises throughout this forecast period, attributable primarily to increasing oilsands deliveries.

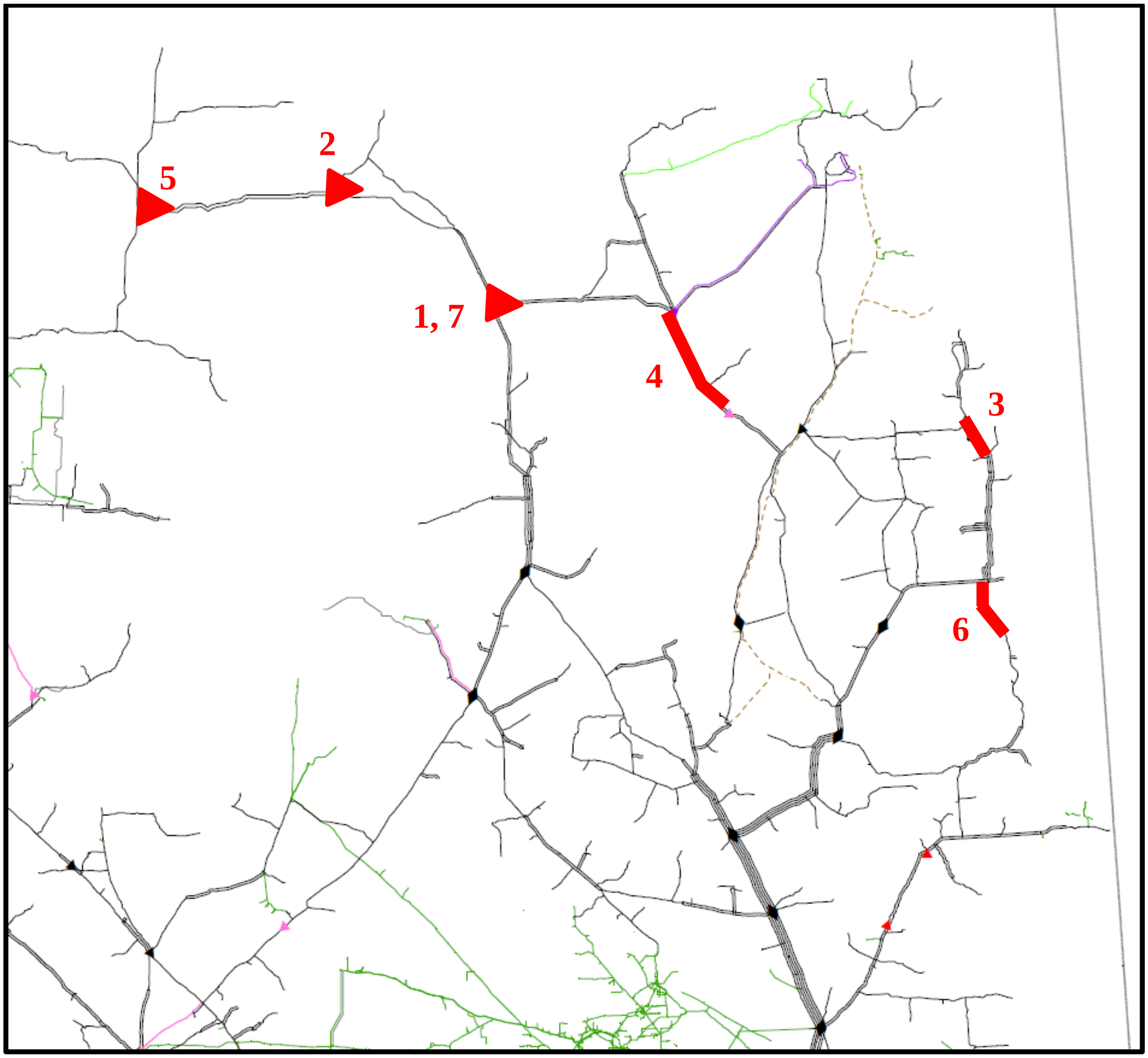
Figure 2-5: Oilsands Delivery Area Design Chart



2.3.2 Proposed Facilities – North and East Project Area

Figure 2-6 shows the location of the proposed facilities required to meet the design flow requirements of the Oilsands Delivery Area.

Figure 2-6: North and East Project Area Map – Proposed Facilities



Applications for the proposed facilities are expected to be filed with the NEB in gas year 2014/2015 and the facilities are proposed to be in-service in 2015 through to 2017. For details on each of the proposed facilities, see Table 2-2.

Table 2-2: North and East Project Area Proposed Facilities

Map Location	Proposed Facility	Description	Target In-Service Date	Forecast Cost ($Millions)
1	Woodenhouse Coolers		Nov 2015	25
2	Goodfish Compressor Station	30 MW	Nov 2016	135

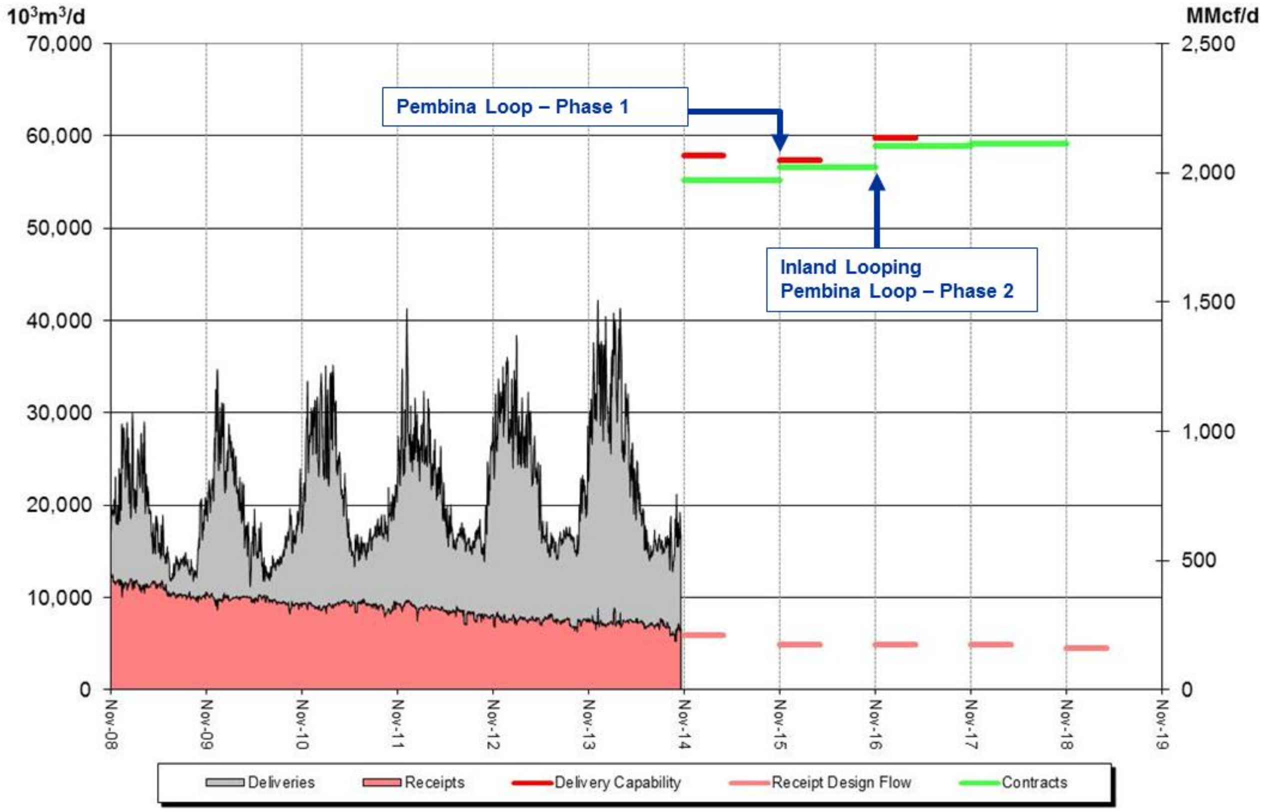
3	Kettle River Lateral Loop (Christina River)	20 km NPS 24	Apr 2017	77
4	Liege Lateral Loop No.2 (Pelican Lake)	56 km NPS 30	Apr 2017	215
5	Otter Lake CS Unit Addition	30 MW	Apr 2017	115
6	South Kirby Expansion Project	42 km NPS 24	Apr 2017	137
7	Woodenhouse CS Unit Addition	30 MW	Apr 2017	136
			Total	**840**

2.3.3 Design Flows – Greater Edmonton Area (ATCO Pipelines)

The design flows for the flow-within design condition in the Greater Edmonton Area are the net effect of contracted deliveries less the minimum available local receipts in the area. Continued delivery growth will be accommodated by three proposed facilities, one in the North and East Area and two in the Mainline Area.

Figure 2-7 shows historical flows, contract level and design capability for the Greater Edmonton Area. Contract level rises throughout this forecast period, attributable to increasing industrial and residential/commercial deliveries.

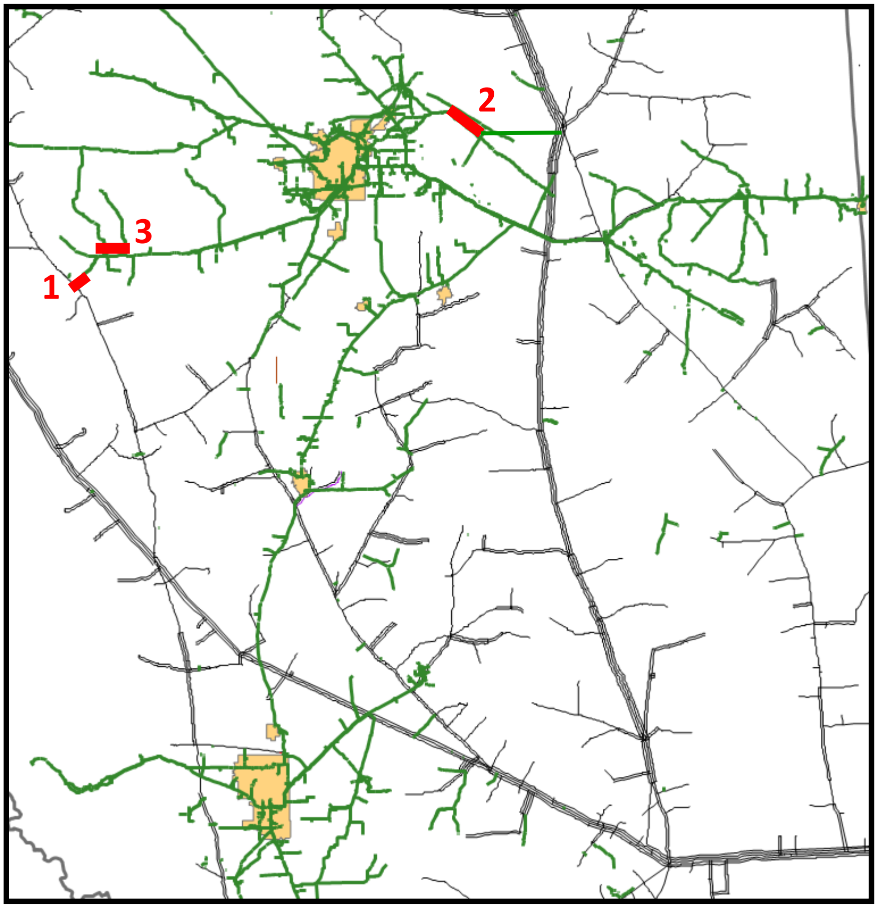
Figure 2-7: Greater Edmonton Area Design Chart



2.3.4 Proposed Facilities – Greater Edmonton Area (ATCO Pipelines)

Figure 2-8 shows the location of the proposed facilities required to meet the design flow requirements of the Greater Edmonton Area.

Figure 2-8: Greater Edmonton Area Map – Proposed Facilities



Applications for the proposed facilities are expected to be filed with the AUC in 2015 and the facilities are proposed to be in-service in 2015 through to 2016. For details on each of the proposed facilities, see Table 2-3.

Table 2-3: Greater Edmonton Area Proposed Facilities

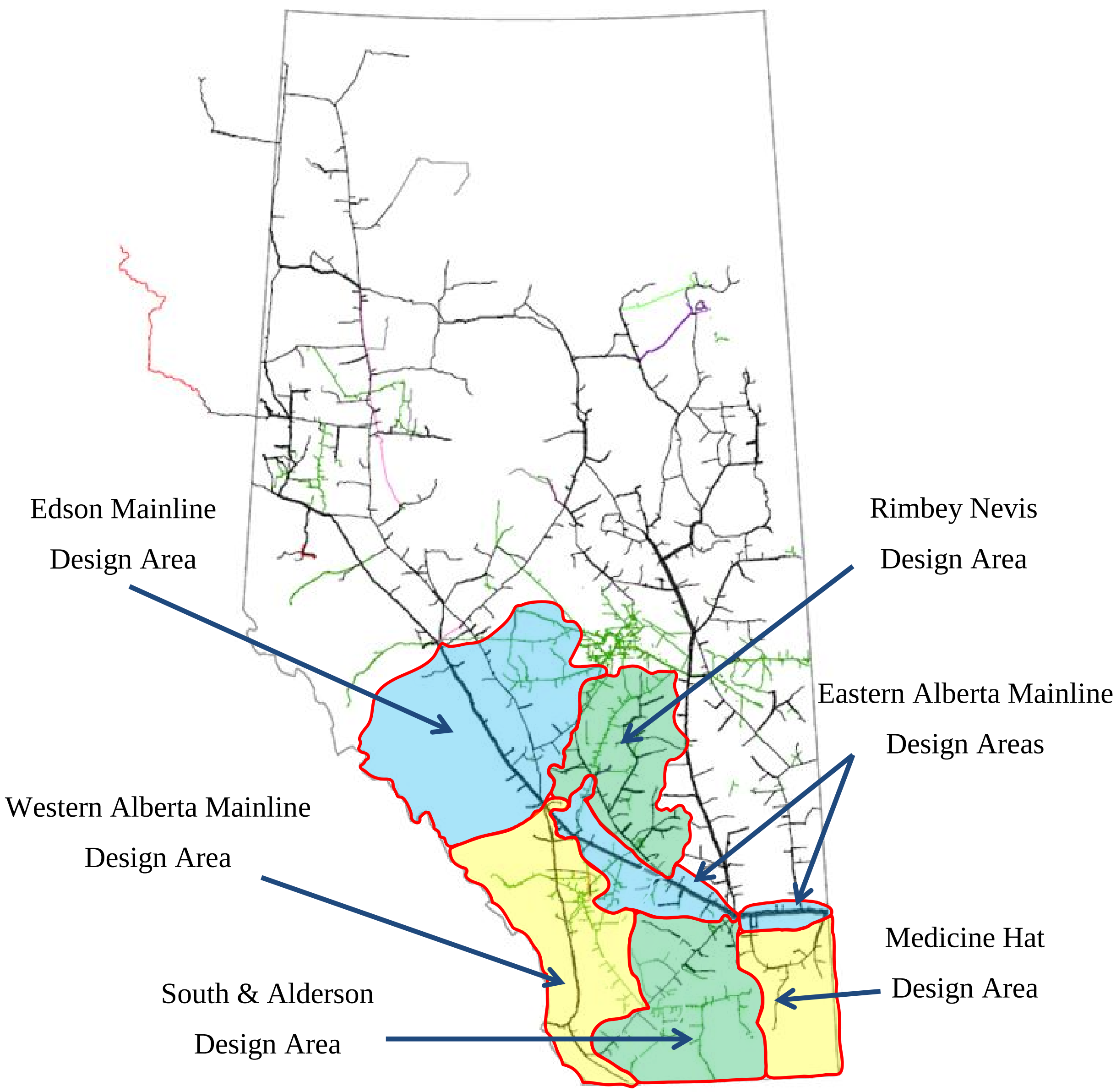
Map Location	Proposed Facility	Description	Target In-Service Date	Forecast Cost ($Millions)
1	Pembina Looping - Phase 1	5 km NPS 24	Nov 2015	9
2	Inland Looping	18 km NPS 20	Nov 2016	29
3	Pembina Looping - Phase 2	17 km NPS 24	Nov 2016	31
			Total	**69**

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 2-9).

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 Edmonton Area. For details regarding the two proposed facilities in the Edson Mainline Design Area required to meet deliveries in the Greater Edmonton Area refer to sections 2.3.3 and 2.3.4.

Figure 2-9: Mainline Project Area

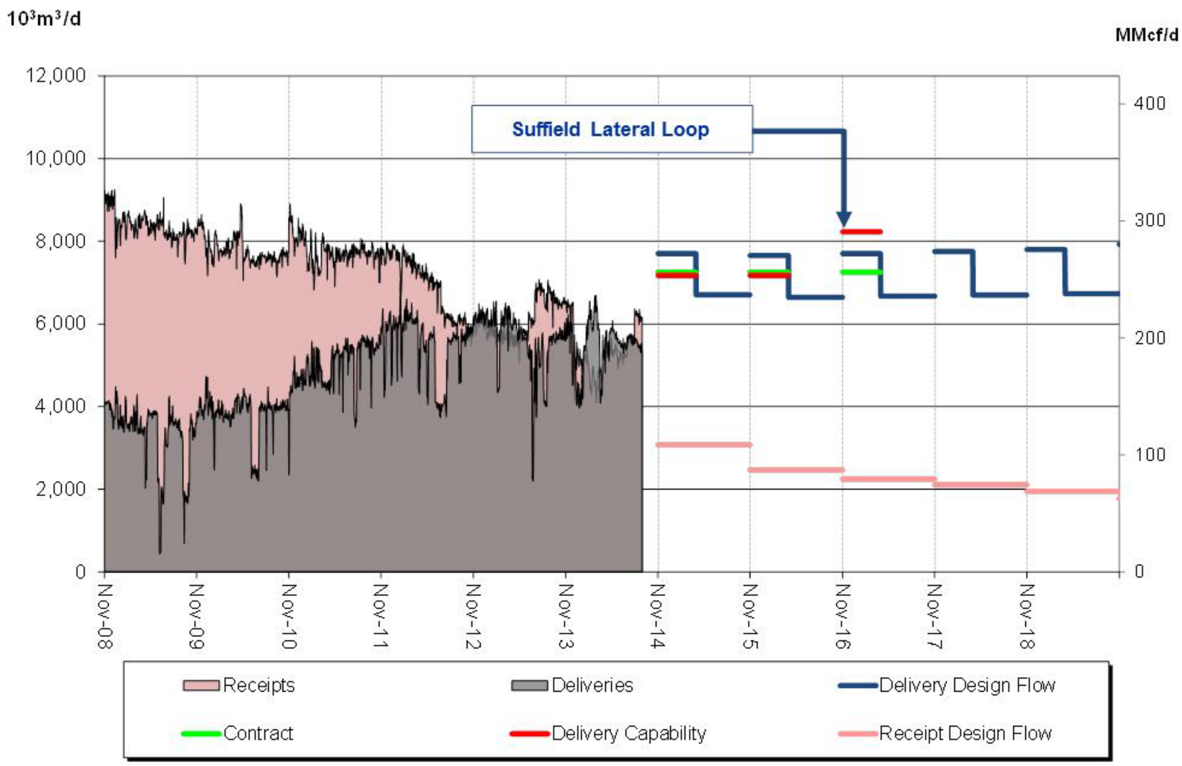


2.4.1 Design Flows – Medicine Hat Design Area

The design flows for the flow-within design condition in the Medicine Hat Design Area are the net effect of maximum deliveries less the minimum available local receipts in the area. Continued receipt decline will be accommodated by one proposed facility.

Figure 2-10 shows historical flows, design flows, contract levels and design capability for the Medicine Hat Design Area. Receipt design flow declines throughout this forecast period, attributable to existing reserve depletion and the absence of any new production.

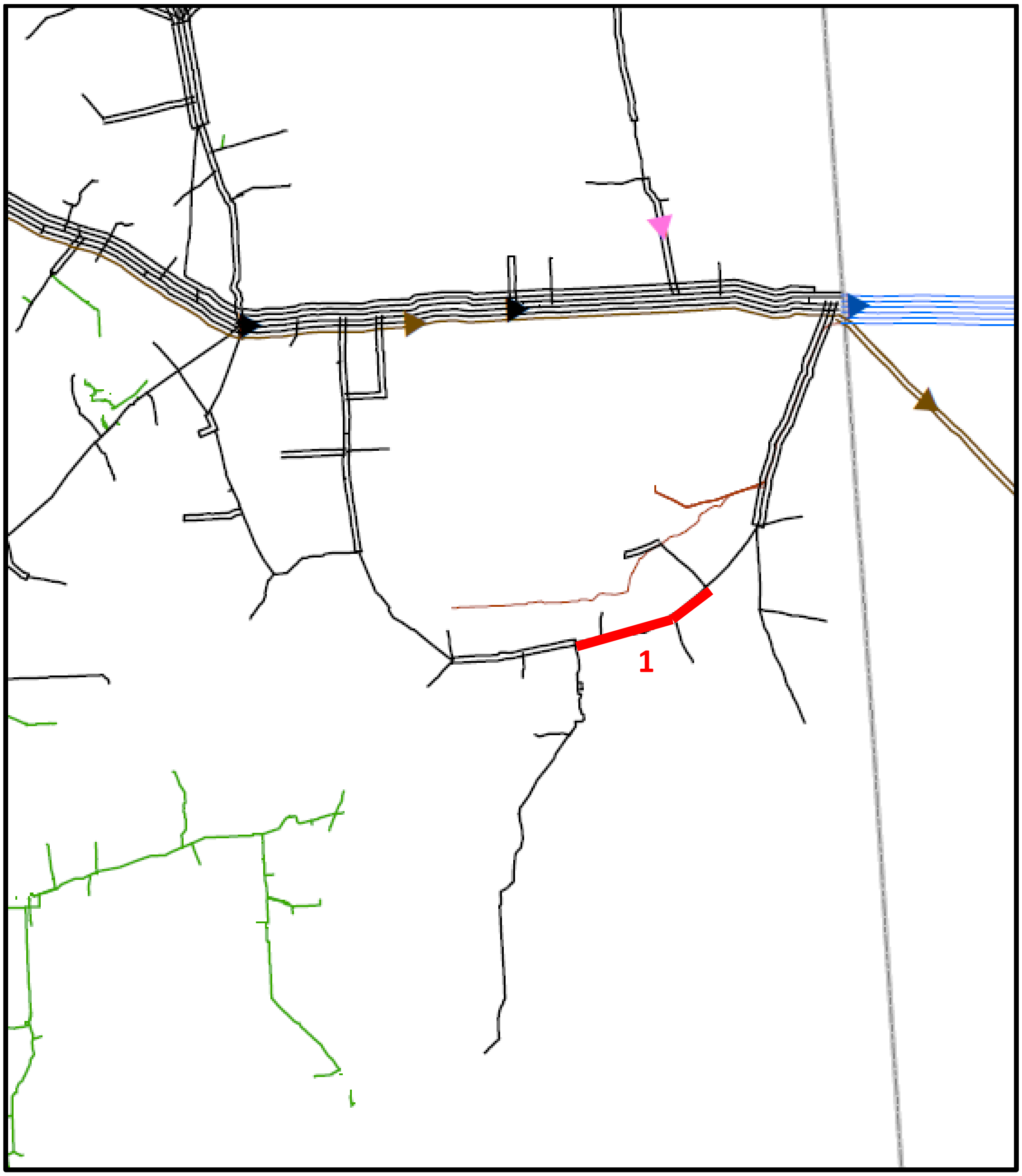
Figure 2-10: Medicine Hat Design Area Design Chart



2.4.2 Proposed Facilities – Medicine Hat Design Area

Figure 2-11 shows the location of the proposed facility required to meet the design flow requirements of the Medicine Hat Design Area.

Figure 2-11: Medicine Hat Design Area Map – Proposed Facility



An application for the proposed facility is expected to be filed with the NEB in 2015 and the facility is proposed to be in-service in 2016. For details on the proposed facility, see Table 2-4.

Table 2-4: Medicine Hat Design Area Proposed Facility

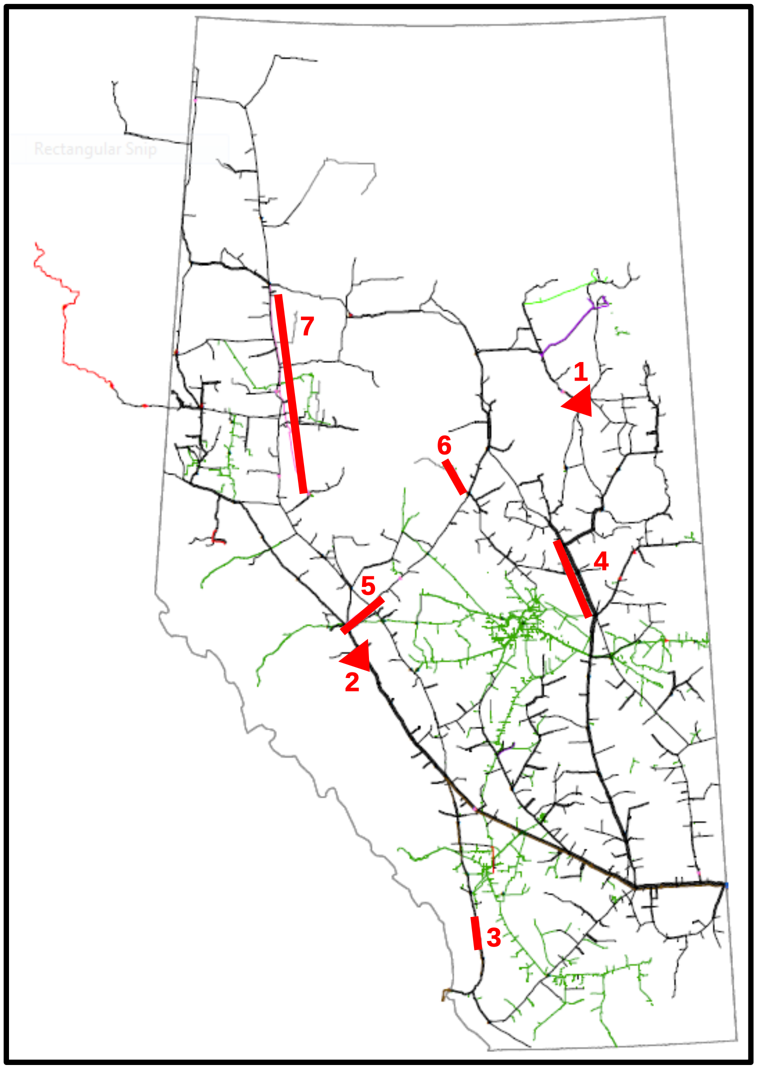
Map Location	Proposed Facility	Description	Target In-Service Date	Forecast Cost ($Millions)
1	Suffield Lateral Loop	27 km NPS 20	Nov 2016	50
			Total	**50**

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 and reduce operating and maintenance expenses. For the locations of the proposed facility deactivation and decommissioning projects, see Figure 2-12.

Figure 2-12: Locations of Proposed Deactivation and Decommissioning Projects



The proposed projects are expected to be applied-for in the 2015 Gas Year and are proposed to be deactivated or decommissioned in 2015. For details on the proposed projects, see Table 2-5.

Table 2-5: Deactivation and Decommissioning Projects

Map Location	Proposed Compressor Project	Description	Target Date	Forecast Cost ($Millions)
1	Leismer C/S Isolation	1 MW	Q1 2015	3
2	Wolf Lake #1 C/S Demolition	15 MW	Q2 2015	4
			Total	**7**

	Proposed Pipeline Project			
3	Western Alberta Mainline Loop - Willow Creek		Q2 2015	TBD
4	Flat Lake Loop		Q3 2015	7
5	Marten Hills Extension		Q3 2015	3
6	Mitsue Lateral Loop		Q3 2015	3
7	Peace River Mainline - Meikle to Valleyview		Q3 2015	14
			Total	**27**

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 the *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 30, 2014.

For a summary of the status of facilities that have been proposed, applied for, under construction or placed in-service since the 2013 Annual Plan, see *Appendix 2: Facility Status Update*.

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

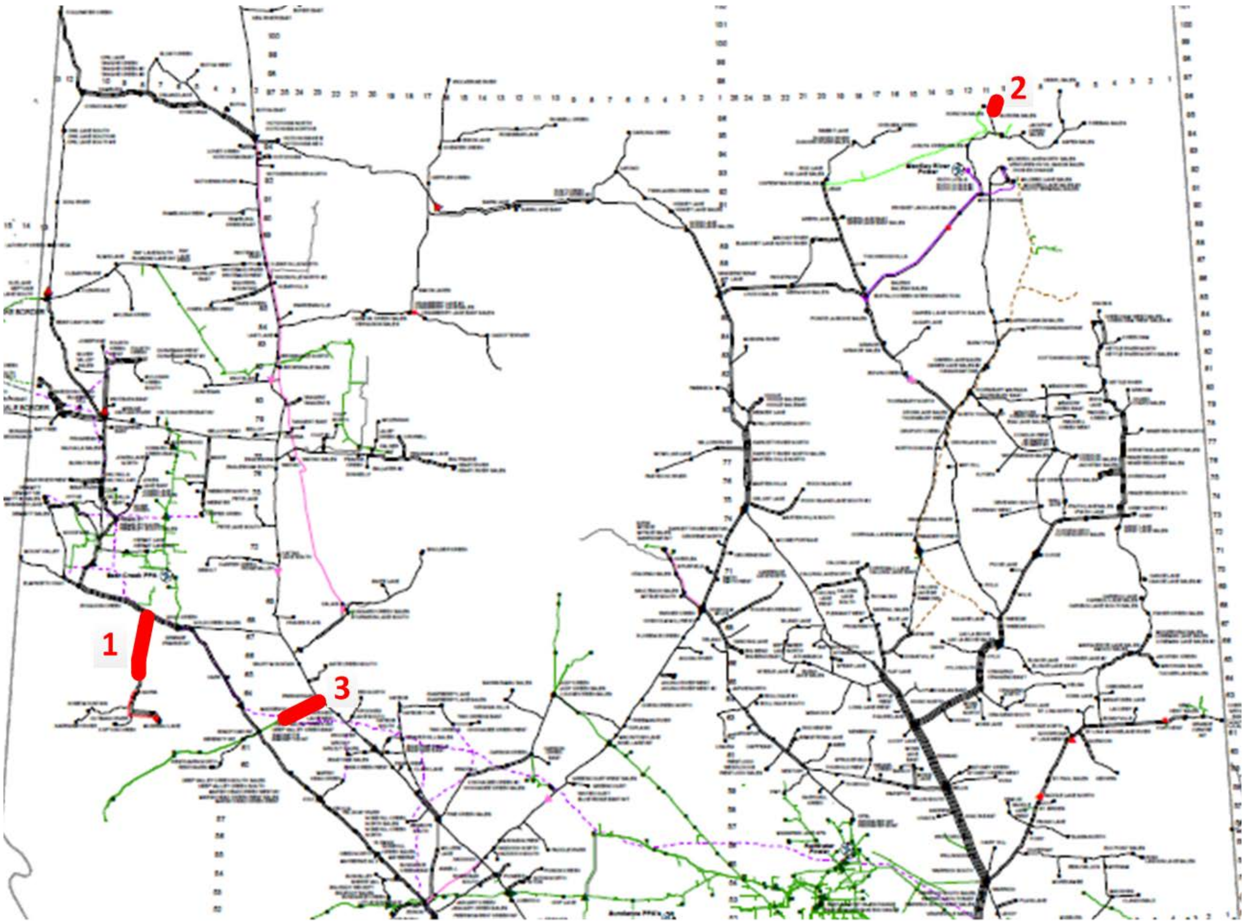


Table 3-1: Proposed Extensions, Lateral Loops and Meter Stations

Map Location	Proposed Facilities	Description	Target In-Service Date	Forecast Cost ($Millions)
1	Cutbank River Lateral Loop No. 2 (Pinto Creek Section) plus Musreau Lake North Receipt Meter Station	32 km NPS 24	Apr 2016	92
2	McDermott Extension plus Calumet River Sales & Calumet River No. 2 Sales Meter Stations	8 km NPS 20	Apr 2016	44
3	Simonette Lateral Loop plus Simonette East Receipt Meter Station	22 km NPS 24	Apr 2016	84
Capital costs are in estimated in-service dollars and include AFUDC.			**TOTAL**	**219**

3.2 FACILITY DESCRIPTION

Cutbank River Lateral Loop No. 2 (Pinto Creek Section)

The Cutbank River Lateral Loop No. 2 (Pinto Creek Section) and the proposed Musreau Lake North Receipt Meter Station are required to accommodate incremental receipt contracts as a result of gas development in the Musreau Lake area.

The target in-service date for the facilities is April 2016. The facility application is scheduled to be filed with the NEB in December 2014.

Simonette Lateral Loop

The 22 km NPS 24 loop of the Simonette Lateral and the proposed Simonette East Receipt Meter Station are required to accommodate incremental receipt contracts as a result of gas development in the Simonette area.

The target in-service date for the facilities is April 1, 2016. The facility application is scheduled to be filed with the NEB in February 2015.

McDermott Extension

The 8 km NPS 20 McDermott Extension, and the two proposed delivery meter stations, Calumet River Sales and Calumet River No. 2 Sales, are required to accommodate incremental delivery contracts related to oilsands development in the area.

The target in-service date for the facilities is April 1, 2016. The facility application is scheduled to be filed with the NEB in December 2014.

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 *2015 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.

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 Field Price

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

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 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 sub design 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.

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: 2014 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 2013 Annual Plan was issued on December 13, 2013. 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 facilities in the ATCO Pipelines footprint.

Table A2-1: Current Status of Facilities

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
2014 Meter Station and Associated Lateral Decommissioning	Beauvallon Botha Caribou Lake Sales Chump Lake Lateral Cottonwood Creek Diamond City Haddock South Keho Lake North Murray Lake North Myrnam Picture Butte Tieland	Q4 2014	Approved Sept. 3, 2014	May 29, 2014 TTFP Notification	3.2	December
Aitken Creek Compressor Station	15 MW Bi-directional	April 2019	Applied for Nov. 8, 2013	October 22, 2013 TTFP Meeting	72	
Alces River Compressor Station Modifications	Bi-directional Flow	November 2015	Proposed	October 22, 2013 TTFP Meeting October 30, 2014 TTFP Meeting	10	December
Alces River C/S Unit Addition	15 MW	April 2017	Proposed	October 30, 2014 TTFP Meeting	79	December
Alder Flats South No. 2	2-1610U Ultrasonic Meter	April 2015	Applied for Sept. 23, 2014	August 13, 2014 TTFP Notification	3.5	December

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

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Bear River No. 2 Receipt Meter Station	882 Orifice Meter	July 2015	Proposed	September 12, 2014 TTFP Notification	2.6	September
Bilbo Meter Station	882 Orifice Meter	December 2014	Approved July 25, 2014	April 11, 2014 TTFP Notification	2.2	July
Bonanza Meter Station Upgrade	2-1284U Ultrasonic Meter	March 2014	In-Service Apr. 16, 2014	October 1, 2013 TTFP Notification	5.0	July
Calgary UPR – West Connector (AP)	22 km NPS 20/24	June 2016	Proposed	October 30, 2014 TTFP Meeting	74.5	December
Cardinal Lake Compressor Station Decommissioning – Units 1, 2 & 3	2 – 0.8 MW units 1 – 1.2 MW unit	April 2014	Completed Jan. 25, 2014	November 12, 2013 TTFP Notification	1.6	June
Carmon Creek East Sales Meter Station	2-2012U Ultrasonic Meter	April 2015	Approved Sept. 22, 2014	May 30, 2014 TTFP Notification	4.3 (less 0.9 CIAC)	December
Cavendish Compressor Station Decommissioning – Units 1 & 2	1 – 1.3 MW unit 1 – 3 MW unit	June 2014	Completed June 28, 2014	October 22, 2013 TTFP Meeting April 25, 2014 TTFP Notification	1.8	December
Chinchaga Lateral Loop No. 3	33 km NPS 48	June 2014	In-Service June 11, 2014	July 12/Sept 13, 2011 TTFP	136.5	December
Clarkson Valley Compressor Station Decommissioning	1 – 15.2 MW unit	November 2014	Notification Filed Sept. 26, 2014	October 22, 2013 TTFP Meeting September 12, 2014 TTFP Notification	2.8	December
Cutbank River Lateral Loop No. 2 (Kakwa Section) [2]	12 km NPS 24	April 2015	Approved Sept. 5, 2014	October 22, 2013 TTFP Meeting	24.0	September
Cutbank River Lateral Loop No. 2 (Pinto Creek Section) Musreau Lake North Receipt Meter Station	32 km NPS 24 2-1284U Ultrasonic meter	April 2016	Applied for Nov. 25, 2014	October 30, 2014 TTFP Meeting	92.0	December

[2] Cutbank River Lateral Loop No. 2 (Kakwa Section) and the Musreau Lake Lateral Loop No. 3 were applied for together in a single NEB Section 58 application.

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Didsbury Compressor Station Decommissioning – Units 5 & 6	2 – 0.7 MW unit	November 2014	Completed May 11, 2014	October 22, 2013 TTFP Meeting	1.1	December
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	Q1 2014	Approved Sept. 19, 2013	May 8, 2013 TTFP Notification	2.2	January
Denning Lake Compressor Station	3.5 MW	November 2014	In-Service Oct. 25, 2014	November 20, 2012 TTFP Meeting June 7, 2013 TTFP Notification	34.7	December
East Calgary B Interconnect Modifications	85 m NPS 20	November 2014	Approved Sept. 3, 2014	May 27, 2014 TTFP Notification	1.2	December
East Calgary Connector – UPR (AP) [3]	9 km NPS 30	2015	Proposed	July 12, 2011 TTFP Meeting	65.6	December
Edmonton UPR – NE Connector (AP)	8 km NPS 20	June 2016	Proposed	October 30, 2014 TTFP Meeting	34.8	December
Flat Lake Loop Decommissioning		Q3 2015	Proposed	October 30, 2014 TTFP Meeting	7	December
Fort Kent No. 2 Sales Meter Station	2-640 T Turbine Meter	August 2014	In-Service July 30, 2014	June 4, 2014 TTFP Notification	1.5	December
Goodfish Compressor Station	30 MW	November 2016	Proposed	October 30, 2014 TTFP Meeting	135	December
Grande Prairie Mainline Loop #2 (McLeod Section)	37 km NPS 48	April 2017	Proposed	October 30, 2014 TTFP Meeting	207	December

[3] ATCO Pipelines filed an application with the AUC for the Urban Pipeline Replacement (UPR) project on March 19, 2013. The AUC approved the UPR project in a decision dated January 17, 2014. The proposed segments of the UPR project that have been presented to the TTFP are identified in the table by the inclusion of "UPR" in the facility name.

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Groundbirch Compressor Station	2-15 MW units – Bi-directional	April 2017	Applied for Nov. 8, 2013 Project Update Mar. 10, 2014	October 22, 2013 TTFP Meeting	103	March
Hangingstone Sales Meter Station	2-1280T Turbine Meter	February 2014	In-Service Apr. 4, 2014	August 20, 2012 TTFP Notification	3.8	July
Hidden Lake North C/S Unit Addition	15 MW	April 2017	Proposed	October 30, 2014 TTFP Meeting	78	December
Inland Looping (AP)	18 km NPS 20	November 2016	Proposed	October 22, 2013 TTFP Meeting October 30, 2014 TTFP Meeting	29.0	December
Japan Canada No. 2 Sales Meter Station	2-860T Turbine Meter 480 m NPS 6 Pipe 54 m NPS 8 Pipe	December 2015	Applied for Oct. 1, 2014	September 5, 2014 TTFP Notification	1.6	December
Jones Lake North Producer Tie-In & Jones Lake North Meter Station Upgrades	PTI and Upgrades	October 2014	In-Service Oct. 9, 2014	August 25, 2014 TTFP Notification	1.06	December
Kettle River Lateral Loop (Christina River Section)	20 km NPS 24	April 2017	Proposed	October 30, 2014 TTFP Meeting	77	December
Kettle River North #2 Sales Meter Station Upgrade	2-1280U Ultrasonic meter	October 2014	In-Service Nov. 16, 2014	May 20, 2014 TTFP Notification	3.0	December
Liege Lateral Loop No.2 (Pelican Lake Section)	56 km NPS 30	April 2017	Proposed	October 30, 2014 TTFP Meeting	215	December
Liege Lateral Loop No.2 (Thornbury Section)[4]	36.6 km NPS 30	April 2016	Applied for Sept. 19, 2014	August 19, 2014 TTFP Meeting	139.0	September
Leming Lake Sales Lateral Loop	37 km NPS 20	April 2014	In-Service May 1, 2014	November 20, 2012 TTFP Meeting	75.2	September

4 The Liege Lateral Loop No.2 (Thornbury Section) and Leismer East Compressor Station were applied for together in a single NEB Section 58 application on September 19, 2014.

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Livingstone Creek Receipt Meter Station	2-1064U Ultrasonic Meter	August 2015	Applied for Nov. 19, 2014	October 23, 2014 TTFP Notification	3.5	December
Livingstone Creek No. 2 Receipt Meter Station	2-1064U Ultrasonic Meter	September 2015	Applied for Nov. 19, 2014	October 23, 2014 TTFP Notification	3.5	December
Leismer East Compressor Station	15 MW	April 2016	Applied for Sept. 19, 2014	August 19, 2014 TTFP Meeting	79.0	September
Leismer Compressor Station Isolation	1 – 1 MW unit	Q1 2015	Proposed	October 30, 2014 TTFP Meeting	3	December
MacKay Sales Meter Station	2-860T Turbine Meter	December 2014	Approved Dec. 11, 2013	June 10, 2013 TTFP Notification	1.6	
Marten Hills Extension Decommissioning	40 km NPS 20	Q3 2015	Proposed	October 22, 2013 TTFP Meeting October 30, 2014 TTFP Meeting	3.0	December
McDermott Extension Calumet River Sales & Calumet River No. 2 Sales Meter Stations	8 km NPS 20 2-1280U LVS-2	April 2016	Applied for Dec. 10, 2014	October 30, 2014 TTFP Meeting	43.7	December
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	Under Construction	October 22, 2013 TTFP Meeting	15.5	September
Meikle River D Compressor Station	33 MW	November 2016	Proposed	October 30, 2014 TTFP Meeting	136	December
Mitchell Creek Meter Station	2-1064U Ultrasonic Meter	February 2014	In-Service Apr. 16, 2014	May 3, 2013 TTFP Notification	3.7	July
Mitsue Lateral Loop Decommissioning	13 km NPS 10 26 km NPS 8	Q3 2015	Proposed	October 22, 2013 TTFP Meeting October 30, 2014 TTFP Meeting	3.1	December

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Monarch Interconnect Facility Modifications	Replace control valves and turbine meters with spool pieces; install NPS 12 isolation valve; re-license 117 m NPS 12 to an MOP of 6720 kPa; and deactivate Monarch North A meter station piping	October 1, 2014	Proposed	March 25, 2014 TTFP Notification	0.7	April
Moosa Crossover	5 km NPS 20	April 2014	In-Service Apr. 10, 2014	November 20, 2012 TTFP Meeting	19.5	September
Musreau Lake Lateral Loop No. 3	16 km NPS 24	April 2015	Approved Sept. 5, 2014	October 22, 2013 TTFP Meeting	31.0	September
Musreau Lake West Meter Station	2-1284U Ultrasonic Meter	July 2014	In-Service Sept. 18, 2014	August 6, 2013 TTFP Notification	3.2	September
North Branch Replacement (AP)	3 km NPS 16	November 2014	Under construction	October 22, 2013 TTFP Meeting	7.0	December
North Montney Mainline (Aitken Creek Section) [5]	180.9 km NPS 42	April 2016	Applied for Nov. 8, 2013	October 22, 2013 TTFP Meeting	762	
North Montney Mainline (Kahta Section)	119 km NPS 42	April 2017	Applied for Nov. 8, 2013 Project Update Mar. 10, 2014	October 22, 2013 TTFP Meeting	530	March

[5] The North Montney Project was filed as a Section 52 application comprised 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 Meter Stations Receipt Meter Stations: Kahta Creek Kahta Creek North Buckinghorse River Mason Creek Beatton River Lily Halfway River Blair Creek Blair Creek East 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 July 2019 April 2017 July 2019 April 2017 April 2017 April 2017 April 2017 April 2017 July 2019 Nov. 2016 April 2016 April 2017 April 2016 April 2016 January 2019	Applied for Nov. 8, 2013 Project Update Mar. 10, 2014	October 22, 2013 TTFP Meeting	66	March
Northeast Calgary Connector – UPR (AP)	17 km NPS 24	2015	Applied for Sept. 19, 2014 (AUC)	2011 Annual Plan	77.8	December
Northwest Mainline Loop (Bear Canyon Section)	27 km NPS 36	April 2017	Proposed	October 30, 2014 TTFP Meeting	110	December
Northwest Mainline Loop (Boundary Lake Section)	91 km NPS 36	April 2017	Proposed	October 30, 2014 TTFP Meeting	384	December
Otter Lake Compressor Station	28 MW	November 2015	Approved Apr. 1, 2014	October 22, 2013 TTFP Meeting	100	April
Otter Lake C/S Unit Addition	30 MW	April 2017	Proposed	October 30, 2014 TTFP Meeting	115	December
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 October 30, 2014 TTFP Meeting	13.7	December
Peigan Trail Pipeline – UPR (AP)	8 km NPS 20	2016	Proposed	July 10, 2012 TTFP Meeting	40.6	December

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Pelican Lake Compressor Station Decommissioning – Unit 2	1 – 3.3 MW unit	March 2014	Completed Mar. 1, 2014	January 6, 2014 TTFP Notification	2.4	April
Pembina Looping – Phase 1 (AP)	5 km NPS 24	November 2015	Proposed	October 30, 2014 TTFP Meeting	9	December
Pembina Looping – Phase 2 (AP)	17 km NPS 24	November 2016	Proposed	October 30, 2014 TTFP Meeting	31	December
Resthaven Meter Station Upgrade	2-1280-4U Ultrasonic Meter	August 2014	In-Service Sept. 12, 2014	October 21, 2013 TTFP Notification	2.2	December
Rimbey Meter Station Sour Shut-In Valve	NPS 24 Block Valve & H2S Analyzer	September 2014	In-Service Sept. 14, 2014	February 20, 2014 TTFP Notification	1.1	September
Saddle Hills Compressor Station Modifications	Bi-directional Flow	November 2015	Proposed	October 22, 2013 TTFP Meeting October 30, 2014 TTFP Meeting	10	December
Saturn Compressor Station	15 MW Bi-directional	April 2017	Applied for Nov. 8, 2013	October 22, 2013 TTFP Meeting	70	
Saturn Compressor Station – Unit 2	15 MW Bi-directional	April 2019	Applied for Nov. 8, 2013	October 22, 2013 TTFP Meeting	63	
Scotford Area Expansion (AP)	6.9 km NPS 16 2 Meter Stations 1.0 km NPS 10 0.7 km NPS 8	Q3 2015	Proposed	August 19, 2014 TTFP Meeting	18.6 (less 2.3 CIAC)	December
Shepard Energy Centre Extension (AP) [6]	15.8 km NPS 20, associated Delivery Station (2-1612T Turbine Meter), 2.4 km NPS 24, and associated system modifications	July 2014 Nov 2014	In-Service May 21, 2014 Associated modifications Approved Aug. 8, 2014 (AUC)	November 20, 2012 TTFP Meeting	71.8	September

[6] The Shepard Energy Centre Project includes the Shepard Extension (15.8 km NPS 20), Shepard Sales Meter Station (2-1612T), East Calgary B Extension (2.4 km NPS 24) and other associated system modifications. ATCO Pipelines submitted separate AUC facility applications for the Project, one application that included the Shepard Extension and Shepard Sales Meter Station, and a separate AUC facility application for East Calgary B Extension.

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Simonette Lateral Loop Simonette East Receipt Meter Station	22 km NPS 24	April 2016	Proposed	October 30, 2014 TTFP Meeting	84	December
Slave Lake Compressor Station Decommissioning – Unit 1	1 – 1 MW unit	April 2014	Completed Mar. 25, 2014	October 22, 2013 TTFP Meeting February 10, 2014 TTFP Notification	1.7	April
Snipe Hills Compressor Station	3.5 MW	November 2015	Approved Sept. 8, 2014	October 22, 2013 TTFP Meeting May 16, 2014 TTFP Notification	50.4	September
South Kirby Expansion Project	42 km NPS 24	April 2017	Proposed	October 30, 2014 TTFP Meeting	137	December
Southeast Calgary Connector – UPR (AP)	13 km NPS 24	Q2 2015	Applied for	July 12, 2011 TTFP Meeting	63.0	December
Southwest Edmonton Connector – UPR (AP)	21 km NPS 20	2015	Proposed	July 10, 2012 TTFP Meeting	76.0	December
Suffield Lateral Loop	27 km NPS 20	November 2017	Proposed	October 30, 2014 TTFP Meeting	50	December
Sunday Creek South Lateral Loop No. 3	12.8 km NPS 24	June 2014	In-Service June 28, 2014	November 20, 2012 TTFP Meeting	46.6	December
Thunder Creek Compressor Station Decommissioning	3.5 MW Compressor Station	March 2015	Under Construction	December 6, 2013 TTFP Notification June 23, 2014 TTFP Notification	8.3	September
Valleyview Compressor Station Decommissioning	1 – 3 MW unit	July 2014	Completed July 28, 2014	June 4, 2014 TTFP Notification	1.9	July
Vermillion Compressor Station (AP)	2 – 1 MW units	November 2014	Under Construction	October 22, 2013 TTFP Meeting	14.0	December
Western Alberta Mainline Loop (Willow Creek Section) Decommissioning		Q2 2015	Proposed	October 30, 2014 TTFP Meeting	TBD	December

Applied-for Facilities	Description	Target In-Service Date	Status	TTFP Reference	Forecast Cost [1]($Millions)	Update Month
Wildhay River South Receipt Meter Station	2-1284-U Ultrasonic Meter	May 2015	Approved Dec. 9, 2014	September 22, 2014 TTFP Notification	4.2	December
Wolf Lake Compressor Station Demolition – Unit #1	1 – 15 MW unit	Q2 2015	Proposed	October 30, 2014 TTFP Meeting	4	December
Wolf Lake Receipt Meter Station	880-2 Orifice Meter	August 2015	Applied for Dec. 9, 2014	November 19, 2014 TTFP Notification	1.7	December
Wolverine River Lateral Loop (Carmon Creek Section)	61 km NPS 20	April 2016	Applied for Mar. 25, 2014	October 22, 2013 TTFP Meeting February 11, 2014 TTFP Meeting	144.0	April
Woodenhouse Coolers		November 2015	Proposed	October 30, 2014 TTFP Meeting	25	December
Woodenhouse C/S Unit Addition	30 MW	April 2017	Proposed	October 30, 2014 TTFP Meeting	136	December

Appendix 3: System Map

The System Map, including the 2014 Annual Plan facilities, is expected to be available in March 2015 and can be accessed at **http://www.transcanada.com/customerexpress/5328.html**.