CHAPTER 3 - DESIGN FORECAST

3.1 Introduction

This Annual Plan is based on the June 2008 design forecast of gas receipts and deliveries, which in turn is based on supply and market assessments completed in May 2008.

From a receipt perspective, the forecasts of field deliverability, average receipts and FS productive capability used in this Annual Plan are subject to uncertainties. Producer success in developing new supply, actual levels of new firm transportation Service Agreements and changes in market demand may result in deviations from forecast values.

From a delivery forecast perspective, the forecast of maximum day delivery at the Export Delivery Points as shown in Section 3.4.2 is equal to the forecast of Firm Transportation-Delivery (“FT-D”) contracts at the Export Delivery Points and does not include Short Term Firm Transportation-Delivery (“STFT”) or Firm Transportation-Delivery Winter (“FT-DW”) contracts. Estimates of FT-D contracts at the Export Delivery Points have become difficult to forecast given the significant gap between these contracts and the actual gas flows at the major Export Delivery Points, as service with short-term contracts are increasingly being utilized.

In addition, significant exploration activity focused on unconventional gas in 2008 has resulted in an expectation of incremental volumes of shale gas entering the Alberta System in the Peace River Project Area in the near future. Open seasons were initiated, both non-binding and binding, during 2008 to assess the need for incremental transmission facilities to connect shale gas production from northeast B.C. from both the Montney and Horn River plays to existing Alberta System facilities. The results of the opens seasons are being reviewed and have not been included in this Annual Plan.

The June 2008 design forecast of gas receipt and delivery applies to the transportation design process for facilities to be in-service for the Planning Period. The June 2008 design forecast comprises two principal parts. The first part is the gas delivery forecast (Sections 2.9.4.3 and 3.4), which is a forecast of the natural gas volumes to be delivered at all Delivery Points on the Alberta System. The second part is the receipt forecast, comprised of field deliverability, average receipts and FS productive capability forecasts (Sections 2.9.4.1, 2.9.4.2 and 3.5) for all Receipt Points on the Alberta System.

An overview of the June 2008 design forecast was presented at the November 18, 2008 TTFP meeting. This chapter presents a detailed description of the June 2008 design forecast.

The June 2008 design forecast includes winter and summer seasonal forecasts of maximum, average, and minimum day delivery for all Delivery Points and a forecast of field deliverability, average receipts and FS productive capability for all Receipt Points on the Alberta System. Refer to Section 2.9.4 for further details on the relationship between field deliverability, average receipts, FS productive capability and Receipt Contract Demand under firm transportation Service Agreements for all Receipt Points on the Alberta System.

Gas from Storage Facilities remains a significant source of winter supply. Currently connected Storage Facilities have a maximum receipt meter capacity of 168.9 $10^6m^3/d$ (6.00 Bcf/d). Actual maximum day receipts from storage will be dependent upon market conditions, storage working gas levels, storage compression power, and Alberta System operations. A discussion of the maximum day receipt meter capability associated with Storage Facilities is provided for information purposes in Section 3.6. Refer to Section 2.6.1.4 for further details on the treatment of storage in the system design.

3.2 Economic Assumptions

3.2.1 General Assumptions

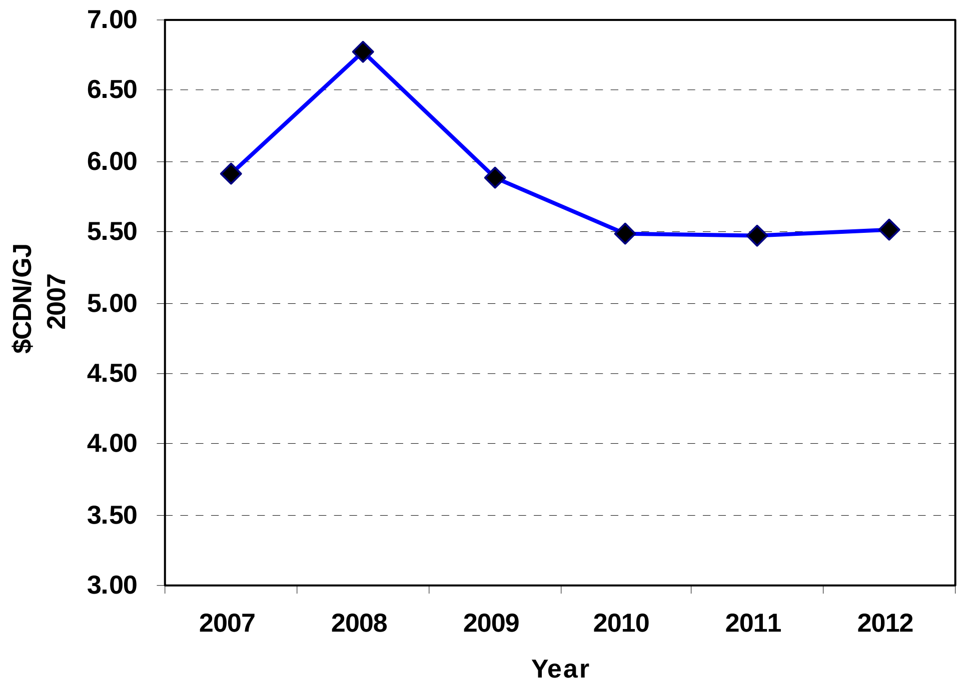
Underlying the forecast of receipts and deliveries are assumptions concerning broader trends in the North American economy and energy markets.
These assumptions, developed in April 2008, include:

- U.S. gas prices (at NYMEX) are expected to have reached a peak in 2008 at $U.S. 8.15/MMBTU or $U.S. 8.05/MMBTU in terms of real 2007$U.S./MMBTU. Prices will slowly decline over the next several years primarily due to increasing U.S. domestic gas production. Prices are expected to hit a low point of $U.S. 5.89/MMBTU in 2012 and then increase slowly to reach $U.S. 6.07/MMBTU by 2015 in real 2007$U.S./MMBTU. This is a long-term equilibrium price that is expected to balance the continental gas market based on the following factors.
- Gas demand is expected to increase with continued economic and population growth in the longer term in both the U.S. and Canada. U.S. gas demand growth will be predominately in the electricity generation sector. Western Canadian industrial gas demand is expected to grow significantly, driven by oil sands and heavy oil activity; and
- The U.S. is expected to be able to supply most of its natural gas needs by drawing from its extensive gas resource base, with production from the Rocky Mountains and U.S. Mid-continent showing significant growth. Much of the new supply will be from unconventional gas – coal bed methane, shale gas and tight gas. U.S. gas supply has shown strength in the past few years due to strong drilling activity and is expected to grow for a few more years, and then plateau.

3.2.2 Gas Price

A gas price forecast is used to help assess North American gas supply and demand. The gas price represents an Alberta average field price at a point just prior to receipt onto the Alberta System. The gas price forecast, shown in Figure 3.2.2, was developed in April 2008 and reflects the general assumptions from Section 3.2.1.

Figure 3.2.2
NGTL Gas Price Forecast
Alberta Average Field Price (Alberta Reference Price)



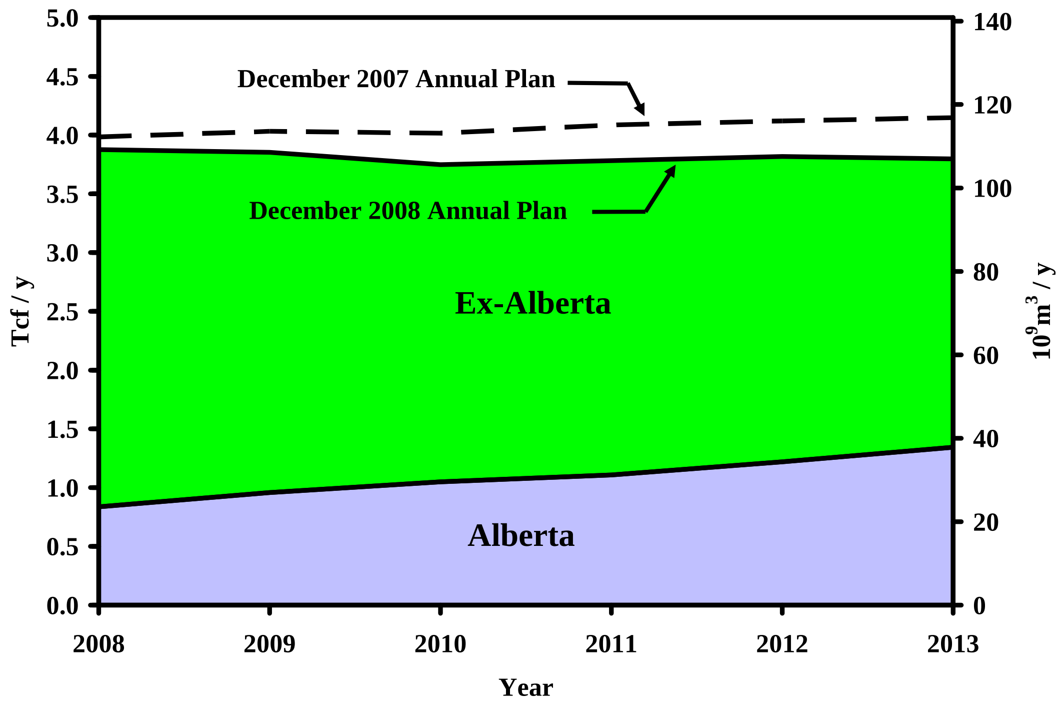
The Alberta average field price in 2008 (in real 2007 $) is forecast to rise to $6.78 Cdn/GJ, up from $5.91 Cdn/GJ in 2007. Alberta prices are expected to drop back to $5.88 Cdn/GJ in 2009, and then stabilize in the 2010 - 2012 period at a slightly lower level before exhibiting growth in real dollar terms out to 2015. By 2015, Alberta prices are expected to have reached a long term equilibrium of $5.80/GJ in real 2007 terms.

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.

3.3 System Annual Throughput

The forecast of system annual throughput is included for informational purposes. The system annual throughput forecast projects the total amount of gas to be transported on the Alberta System in future years and is shown in Figure 3.3.1.

Figure 3.3.1
System Annual Throughput



3.4 Gas Delivery Forecast

The gas delivery forecast describes one of the two principal components of the June 2008 design forecast. The second component, the receipt forecast, is described in Section 3.5.

3.4.1 System Maximum Day Delivery Forecast

The system maximum day delivery forecast projects aggregate maximum day delivery for the entire Alberta System in each of the winter and summer seasons for the 2009/10 through 2012/13 Gas Years. NGTL does not anticipate delivering the maximum day delivery at all Delivery Points simultaneously, although the maximum day delivery at individual Delivery Points may occur at some time during a season. A breakdown of the system maximum day delivery forecast for both the winter and summer seasons of the Planning Period is provided in Tables 3.4.2.1 and 3.4.2.2.

3.4.2 Export Delivery Points

The June 2008 design forecast of maximum day delivery at the Export Delivery Points is consistent with the downstream capacity assumption (Section 2.6.1.3).

Table 3.4.2.1
Winter System Maximum Day Delivery Forecast

	June 2008 Design Forecast				
Gas Year	**08/09**	**09/10**	**10/11**	**11/12**	**12/13**
(Volumes in $10^6 m^3/d$ at 101.325 kPa and 15°C)					
Empress	51.4	43.6	38.8	38.6	38.8
McNeill	34.6	16.4	11.4	13.1	12.3
Alberta/B.C.	62.3	63.6	52.6	39.6	40.4
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Unity	0.0	0.0	0.0	0.0	0.0
Cold Lake	0.0	0.0	0.0	0.0	0.0
Gordondale	0.0	0.0	0.0	0.0	0.0
Alberta/Montana	2.6	2.6	2.6	2.6	2.6
Alberta	141.2	151.2	160.5	176.0	187.0
TOTAL SYSTEM	**292.1**	**277.3**	**265.8**	**269.8**	**281.0**
(Volumes in Bcf/d at 14.65 psia and 60°F)					
Empress	1.82	1.55	1.38	1.37	1.38
McNeill	1.23	0.58	0.40	0.46	0.44
Alberta/B.C.	2.21	2.26	1.87	1.41	1.43
Boundary Lake	0.00	0.00	0.00	0.00	0.00
Unity	0.00	0.00	0.00	0.00	0.00
Cold Lake	0.00	0.00	0.00	0.00	0.00
Gordondale	0.00	0.00	0.00	0.00	0.00
Alberta/Montana	0.09	0.09	0.09	0.09	0.09
Alberta	5.01	5.37	5.70	6.25	6.64
TOTAL SYSTEM	**10.37**	**9.84**	**9.43**	**9.58**	**9.97**

NOTES:

- Delivery volumes shown are not anticipated to occur simultaneously but may occur at some time during the winter season.
- Numbers may not add due to rounding.

Table 3.4.2.2
Summer System Maximum Day Delivery Forecast

	June 2008 Design Forecast				
Gas Year	**08/09**	**09/10**	**10/11**	**11/12**	**12/13**
(Volumes in $10^6 m^3/d$ at 101.325 kPa and 15°C)					
Empress	50.0	38.8	38.8	38.6	38.8
McNeill	18.1	13.6	11.4	13.1	12.3
Alberta/B.C.	63.7	63.6	52.6	39.6	40.4
Boundary Lake	0.0	0.0	0.0	0.0	0.0
Unity	0.0	0.0	0.0	0.0	0.0
Cold Lake	0.0	0.0	0.0	0.0	0.0
Gordondale	0.0	0.0	0.0	0.0	0.0
Alberta/Montana	1.9	2.6	2.6	2.6	2.6
Alberta	108.5	116.9	127.9	146.0	152.1
TOTAL SYSTEM	**242.3**	**235.3**	**233.2**	**239.8**	**246.2**
(Volumes in Bcf/d at 14.65 psia and 60°F)					
Empress	1.78	1.38	1.38	1.37	1.38
McNeill	0.64	0.48	0.40	0.46	0.44
Alberta/B.C.	2.26	2.26	1.87	1.41	1.43
Boundary Lake	0.00	0.00	0.00	0.00	0.00
Unity	0.00	0.00	0.00	0.00	0.00
Cold Lake	0.00	0.00	0.00	0.00	0.00
Gordondale	0.00	0.00	0.00	0.00	0.00
Alberta/Montana	0.07	0.09	0.09	0.09	0.09
Alberta	3.85	4.15	4.54	5.18	5.40
TOTAL SYSTEM	**8.60**	**8.35**	**8.28**	**8.51**	**8.74**

NOTES:
- Delivery volumes shown are not anticipated to occur simultaneously but may occur at some time during the summer season.
- Numbers may not add due to rounding.

3.4.2.1 Empress, McNeill and Alberta/British Columbia

The forecast of maximum day delivery at the major Export Delivery Points reflects the forecast level of firm transportation Service Agreements at the each major Export Delivery Point.

3.4.2.2 Other Exports

The June 2008 design forecast maximum day delivery for the 2009/10 Gas Year ("Planning Period") for the Alberta/Montana Export Delivery Point is 2.6 $10^6 m^3/d$ (0.09 Bcf/d).

The June 2008 design forecast maximum day delivery for the Planning Period for each of the Boundary Lake, Cold Lake, Gordondale and Unity Delivery Points is zero. This is unchanged from the maximum day delivery forecast for the previous Planning Period.

3.4.3 Alberta Deliveries

The June 2008 Alberta maximum day delivery forecast for the winter season of the Planning Period is 151.2 $10^6 m^3/d$ (5.37 Bcf/d). This is an increase of 10.0 $10^6 m^3/d$ (0.35 Bcf/d), or 7.1 percent, from the previous Planning Period winter season value in the June 2008 design forecast. The June 2008 Alberta maximum day delivery forecast for the summer season of the Planning Period is 116.9 $10^6 m^3/d$ (4.15 Bcf/d). This is an increase of 8.3 $10^6 m^3/d$ (0.30 Bcf/d), or 7.7 percent, from the previous Planning Period summer season value in the June 2008 design forecast.

Several sources of information were considered in developing the Alberta maximum day 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 the 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.

A summary of the June 2008 design forecast winter and summer maximum day delivery for Alberta Deliveries by project area is provided in Tables 3.4.3.1, and 3.4.3.2, respectively.

Table 3.4.3.1
Winter Maximum Day Delivery Forecast

Project Area	**June 2008 Design Forecast ($10^6m^3/d$)**	
	2008/09	**2009/10**
Peace River	6.7	6.8
North and East	72.8	80.9
Mainline	56.8	58.6
Gas taps	4.9	5.0
TOTAL ALBERTA	**141.2**	**151.2**
Project Area	**June 2008 Design Forecast (Bcf/d)**	
	2008/09	**2009/10**
Peace River	0.24	0.24
North and East	2.58	2.87
Mainline	2.02	2.08
Gas taps	0.18	0.18
TOTAL ALBERTA	**5.01**	**5.37**

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

Table 3.4.3.2
Summer Maximum Day Delivery Forecast

Project Area	June 2008 Design Forecast ($10^6m^3/d$)	
	2008/09	**2009/10**
Peace River	4.6	4.6
North and East	66.3	73.3
Mainline	35.3	36.6
Gas taps	2.3	2.3
TOTAL ALBERTA	**108.5**	**116.9**
Project Area	**June 2008 Design Forecast (Bcf/d)**	
	2008/09	**2009/10**
Peace River	0.16	0.16
North and East	2.35	2.60
Mainline	1.25	1.30
Gas taps	0.08	0.08
TOTAL ALBERTA	**3.85**	**4.15**

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

3.5 Receipt Forecast

The following receipt forecasts comprise the second principal part of the Forecast.

3.5.1 System FS Productive Capability Forecast

The system FS productive capability forecast from the June 2008 design forecast is 256.2 $10^6m^3/d$ (9.09 Bcf/d) in the Planning Period. This is down from the previous Planning Period forecast of 268.3 $10^6m^3/d$ (9.52 Bcf/d) in the June 2008 design forecast.

A summary of system FS productive capability from the June 2008 design forecast by project area is provided in Table 3.5.1.

Table 3.5.1
System FS Productive Capability Forecast

Project Area	June 2008 Design Forecast ($10^6 m^3/d$)				
	2008/09	**2009/10**	**2010/11**	**2011/12**	**2012/13**
Peace River	105.0	98.6	94.4	96.4	94.8
North and East	33.0	30.7	32.8	35.7	37.7
Mainline	130.4	126.9	131.4	129.5	127.4
TOTAL SYSTEM	268.3	256.2	258.7	261.6	259.8
Project Area	**June 2008 Design Forecast (Bcf/d)**				
	2008/09	**2009/10**	**2010/11**	**2011/12**	**2012/13**
Peace River	3.73	3.50	3.35	3.42	3.36
North and East	1.17	1.09	1.17	1.27	1.34
Mainline	4.63	4.50	4.66	4.60	4.52
TOTAL SYSTEM	9.52	9.09	9.18	9.28	9.22

NOTE:
- Numbers may not add due to rounding.

3.5.2 System Field Deliverability Forecast

In updating the field deliverability for the June 2008 design forecast, three major sources of gas supply were included:

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

Incremental supply from reserve additions and from the unconnected component of discovered reserves are expected to become available to offset declines in field deliverability from connected established reserves as economics permit.

In aggregate, the Western Canada Sedimentary Basin ("WCSB") field deliverability is expected to remain relatively flat over the forecast period based on the June 2008 design forecast.

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 3.6.

Supply from reserve additions was forecast on an area basis, based on economic potential estimates from the Canadian Gas Potential Committee Report – Natural Gas Potential in Canada – 2005, and from 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 of future supply at each Receipt Point.

A summary of system field deliverability from the June 2008 design forecast by project area is shown in Table 3.5.2.

Table 3.5.2
System Field Deliverability Forecast

Project Area	June 2008 Design Forecast ($10^6m^3/d$)				
	2008/09	**2009/10**	**2010/11**	**2011/12**	**2012/13**
Peace River	151.4	141.7	136.0	137.9	135.9
North and East	55.1	51.0	54.2	58.3	61.7
Mainline	189.9	186.2	194.3	191.3	188.1
TOTAL SYSTEM	396.4	379.0	384.6	387.5	385.6
Project Area	**June 2008 Design Forecast (Bcf/d)**				
	2008/09	**2009/10**	**2010/11**	**2011/12**	**2012/13**
Peace River	5.37	5.03	4.83	4.89	4.82
North and East	1.96	1.81	1.93	2.07	2.19
Mainline	6.74	6.61	6.90	6.79	6.67
TOTAL SYSTEM	14.07	13.45	13.65	13.75	13.69

NOTES:
- Numbers may not add due to rounding.
- Does not include significant volumes of shale gas.

3.5.3 Firm Transportation Service Agreements

The following is a summary of the aggregate Receipt Contract Demand forecast to be held under firm transportation Service Agreements on the Alberta System.

The June 2008 design forecast of aggregate Receipt Contract Demand under firm transportation Service Agreements is 257.9 $10^6m^3/d$ (9.15 Bcf/d) for the Planning Period, as shown in Table 3.5.3. This is a decrease of 11.7 $10^6m^3/d$ (0.42 Bcf/d), or 4.3 percent, from the previous Planning Period and reflects the net effect of both new and non-renewing firm transportation Service Agreements.

Table 3.5.3
Forecast of Receipt Contract Demand under Firm Transportation Service Agreements

Gas Year	June 2008 Design Forecast	
	(10^6m^3/d)	(Bcf/d)
2008/09	269.6	9.57
2009/10	257.9	9.15
2010/11	260.7	9.25
2011/12	267.1	9.48
2012/13	265.8	9.44

NOTE:
- Represents Alberta System peak values anticipated in Gas Year.

3.5.4 System Average Receipts

The system average receipt forecast from the June 2008 design forecast is 289.3 10^6m^3/d (10.27 Bcf/d) in the Planning Period. This is a decrease from the previous Planning Period forecast of 297.5 10^6m^3/d (10.56 Bcf/d).

A summary of system average receipts from the June 2008 design forecast by project area is shown in Table 3.5.4.

Table 3.5.4
System Average Receipts

	June 2008 Design Forecast ($10^6m^3/d$)				
Project Area	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**
Peace River	114.5	109.8	105.0	106.6	104.7
North and East	39.7	37.3	39.8	43.2	46.2
Mainline	143.3	142.2	147.6	145.2	142.4
TOTAL SYSTEM	297.5	289.3	292.4	294.9	293.3
	June 2008 Design Forecast (Bcf/d)				
Project Area	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**
Peace River	4.06	3.90	3.73	3.78	3.71
North and East	1.41	1.32	1.41	1.53	1.64
Mainline	5.09	5.05	5.24	5.15	5.05
TOTAL SYSTEM	10.56	10.27	10.38	10.47	10.41

NOTE:

- Does not include significant volumes of shale gas

3.5.5 Established Natural Gas Reserves

Table 3.5.5.1 presents a summary of remaining established gas reserves in Alberta by project area as of October 2007. This summary is based on an assessment of available information. The ERCB estimates 1104.3 10^9m^3 (39.2 Tcf) of CBM and conventional gas reserves to year end 2006. NGTL's estimate is based on the ERCB established reserves which existed at year end 2006 augmented by more recent data provided by customers and by additional reserves discovered as of October 2007. The reserves have been adjusted for production to October 2007.

NGTL's estimate of 1091 10^9m^3 (38.7 Tcf) remaining established gas reserves in Alberta is a decrease of about 22 10^9m^3 (0.8 Tcf), or 2.0 percent, from the 1113 10^9m^3 (39.5 Tcf) reported in the December 2007 Annual Plan.

Table 3.5.5.1
Remaining Established Alberta Gas Reserves by Project Area

Project Area	NGTL Estimate ($10^9 m^3$)	NGTL Estimate (Tcf)
Peace River	225	8.0
North & East	169	6.0
Mainline	469	16.6
Other[1]	229	8.1
Total[2]	**1091**	**38.7**

NOTES:
1 Reserves not directed to NGTL.
2 Numbers may not add due to rounding.

Table 3.5.5.2 presents the estimate of remaining established reserves. For British Columbia and the lower Northwest Territories, the estimate is limited to areas connected or likely to be connected to the Alberta System.

Table 3.5.5.2
Remaining Established Reserves

Reserve Basis	Alberta		B.C. and N.W.T.		Total	
	$10^9 m^3$	Tcf	$10^9 m^3$	Tcf	$10^9 m^3$	Tcf
Remaining Established Reserves connected to the Alberta System [1,2]	862	30.6	117	4.2	980	34.8
Remaining Established Reserves not connected to the Alberta System [3,4,5]	229	8.1	-	-	229	8.1
TOTAL	**1091**	**38.7**	**117**	**4.2**	**1208**	**42.9**

NOTES:
1 The remaining established reserves are those connected and those expected to be connected to the Alberta System and include reserve estimates from NGTL initiated reserve studies.
2 Reserves not connected to the Alberta System are those which would be transported on other systems.
3 Only the estimates of B.C. reserves that are forecast to flow on the Alberta System are provided.
4 Numbers may not add due to rounding.
5 Does not include shale gas from British Columbia

3.6 Storage Facilities

There are seven storage facilities presently connected to the Alberta System, as shown in Table 3.6.1. They are located at the AECO ‘C’, Big Eddy, Carbon, Chancellor, Crossfield East #2, January Creek and Severn Creek Meter Stations (Figure 2.6.1.4). The total deliverability from Storage Facilities is significant when compared to the field deliverability available from other Receipt Points on the Alberta System.

The receipt meter capacity for each of the connected Storage Facilities for the Planning Period is shown in Table 3.6.1.

Table 3.6.1
Receipt Capacity from Storage Facilities

	Receipt Meter Capacity from Storage Facilities 2009/10	
	$10^6m^3/d$	Bcf/d
AECO C	50.7	1.80
Big Eddy	35.4	1.25
Carbon	13.8	0.49
Chancellor	35.2	1.25
Crossfield East #2	14.1	0.50
January Creek	14.1	0.50
Severn Creek	5.6	0.21
TOTAL	**168.9**	**6.00**

NOTES:
- Storage is presently considered as an interruptible supply source. Refer to Section 2.6.4 for details on the treatment of storage in the system design.
- Numbers may not add due to rounding.