TransCanada
In business to deliver

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

Tel: (403) 920-2046
Fax: (403) 920-2347
Email: dave_schultz@transcanada.com

December 20, 2010

All Customers
Other Interested Parties

Re: 2010 Annual Plan

NOVA Gas Transmission Ltd. ("NGTL") has posted its 2010 Annual Plan on TransCanada PipeLines Limited's website at:

http://www.transcanada.com/customerexpress/5070.html

Customers and other interested parties are encouraged to communicate their suggestions and comments to NGTL regarding the development and operation of the Alberta System and other related issues to me at (403) 920-5574.

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

[Original Signed by]

Dave Schultz
Director, System Design
System Design and Commercial Operations

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EXECUTIVE SUMMARY

The 2010 Annual Plan provides NOVA Gas Transmission Ltd.'s ("NGTL") Customers and other interested parties with an overview of the potential Alberta System facilities that are expected to be applied for in the 2011 calendar year. This year's Plan includes a total of 16 facilities totaling approximately $1.1 billion. The majority (15) of these facilities is related to connecting and transporting additional supply with one facility in the Northeast quadrant of Alberta enabling additional demand. This 2010 Annual Plan includes the following sections:

- Executive Summary
- Chapter 1 – Design Forecast
- Chapter 2 – Design Flow Requirement and Proposed Mainline Facilities
- Chapter 3 – Extension Facilities, Lateral Loops and Meter Stations
- Appendix 1 – Glossary
- Appendix 2 – Facility Status Update
- Appendix 3 – System Map (available in February 2011)

TransCanada has facility planning processes that it uses to establish the faculties' described in this Annual Plan. An overview of these processes is contained in the Facilities Design Methodology Document. While this document is separate from each year's Annual Plan, one notable addition this year came about as a result of the new Alberta Rate Design implemented on November 1 2010. These Delivery Design Areas have been added to provide guidance to customers regarding firm transportation delivery transfers between facilities. At that same time, the integration plan between NGTL and ATCO Pipelines included a provision for NGTL to determine facility requirements for ATCO Pipelines. This plan was approved by the NEB in August 2010 which did not provide sufficient time for TransCanada to properly assess facility requirements for ATCO Pipelines and as such they are not included in this Annual Plan.

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

http://www.transcanada.com/customerexpress/5070.html

The NGTL's Gas Transportation Tariff can be accessed at the following website:

http://www.transcanada.com/Alberta/info_postings/tariff/index.html

The Annual Plan describes NGTL's long term outlook for receipts, deliveries, peak expected flows, design flow requirement and proposed facilities for the 2011/12 to 2013/14 Gas Years. This Annual Plan is based on NGTL's June 2010 design forecast of receipts and deliveries. The forecast includes significant future receipt volumes from unconventional shale gas plays.

The proposed facilities included in the 2010 Annual Plan for the 2011/12 to 2013/14 Gas Years are shown below in Table 1.

Table 1
Proposed Facilities

Project Area	Proposed Facilities	Annual Plan Reference	Description	Required In-Service Date	Capital Cost ($ millions)
Peace River	Bear River Lateral Loop No. 2	Chapter 3	10 km NPS 10	Nov 11	7.7
Peace River	Gordondale Lateral Loop No. 2	Chapter 2	24 km NPS 42	Nov 11	65.3
Peace River	Gold Creek C/S Unit Addition	Chapter 2	28 MW	Nov 11	60.3
Peace River	Groundbirch Mainline (Saturn Section) & Meter Station	Chapter 3	24 km NPS 36	Apr 12	59.0
Peace River	Tanghe Creek Lateral Loop No. 2 (Sloat Creek Section)	Chapter 2	38 km NPS 48	Apr 12	115.0
Peace River	GPML Loop (Karr North Section)	Chapter 2	16 km NPS 42	Apr 12	39.2
Peace River	GPML Loop (Nosehill Creek Section)	Chapter 2	3 km NPS 42	Apr 12	21.4
Peace River	Moody Creek C/S	Chapter 2	15 MW	Nov 12	62.1
Peace River	Hidden Lake North C/S	Chapter 2	15 MW	Nov 12	62.1
Peace River	Berland Rvr C/S Unit Addition	Chapter 2	28 MW	Nov 12	66.4
Peace River	Horn River Mainline Loop (Ekwan Section)	Chapter 2	30 km NPS 42	Apr 13	86.0
Peace River	NWML Loop (Timberwolf Section)	Chapter 2	25 km NPS 48	Apr 13	82.4
Peace River	NWML Loop (Sabbath Section)	Chapter 2	24 km NPS 48	Apr 13	71.2
Peace River	Tanghe Creek Lateral Loop No. 2 (Cranberry Section)	Chapter 2	32 km NPS 48	Apr 13	89.2
Peace River	GPML Loop No. 2 Macleod River Section)	Chapter 2	35 km NPS 48	Apr 13	81.6
North & East	Leismer to Kettle River Crossover	Chapter 2	86 km NPS 24	Apr 13	137.2
Capital Costs are in 2010 dollars and include AFUDC			**Total**		**1106.1**

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

- Landen Stein, Manager, Customer Solutions, at (403) 920-5311;
- Gord Toews, Manager, Mainline Planning West, at (403) 920-5903;
- Roland Guebert, Manager, Receipt and Delivery Forecasting, at (403) 920-5386;
- Dave Schultz, Director, System Design, at (403) 920-5574;
- Steve Emond, Vice President, System Design and Commercial Operations, at (403) 920-5979;

CHAPTER 1 - DESIGN FORECAST

1.1 Introduction

This Annual Plan is based on the June 2010 Design Forecast of receipts and deliveries for the Alberta System. An overview of the June 2010 Design Forecast was presented at the November 23, 2010 TTFP meeting.

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

http://www.transcanada.com/customerexpress/5070.html

In this Chapter, NGTL describes the economic assumptions used in the development of its 2010 Design Forecast, receipts and deliveries for the Alberta System, and the supply contribution (winter withdrawal) from Storage Facilities used in the design process.

1.2 Economic Assumptions

1.2.1 General Assumptions

Underlying the forecast of receipts and deliveries are assumptions concerning broader trends in the North American economy and energy markets. These assumptions, developed in January 2010, include:

- North American natural gas demand will slowly recover in the short-term as the U.S. and Canadian economies recover. 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 will be predominantly in the electricity

generation sector. Western Canadian industrial gas demand is expected to grow significantly, driven by development of the oil sands.

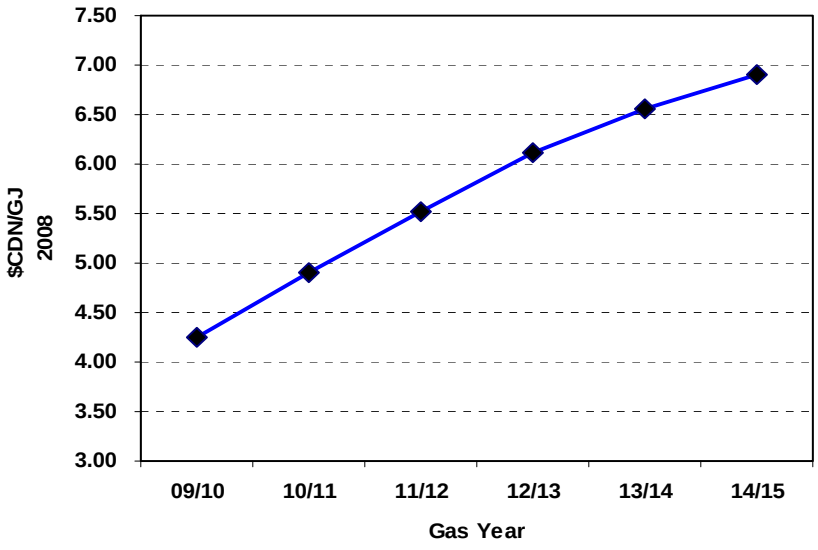
- The North American market will be well supplied with natural gas sourced from North America due to the strength in unconventional gas production, primarily shale gas. This strong domestic supply growth is now expected to be able to keep pace with the growth in gas demand, leaving a greatly reduced volume of imported LNG required to balance the continental market relative to previous expectations.
- Due to weakness in natural gas demand from the slow pace of economic recovery and to the rapid expansion of shale gas supplies, short-term gas prices are expected to be soft. However, this is expected to be a temporary situation as present prices are below the full cycle supply costs of most new sources. A NYMEX gas price level above $7.00/MMBtu in Real 2008 $US by 2015 would be sufficient to encourage the development of the extensive unconventional gas resource and to provide adequate returns for the production of the large volumes of conventional gas that will still be required to meet market demands. NYMEX natural gas prices are forecast to recover over the next few years as the economy and gas demand improve. The gas price forecast used in this Annual Plan rises from today's low prices to $US 7.17/MMBtu in real 2008 $US by 2015.
- Currently, low gas prices are putting pressure on producers to be efficient and cost-effective. Recent drilling successes in many shale and tight gas plays have led to more fracture stages, higher initial production rates, and increases in the estimated ultimate recovery (EUR) per well, resulting in a lower cost per well for producers. These improvements have led to additional shale and tight gas resources being economic to produce in a low gas price environment edging out higher cost conventional supply. However, even with strong growth in shale and tight gas production, there continues to be a need for a significant proportion of supply from conventional resources.

- Due to the continued drilling success experienced in shale and tight gas plays, in August, 2010, TransCanada lowered its NYMEX gas price forecast by 54 cents in 2015 ($6.63/MMBtu in real 2008 $US) compared to the forecast used for this Design Forecast. This reduction in gas price will result in lower conventional production levels in the Western Canadian Sedimentary Basin ("WCSB"). However, lower conventional production is expected to be offset by higher shale and tight gas production due to continued technical improvements and lower production costs. As a result, TransCanada believes that the June 2010 Design Forecast remains reasonable as the basis for its design process.

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 prior to receipt onto the Alberta System. The gas price forecast, shown in Figure 1.2.2, was developed in January 2010 and reflects the general assumptions from Section 1.2.1.

Figure 1.2.2
NGTL Gas Price Forecast
Alberta Average Field Price (Alberta Reference Price)



The Alberta Average Field Price is forecast to rise from $4.25 Cdn/GJ in real 2008 $ in 2010 to the long term equilibrium price of $6.90 Cdn/GJ by 2015.

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 activity required to discover and to develop new reserves.

1.3 Gas Delivery Forecast

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

Several sources of information were considered in developing the gas delivery forecast. First, operators of downstream facilities such as connecting pipelines and industrial plant operators were requested to provide a forecast of their maximum, average, and minimum requirements for deliveries from the Alberta System over the next ten years. The forecasts were analyzed and compared to historical flow patterns at Alberta Delivery Points. In cases where NGTL's analysis differed substantially with 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

The Average Annual Delivery forecast shown below is the forecast aggregate deliveries for the Alberta System for the 2010/11 through 2014/15 Gas Years. Forecast deliveries by Gas Year are expressed as an average daily flow and are listed by Delivery Point in Table 1.3.1.1. Alberta deliveries are further detailed by Project Area in Table 1.3.1.2.

Table 1.3.1.1
System Average Annual Delivery Forecast by Delivery Point

	June 2010 Design Forecast				
Gas Year	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**
(Volumes in $10^6 m^3/d$ at 101.325 kPa and 15°C)					
Empress	81.7	95.6	102.9	107.9	111.4
McNeill	40.7	45.8	46.2	47.1	47.7
Alberta/B.C.	56.0	42.1	46.0	49.0	51.6
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Unity	0.8	0.8	0.8	0.8	0.8
Cold Lake	0.9	1.0	1.0	1.0	1.0
Gordondale	0.0	0.0	0.0	0.0	0.0
Alberta/Montana	0.8	0.8	0.9	1.0	1.2
Alberta	82.1	86.8	92.1	96.8	103.8
TOTAL SYSTEM	**262.7**	**272.9**	**289.4**	**303.4**	**317.1**
(Volumes in Bcf/d at 101.325 kPa and 15°C)					
Empress	2.88	3.37	3.63	3.81	3.93
McNeill	1.44	1.62	1.63	1.66	1.68
Alberta/B.C.	1.98	1.49	1.62	1.73	1.82
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Unity	0.03	0.03	0.03	0.03	0.03
Cold Lake	0.03	0.03	0.03	0.03	0.04
Gordondale	0.0	0.0	0.0	0.0	0.0
Alberta/Montana	0.03	0.03	0.03	0.04	0.04
Alberta	2.90	3.07	3.25	3.42	3.67
TOTAL SYSTEM	**9.27**	**9.63**	**10.22**	**10.71**	**11.20**

NOTES:
- Numbers may not add due to rounding.
- Volumes expressed as an average daily flow for each Gas Year.

Table 1.3.1.2
Alberta Deliveries - Average Annual Delivery Forecast by Project Area

	June 2010 Design Forecast ($10^6m^3/d$)				
Project Area	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**
Peace River	2.3	2.3	2.4	2.4	2.6
North and East	49.0	52.0	56.2	60.0	66.1
Mainline	28.3	29.9	30.1	31.8	32.4
Gas taps	2.6	2.6	2.6	2.7	2.7
TOTAL ALBERTA	**82.1**	**86.8**	**92.1**	**96.8**	**103.8**
	June 2010 Design Forecast (Bcf/d)				
Project Area	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**
Peace River	0.08	0.08	0.08	0.08	0.09
North and East	1.73	1.84	1.98	2.12	2.33
Mainline	1.00	1.05	1.09	1.12	1.14
Gas taps	0.09	0.09	0.09	0.09	0.10
TOTAL ALBERTA	**2.90**	**3.07**	**3.25**	**3.42**	**3.67**

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

1.3.2 Maximum Day Delivery Forecast

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

A summary of the June 2010 Design Forecast winter and summer Maximum Day Delivery by Project Area for Alberta Deliveries is provided in Table 1.4.2.1 and Table 1.4.2.2 respectively.

Table 1.4.2.1
Winter Maximum Day Delivery Forecast

	June 2010 Design Forecast ($10^6m^3/d$)				
Project Area	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**
Peace River	6.9	6.9	7.0	7.1	7.3
North and East	75.1	78.4	84.7	89.0	96.4
Mainline	61.3	62.0	64.7	65.9	66.8
Gas taps	5.1	5.1	5.2	5.3	5.3
TOTAL ALBERTA	**148.3**	**152.5**	**161.7**	**167.1**	**175.8**
	June 2010 Design Forecast (Bcf/d)				
Project Area	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**
Peace River	0.24	0.24	0.25	0.25	0.26
North and East	2.65	2.77	2.99	3.14	3.40
Mainline	2.16	2.19	2.29	2.32	2.36
Gas taps	0.18	0.18	0.18	0.19	0.19
TOTAL ALBERTA	**5.24**	**5.38**	**5.71**	**5.90**	**6.21**

NOTES:
- Numbers may not add due to rounding.
- Gas taps are located in all areas of the province.

Table 1.4.2.2
Summer Maximum Day Delivery Forecast

	June 2010 Design Forecast ($10^6m^3/d$)				
Project Area	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**
Peace River	4.5	4.5	4.5	4.6	4.7
North and East	65.4	68.6	74.5	78.6	85.8
Mainline	36.3	37.1	37.8	38.3	38.8
Gas taps	2.4	2.4	2.4	2.5	2.5
TOTAL ALBERTA	**108.5**	**112.6**	**119.3**	**123.9**	**131.8**
	June 2010 Design Forecast (Bcf/d)				
Project Area	**10/11**	**11/12**	**12/13**	**13/14**	**14/15**
Peace River	0.16	0.16	0.16	0.16	0.17
North and East	2.31	2.42	2.63	2.77	3.03
Mainline	1.28	1.31	1.33	1.35	1.37
Gas taps	0.08	0.08	0.09	0.09	0.09
TOTAL ALBERTA	**3.83**	**3.97**	**4.21**	**4.37**	**4.65**

NOTES:
- Numbers may not add due to rounding.
- Gas taps are located in all areas of the province.

1.4 Receipt Forecast

Exploration activity focused on unconventional gas has resulted in an expectation of significant incremental volumes of shale and tight gas entering the Alberta System in the Peace River Project Area in the near future. Incremental shale and tight gas supply is expected to offset declines in production from connected established reserves, resulting in an increase in overall production levels in the WCSB over the next five years..

In updating the Average Receipt Forecast for the June 2010 Design Forecast, three major sources of gas supply were included:

- 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.

Supply from reserve additions was forecast on an area basis, based on resource potential estimates from the Canadian Gas Potential Committee Report "Natural Gas Potential in Canada – 2005" and expected delivery requirements. The supply from reserve additions was then allocated to each Receipt Point within the forecast area. The allocated supply from reserve additions was combined with the established supply forecast from connected gas and existing economic unconnected gas to provide a forecast at each Receipt Point.

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

1.4.1 Average Receipt Forecast

The Average Receipt Forecast shown below is the forecast aggregate receipts for the Alberta System for the 2010/11 through 2014/15 Gas Years. A summary of System Average Receipts by Gas Year and Project Area are expressed as an average daily flow in Table 1.4.1.

Table 1.4.1
System Average Receipts

	June 2010 Design Forecast ($10^6m^3/d$)				
Project Area	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
Peace River	128.4	138.7	148.8	156.0	166.0
North and East	24.7	22.4	24.7	24.7	24.8
Mainline	110.9	113.0	116.9	123.6	127.2
TOTAL SYSTEM	264.0	274.1	290.4	304.4	318.0
	June 2010 Design Forecast (Bcf/d)				
Project Area	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**
Peace River	4.53	4.89	5.25	5.51	5.86
North and East	0.87	0.79	0.87	0.87	0.88
Mainline	3.91	3.99	4.13	4.36	4.49
TOTAL SYSTEM	9.32	9.67	10.25	10.75	11.23

NOTE:
- Numbers may not add due to rounding.

1.5 Supply Demand Balance

Supply received on to the Alberta System is balanced with deliveries off of the System (net of gas in storage). System deliveries by destination are shown in Figure 1.3.1, while System receipts by Project Area are shown in Figure 1.3.2.

Figure 1.3.1
System Deliveries by Destination

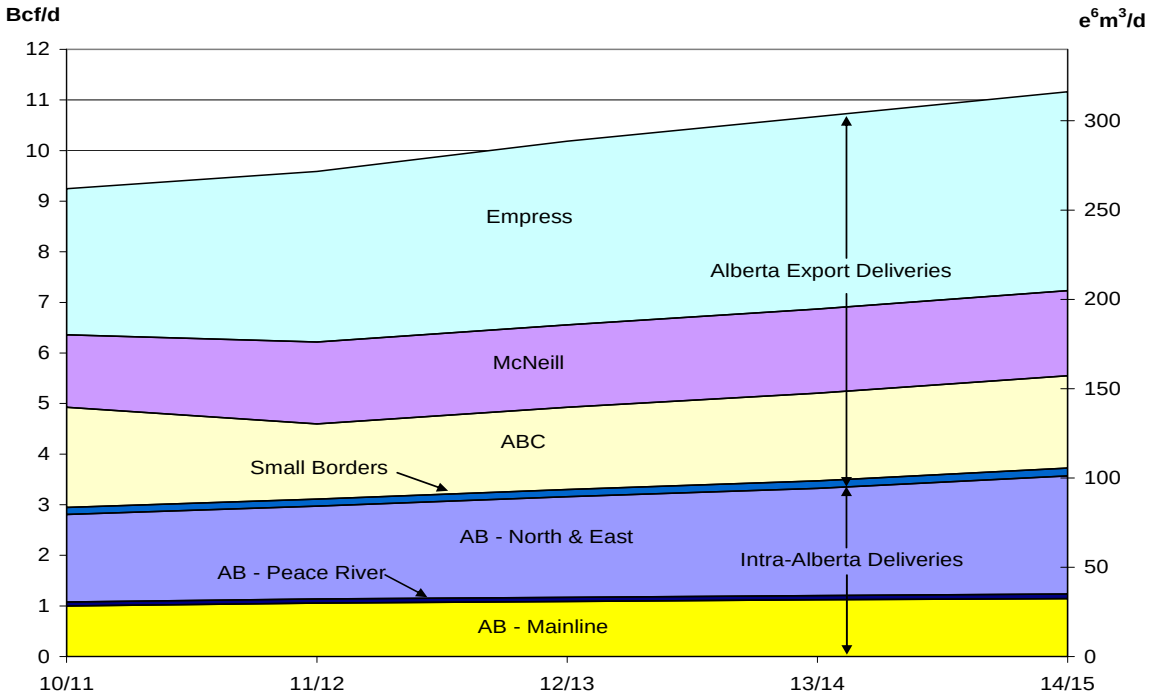
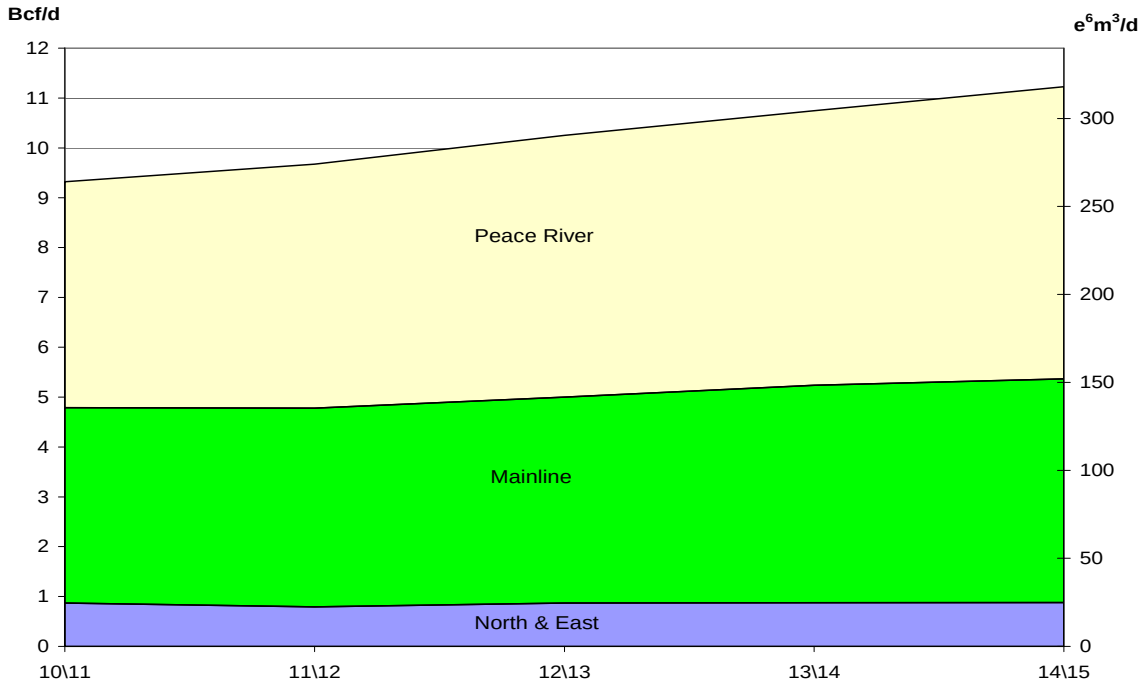


Figure 1.3.2
System Receipts by Project Area



1.6 Storage Facilities

There are eight storage facilities connected to the Alberta System, as shown in Table 1.6.1 (AECO 'C', Big Eddy, Carbon, Chancellor, Crossfield East #2, January Creek, Severn Creek and Warwick Southeast Meter Stations). The total deliverability from Storage Facilities is significant, but actual maximum day receipts from storage is dependent upon a number of factors including market conditions, storage working gas levels, storage compression power, and Alberta System operations.

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

The receipt meter capacity for each of the connected Storage Facilities for the Planning Period is shown in Table 1.6.1.

Table 1.6.1
Receipt Capacity from Storage Facilities

	Receipt Meter Capacity from Storage Facilities 2010/11	
	$10^6m^3/d$	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
Severn Creek	5.6	0.20
Warwick Southeast	6.1	0.22
TOTAL	**175.0**	**6.18**

NOTES:
- Storage is presently considered as an interruptible supply source.
- Numbers may not add due to rounding.

CHAPTER 2 DESIGN FLOW REQUIREMENT AND PROPOSED MAINLINE FACILITIES

2.1 Introduction

This chapter presents an overview of the design flow requirement, as described in Section 3.5 – Mainline Facilities Flow Determination of the Facilities Design Methodology Document, which can be accessed online at:

http://www.transcanada.com/customerexpress/5070.html

This chapter also presents the proposed natural gas transportation mainline facilities to be applied-for on the Alberta System in the 2011 calendar year to transport the design flow requirements for the 2011/12 to 2013/14 Gas Years. Included is information regarding size, routes, locations and cost estimates for the proposed facilities.

The design flow requirements are represented by peak expected flows and are presented for those design areas where new mainline facilities are required. Peak expected flows are based on the June 2010 design forecast presented in Chapter 1.

An overview of the design peak expected flows and proposed facilities resulting from the June 2010 design forecast was presented at the TTFP meeting on November 23, 2010.

The figures in Sections 2.2.1, 2.2.2, 2.2.3 and 2.3.1 show a comparison between winter and summer historical actual flow for the 2005/06 Gas Year through to the 2009/10 Gas Year. The figures also show the projected winter and summer peak expected flow and Firm Transportation (FT) contract level to the 2014/15 Gas Year. Additionally, the current design capability is shown for the Gas Year when facilities

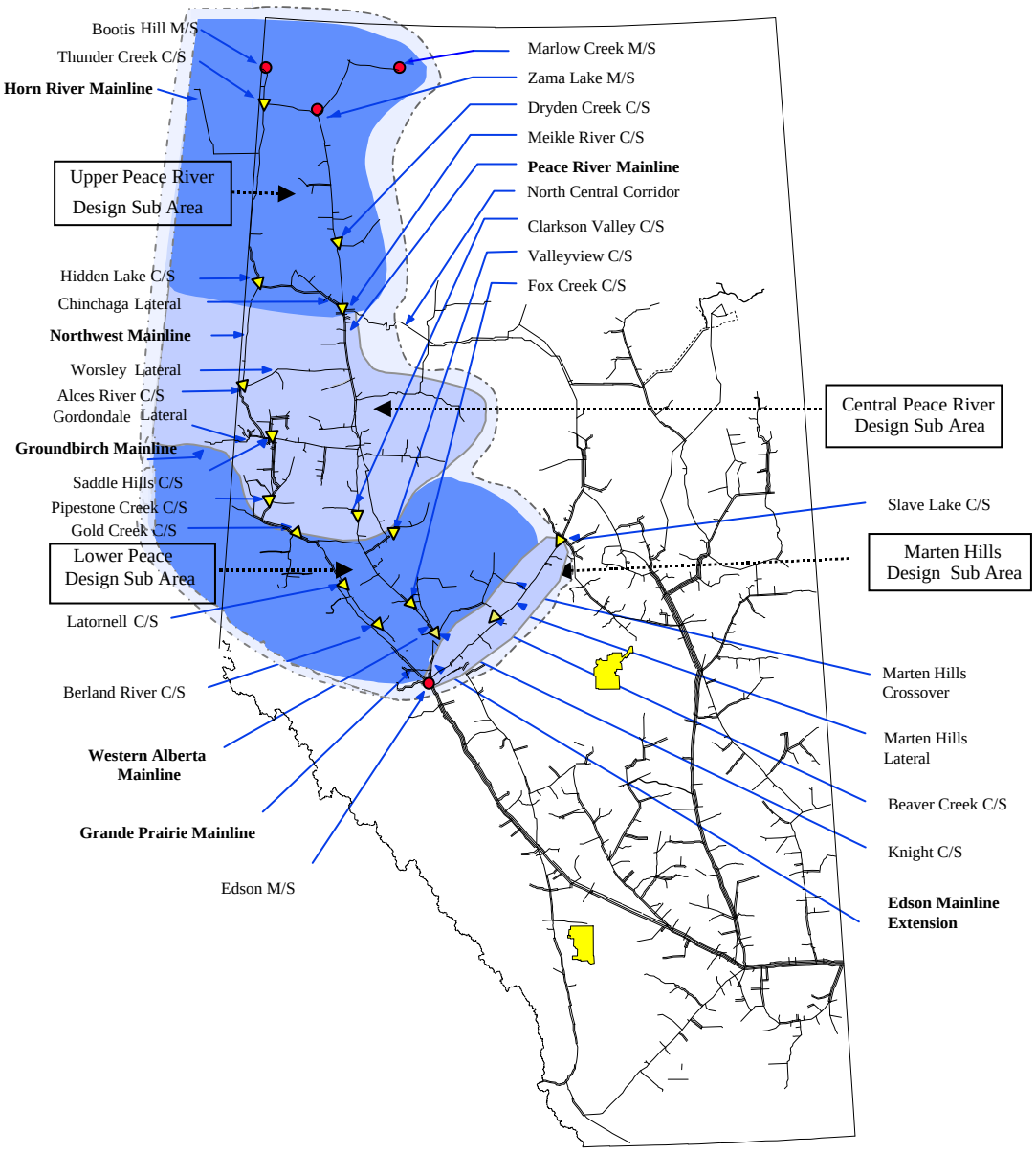
are required within each particular design area. Where there is a shortfall between peak expected flow and the existing design capability, a facility solution has been proposed. A facility application to the regulator for construction and operation is triggered by FT contracts such that the facility is in place in time to meet the FT requirements.

A summary of the status of mainline facilities that have been applied-for or placed in-service since the December 2009 Annual Plan was issued is included under Appendix 2 – Facility Status Update.

2.2 Peace River Project Area

The Peace River Project Area comprises the Peace River and Marten Hills Design Areas (Figure 2.2).

Figure 2.2
Peace River Project Area



In the Peace River Project Area, the proposed facilities are required to transport growing receipts in the Peace River Project Area to deliveries throughout the Alberta System. Additional information on design flow conditions can be found in Section

3.5 – Mainline Facilities Flow determination of the Facility Design Methodology Document.

2.2.1 Peace River Design Area

2.2.1.1 Design Flows -Upper Peace River Design Sub Area

The peak expected flow for the Upper Peace River Design Sub Area is the flow out of the area at the Hidden Lake and Meikle River Compressor Stations.

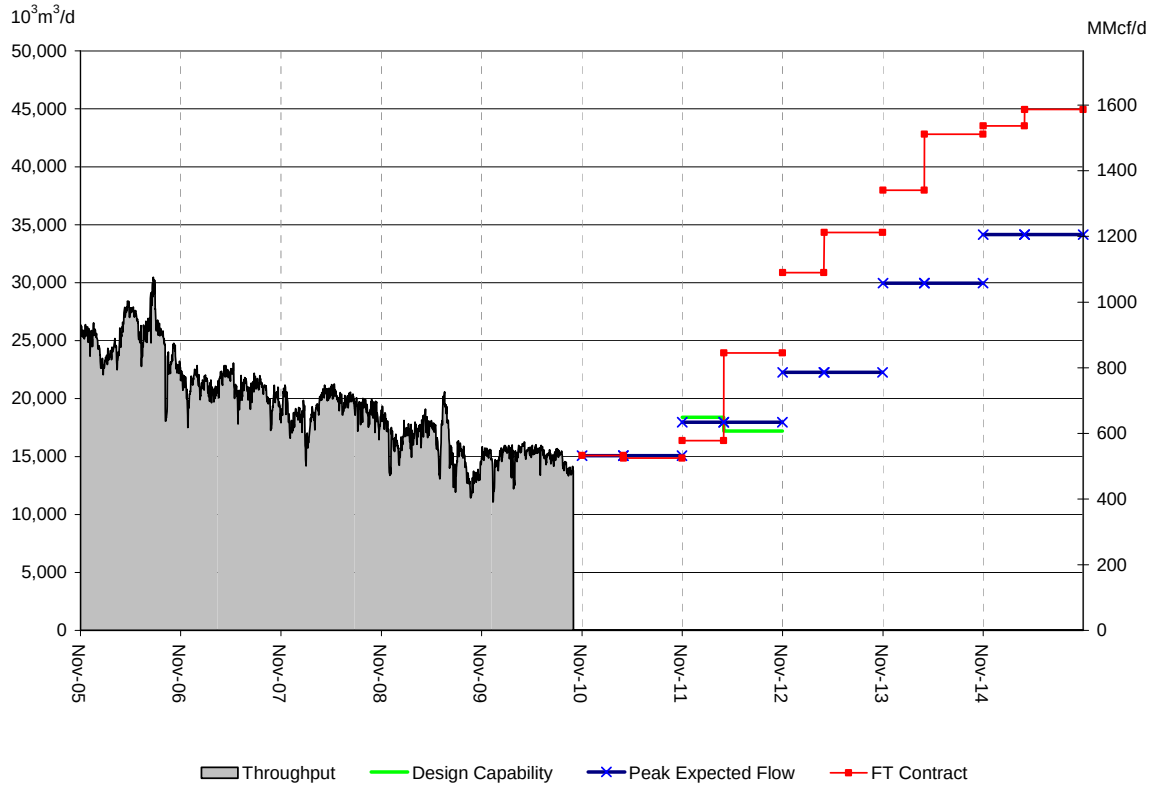
Figure 2.2.1 provides historical actual flow, the design capability for the area, projected peak expected flow and expected FT contract level consisting of confirmed and requested contracts as of November 2010. While peak expected flow is anticipated to rise throughout this forecast period, the near term producer interest in firm transportation service appears to be even greater as evidenced by the FT confirmed and requested contract level for both the 2011/12 and 2012/13 Gas Years.

These FT contract level within this design sub-area during the period covered by this Annual Plan have resulted in the identified new mainline facilities.

Figure 2.2.1

Throughput / Design Capability / Contracted Flow /Peak Expected Flow

Upper Peace River Design Area



2.2.1.2 Proposed Facilities -Upper Peace River Design Sub Area

Figure 2.2.1.2
Upper Peace River Design Area
Proposed Facilities

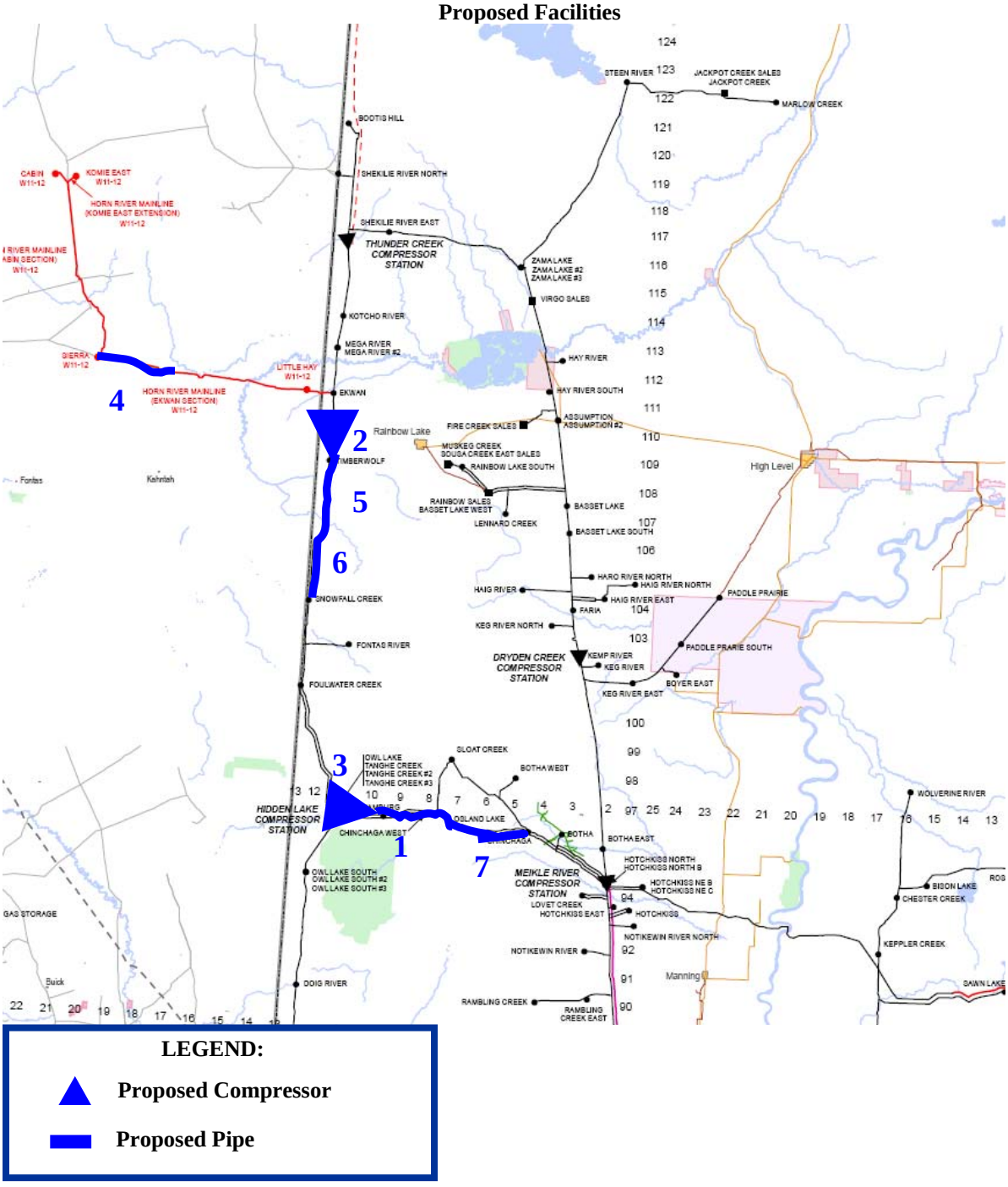


Table 2.2.1
Upper Peace River Design Sub Area
Proposed Facilities

Map Location	Proposed Facility	Description	Required In-Service Date	Capital Cost ($Millions)
1	Tanghe Creek Lateral Loop #2 (Sloat Creek Section)	38 km NPS 48	Apr 12	115.0
2	Moody Creek C/S	15 MW	Nov 12	62.1
3	Hidden Lake North C/S	15 MW	Nov 12	62.1
4	Horn River Mainline Loop (Ekwan Section)	30 km NPS 42	Apr 13	86.0
5	NWML Loop (Timberwolf Section)	25 km NPS 48	Apr 13	82.4
6	NWML Loop (Sabbath Section)	24 km NPS 48	Apr 13	71.2
7	Tanghe Creek Lateral Loop #2 (Cranberry Section)	32 km NPS 48	Apr 13	89.2
Capital Costs are in 2010 dollars and include AFUDC			**TOTAL**	**568.0**

The proposed facilities in this design sub-area serve multiple purposes:

- The two Tanghe Creek Lateral loops (Map Location 1 & 7) enable incremental flow to be transported to the North Central Corridor and help defer and/or offset additional facilities on the Grand Prairie Mainline (GPML).
- Horn River Mainline Loop (Ekwan Section) (Map Location 4) enables additional flow from the Horn River shale area, and
- The remaining proposed facilities serve the aggregate upstream flow requirements both within Alberta and N.E. B.C.

2.2.2.1 Design Flows - Upper and Central Peace River Design Sub Areas

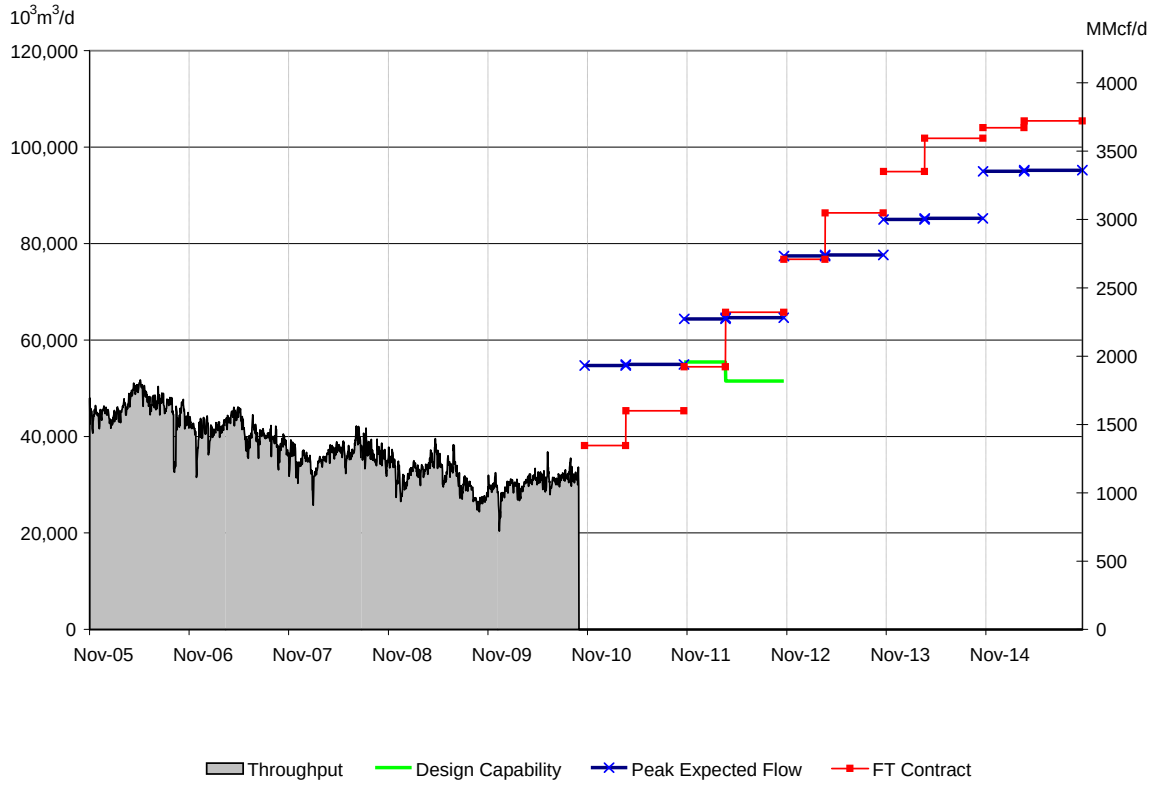
The peak expected flow for the Upper and Central Peace River Design Sub Areas is the flow out of the area at the Meikle Compressor Station toward the North Central Corridor and at the Saddle Hills, Clarkson Valley and Valleyview Compressor Stations toward the Lower Peace River Design Area.

Figure 2.2.2 provides historical actual flow, the design capability for the area, projected peak expected flow and FT contract level. As shown in the Figure both peak expected flow and FT contract level is expected to exceed the design capability for this area during the 2011/12 Gas Year.

Figure 2.2.2

Throughput / Design Capability / Peak Expected Flow

Upper and Central Peace River Design Area



2.2.2.2 Proposed Facilities - Central Peace River Design Sub Area

Figure 2.2.2.2
Central Peace River Design Sub Area
Proposed Facilities

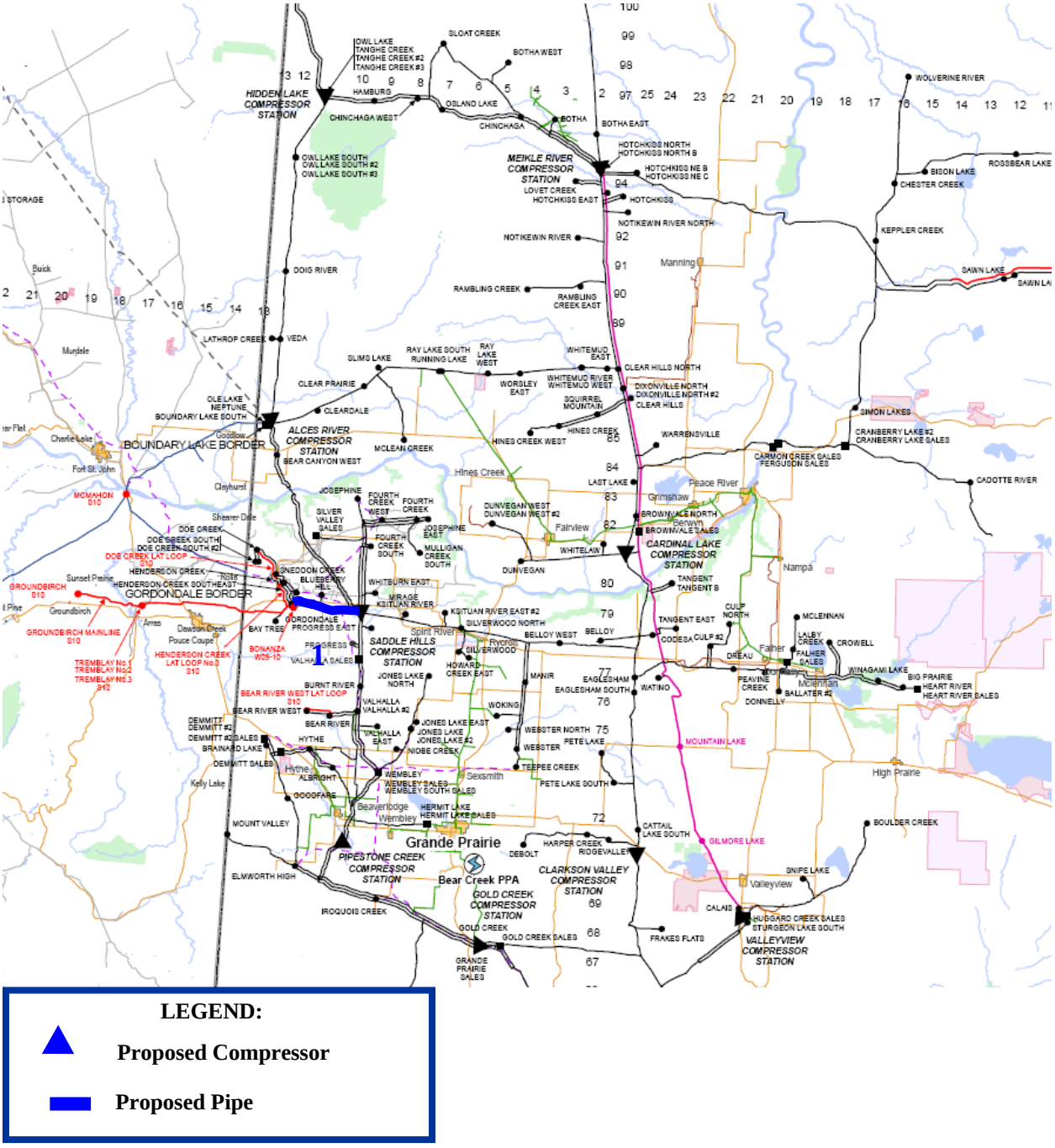


Table 2.2.2
Central Peace River Design Sub Area
Proposed Facilities

Map Location	Proposed Facility	Description	Required In-Service Date	Capital Cost ($Millions)
1	Gordondale Lateral Loop No.2	24 km NPS 42	Nov 11	65.3
Capital Costs are in 2010 dollars and include AFUDC			**TOTAL**	**65.3**

The Gordondale Lateral Loop No. 2 increases the capacity to transport incremental supply from a number of areas including the Doe Creek area, Spectra Pipeline through the Gordondale Border Receipt Station and from the new Groundbirch Mainline.

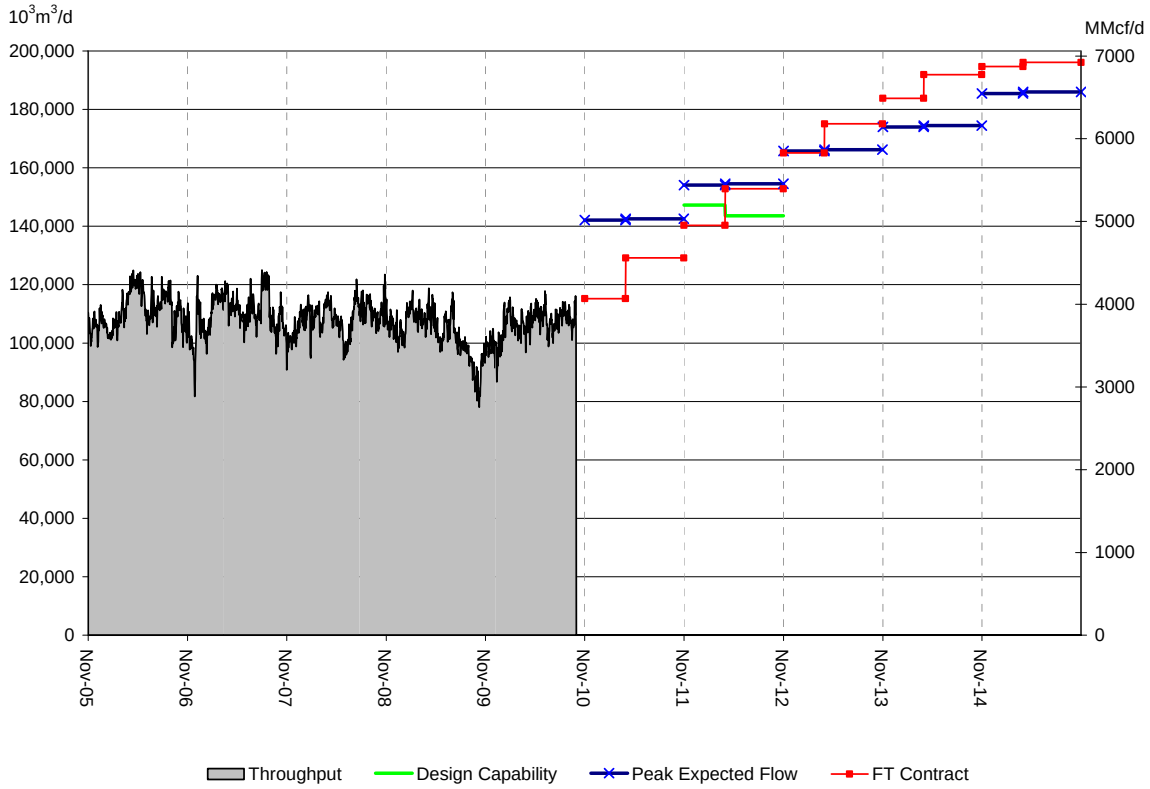
2.2.3.1 Design Flows - Upper, Central and Lower Peace River Design Sub Areas

The peak expected flow for the Upper, Central and Lower Peace River Design Sub Areas is the flow out of the area at the Meikle Compressor Station as well as the flow from the Grande Prairie Mainline and the Edson Mainline Extension at the Edson Meter Station, excluding the Marten Hills Lateral flow.

Figure 2.2.3 provides historical actual flow, the design capability for the area, projected peak expected flow and FT contract level. The FT contract level is expected to exceed the design capability within a portion of this area in the 2011/12 Gas Year.

Figure 2.2.3

Throughput / Design Capability / Peak Expected Flow
Upper, Central and Lower Peace River Design Area



2.2.3.2 Proposed Facilities - Lower Peace River Design Sub Area

Figure 2.2.3.1
Lower Peace River Design Sub Area
Proposed Facilities

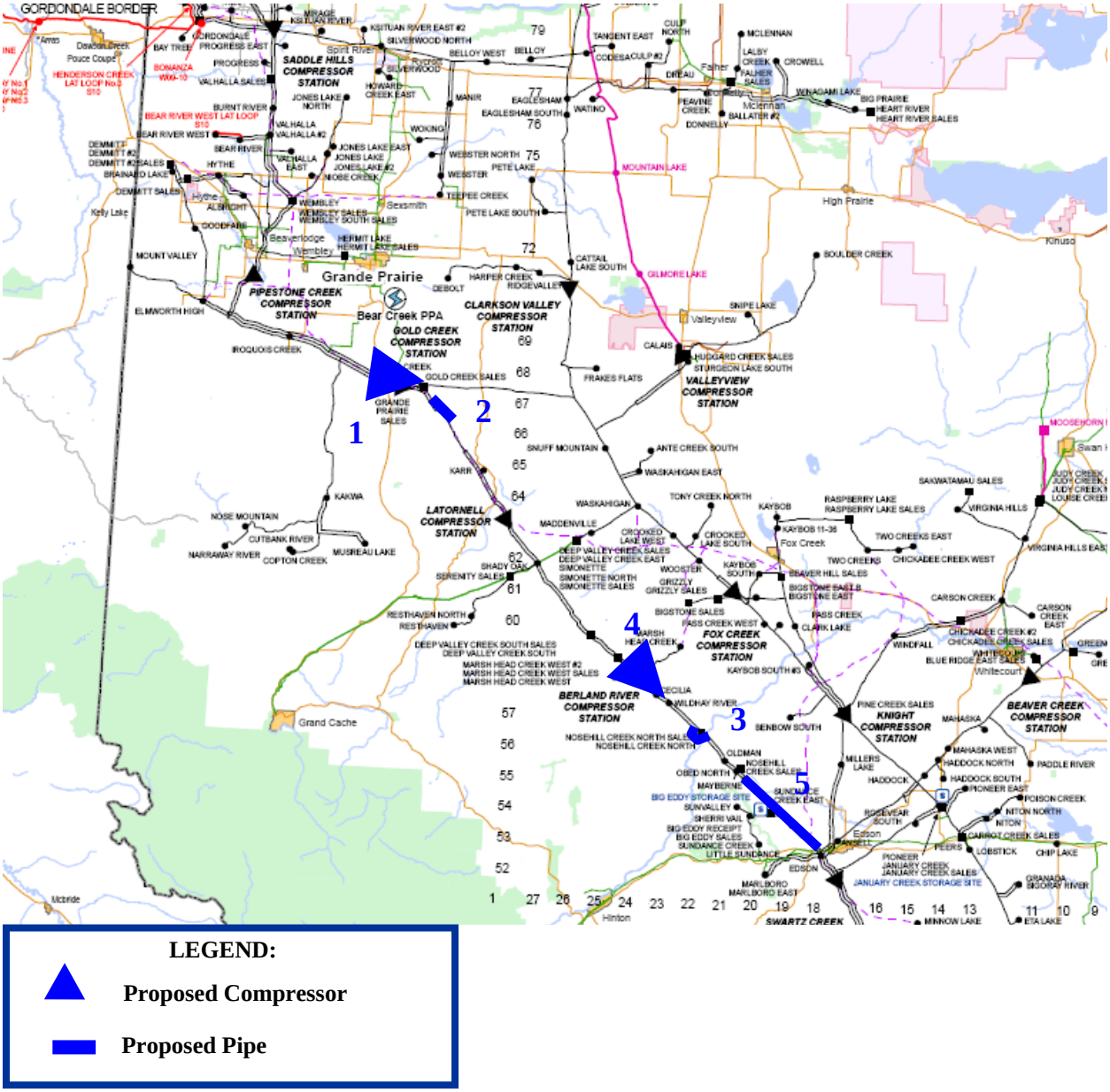


Table 2.2.3
Lower Peace River Design Sub Area
Proposed Facilities

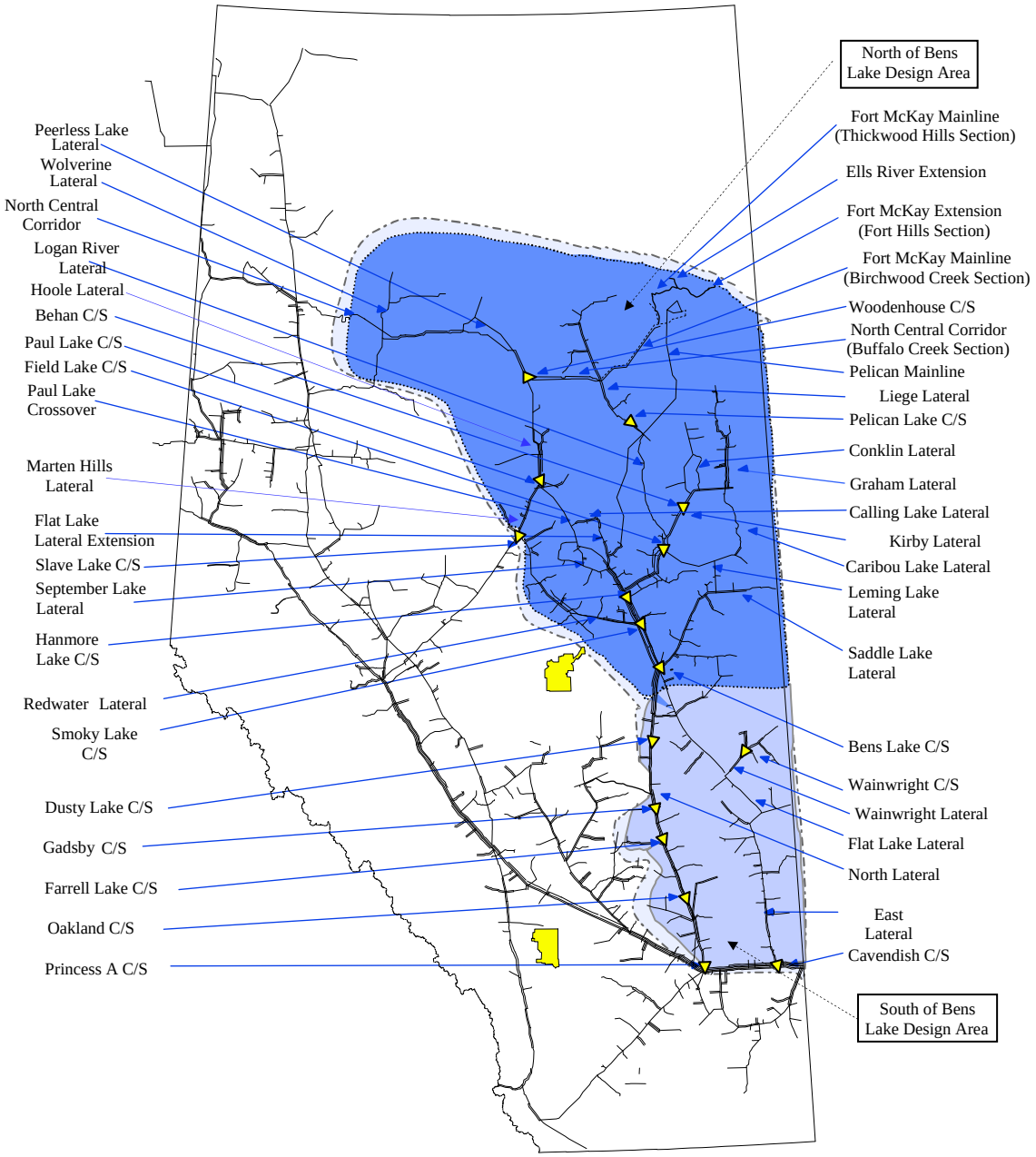
Map Location	Proposed Facility	Description	Required In-Service Date	Capital Cost ($Millions)
1	Gold Creek C/S Unit Addition	28 MW	Nov 11	60.3
2	GPML Loop (Karr North Section)	16 km NPS 42	Apr 12	39.2
3	GPML Loop (Nosehill Creek Section)	3 km NPS 42	Apr 12	21.4
4	Berland Rvr C/S Unit Addition	28 MW	Nov 12	66.4
5	GPML Loop No. 2 (Macleod River Section)	35 km NPS 48	Apr 13	81.6
Capital Costs are in 2010 dollars and include AFUDC			**TOTAL**	**268.9**

These proposed facilities are required to service the aggregate needs of all upstream supply including gas from the Montney area through the Groundbirch Mainline, the Spectra Pipeline through Gordondale Border Receipt Station and upstream supply from the Northwest Mainline. These facilities provide incremental capability to transport natural gas southbound through the Grande Prairie Mainline and towards the major export points.

2.3 North and East Project Area

The North and East Project Area (Figure 2.3) is comprised of the North of Bens Lake and South of Bens Lake Design Areas.

Figure 2.3
North and East Project Area



Two distinct flow conditions are examined in assessing facilities requirements in the North and East Project Area. First, there is the "flow through" condition that is governed by the North and East Project Area design flow requirements methodology. Second, there is the "flow within" condition that is governed by the maximum day delivery to the North of Bens Lake Design Area. Currently, the "flow within" condition governs facilities requirements in the North and East Project Area. Additional information on design flow conditions can be found in Section 3.5 – Mainline Facilities Flow Determination of the Facilities Design Methodology Document.

2.3.1 North of Bens Lake Design Area

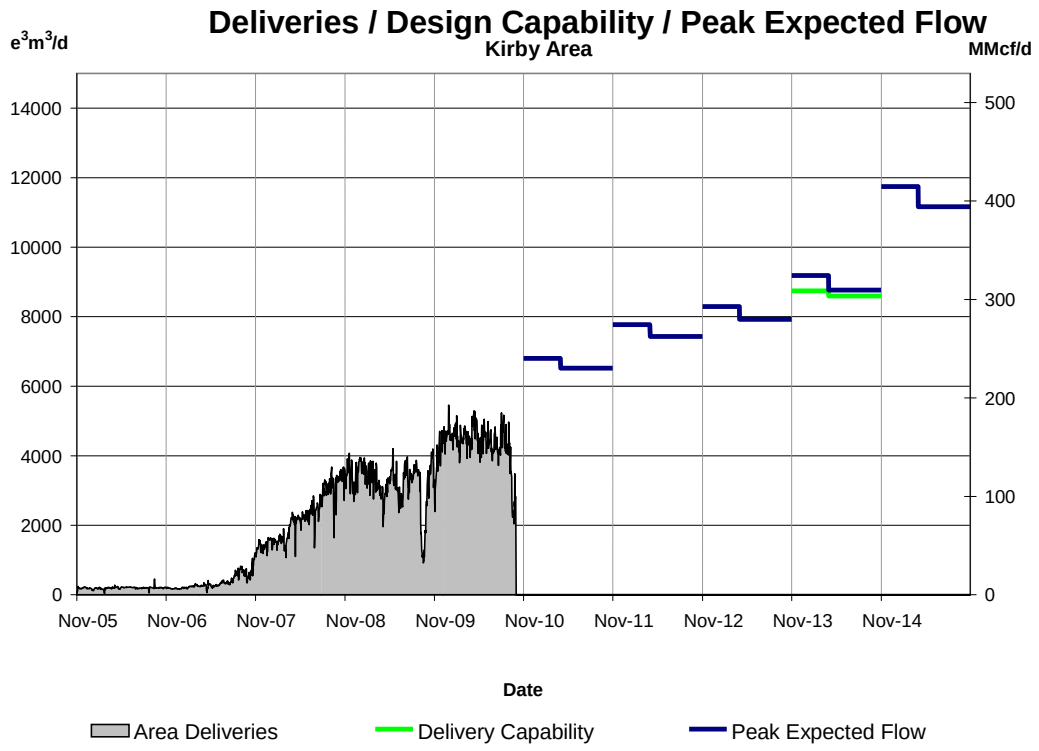
2.3.1.1 Design Flows – North of Bens Lake Design Areas

The peak expected flow, for the flow within condition, in the North of Bens Lake Design Area is the net effect of localized minimum available supply less the maximum deliveries expected within the area. As outlined in Chapter 1, Alberta deliveries to the North of Bens Lake Design Area are forecast to increase in the future. The productive capability required to meet the maximum day delivery draws from available receipts on the Liege, Logan, Conklin and Kirby Laterals plus the supply that is brought into the area from the Peerless Lake Lateral, via the North Central Corridor (Buffalo Creek Section) and the Marten Hills design area through the Slave Lake compressor.

Figure 2.3.1 provides historical actual flow, the design capability for the area, projected peak expected flow and FT contract levels. Peak expected flow is expected to rise in the North of Bens Lake Design Area throughout this forecast period and specifically, there is an increase in peak expected deliveries within the Kirby region of this area that will require additional mainline facilities to be in service by November 2013. This proposed facility is located in an area which requires facilities

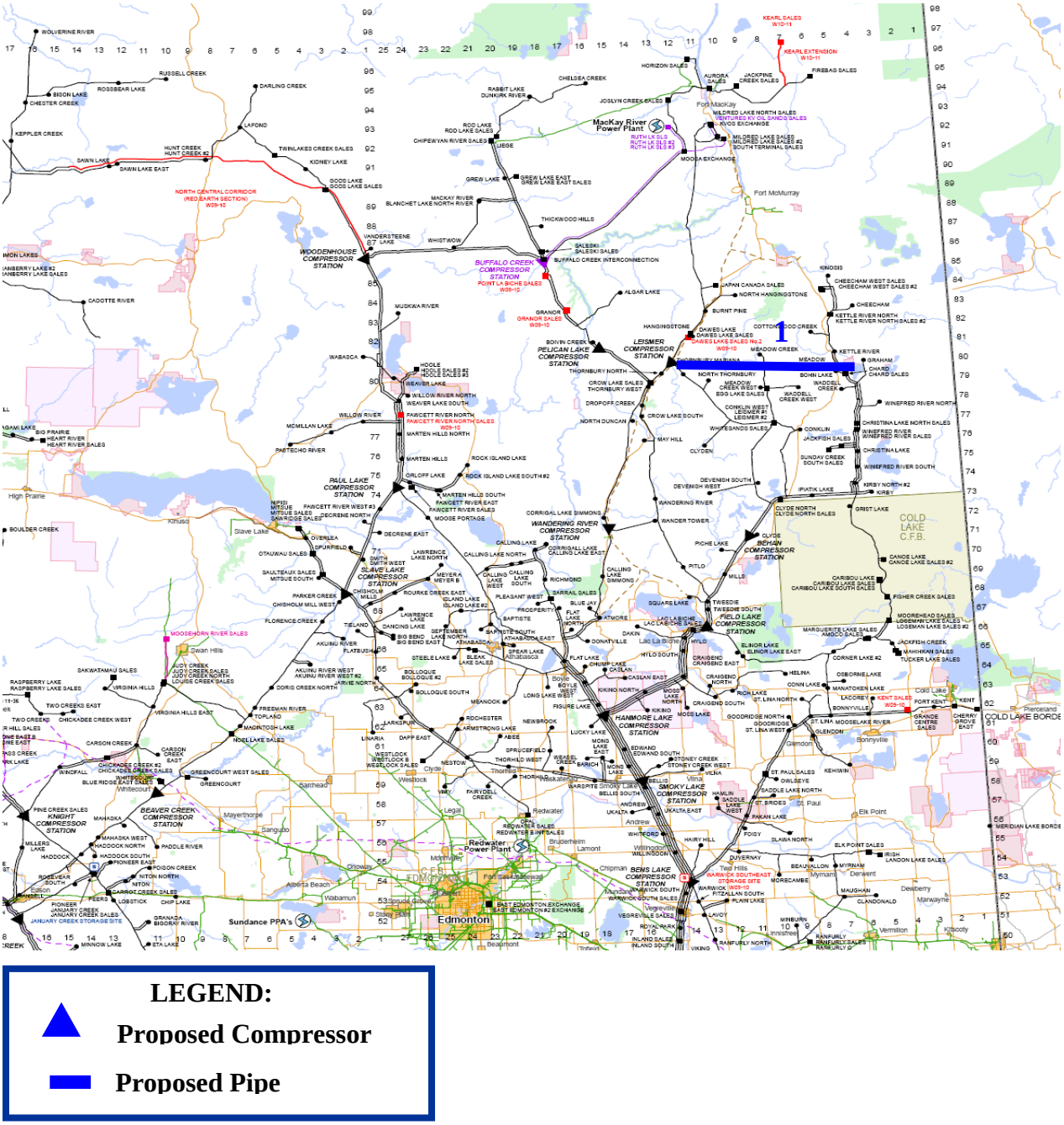
to be constructed during the winter season. Therefore, the in-service date will be April, 2013.

Figure 2.3.1
Deliveries / Design Capability / Peak Expected Flow
Kirby Area



2.3.1.2 Proposed Facilities – North of Bens Lake Design Areas

Figure 2.3.1.2
North of Bens Lake Design Area
Proposed Facilities



2.3.1.3 Proposed Facilities - North of Bens Lake Design Areas

Table 2.3.1
North & East Project Area
Proposed Facilities

Map Location	Proposed Facility	Description	Required In-Service Date	Capital Cost ($Millions)
1	Leismer to Kettle River Crossover	86 km NPS 24	April 13	137.2
Capital Costs are in 2010 dollars and include AFUDC			**TOTAL**	**137.2**

The Leismer to Kettle River Crossover will transport additional gas supply to meet increasing delivery requirements in the Kirby Area due to increasing development of in-situ oil sands production.

CHAPTER 3 – EXTENSION FACILITIES, LATERAL LOOPS AND METER STATIONS

3.1 Introduction

This chapter presents an overview of the receipt and delivery meter stations, extension facilities and lateral loops that are required to meet customer requests for firm service. These facilities are designed following the Transportation Design Process in section 4 of the Facilities Design Methodology Document, which can be accessed online at:

http://www.transcanada.com/customerexpress/5070.html

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

A summary of the status of the facilities that have been placed in-service or applied-for since the 2009 Annual Plan was issued is included under Appendix 2 – Facility Status Update.

Proposed extensions, lateral loops, and associated meter stations are listed in Table 3.1 and shown on Figure 3.1. These proposed facilities were presented at the TTFP meeting held on November 23, 2010.

Figure 3.1
Proposed Extensions, Lateral Loops and Meter Stations

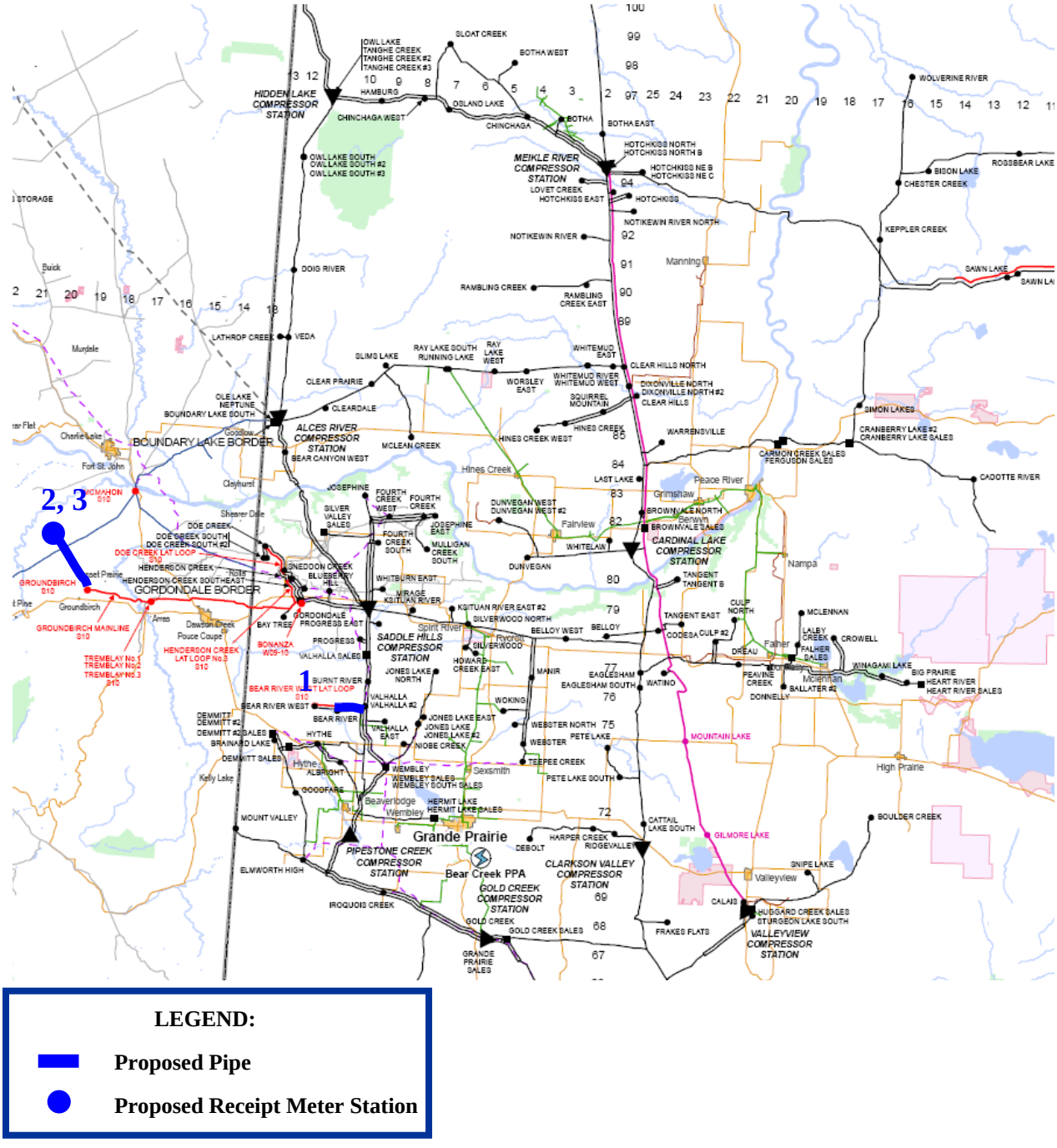


Table 3.1
Proposed Extensions, Lateral Loops and Meter Stations

Map Location	Proposed Facility	Description	Required In-Service Date	Capital Cost ($Millions)
1	Bear River Lateral Loop No. 2	10 km NPS 10	Nov 11	7.7
2	Groundbirch Mainline (Saturn Section)	24 km NPS 36	Apr 12	55.4
3	Saturn Receipt Meter Station	NPS 10 Ultrasonic	Apr 12	3.5
Capital Costs are in 2010 dollars and include AFUDC			**TOTAL**	**66.6**

3.2 Facility Description

- **Groundbirch Mainline (Saturn Section) and Meter Station**

  The 24 kilometer NPS 36 Groundbirch Mainline (Saturn Section) and the Saturn Receipt Meter Station are required to connect incremental supply to the Alberta System. This section is required for April 1, 2012. Due to seasonal construction requirements it will be in-service on or about November 1, 2011. The facilities application was filed with the NEB on December 9, 2010.

- **Bear River Lateral Loop No. 2**

  The 10 kilometer NPS 10 Bear River Lateral No. 2 is required to meet incremental firm service requirements for the 2011/12 Gas Year. The facility is required to be in-service on November 1, 2011 and the application is anticipated to be filed in the 1st quarter of 2011.

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 upon in interpreting NGTL's Gas Transportation Tariff or any Service Agreement. Capitalized terms not otherwise defined here are defined in NGTL's Gas Transportation Tariff. The defined terms in this Glossary of Terms may not be capitalized in their use throughout the Annual Plan.

Alberta Average Field Price

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

Allowance for Funds Used During Construction ("AFUDC")

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

Annual Plan

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

Average Annual Delivery

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

Average Day Delivery

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

Average Receipt Forecast

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

Coincidental

Occurring at the same time.

Delivery Meter Station

A facility which measures gas volumes leaving the Alberta System.

Delivery Point

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

Delivery Design Area

The Alberta System is divided into 5 delivery design areas used to facilitate the transfer of delivery service within or between Delivery Design Areas. The Delivery Design Areas are:

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

Demand Coincidence Factor

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

Design Area

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

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

Design Capability

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

Design Flows

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

Design Forecast

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

Expansion Facilities

Expansion facilities are those facilities which will expand the existing Alberta System to/from the point of Customer connection including any pipeline loop of the existing system, metering and associated connection piping and system compression.

Extension Facilities

Extension facilities are those facilities which connect new or incremental supply or markets to the Alberta System.

Firm Transportation

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

Gas Year

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

Interruptible Transportation

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

Lateral

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

Load / Capability Analysis

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

Loop

The paralleling of an existing pipeline by another pipeline.

Mainline

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

Maximum Day Delivery

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

Maximum Operating Pressure

The maximum operating pressure at which a pipeline is operated.

Minimum Day Delivery

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

NPS

Nominal pipe size, in inches.

Non-coincidental

Non-simultaneous occurrence.

Peak Expected Flow

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

Project Area

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

Dividing the system this way allows the system to be modelled in a way that best reflects the pattern of flows in each specific area of the system. The Project Area may be amended from time to time by Company in consultation with the Facility Liaison

Committee (or any replacement of it), provided Company has given six months notice of such amendment to it Customers.

Receipt Area

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

Receipt Meter Station

A facility which measures gas volumes entering the Alberta System.

Receipt Point

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

Storage Facility

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

Summer Season

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

System Annual Throughput

The total amount of gas that is transported or anticipated to be transported in one calendar year.

System Average Annual Throughput

The total amount of gas that is transported or anticipated to be transported in one gas year.

System Average Receipts

The forecast of aggregate average receipts at all Receipt Points.

System Maximum Day Deliveries

The forecast of aggregate maximum day deliveries at all Delivery Points.

Transportation Design Process

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

Two-way Flow Stations

A meter station on the Alberta System where gas can either be received onto the Alberta System or be delivered off of the Alberta System.

Winter Season

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

APPENDIX 2 – 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 2009 Annual Plan was issued.

Applied-for Facilities	Description	Status	Previous Annual Plan Reference	Forecast Cost as of October 31, 2010 ($Millions)
North Central Corridor (Red Earth Section)	160 km NPS 42	In-service	2006	356.1
Bear River West Lateral Loop	8.6 km NPS 10	In-service	2009	6.3
Cabin Meter Station	2-2012U-8 Ultrasonic meter	Applied-for	2009	4.7
Doe Creek Lateral Loop / Henderson Creek Lateral Loop No.3	17.7 km NPS 16	In-service	2009	13.5
Granor Sales Meter Station	NPS 2 LVS	In-service	2009	0.5
Groundbirch Receipt Meter Station	1010U-4 Ultrasonic meter	In-service	2009	3.1
Horn River Project (Ekwan & Cabin Sections)	85.2 km NPS 24 72 km NPS 36	Applied-for	2009	253.2
Kearl Extension and Sales Meter Station	4.16 km NPS 24 19.14 NPS 20	Under construction	2009	34.3
Komie East Extension	2.2 km NPS 24	Applied-for	2009	3.2
Komie East Meter Station	1010U-4 Ultrasonic meter	Applied-for	2009	2.6
Little Hay Creek Meter Station	442 Orifice meter	Applied-for	2009	1.7
Sierra Meter Station	880U-4 Ultrasonic meter	Applied-for	2009	3.3
Tremblay Receipt Meter Station	1010U-4 Ultrasonic meter	In-service	2009	2.6
Tremblay No. 2 Receipt Meter Station	1010U-4 Ultrasonic meter	In-service	2009	2.6

Applied-for Facilities	Description	Status	Previous Annual Plan Reference	Forecast Cost as of October 31, 2010 ($Millions)
Albright Crossover	19 km NPS 20	In-service		13.0
Bear River West Meter Station Upgrade	882 Orifice meter	Under construction		1.4
Bonanza Receipt Meter Station	880 Orifice meter	In-service		1.3
Cutbank River Lateral Loop (Bald Mountain Section)	38 km NPS 24	Applied-for		46.1
Dawes Lake No. 2 Sales	2-880 Turbine meters	In-service		1.1
Fawcett River North Sales	NPS 2 LVS	In-service		0.3
Groundbirch Pipeline Project	77 km NPS 36	In-service		143.1
Kent Sales Meter Station	2-880 Turbine meter	In-service		0.9
Pelican Mainline Back-up Loop Relocation	1.4 km NPS 10	Applied-for		5.8
Pointe La Biche Sales	NPS 4 LVS	In-service		0.6
Saamis Sales Meter Station	2-640 Turbine meters	Applied-for		1.2
Tremblay No. 3 Receipt Meter Station	662 Orifice meter	In-service		1.9
Warwick Southeast Storage Meter Station and Connection Pipe	2-1208U Ultrasonic meter plus 0.8 km NPS 12	In-service		2.7
Watino Crossover and Calais Extension	6.8 km NPS 4	Applied-for		9.0