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.

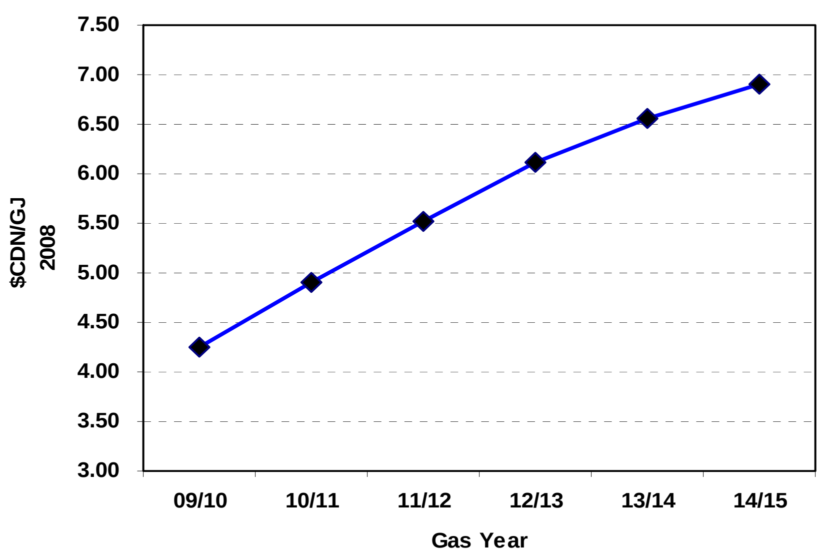
- The North American market will be well supplied with natural gas sourced from North America due to the strength in unconventional gas production, primarily shale gas. This strong domestic supply growth is now expected to be able to keep pace with the growth in gas demand, leaving a greatly reduced 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 $10^6m^3/d$ 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 ($10^6 m^3/d$)				
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

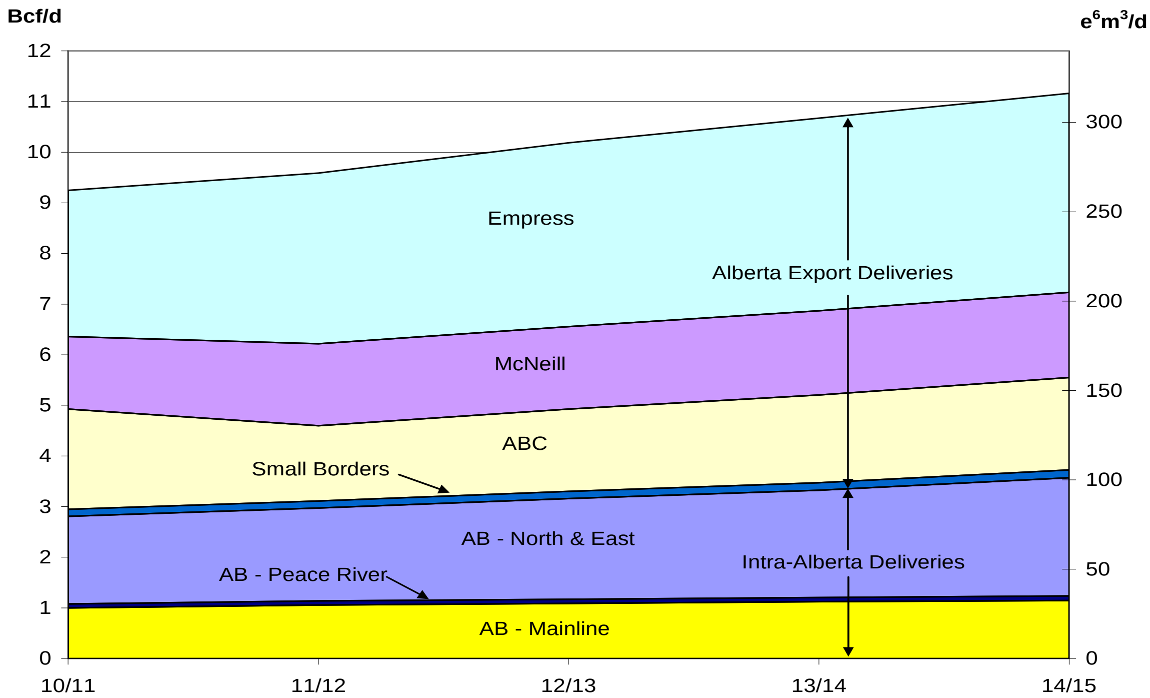
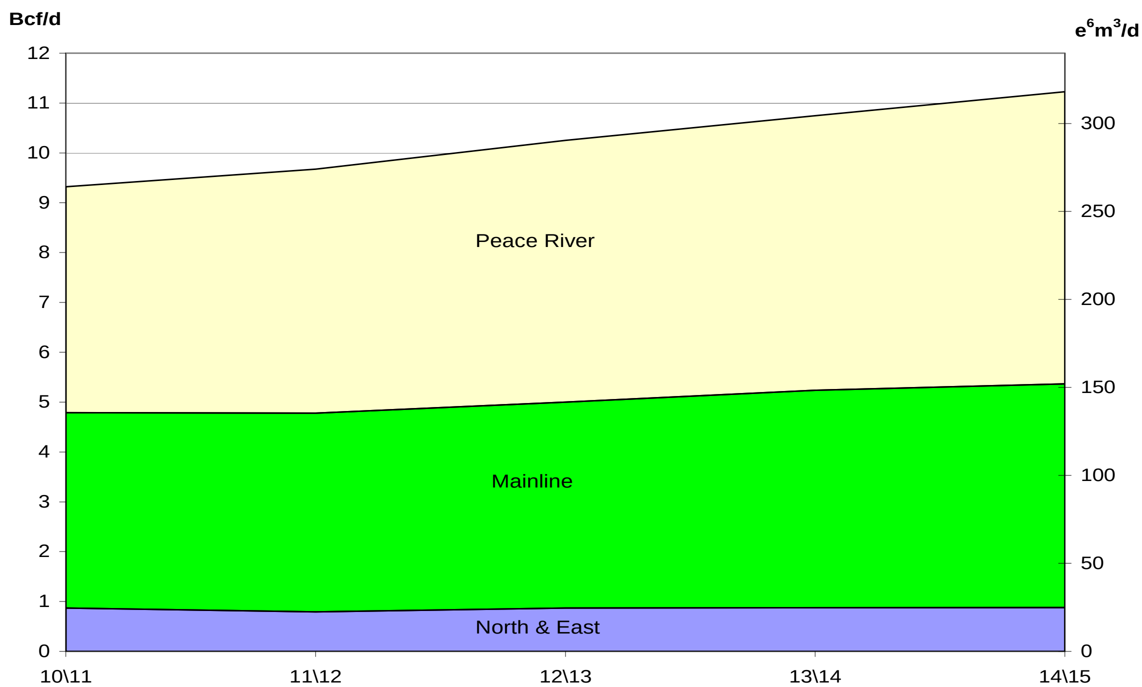


Figure 1.3.2
System Receipts by Project Area



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.