NOVA Gas Transmission Ltd.

December 2008
Annual Plan

December 2008

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DECEMBER 2008
ANNUAL PLAN

NOVA Gas Transmission Ltd.

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EXECUTIVE SUMMARY

This Annual Plan provides NOVA Gas Transmission Ltd.'s ("NGTL") Customers and other interested parties with a comprehensive overview of the expected Alberta System facilities for the 2009/10 Gas Year.

Historically, NGTL prepared an Annual Plan in compliance with the requirements of EUB Informational Letter IL 90-8, *Procedures for the Assessment of NOVA Pipeline Applications,* as amended. IL 90-8 set out the steps NGTL was to take in making a facility application. Section C of IL 90-8 required that NGTL follow a two-stage application process when it sought to add facilities to the Alberta System. The first stage was the filing with the EUB of an annual preliminary overall system plan, the Annual Plan, containing all planned facility additions and major modifications. The second stage was the filing of the final technical, cost, routing/siting, land, environmental and other information required to complete the application for each facility contained in the Annual Plan. The application was the second stage of the two stage process.

Effective January 1, 2008, the Alberta Energy and Utilities Board ("EUB") was separated into the Alberta Utilities Commission ("AUC") and the Energy Resources Conservation Board ("ERCB"). The AUC is now responsible for the approval and ongoing supervision of gas utility pipelines, as well as the economic regulation of gas utilities.

The AUC stated in Decision 2008-095, issued October 10, 2008, that it did not adopt IL 90-8 and therefore the requirements contained in it will no longer apply to gas utility pipeline applications filed with the AUC by NGTL. Consequently, NGTL is no longer required to prepare and file an Annual Plan for regulatory purposes. However, NGTL recognizes its customers and other interested parties value the information historically included in the Annual Plan. NGTL has therefore produced an Annual Plan for 2008.

The December 2008 Annual Plan will be posted on TransCanada PipeLines Limited's web site located at:

http://www.transcanada.com/Alberta/regulatory_info/facilities/index.html

Definitions for terms commonly used in the Annual Plan are located in the Glossary in Appendix 1. Capitalized terms used in the Annual Plan are defined in NGTL's Gas Transportation Tariff, which can be accessed at:

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

The Annual Plan contains design methodology, including assumptions and criteria, design forecast, including its long term outlook for system field deliverability, system FS productive capability, system average receipts, gas deliveries, design flow requirements and proposed facilities for the 2009/10 Gas Year. This Annual Plan is based on NGTL's June 2008 design forecast of gas receipt and delivery.

The primary factor affecting facilities requirements for the 2009/10 Gas Year are the increasing delivery requirements in the North of Bens Lake Design Area. The facilities additions proposed for the 2009/10 Gas Year are listed in Table 1. Costs associated with the proposed facilities will generally occur in the 2009 calendar year.

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 open seasons are being reviewed and have not been included in this Annual Plan.

Table 1
Proposed Facilities

Project Area	Proposed Facilities	Annual Plan Reference	Description	Required In-Service Date	Capital Cost ($ millions)
Peace River	Doe Creek South Lateral Loop	Chapter 6	5 km x NPS 12	November 2009	4.5
	Sneddon Creek Lateral Loop #2	Chapter 6	5 km x NPS 16	November 2009	6.0
North & East	Miscellaneous[1]	Chapter 5		November 2009	12.1
Mainline	No facilities required				
Capital Costs are in 2008 dollars and include AFUDC			**Total**		**22.6**

Note:

1 Miscellaneous represents compressor station yard modifications at Gadsby and Smoky D Compressor Stations.

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. Please provide your comments to:

- Landen Stein, Manager, Customer Solutions, at (403) 920-5311;
- Gord Toews, Manager, Mainline Planning West, at (403) 920-5903;
- Dave Schultz, Director, System Design, at (403) 920-5574;
- Steve Emond, Vice President, System Design and Commercial Operations, at (403) 920-5979; or
- Stephen Clark, Vice President, Commercial - West, Canadian and Eastern U.S Pipelines at (403) 920-2018.

Should you have any questions or comments regarding this Annual Plan, please contact Darlene Maier at (403) 920-5108.

CHAPTER 1 – THE ANNUAL PLAN PROCESS

1.1 Introduction

This chapter provides background information to the Annual Plan and gives an overview of how industry participates with NOVA Gas Transmission Ltd. ("NGTL") to understand and influence the development of the Alberta System.

1.2 Annual Plan Scope

The December 2008 Annual Plan contains facilities requirements for the 2009/10 Gas Year commencing on November 1, 2009 and ending on October 31, 2010 ("Planning Period").

1.3 Annual Plan Changes

Changes that have been incorporated in this Annual Plan include:

- Storage Assumption – Chapter 2, Section 2.6.1.4;

  The storage assumption will now be applied to all design areas where it leads to a reduction in the design flow requirement, rather than being restricted to the upstream design areas. This results in a better correlation between storage withdrawals and system peak deliveries;

- Facilities Requirements – in this Annual Plan only those Design Areas where facilities are required will be included in Chapters 4 (Design Flow Requirements and Peak Expected Flows), Chapter 5 (Mainline Facility Requirements), Appendix 2 (Design Flow Requirements) and Appendix 3 (Flow Schematics);

- Chapter 3, Figure 3.5.2, System Field Deliverability by Component, has been removed;

- Chapter 3, Section 3.7, Receipt to Delivery Comparisons, has been removed;
- Chapter 7, Capital Expenditure and Financial Forecast has been removed as financial information normally included in this Chapter is routinely available through applications and other reporting;
- Appendix 2, EUB Informational Letters have been removed as they are no longer applicable;
- Appendix 3, Criteria for Determining Primary Term has been removed as it is available in NGTL's Gas Transportation Tariff, Appendix E; and
- Appendix 7, does not contain a December 2008 System Map. An updated System Map will be available in 2009.

1.4 June 2008 Design Forecast

The June 2008 design forecast of gas delivery, FS productive capability, average receipts and field deliverability was used in the preparation of this Annual Plan.

1.5 Industry Participation

To facilitate a more participative and consultative role for industry participants in policy formation and system design, NGTL uses:

- committees;
- discussion papers or proposals which target specific issues;
- information circulars;
- industry presentations; and
- the Internet, including Customer Express and NrG Highway.

The Tolls, Tariff, Facilities and Procedures Committee ("TTFP") is an important forum for reviewing Alberta System facilities plans with industry. Participation on the TTFP is open to any affected party that would directly experience implications of importance due to outcomes achieved by this committee, including facility-related decisions. The TTFP provides for the timely exchange of information among interested parties and provides a significant opportunity for parties to influence facility proposals and long-term planning. The design forecast, design flows and facility requirements were presented to the TTFP on November 18, 2008, prior to the finalization of this Annual Plan.

Periodic updates on the Alberta System expansion plans and capital program, and the impact of the plans and program on the cost of transportation, are provided to all Customers. These updates provide opportunity for Customer input. NGTL also makes presentations to other industry committees and government agencies, and offers to meet with any association or Customer on system design inquiries or any other issue. Over the last year, NGTL has participated in meetings with various Customers and a broad range of consumers, marketers, and distributors in which Alberta System facilities requirements and capital programs were discussed.

CHAPTER 2 – FACILITIES DESIGN METHODOLOGY

2.1 Introduction

This chapter provides an overview of the facility planning processes employed to identify mainline facility requirements and new receipt and delivery meter stations and extension facilities. The overview will provide readers with the background to understand the purpose of and necessity for the facilities requirements for the Planning Period.

The Guidelines for New Facilities describe the new facilities that NGTL may construct. The Guidelines for New Facilities can be accessed on TransCanada's Web site at:
http://www.transcanada.com/Alberta/industry_committee/tolls_tariff_facilities_procedures/index.html

New Facilities are divided into two categories:

- expansion facilities, which would include pipeline loop of the existing system, metering and associated connection piping and system compression; and
- extension facilities, which would include pipelines generally greater than 20 km in length, 12 inches or more in diameter, with volumes greater than 100 MMcf/d, that are expected to meet the aggregate forecast of two or more facilities (gas plants/industrials).

The transportation design process, described in Section 2.9, contains two distinct facility planning sub-processes. The first sub-process relates to the facilities planning, design and construction of mainline/expansion facilities. The second sub-process relates to the facilities planning, design and construction of new receipt and Alberta delivery facilities and connecting extensions. NGTL has used these sub-processes to identify the necessary facility additions required to be placed in-service in the Planning Period.

An important element of the transportation design process is the filing of specific facility applications connected with the requirement for facility additions. Facilities applications are filed with the regulator to coincide with proposed construction schedules, which must account for summer or winter construction constraints and the long period of time required to procure major facility components such as pipe, compressors and valves.

The design flow determination as described in Section 2.6.1 is used to determine the mainline/expansion facility requirements. The mainline system facilities flow determination includes a peak expected flow determination, as described in Section 2.6.2. The peak expected flow determination is being used because of the increasing difference between levels of firm transportation contracts and actual flows and is used to identify the potential of transportation service constraints where the peak expected flow exceeds the system capability. Should a capability constraint be identified, any resulting facilities additions required to transport the peak expected flows are subjected to a risk of shortfall analysis prior to being recommended.

Receipt and Alberta delivery facilities, intended to meet Customers' firm transportation Service Agreements, are designed as part of the transportation design process but are constructed independently of the construction of mainline/expansion facilities. If these facilities are in place prior to the completion of mainline/expansion facilities, Customers may be offered interruptible transportation pending the availability of firm transportation capability.

These two facility planning sub-processes form the basis for determining facilities requirements. An important element of the transportation design process is the timely planning of transportation capability requirements and the evaluation of facilities requirements in response to industry activity and Customer requirements for service. NGTL monitors industry activity, thereby anticipating and responding to Customer requirements for service, by conducting periodic design reviews throughout each year. NGTL's most recent design review presented in this Annual Plan is based upon the June 2008 design forecast ("Forecast"), which forms the basis for determining the facilities requirements in this Annual Plan.

2.2 The Alberta System

The physical characteristics of the Alberta System and the changing flow patterns on the system present significant design challenges. The Alberta System transports gas from many geographically diverse Receipt Points and moves it through pipelines that generally increase in size as they approach the three large Export Delivery Points at Empress, McNeill and Alberta/British Columbia. The approximately 1000 Receipt Points and 200 Delivery Points on the system have a significant impact on the sizing of extension and mainline facilities necessary to ensure that firm transportation obligations can be met. Extension facilities are designed to field deliverability for receipt facilities and maximum day delivery for delivery facilities in accordance with the meter station and extension facilities design assumptions (Section 2.4 and 2.5), whereas mainline facilities are designed in accordance with the mainline system facilities flow determination (Section 2.6).

The Alberta System is designed to meet the peak day design flow requirements of its firm transportation Customers. NGTL's obligation under its firm transportation Service Agreements with each Customer is to:

- receive gas from the Customer at the Customer's Receipt Points including the transportation of gas; and/or
- deliver gas to the Customer at the Customer's Delivery Points including the transportation of gas.

NGTL's facility design must meet two important objectives. One is to provide fair and equitable service to Customers requesting new firm transportation Service Agreements. The other is to prudently size facilities to meet peak day firm transportation delivery requirements. The system design methodology developed to achieve both of these objectives is described in the remainder of this chapter.

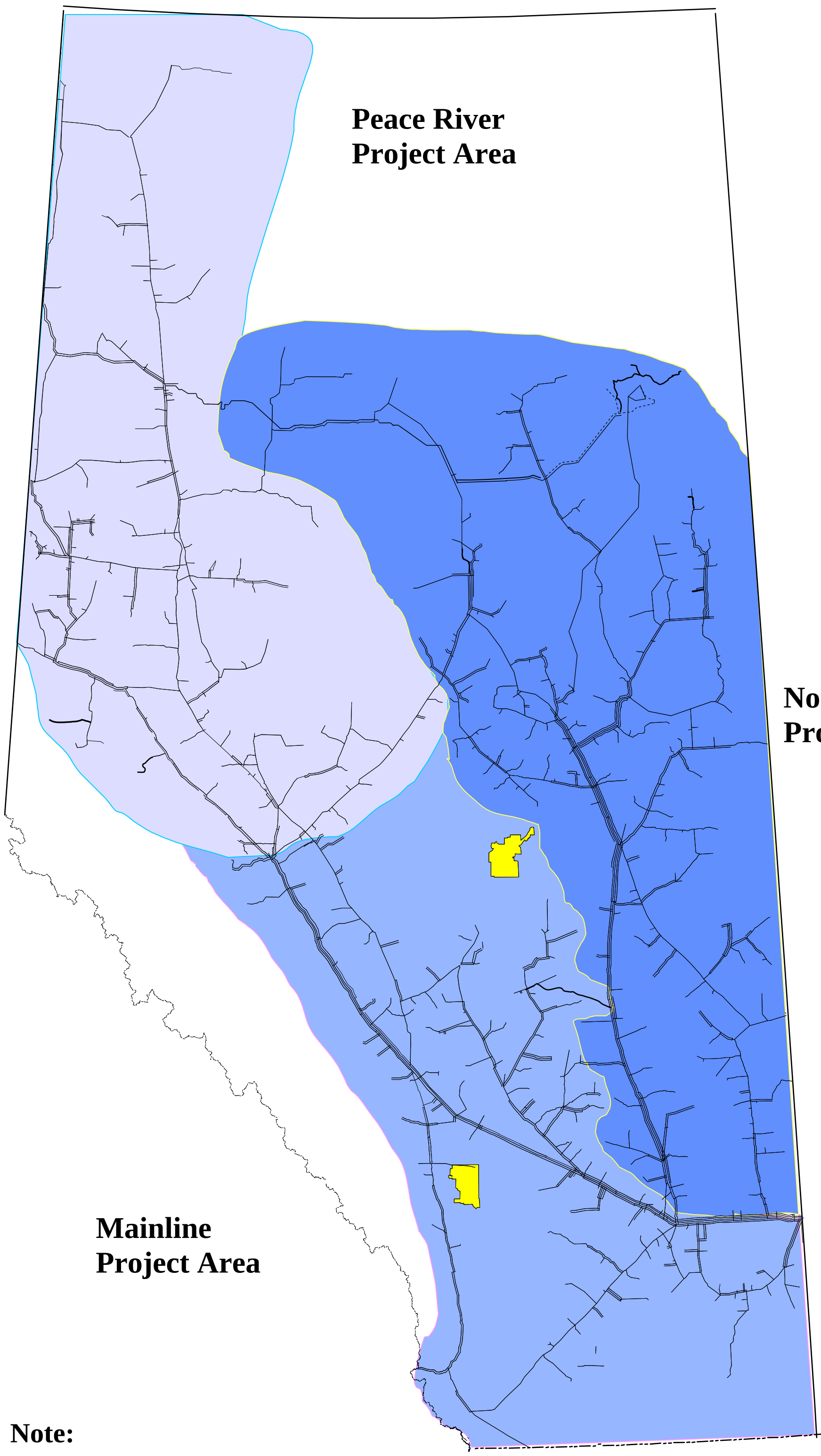
On average, approximately 80 percent of the gas transported on the Alberta System is delivered to Export Delivery Points, for removal from the Province. The remainder is delivered to the Alberta Delivery Points. The location of new Alberta Delivery Points and changing requirements at existing Alberta Delivery Points, particularly in the North of Bens Lake Design Area, may have a significant impact on the flow of gas in the system and, consequently, on system design. As well, the shift in the locations of new receipt volume additions to the system continues to be an important factor impacting gas flows and system design for the Planning Period.

Firm transportation capability may exist from time to time at certain Export Delivery Points for Short Term Firm Transportation-Delivery service ("STFT"). This capability availability is either ambient capability or capability created by unsubscribed Firm Transportation Delivery ("FT-D") transportation. Firm transportation capability may also exist in the winter season at certain Export Delivery Points for Firm Transportation-Delivery Winter service ("FT-DW") due to ambient capability. Interruptible transportation capability may exist from time to time on certain parts of the Alberta System. NGTL will not construct facilities for STFT, FT-DW or IT service. Therefore volumes under these services are not included in the transportation design process described in Section 2.9.

2.3 NGTL Project and Design Areas

For design purposes, the Alberta System is divided into the three project areas shown in Figure 2.3, which are in turn divided into the design areas and design sub areas described in Sections 2.3.1 to 2.3.3. Dividing the pipeline system this way allows the system to be modeled in a way that best reflects the pattern of flows in each specific area of the system, as described in Section 2.6.

Figure 2.3
NGTL Project Areas

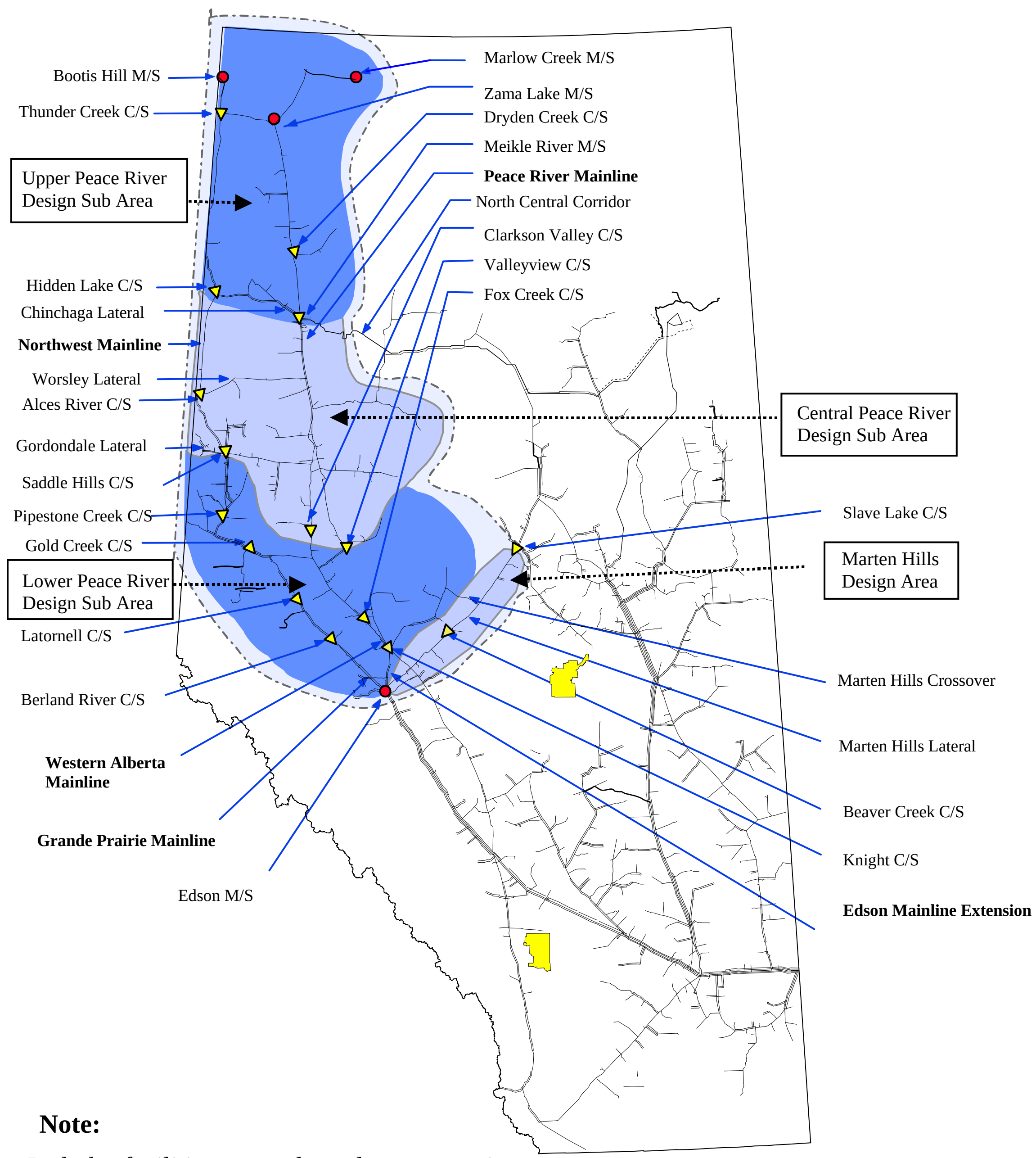


Note:
Includes facilities currently under construction

2.3.1 Peace River Project Area

The Peace River Project Area comprises the Peace River and Marten Hills Design Areas (Figure 2.3.1).

Figure 2.3.1
Peace River Project Area



Note:
Includes facilities currently under construction

Peace River Design Area

The Peace River Design Area comprises three design sub areas: the Upper Peace River Design Sub Area; the Central Peace River Design Sub Area; and the Lower Peace River Design Sub Area. The Upper Peace River Design Sub Area comprises the Peace River Mainline from the Zama Lake Meter Station to the Meikle River Compressor Station and the Northwest Mainline from the Bootis Hill Meter Station and the Marlow Creek Meter Station to the Hidden Lake Compressor Station. The Central Peace River Design Sub Area comprises the Western Alberta Mainline from the discharge of the Meikle River Compressor Station to the Clarkson Valley Compressor Station, as well as to the Valleyview Compressor Station on the Peace River Mainline plus the Northwest Mainline from the discharge of the Hidden Lake Compressor Station to the Saddle Hills Compressor Station on the Grande Prairie Mainline. The Lower Peace River Design Sub Area comprises the Grande Prairie Mainline from the discharge of the Saddle Hills Compressor Station to the Edson Meter Station as well as the Western Alberta Mainline from the discharge of the Clarkson Valley Compressor Station plus the Peace River Mainline from the discharge of the Valleyview Compressor Station to the Edson Meter Station. The North Central Corridor is located in the Peace River Design Area west of LSD 07-07-091-16 W5M.

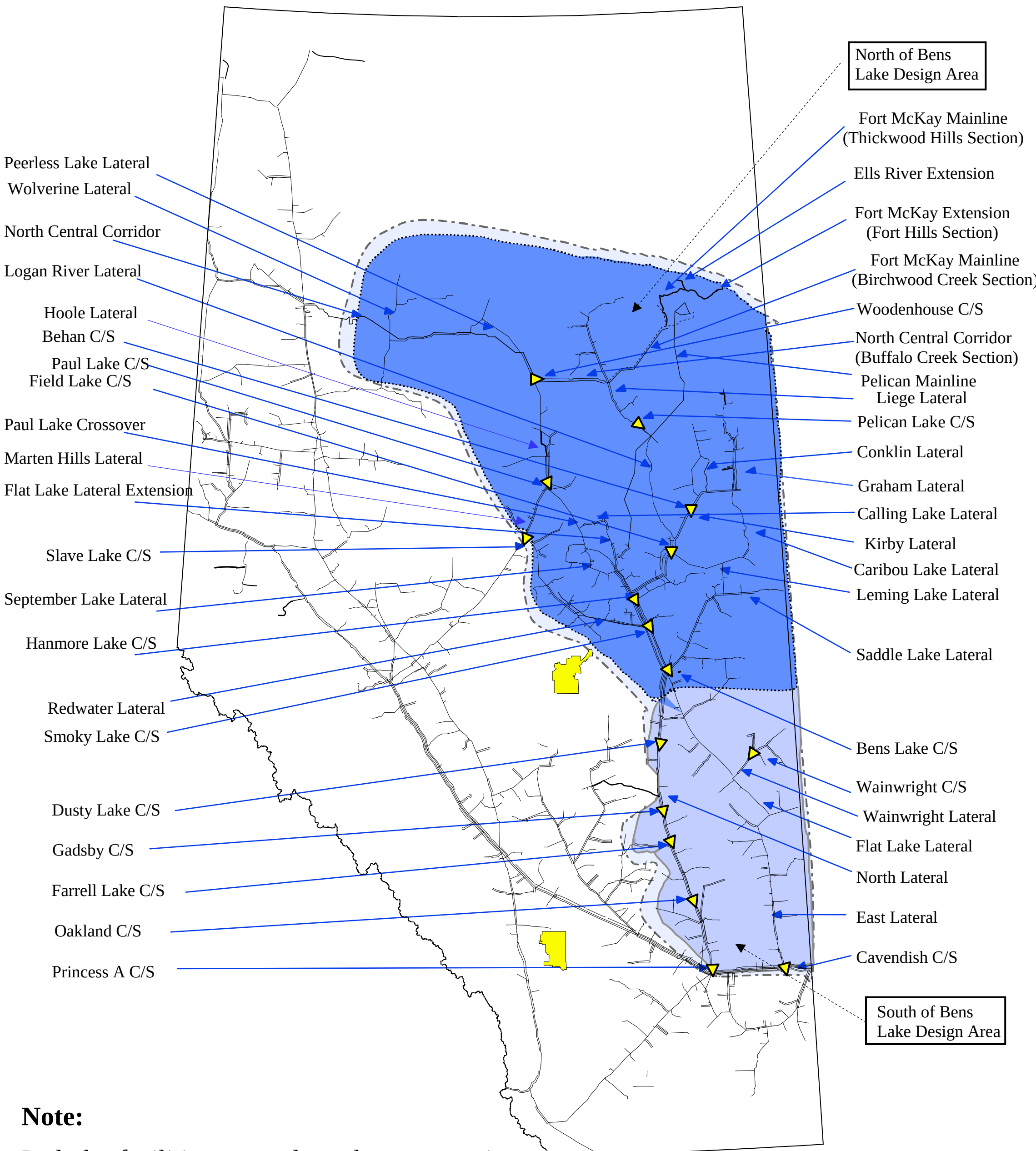
Marten Hills Design Area

The Marten Hills Design Area extends from the Slave Lake Compressor Station along the Marten Hills Lateral to the Edson Meter Station.

2.3.2 North and East Project Area

The North and East Project Area (Figure 2.3.2) comprises the North of Bens Lake and South of Bens Lake Design Areas.

Figure 2.3.2
North and East Project Area



Note:

Includes facilities currently under construction

North of Bens Lake Design Area

The North of Bens Lake Design Area comprises the Liege, Logan River, Kirby, Graham, Conklin, Calling Lake, September Lake, Caribou Lake, Leming Lake, Redwater, Pelican Mainline, Ells River Extension, Fort McKay Extension (Fort Hills Section), Fort McKay Mainline (Thickwood Hills Section), the Fort McKay Mainline (Birchwood Creek Section) and Saddle Lake Laterals, as well as the Flat Lake Lateral Extension, the Paul Lake Crossover, the Peerless Lake Lateral, the Wolverine Lateral, the Hoole Lateral and the Marten Hills Lateral north of the Slave Lake Compressor Station, which are all north of the Bens Lake Compressor Station. As capability on the Ventures Oil Sands Pipeline has been contracted under a Transportation by Others ("TBO") agreement, the Ventures Oil Sands Pipeline has been included in the North of Bens Lake Design Area. The North Central Corridor is located in the North of Bens Lake Design Area east of LSD 07-07-091-16 W5M.

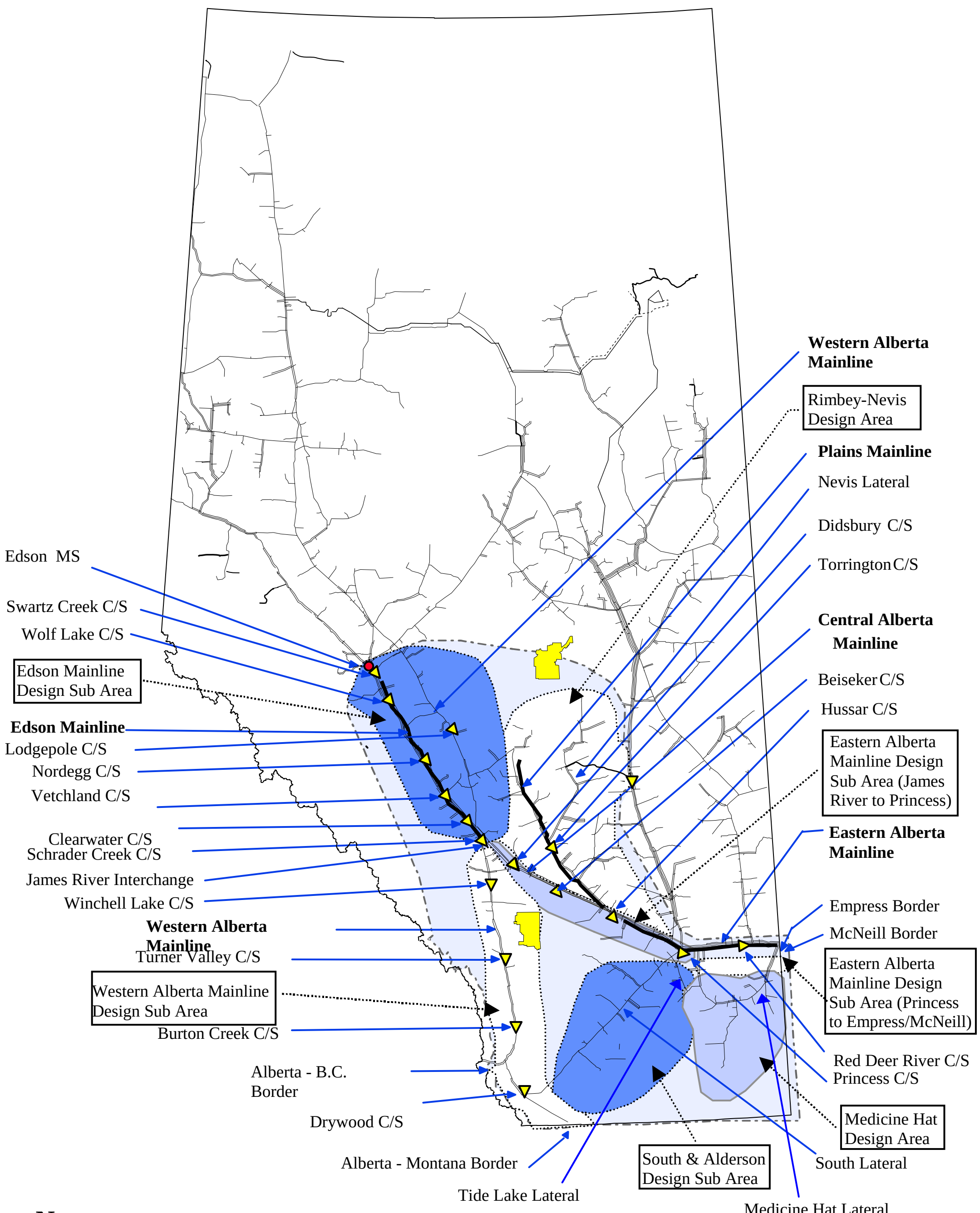
South of Bens Lake Design Area

The South of Bens Lake Design Area comprises the Flat Lake Lateral, the Wainwright Lateral and the North and East Laterals which extend to the Princess "A" and Cavendish Compressor Stations, which are all south of the Bens Lake Compressor Station.

2.3.3 Mainline Project Area

The Mainline Project Area (Figure 2.3.3) comprises the Mainline Design Area, the Rimbey-Nevis Design Area, the South and Alderson Design Area and the Medicine Hat Design Area.

Figure 2.3.3
Mainline Project Area



Note:

Includes facilities currently under construction

Mainline Design Area

The Mainline Design Area comprises four design sub areas: the Edson Mainline Design Sub Area; the Eastern Alberta Mainline Design Sub Area (James River to Princess); the Eastern Alberta Mainline Design Sub Area (Princess to Empress/McNeill); and the Western Alberta Mainline Design Sub Area.

The Edson Mainline Design Sub Area comprises the Edson Mainline from and including the Edson Meter Station to the Clearwater Compressor Station and the Western Alberta Mainline from the Knight Compressor Station to the Schrader Creek Compressor Station. The Eastern Alberta Mainline Design Sub Area (James River to Princess) comprises the Central Alberta Mainline from the Clearwater Compressor Station and the portion of the eastern leg of the Foothills Pipe Lines (Alberta) Ltd. from the Schrader Creek Compressor Station to the Princess Compressor Station. The Eastern Alberta Mainline Design Sub Area (Princess to Empress/McNeill) comprises the Eastern Alberta Mainline and the portion of the eastern leg of the Foothills Pipe Lines (Alberta) Ltd. from the Princess Compressor Station to the Empress and McNeill Export Delivery Points. The Western Alberta Mainline Design Sub Area comprises the Western Alberta Mainline from the Schrader Creek Compressor Station to the Alberta/British Columbia and the Alberta/Montana Export Delivery Points as well as the pipeline sections on the western leg of the Foothills Pipe Lines (Alberta) Ltd. between Schrader Creek Compressor Station and the Alberta/British Columbia Export Delivery Point.

Rimbey-Nevis Design Area

The Rimbey-Nevis Design Area comprises the area upstream of the discharge of the Hussar “A” Compressor Station on the Plains Mainline as well as the Plains Mainline, the Nevis Lateral and the Nevis-Gadsby Crossover upstream of the Torrington Compressor Station.

South and Alderson Design Area

The South and Alderson Design Area comprises two laterals that connect to the Princess Compressor Station. The South Lateral extends from the Waterton area and the Alderson Lateral extends from the Alderson area.

Medicine Hat Design Area

The Medicine Hat Design Area comprises the Tide Lake Lateral upstream of the Tide Lake Control Valve and the Medicine Hat Lateral upstream of the Medicine Hat Control Valve.

2.4 Receipt Meter Station and Extension Facilities Design Assumption

The design of new receipt meter stations is based on the assumption that the highest possible flow through the receipt meter station will be the lesser of the aggregate Receipt Contract Demand under firm transportation Service Agreements for all Customers at the meter station or the capability of upstream producer facilities.

Extension facilities for receipts are designed to transport field deliverability (Section 2.9.4.1), taking into consideration Receipt Contract Demand under firm transportation Service Agreements and the extension facilities criteria as described in the Guidelines for New Facilities shown in Table 2.4.1.

Table 2.4.1
Extension Facilities Criteria

NGTL Builds (Owns/Operates)
Facilities to serve aggregate forecast as per Annual Plan process
Facilities greater than or equal to 12 inches in diameter
Facilities greater than 20 kilometers in length
Volumes greater than 100 MMcf/d

Field deliverability is based on an assessment of reserves, flow capability, future supply development and the capability of gathering and processing facilities at each receipt meter station on the extension facility.

This design assumption recognizes and accommodates the potential for Customers to maximize field deliverability from a small area of the Alberta System. In NGTL's assessment of facility alternatives to accommodate current and future field deliverability, a number of facility configurations are considered which may include future facilities. The assessment of facility alternatives includes both NGTL and third party costs to ensure the most orderly, economic and efficient construction of combined facilities. NGTL selects the proposed facilities and the optimal tie-in point on the basis of overall (NGTL and third party) lowest cumulative present value cost of service ("CPVCOS").

2.5 Alberta Delivery Meter Station and Extension Facilities Design Assumption

The design of new Alberta delivery meter stations is based on the assumption that maximum day deliveries through such facilities will not exceed the capability of the facilities downstream of the delivery meter station. The capability of the downstream facilities is determined through ongoing dialogue with the operators of these facilities.

Delivery extension facilities are designed to transport maximum day delivery taking into consideration the extension facilities criteria as described in the Guidelines for

New Facilities as shown in Table 2.4.1. In NGTL's assessment of facility alternatives to accommodate current and future maximum day delivery, a number of facility configurations are considered which may include future facilities. NGTL's assessment of facility alternatives includes both NGTL and third party costs to ensure the most orderly, economic and efficient construction of combined facilities. NGTL selects the proposed facilities and the optimal tie-in point on the basis of overall (NGTL and third party) lowest CPVCOS.

2.6 Mainline System Facilities Flow Determination

The Mainline system facilities flow determination contains two processes: the design flow requirements determination as described in Section 2.6.1 and the peak expected flow determination as described in Section 2.6.2.

2.6.1 Design Flow Requirements Determination

In each periodic design review, the facilities necessary to provide the capability to meet future firm transportation requirements are identified. To ensure the facilities identified are the most economic, a five year forecast of facilities requirements is considered.

While the design of the Alberta System is affected by many interrelated factors, the following major design assumptions currently underlie the mainline system design:

- equal proration assumption;
- design area delivery assumption;
- downstream capability assumption;
- storage assumption; and
- FS productive capability assumption.

These assumptions are briefly described in Sections 2.6.1.1 to 2.6.1.5.

2.6.1.1 Equal Proration Assumption

The Alberta System is designed primarily to transport gas from many Receipt Points to a limited number of large-volume Delivery Points (Section 2.2). The pipeline system is designed to meet deliveries based on the general assumption that gas will be drawn on an equally prorated basis from each Receipt Point on the pipeline system. NGTL works with Customers to attempt to ensure that gas is drawn from each Receipt Point so that the system can meet each Customer’s firm transportation deliveries. However, if gas is nominated in a manner that differs from the pattern assumed in the system design, shortfalls in deliveries may occur.

Application of the equal proration assumption results in a system design that will meet peak day delivery requirements by drawing on FS productive capability equally from all Receipt Points on the system. Since forecast supply is closely balanced to forecast peak day delivery requirements, the equal proration assumption did not apply to the facilities design within the Planning Period of this Annual Plan.

2.6.1.2 Design Area Delivery Assumption

In identifying facilities to transport gas within or through a design area, an assumption that the facilities must be capable of transporting the highest required flow into or out of that area is made. This is accomplished using the design area delivery assumption, which considers the following key factors:

- delivery requirements within the design area;
- delivery requirements within Alberta but outside the design area; and
- delivery requirements at the major Export Delivery Points.

This assumption is periodically reviewed to ensure load conditions that are likely to occur under system operations are reflected in the system design.

The design area delivery assumptions relied upon for the design review process for each design area are described in Table 2.6.1.2.

Table 2.6.1.2
Design Area Delivery Assumptions

Design Area	Prevailing Design Season	Winter[1]	Summer[1]
• Peace River (including Upper, Central & Lower Design Sub Areas)	Summer	Min u/s James[2]/Avg/Max	Min u/s James[2]/Max/Max
• Marten Hills	Summer	Min u/s James[2]/Avg/Max	Min u/s James[2]/Max/Max
• North and East Project Area (North and South of Bens Lake Design Areas)			
• Flow Through	Summer	Min[3]/Avg/Max	Min[3]/Max/Max
• Flow Within	Winter[4]	Max Area Delivery	Max Area Delivery
• Mainline	Summer	Min u/s James[2]/Avg/Max	Min u/s James[2]/Max/Max
• Rimbey Nevis	Summer	Min/Avg/Max	Min/Max/Max
• South and Alderson	Summer	Min/Avg/Max	Min/Max/Max
• Medicine Hat			
• Flow Through	Summer	Min/Avg/Max	Min/Max/Max
• Flow Within	Winter[5]	Max Area Delivery	Max Area Delivery

NOTES:
1 Within design area/outside design area and within Alberta/Export Delivery Points.
2 u/s James = upstream James River Interchange.
3 Total North and East Project Area.
4 Seasonally Adjusted Receipt Flow Conditions.
5 Average Receipt Flow Conditions.

Min = minimum   Avg = average   Max = maximum

For example, in the Peace River Design Area, a Min upstream James/Max/Max design flow assumption is applied to generate design flow requirements for summer conditions. The Min upstream James/Max/Max design flow condition assumes that the Alberta Delivery Points upstream of the James River Interchange and the Gordondale and Boundary Lake Export Delivery Points are at their minimum day delivery values, while the Alberta Delivery Points elsewhere on the system and the major Export Delivery Points are at their maximum day delivery values.

By contrast, a Min upstream James/Avg/Max design flow condition is applied for the same design area to generate design flow requirements for winter conditions. The Min upstream James/Avg/Max design area delivery assumption assumes that the Alberta Delivery Points within the area upstream of James River are at their minimum day delivery values while Alberta Delivery Points elsewhere on the system are at their average day delivery values and major Export Delivery Points are at their maximum day delivery values.

For the North and East Project Area and the Medicine Hat Design Area there are two distinct flow conditions that are examined in assessing facilities requirements. First, there is the “flow through” condition that is governed by the design flow requirements assumption. The “flow through” design condition occurs when the receipts are at the peak expected volume and the deliveries are at an seasonal minimum volume. Second, there is the “flow within” condition that is governed by the maximum day delivery and seasonal available supply within the area. The “flow within” design condition occurs when the receipts in the North and East Project Area are at a seasonal low volume and the deliveries are at a seasonal maximum volume. Currently, the “flow within” condition governs facilities requirements in the North and East Project Area.

For the North and East Project Area the flow through condition, the following approach is used as a basis for generating the design flow requirements. First, the design focuses on optimizing the flow in the South of Bens Lake Design Area in order to maximize the utilization of existing facilities in this area. Second, if the design flow requirements in the South of Bens Lake Design Area have been maximized and there is a requirement to transport additional FS productive capability from the area, the design will focus on directing these volumes through the Marten Hills Design Area in order to maximize the utilization of existing facilities in the Marten Hills Design Area. Finally, if both the South of Bens Lake and the Marten Hills Design Areas are flowing at their existing capability and there is a requirement to transport additional FS productive capability then the design will focus on transporting these volumes through the Peace River Design Area.

In the North and East Project Area, seasonally adjusted receipt flows and maximum day delivery are the most appropriate conditions to describe the constraining design. In the Medicine Hat Design Area, average receipt flows and maximum day delivery are the most appropriate conditions to describe the constraining design.

NGTL reviews Alberta delivery patterns for each design area. These reviews show that while individual Alberta Delivery Points will require maximum day delivery, the probability that all Alberta Delivery Points will require maximum day delivery simultaneously is extremely low. To account for this, a factor, called the demand coincidence factor, was applied to decrease the forecast maximum day delivery for the aggregate of all the Alberta Delivery Points within each design area to a value more indicative of the forecast peak day deliveries. Similarly, demand coincidence factors were determined and applied to increase the aggregate minimum day delivery values at Alberta Delivery Points within each design area to be more indicative of the expected minimum day delivery.

2.6.1.3 Downstream Capability Assumption

The system design is based on the assumption that the maximum day delivery at the Delivery Points will not exceed the lesser of the capability of the downstream pipeline or the aggregate of the firm transportation Service Agreements associated with those Delivery Points. Downstream capability is determined through ongoing dialogue with downstream pipeline operators.

2.6.1.4 Storage Assumption

The Storage Facilities connected to the Alberta System at the AECO ‘C’, Carbon, Crossfield East, January Creek, Severn Creek, Chancellor and Big Eddy Meter Stations are shown in Figure 2.6.1.4. Maximum receipt meter capabilities for Storage Facilities are presented in Section 3.6.

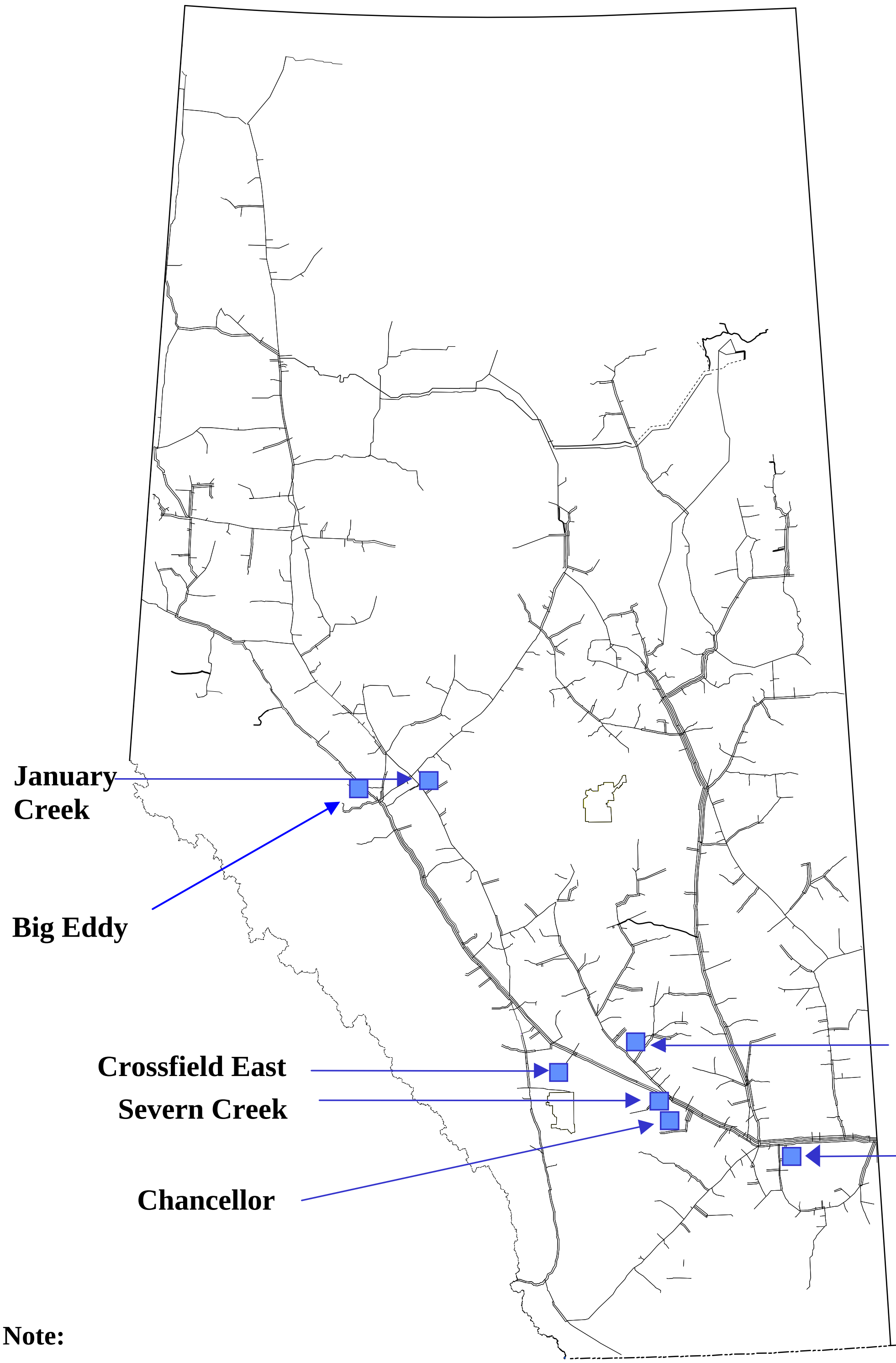
For the Planning Period it was assumed that:

- For the winter period, system design flow requirements will include receipt volumes from selected Storage Facilities onto the Alberta System at approximately average historical withdrawal levels.

  This assumption recognizes the supply contribution from Storage Facilities 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. The historical withdrawal flows were observed during recent winter periods at the AECO ‘C’, Carbon, Crossfield East, Chancellor and Severn Creek Meter Stations. The level of storage withdrawal used in the design of the Alberta System for the winter of the Planning Period was 17.7 $10^6m^3/d$ (630 MMcf/d). The result of applying the storage assumption is a reduction in the design flow requirements. Volumes withdrawn from the Storage Facilities will be considered as interruptible flows, but will be incorporated into the flow analysis within all design areas where it may lead to a reduction in the design flow requirements and a potential reduction in additional mainline facilities.

- For the summer period, system design flow requirements will not include delivery volumes from the Alberta System into Storage Facilities. Consequently, for the purpose of calculating design flow requirements, volumes injected into the Storage Facilities will be considered to be interruptible flows and will therefore not be reflected in the design of mainline facilities.

Figure 2.6.1.4
Locations of Storage Facilities on the Alberta System



Note:

Includes facilities currently construction

2.6.1.5 FS Productive Capability Assumption

In areas where gas is drawn from a small collection of Receipt Points, there is a greater likelihood that the FS productive capability will be drawn simultaneously from all such Receipt Points than is the case when gas is drawn from an area having a large number of Receipt Points. As a result, the system design for those areas with a small collection of Receipt Points, usually at the extremities of the system, is based on the assumption that the system must be capable of simultaneously receiving the aggregate FS productive capability from each Receipt Point. However, when the FS productive capability assumption is applied to any collection of Receipt Points, the flows from the other areas upstream of a common point are reduced such that the equal proration assumption (Section 2.6.1.1) is maintained through that common point. This results in the system upstream of the common point being designed to match the capability of the system downstream of the common point.

2.6.2 Peak Expected Flow Determination

In order to predict peak expected flows a peaking factor is applied to the forecast of average receipts to yield a more realistic peak expected flow condition in the receipt dominated design areas. Receipt dominated design areas are those areas where the flows in the pipeline are primarily determined by supply entering the system. The peaking factor is derived from an analysis of historical coincidental peak to average flow observed within the design areas over several gas years. When the peak expected flow analysis is applied to the facility design process, is used as a guide, not an absolute determinant, in assessing the requirement for facilities additions. When the peak expected flow determination identifies the potential need for facilities additions, a risk of shortfall analysis (load/capability analysis) is completed prior to recommending the required facilities additions.

For this Annual Plan the assessment of peak expected flow will be confined to areas that are governed by receipt dominant flow conditions. Assessments of areas governed by delivery dominant flow conditions are still under development and will be addressed at a later date.

2.7 Maintaining Required Delivery Levels

Historically, the design of the Alberta System has been based on the assumption that facilities comprising the system are in-service and operating. However, compression facilities are not 100 percent reliable and are not always available for service. Even with stringent maintenance programs, compression facilities still experience unanticipated and unscheduled down-time, potentially impacting the ability to maintain required deliveries. Compression facilities generally require two to four weeks of scheduled maintenance per year.

Designing facilities to ensure that Customer delivery expectations and firm transportation requirements are met is an important consideration in the design of the Alberta System.

2.8 System Optimization and Compressor Modernization

System optimization has been and will continue to be an integral part of the overall system design process to evaluate how the Alberta System can be optimized to reduce operating and maintenance costs, minimize fuel usage, greenhouse gas emissions and maintain flexibility without adversely affecting throughput. The intent is to maximize volumes on the system in order to minimize rates. Accordingly, cost reduction initiatives are not intended to reduce system volumes. The 2008 design review system optimization results are described in Section 5.2. The identification of compressor units that should be removed from service or replaced will continue to be an integral part of the overall system design.

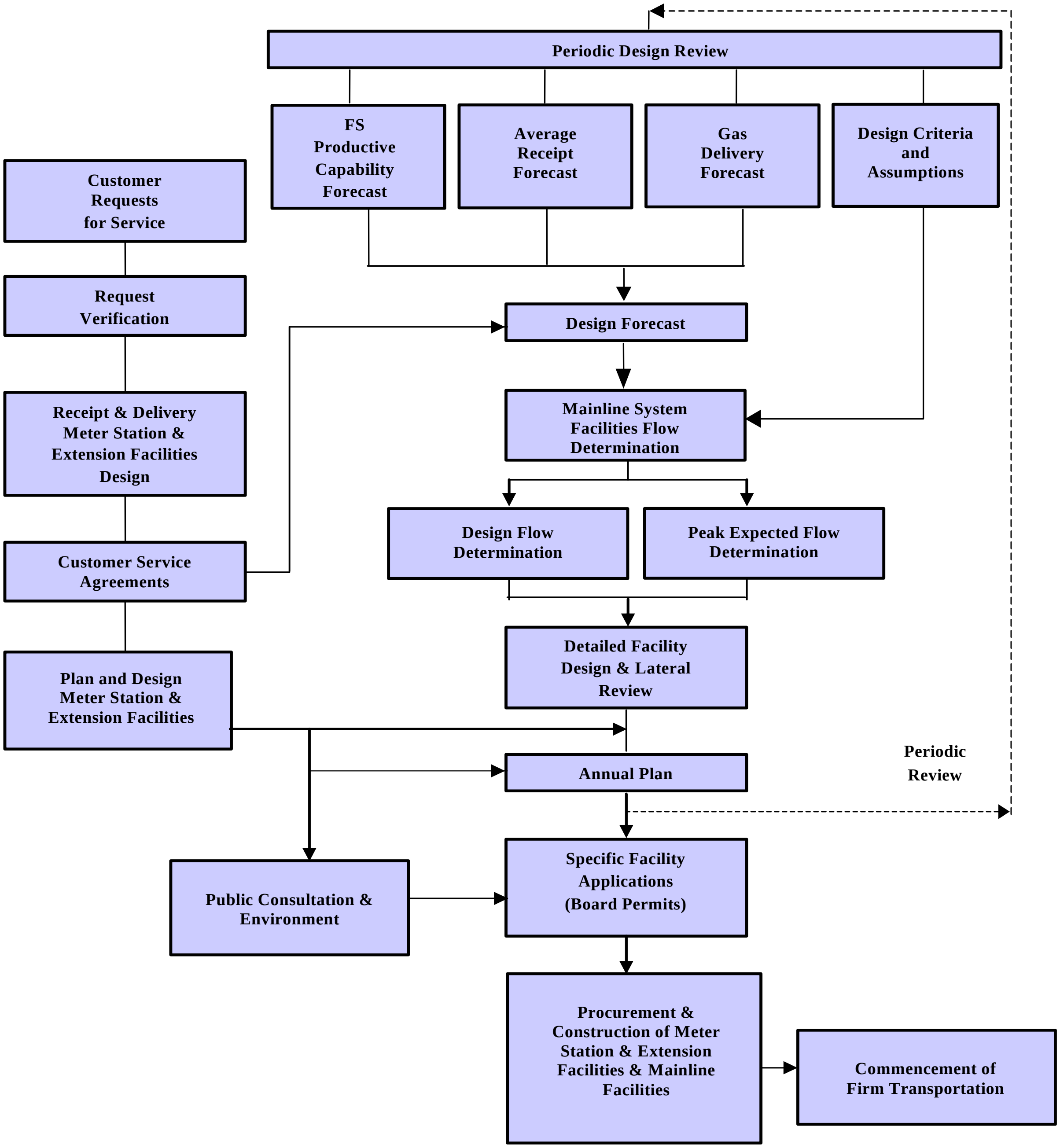
2.9 Transportation Design Process

As stated in Section 2.1, periodic design reviews are conducted throughout the year to closely monitor industry activity and respond to Customer requirements for firm transportation on a timely basis.

The following is a brief overview of the significant activities involved in the transportation design process for the Planning Period. While Receipt Points, Alberta Delivery Points and extension facilities are designed as part of the transportation design process, the construction of these facilities takes place independently of the construction of mainline facilities.

The activities relating to the transportation design process are described below and are shown in the process flow chart included as Figure 2.9.1. Although activities have been grouped in distinct phases, some of the activities occur concurrently.

Figure 2.9.1
Transportation Design Process



2.9.1 Customer Request Phase

Requests for firm transportation for the Planning Period were received by NGTL and included in the transportation design process for the Planning Period.

Requests for firm transportation, which are based on insufficient field deliverability, duplications, or over-contracting at a Receipt Point, are removed from the transportation design process.

Requests for firm transportation are reviewed through this process and categorized as requiring new facilities, requiring expansion of existing facilities, or not requiring either new facilities or expansion of existing facilities. Each category of receipt and delivery facility is treated somewhat differently in the following phases of the design process.

2.9.2 New Meter Station and Extension Facilities Design

NGTL proceeds with the design of new meter stations and extension facilities to meet Customers' requirements for those requests for firm transportation that remain after the initial review process and are consistent with the Guidelines for New Facilities.

NGTL, with significant input from Customers, has established economic criteria that must be met prior to receipt meter stations being constructed. The criteria are described in Appendix E of NGTL's Gas Transportation Tariff entitled *Criteria for Determining Primary Term*.

In the design of new extension facilities, the receipt or delivery volume and location of each new facility is identified. In the case of receipt facilities, a review is undertaken of the reserves that are identified as supporting each new extension facility to ensure the field deliverability forecast for the area can be accommodated.

In the case of delivery facilities, a review is undertaken to establish the peak day demand levels that are identified as supporting each new extension facility to ensure the maximum day delivery for the area can be accommodated. Hydraulic and economic analyses are also conducted, using the design assumptions for new meter station and extension facilities described in Section 2.4 and Section 2.5.

Once the design is completed and construction costs estimated, Project and Expenditure Authorizations for new receipt and delivery meter stations and related Service Agreements are prepared and forwarded to Customers for authorization.

2.9.3 Existing Meter Station Design

Concurrent with the design of new meter stations and extension facilities (Section 2.9.2), NGTL proceeds with the identification of new metering requirements and lateral restrictions associated with incremental firm transportation requests at existing Receipt and Delivery Points. If no new facilities are required, Customers requesting Service are asked to execute firm transportation Service Agreements. Where additional metering is identified as being required, construction costs are estimated, and Project and Expenditure Authorizations and related Service Agreements are prepared and forwarded to Customers for authorization. When a lateral restriction is identified, a review of the area field deliverability is undertaken to determine potential looping requirements. Lateral loops are designed in conjunction with the design of mainline facilities.

2.9.4 Design Forecast Methodology

As shown in Figure 2.9.1, the transportation design process involves the preparation of a design forecast. The design forecast is a projection of anticipated FS productive capability, average receipts and gas delivery requirements on the Alberta System, and plays an essential role in the determination of future facility requirements and planning capital expenditures.

The design forecast comprises the FS productive capability forecast, average receipt forecast and the gas delivery forecast. The following sections describe these forecasts and the methods by which they are developed.

2.9.4.1 FS Productive Capability Forecast

The FS productive capability forecasts are the receipt component of the design forecast, and represent the forecast peak rate at which gas can be received onto the Alberta System under firm transportation Service Agreements at each Receipt Point. This section describes the method for determining a FS productive capability forecast. The key forecasting terms are field deliverability, FS productive capability, and Receipt Contract Demand.

Field Deliverability

Field deliverability is the forecast peak rate at which gas can be received onto the Alberta System at each Receipt Point. NGTL forecasts field deliverability through an assessment of reserves, flow capability and future supply development. This information is gathered from ERCB sources, NGTL studies, and through interaction with producers and Customers active in the area. With this information, the field deliverability forecast is developed using NGTL's supply forecasting model.

Section 2.4 describes how field deliverability is used to identify facility requirements, while Section 3.5 presents the forecast of field deliverability.

FS Productive Capability

FS productive capability is the lesser of the field deliverability and the aggregate Receipt Contract Demand under firm transportation Service Agreements held at each Receipt Point.

Section 2.6.1 describes how FS productive capability is used to identify facility requirements, while Section 3.5 presents the forecast of FS productive capability.

Aggregate Receipt Contract Demand Under Firm Transportation Service Agreements

In order to prepare a forecast of FS productive capability, a method of forecasting the aggregate Receipt Contract Demand under firm transportation Service Agreements is required.

At each Receipt Point, the aggregate Receipt Contract Demand under firm transportation Service Agreements for the Planning Period consists of the sum of Receipt Contract Demand under:

- firm transportation Service Agreements with terms extending beyond the design period;
- firm transportation Service Agreements terminating before the end of the design period; and
- new requests for firm transportation to be authorized for commencement of service before the end of the design period.

To prepare a forecast of FS productive capability, the volume associated with firm transportation Service Agreements terminating before the end of the design period that will be renewed and the volume associated with new requests for firm transportation to be authorized for commencement of service before the end of the design period are both forecast.

Assumptions based upon historical data, contract utilization and supply potential are made to forecast the volume associated with new requests for firm transportation Service Agreements that will be authorized and will commence service before the end of the design period.

2.9.4.2 Average Receipt Forecast

Average receipt is the forecast of the annual average volume expected to be received onto the pipeline system at each Receipt Point. Section 3.5 presents the forecast of average receipts within the three main Project Areas on the Alberta System.

2.9.4.3 Gas Delivery Forecast

Delivery forecasts for each Alberta Delivery Point and each Export Delivery Point are developed. Each forecast includes average annual delivery as well as average, maximum and minimum delivery for both the winter and summer seasons. These seasonal conditions are used in the transportation design process to meet firm transportation delivery requirements over a broad range of operating conditions. The gas delivery forecast is reported in detail in Section 3.4.

The development of the gas delivery forecast draws upon historical data and a wide variety of information sources, including general economic indicators and growth trends. These gas forecasts are augmented by analysis of each regional domestic and U.S. end use market and other natural gas market fundamentals.

A consideration in developing the maximum day gas delivery forecast for Export Delivery Points is the forecast of new firm transportation Service Agreements. Firm transportation Service Agreements (new Service Agreements or renewals of expiring Service Agreements) are assumed to be authorized at each major Export Delivery Point (Empress, McNeill and Alberta/British Columbia) to a level based on the average annual delivery forecast and historical data. The average annual delivery forecast is developed through consideration of Customer requests for firm transportation and from NGTL's market analysis. NGTL's market analysis considers market growth, the competitiveness of Alberta gas within the various markets and a general assessment of the North American gas supply and demand outlook (Section 3.2).

The key component to the development of the Alberta delivery forecast is the assessment of economic development by market sectors within the province. The potential for additional electrical, industrial and petrochemical plants, oil sands, heavy oil exploitation, miscible flood projects, new natural gas liquids extraction facilities and residential/commercial space heating is evaluated. Each year, NGTL also surveys approximately forty Alberta based customers who receive gas from the Alberta System within the province regarding their forecast of gas requirements for the next several years.

2.9.5 Mainline Design Phase

The detailed mainline hydraulic design was completed using the Forecast and the mainline facilities design assumptions described in Section 2.6 as well as system optimization and compressor modernization described in Section 2.8. Computer simulations of the pipeline system are performed to identify the facilities that would be required to meet firm and peak transportation expectations for the Planning Period.

The following guidelines are used in assessing and determining the facilities requirements in this Annual Plan.

2.9.5.1 Maximum Operating Pressure

A higher maximum operating pressure ("MOP") results in a more efficient system. It is possible to consider more than one MOP when reviewing the long term expansion of the pipeline system. If the expansion is such that a complete looping of an existing pipeline is likely within a few years, then it may be appropriate to consider developing a high-pressure line that will eventually be isolated from the existing system.

2.9.5.2 Temperature Parameters

Pipeline design requires that reasonable estimates be made for ambient air and ground temperatures. These parameters influence the design in the following areas:

- power requirements for compressors;
- cooling requirements at compressor stations; and
- pressure drop calculations in pipes.

Winter and summer design ambient temperatures are determined using historical daily temperatures from Environment Canada at twenty locations throughout the province. An interpolation/extrapolation method was used to calculate the peak day ambient temperature for pipeline sections within each design area.

Ambient and ground temperatures based on historical information for each design area as described in Section 2.3 are shown in Tables 2.9.5.2.1 and 2.9.5.2.2.

Table 2.9.5.2.1
Ambient Air Temperature Parameters
(Degrees Celsius)

Design Area	Summer Design Temperature	Summer Average Temperature	Winter Design Temperature	Winter Average Temperature
Upper Peace River [1]	19	10	-1 to 0	-11
Central Peace River [1]	19	10	1 to 3	-11
Lower Peace River [1]	18 to 19	10	3	-11
Marten Hills	18	10	3	-9
North of Bens Lake	19 to 20	10	2 to 3	-11
South of Bens Lake	20 to 23	13	1 to 5	-8
Edson Mainline[2]	18	10	3 to 4	-8
Eastern Alberta Mainline[2] (James – Princess)	18 to 21	11	4 to 5	-7
Eastern Alberta Mainline[2] (Princess - Empress/McNeill)	22 to 23	13	6	-7
Western Alberta Mainline[2]	18 to 20	11	4 to 7	-4
Rimbey-Nevis	19 to 20	11	3 to 4	-7
South and Alderson	21 to 22	13	6 to 7	-7
Medicine Hat	23	13	7	-6

NOTES:
[1] Design Sub Areas within the Peace River Design Area.
[2] Design Sub Areas within the Mainline Design Area.

Table 2.9.5.2.2
Ground Temperature Parameters
(Degrees Celsius)

Design Area	Summer Design Temperature	Summer Average Temperature	Winter Design Temperature	Winter Average Temperature
Upper Peace River [1]	14	8	4	1
Central Peace River [1]	14	8	4	1
Lower Peace River [1]	14	8	4	1
Marten Hills	12	7	5	2
North of Bens Lake	11	6	5	2
South of Bens Lake	14	8	5	2
Edson Mainline[2]	12	8	5	2
Eastern Alberta Mainline[2] (James - Princess)	14	9	5	2
Eastern Alberta Mainline[2] (Princess-Empress/McNeill)	15	9	5	2
Western Alberta Mainline[2]	14	9	5	1
Rimbey-Nevis	14	10	5	2
South and Alderson	16	11	7	3
Medicine Hat	17	12	7	2

NOTES:
[1] Design Sub Areas within the Peace River Design Area.
[2] Design Sub Areas within the Mainline Design Area.

2.9.5.3 Pipe Size and Compression Requirements

A combination of pipe and compression facilities is reviewed to meet the design flow requirements. The possible combinations are almost unlimited so guidelines have been developed based upon experience and engineering judgment to assist in determining pipe size and compression requirements.

Experience has shown that the pressure drop along the mainline system should be within a range of approximately 15 to 35 kPa/km (3.5 to 8.0 psi/mile) of pipe. Above this range, compressor power requirements become excessive because of high friction losses, and pipeline loop usually becomes more economical than adding compression.

In addition, experience has also shown that generally it is advantageous to provide for a loop with a diameter at least as large as the largest existing line being looped. As a guide to selecting loop length, the loop should extend between two existing block valves where possible, thus minimizing system outages and impact from failures. In cases where design flow requirements are projected to increase, it is usually cost effective to add loop in a manner that will ensure that no additional loop will be required in the same area in the near future.

There is some flexibility in the location of compressor stations when new compression is required. Shifting the location changes the pressure at the inlet to the station and, hence, the compression ratio (i.e., the ratio of outlet pressure to inlet pressure). Capital costs, fuel costs, and environmental and public concerns are also key factors in selecting compressor station location.

2.9.5.4 Selection of Proposed and Alternative Facilities

Various alternatives are identified when combinations of the facility configurations and optimization parameters are considered. This process requires a careful evaluation of alternative designs to select those appropriate for further study.

Facilities that are most likely to meet future gas flows and minimize the long term cost of service are considered. As well, when appropriate, TBO or purchase of existing other party facilities are considered as an alternative to constructing facilities.

The process to identify the potential for facilities requirements begins with the generation of design flow and peak expected flow requirements (Chapter 4). Then, design capabilities on the system are determined to identify where capability restrictions will occur. Pipe sizes, MOP and routings, as well as compressor station sizes and locations are evaluated as part of alternative solutions to eliminate these capability restrictions.

The capital cost of each reasonable alternative is then estimated. Rule of thumb costing guidelines are established at the beginning of the process. These guidelines take the form of cost per kilometer of pipeline and cost per unit type of compression and are based on the latest actual construction costs experienced by NGTL. Adjustments may be made for exceptions (i.e., winter/summer construction, location, and river crossings) that significantly impact these rule of thumb costing guidelines.

The results of the preliminary hydraulics and rule of thumb costs are compared and the best alternatives are given further study.

Simulations of gas flows on the Alberta System are performed for future years to determine when each new compressor station or section of loop should be installed and to establish the incremental power required at each station. Additional hydraulic flow simulations beyond the design period are performed for each remaining alternative to further define the location and size of compressor stations and loops.

Once the requirement for facilities in each year is determined, hydraulic flow simulations are performed based on seasonal average flows for each of the future years to determine compressor fuel usage, annual fuel, and operating and maintenance costs for each facility.

Next, detailed capital cost estimates for new facilities are determined to further improve upon the assessment of alternatives. Where appropriate, the alternatives include the use of standard compressor station designs which are incorporated into the cost estimates. These capital cost estimates reflect the best available information regarding the cost of labor and materials based on the preliminary project scope and also consider land and environmental constraints that may affect project timing and costs.

In reviewing capital, fuel, operating and maintenance costs, it is possible that some alternatives will have higher costs in all of these categories than other alternatives. The higher cost alternatives are eliminated from further consideration.

The annual cost of service, based on capital and operating cost estimates, is determined for each remaining alternative. This calculation includes annual fuel costs, capital costs escalated to the in-service date, annual operating costs, municipal and income taxes, return on investment and depreciation. The present value of each of the annual cost of service calculations are determined and then summed to calculate the CPVCOS for each alternative.

The proposed facilities are usually selected on the basis of lowest CPVCOS and lowest first year capital cost. However, a number of alternatives may be comparable when these costs are considered. For practical purposes, when these alternatives are essentially equal based on financial analyses, the selection decision will consider other relevant factors including operability of the facilities, environmental considerations and land access.

2.9.5.5 Preliminary Site and Route Selection Areas

Preliminary site and route selection areas are defined by hydraulic parameters. The downstream boundary of a compressor station is determined by locating the compressor station at a point where the maximum site-rated power available for the selected unit is fully used and the compressor station is discharging at the pipeline MOP while compressing the design flow requirements. The upstream boundary is determined by locating the selected unit at a location where any excess power available at the next downstream compressor station is consumed and the compressor station is discharging at the pipeline MOP while compressing the design flow requirements.

The preliminary route selection area for new pipelines is defined by the reasonable alternative routes between the end points of the new pipeline.

2.9.6 Final Site and Route Selection

Once preliminary site and route selection areas have been identified, efforts are directed at locating final sites for compression and metering facilities and routes for pipelines that meet operational, safety and environmental considerations and have minimal social impact.

2.9.6.1 Compressor Station Site Selection Process

The final site selection for a new compressor station is a two step process. The first step is a screening process where the preliminary site selection area is examined against relevant screening criteria with the objective of eliminating those locations determined to be inappropriate. This methodology is essentially one where geographical, physical, environmental and landowner impact constraints are used to eliminate unsuitable areas.

In the second step, a matrix is used to rank candidate sites against a number of engineering, operational, environmental, social and land use criteria. With appropriate weighting assigned to each of these criteria, based on input received from the public consultation process (Section 2.9.7), each candidate site is ranked relative to the others.

The criteria used to select compressor station sites include the following:

(1) Terrain:

Ideally, flat and well-drained locations are preferred, so that grading can be minimized and the surrounding landscape can be utilized to reduce visual impact to the surrounding residences.

(2) Access:

Compressor facilities are located as close as possible to existing roads and highways to minimize the cost and surface disturbance associated with new road construction.

(3) Land Use:

Compressor facilities are located, where possible, within areas cleared of vegetation and in areas where existing access routes can be utilized.

(4) Proximity to Residences:

Compressor facilities are designed to be in compliance with regulatory requirements and located as far away as possible from residences to minimize visual and noise impacts.

2.9.6.2 Meter Station Site Selection Process

Criteria similar to those applied to siting compressor stations are used to select meter station sites.

2.9.6.3 Pipeline Route Selection Process

The final pipeline route selection process consists of a review and an analysis of all available and relevant information, including: alignment sheets; aerial photographs; topographical maps; county maps; soil maps and historical data. Using this information, an aerial and/or ground reconnaissance of the preliminary route selection area is conducted to confirm the pipeline end points and to identify alternative pipeline routes between end points.

Input is sought from landowners and the public affected by the alternate pipeline routes (Section 2.9.7) through public consultation. The pipeline route that best satisfies a variety of route selection criteria, including: geographical; physical; environmental; engineering; and landowner and public concerns is selected.

The criteria used to select pipeline routes include the following:

(1) Terrain:

To minimize environmental and construction impacts, the driest and flattest route possessing both stable and non-sensitive soils is preferred. Other terrain features, such as side slopes, topsoil, rocky areas, wet areas and water crossings are also considered.

(2) Land Use:

To the extent possible, existing corridors are utilized while taking into consideration, the other current land use activities.

(3) Right-of-Way Corridors:

To the extent possible existing utility, seismic or pipeline right-of-way corridors within the route selection area are used. Utilizing existing corridors may reduce the amount of clearing and land disturbance and, in the case of shared right-of-way, allows for narrower new Right-of-Way width by overlapping existing pipeline corridors.

(4) Crossings:

On many occasions the pipeline route selected crosses both natural and man-made obstacles such as creeks, drainages, roads and other pipelines. Where practical, the pipeline is routed such that these crossings are avoided. However, when a crossing is necessary, the best possible location is selected considering terrain, land use, pipeline corridors, environmental considerations and the requirements of relevant regulatory authorities.

(5) Access:

The route which provides access during construction and that minimizes interference with surrounding land use is preferred. It is also preferable to locate the pipeline so that valves are easily accessible for day-to-day operations.

(6) Construction Time Frame:

The approximate timing of the construction phase, which is related to the required in-service date of the pipeline, is considered during pipeline route selection. The available construction time frame can be affected by terrain, land use, and the environment. Timing can also influence cost factors.

(7) Future System Expansion:

The possibility of future system expansion and any constraints that the proposed routing may have on future looping are considered.

2.9.7 Public Consultation Process

NGTL is involved in a variety of public consultation activities that help it establish and maintain positive relationships with people affected by the construction and operation of the pipeline system. Part of the public consultation process involves information sharing on new projects and soliciting public input for the siting of new facilities.

The public consultation process enables NGTL to identify and address issues involving the public, share information on NGTL's plans and solicit input on decisions that may affect public stakeholders.

While public consultation is an integral and important component of the facility site and route selection process that precedes every facility application, the nature and scope of each public consultation program depends on a number of factors, including the nature of the facility, the potential for public impact, and the level of public interest. All contact with stakeholders throughout the consultation process is documented in a tracking form that is reviewed regularly to ensure that all commitments are recorded and issues of concern are addressed.

As part of the stakeholder identification process, title searches of all lands directly impacted by or adjacent to each proposed facility are conducted to identify potentially impacted landowners and occupants. Public Land Standing Reports are obtained from Alberta Sustainable Resource Development to verify all Crown land disposition holders that would have an interest in the lands.

Lands potentially impacted may include:

- All lands crossed by the proposed pipeline route(s);
- All parcels of land lying within 0.2 km of the proposed pipeline route(s); and
- All lands lying within a 1.5 km radius of all proposed compressor station facilities.

NGTL representatives meet with all directly impacted landowners and occupants to introduce them to the facility proposal and provide an opportunity for input regarding routing and scheduling.

In addition, the Member of Parliament and Member of the Legislative Assembly, the regulatory local area supervisor, as well as local elected officials and staff, civic organizations and other potentially interested and impacted stakeholders are identified and notified of the proposal.

Standard information packages for all stakeholders contain:

- A fact sheet outlining project specific information such as length of the project, the start and end points, proposed pipe size, maximum operating pressure, new Right-of-Way, existing corridors, the proposed construction timing, as well as environmental, safety and consultation commitments;
- A map depicting the geographic location of the proposed pipeline route/facility site as well as company contact information;
- Letter from the Chairman of the ERCB;
- Letter from the Chairman of the AUC;
- ERCB brochure *Understanding Oil and Gas Development in Alberta;*
- ERCB public information document *EnerFAQs No. 7: Proposed Oil and Gas Development: A Landowners Guide;*
- ERCB public information document *EnerFAQs No. 9: The ERCB and You: Agreements, Commitments and Conditions;*
- ERCB public information document *EnerFAQs No. 11: All About Appropriate Dispute Resolution (ADR);*
- Required EnerFAQs as outlined in ERCB Directive 56: *Energy Development Application Guide;*
- ERCB Brochure: *Safe Excavation Near Pipelines;*
- Alberta Agriculture, Food and Rural Development pamphlet: *Negotiating Surface Rights;* and
- Alberta Agriculture, Food and Rural Development pamphlet: *Pipelines in Alberta*.

Advertisements respecting proposed facilities are placed in local newspapers for a two week period. Any landowner or public concerns generated from the advertisement process are dealt with on a one-on-one basis.

Upon request or if deemed appropriate, specific interested individuals or groups, such as municipalities, civic organizations, or special interest groups, will receive a personal consultation to provide further details of the proposed facilities and gain input from stakeholders.

A community meeting or open house is held, where appropriate, to provide information regarding specific proposed facilities and gain input from stakeholders. Community meetings provide a forum to review, discuss and resolve issues or concerns of interested parties. Invitations are extended to all potentially impacted landowners, occupants, government officials and general community members who may be impacted by or interested in the proposed facilities, as identified by NGTL. NGTL endeavors to answer any questions with regard to proposed facilities at these meetings. If NGTL is unable to respond to questions at that time, additional information is gathered and is provided following the meeting. Attendees are requested to sign into the open house and provide feedback on the effectiveness of the open house in addressing their issues or concerns with the proposed project. A summary of the information shared, the comments received, and any commitments made, is entered into the consultation tracking form.

As a demonstration of its respect for the diversity of aboriginal cultures and its commitment to work with aboriginal communities, an Aboriginal Policy was developed. All communications with aboriginal communities in areas of proposed facilities are guided by this policy. In developing its projects, NGTL strives to engage communities in dialogue to support an understanding of the potential impacts of proposed facilities, mitigate potential impacts on traditional land use and provide the opportunity to work closely with the communities to seek mutually acceptable solutions and benefits.

A copy of the Aboriginal Policy can be found on TransCanada’s Web site at: http://www.transcanada.com/social/reports.html

2.9.8 Environmental Considerations

Facility sites and pipeline routes that allow the facility to be constructed and operated in a cost effective manner with minimal environmental impact are selected. The route and site selection processes consider the impact of proposed facilities on all aspects of the environment, including: surficial geology and landform; soils; timber; water resources; vegetation; fisheries; wildlife; land use; aesthetics; air quality and noise levels as outlined in Alberta Environment's ("AENV") *Guide for Pipelines, 1994* and *the NGTL Conservation and Reclamation Standard, 1999.* All identified potential environmental impacts are examined during the selection process and evaluated together with any mitigative measures that may be required to reduce the impacts of facility construction and operation. Measures appropriate to address hazardous materials, waste management, weed control, reclamation and various environmental components potentially impacted by the project are designed to meet project specific conditions. Based on the consideration of potential environmental impacts and the design of mitigation measures, an Environmental Protection Plan is developed to communicate these mitigation measures.

2.9.8.1 Site Preparation

During the construction of meter stations and compressor stations, the topsoil in the White Area (arable lands) of the Province and the surface organic and near surface mineral material in the Green Area (non-arable lands) are stripped from the entire graded area. The stripped material is stockpiled at an appropriate location to conserve the material for use during reclamation of the site upon decommissioning and abandonment. The stockpile is seeded with a mixture of species compatible with the surrounding area to prevent wind and water erosion.

2.9.8.2 Right-of-Way Preparation

During the construction of pipelines in the White Area of the Province, topsoil is conserved to maintain land capability following construction. Soil surveys are conducted in selected areas of the province to ensure that handling techniques are compatible with the soil conditions of the right-of-way.

In the Green Area of the Province, surface materials are conserved through grubbing procedures. Grubbing is the removal of woody debris (e.g. stumps, roots) from the right-of-way to allow for the safe passage of construction equipment. Timber is salvaged from the Right-of-Way when the trees meet merchantable criteria established in consultation with Alberta Sustainable Resource Development.

2.9.8.3 Vegetation Management

The vegetation management program is designed to assess and respond to weed problems on newly constructed and operating pipelines and facilities. All reasonable measures are employed to prevent the proliferation of weeds and promote desirable, relatively stable plant communities that are compatible with existing land use. Certificates of Analysis are obtained for all grass and legume seed mixes used in the reclamation program to ensure that prohibited and noxious weeds are not introduced to an area through seed application. In addition, construction equipment is cleaned of mud and vegetative debris prior to entering the Right-of-Way.

Measures to prevent the proliferation of weeds include tilling, mowing, spraying, or in rare cases, hand pulling of weeds. The method of control is chosen to accommodate site conditions, landowner requirements and regulatory agency recommendations.

2.9.8.4 Surface and Groundwater Considerations

Surface water movements are taken into consideration during the facility site and pipeline route selection process. During construction, near surface groundwater flow may be encountered. In these situations, the potential for impacting flow direction is assessed and, where necessary, below ground piping is installed or other appropriate measures are taken to ensure that groundwater moves across the facility.

2.9.8.5 Fisheries and Wildlife Resources

The identification and evaluation of fish and fish habitat is required for each watercourse traversed by a pipeline route. This process enables NGTL representatives to: determine fish and fish habitat parameters and criteria at each watercourse crossing; evaluate and recommend appropriate crossing methodologies; identify construction mitigation measures; evaluate the need for specific reclamation measures at each crossing location; and meet applicable provincial and federal legislative requirements.

Crossing evaluations and habitat assessment information establishes the recommended crossing methodology. This information provides documentation to meet the intent of the federal *Fisheries Act* and all other applicable legislation as well as the 'no net loss' principle. Information from the crossing evaluation (e.g., geotechnical assessment) and findings from the fisheries assessment are integrated to determine the most appropriate crossing methodology.

The evaluation and assessment are documented to ensure and demonstrate due diligence in determining impacts associated with a crossing technique and/or proposed mitigation measures. Each crossing is installed as quickly as possible to minimize potential environmental impacts during construction.

Identifying and evaluating wildlife and their habitats along the pipeline alignment and adjacent areas is part of the environmental planning process. Wildlife and habitat information is reviewed to: ensure that pipeline activities have a minimal impact on these resources and their habitat; meet the requirements of the *Alberta Wildlife Act* and all other applicable legislation; and identify the status of critical key wildlife species and their habitat (i.e., endangered, threatened or vulnerable). NGTL then determines the most appropriate route alignment by and if possible, avoiding routing through critical and/or key habitat. If key and/or critical habitat cannot be avoided, NGTL identifies appropriate mitigative measures in consultation with local resource managers and documents these measures in the Environmental Protection Plan to be implemented during construction.

2.9.8.6 Historical and Paleontological Resources

Class I pipelines, as described in Section 2.9.9, are referred to Alberta Culture and Community Spirit to determine whether or not a Historical Resource Impact Assessment is required. The need for a historical resource assessment is based on the following principles: that crown owned archaeological and paleontological resources are held as a public trust; 'users pay' principle applies to all historical resource discoveries and therefore developers that create an impact on historical resources are responsible to undertake an impact assessment and implement mitigation measures to protect these resources; and the Minister responsible for historical resources management has discretionary powers to order an assessment and mitigation of historical resources impacts.

For Class II pipelines, available provincial archaeological resources sensitivity maps and significant sites and area maps are removed. In cases where this review suggests that a proposed project may have potential impact to an identified site, NGTL works with the appropriate Alberta Culture and Community Spirit representative to determine appropriate next steps.

If a significant historical site is discovered during the assessment of a proposed facility, the service of a qualified archaeologist is employed to further delineate historical resources in relation to construction activities. If warranted, mitigative measures are employed during construction to conserve and preserve historical resources. Although the assessment is intensive, it is still possible to encounter new sites during construction. In accordance with Section 27 of the *Alberta Historical Resources Act*, should any cultural material be uncovered during construction, Alberta Culture and Community Spirit is contacted immediately to determine further requirements.

2.9.8.7 Land Surface Reclamation

The primary objective of surface land reclamation is to return lands to equivalent land capability. As a result, the focus is on the land capability of surface material and vegetation criteria. Surface land reclamation must be practical, feasible and cost-effective in meeting the objectives of equivalent land capability. Remedial efforts focus on reducing long-term risk and mitigating concerns.

Reclamation requirements are outlined in the Environmental Protection Plan. NGTL identifies reclamation criteria in the planning and preparation phase of a pipeline to ensure that any disturbed land is returned to an equivalent land capability. The reclamation criteria addresses: vegetation; drainage; moisture availability; erosion, contour or landscape pattern; and slope stability.

The following principles are adhered to when developing and implementing a Reclamation Plan: salvage all surface materials/topsoil and store it separately from the subsoil and spoil material so it can be used for reclamation of the site; develop Reclamation Plans for all facilities; and obtain the appropriate regulatory approvals when abandoning a facility.

2.9.8.8 Air Emissions and Alberta Environmental Protection and Enhancement Act ("AEPEA") Approvals

Compressor Stations are designed and constructed in compliance with the requirements of AEPEA.

2.9.8.9 Noise Regulations

NGTL complies with regulatory requirements in the design and construction of facilities.

2.9.9 Facility Applications, Procurement and Construction Phase

Applications for facilities for the Planning Period will be submitted to the regulator throughout 2009. As facility applications are being prepared, discussions with industry representatives will continue and modifications to specific facility applications, if warranted, will be made to reflect industry feedback on the Annual Plan. If any significant changes are made to accommodate a concern, timing of the completion of the facilities may be affected and result in a delay in the provision of firm transportation. However, all reasonable steps to mitigate such delays will be taken.

Under the provisions of AEPEA and the *Activities Designation Regulation*, NGTL is required to submit Conservation and Reclamation ("C&R") applications to AENV for Class I pipelines with the exception of those located in the Green Area. Class I pipelines are those projects in which the pipe diameter (in millimeters) multiplied by the cumulative length (in kilometers) is equal to or greater than 2690. A C&R application contains details with respect to location of the pipeline, area description, environmental consultation activities, potential environmental impacts and an environmental protection plan. Environmental protection plans for all pipeline construction projects, Class I and Class II, are developed. Class II pipelines are those projects in which the pipe diameter (in millimeters) multiplied by the cumulative length (in kilometers) is less than 2690. C&R applications are reviewed and approved by AENV prior to construction. During the review process, the submission of the application is advertised, thereby allowing the public further opportunity to review and/or comment on the application. Statements of concern brought forth by the public to AENV are addressed prior to a decision being made on the application. The application process typically parallels the regulatory facility application review process.

NGTL has developed and implemented the NGTL C&R Standard compiling NGTL environmental policies and standard environment protection procedures. All project-specific C&R applications will refer to and incorporate the appropriate policies and procedures set out in NGTL's C&R Standard.

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.

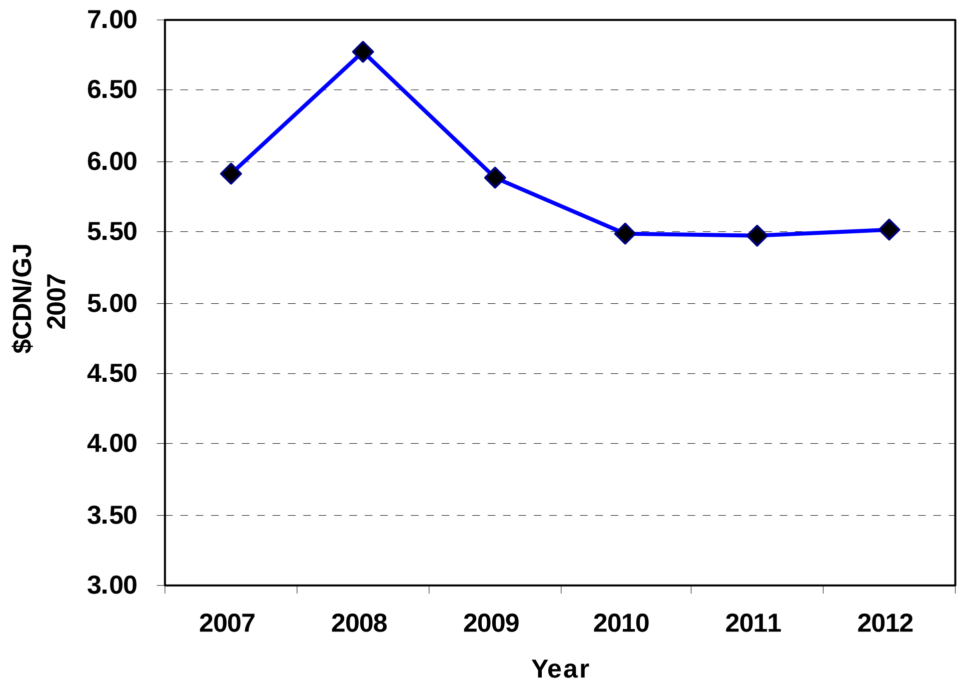
- Gas demand is expected to increase with continued economic and population growth in the longer term in both the U.S. and Canada. U.S. gas demand growth will be predominately in the electricity generation sector. Western Canadian industrial gas demand is expected to grow significantly, driven by oil 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)



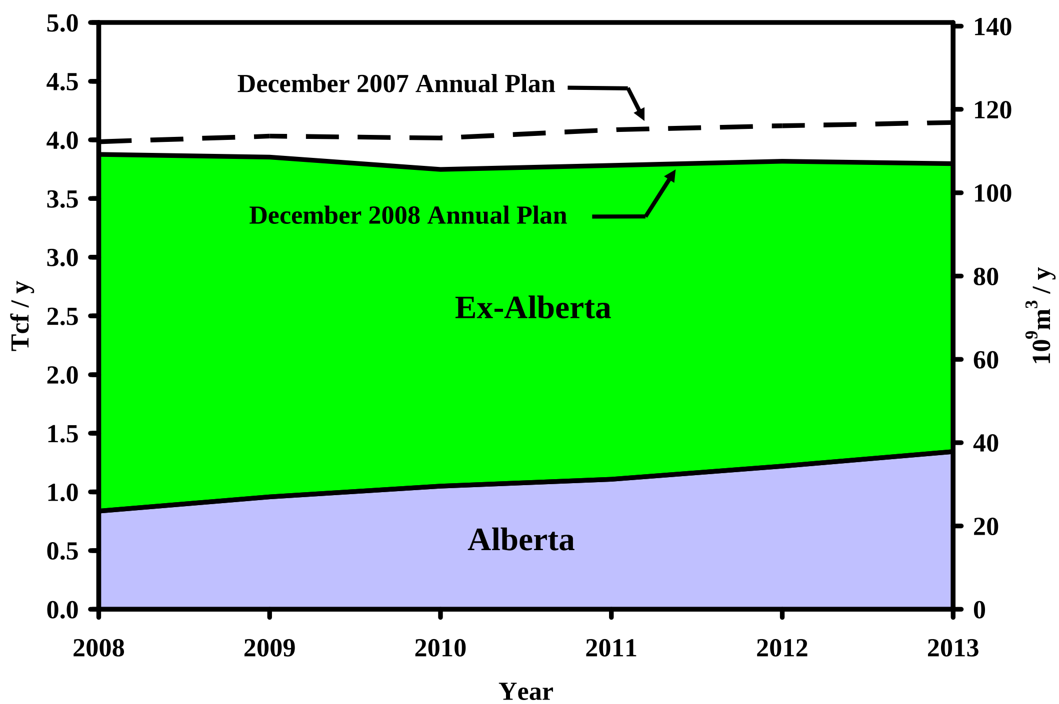
The Alberta average field price in 2008 (in real 2007 $) is forecast to rise to $6.78 Cdn/GJ, up from $5.91 Cdn/GJ in 2007. Alberta prices are expected to drop back to $5.88 Cdn/GJ in 2009, and then stabilize in the 2010 - 2012 period at a slightly lower level before exhibiting growth in real dollar 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 $10^6m^3/d$ (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 $10^6m^3/d$ (5.37 Bcf/d). This is an increase of 10.0 $10^6m^3/d$ (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 $10^6m^3/d$ (4.15 Bcf/d). This is an increase of 8.3 $10^6m^3/d$ (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 ($10^6m^3/d$)				
	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.

CHAPTER 4 – DESIGN FLOW REQUIREMENTS AND PEAK EXPECTED FLOWS

4.1 Introduction

This chapter presents an overview of the design flow requirements and the peak expected flow, as described in Section 2.6. In this Annual Plan, design flow requirements, will only be presented for those design areas where new mainline facilities are required. For this Annual Plan the only design area requiring new facilities is the North and East Project Area.

Design flow requirements are based on the June 2008 design forecast and the applicable design assumptions discussed in Section 2.6.1. The design area delivery assumption, storage assumption and downstream capacity assumption were applied in each design area. The FS productive capability assumption was applied to each of the areas shown in Figure 2.6.1.5.

The design flow requirements for the North and East Project Area are presented in Appendix 2. Figure(s) presented in this chapter illustrate both historical and forecast trends within the North and East Project Area.

An overview of the design flow requirements resulting from the June 2008 design forecast was presented at the TTFP meeting on November 18, 2008.

The peak expected flow determination, is included in the facility design process, and is described Section 2.6.2. Peak expected flows were determined for all design areas having a receipt dominant flow condition. No new mainline facilities are expected to be required within these areas based on the June 2008 design forecast.

Historical data is included to illustrate the correlation between design flow requirements and actual flows, including historical peak flows. Historical actual flows and historical design flow requirements are shown for the 2002/03 Gas Year through the 2007/08 Gas Year. Historical design flow requirements represent the values that influenced the design for each Gas Year from 2002/03 to 2007/08.

The figure in Section 4.2 shows a comparison between winter and summer historical design flow requirements and historical actual flows for the 2002/03 Gas Year through to the 2007/08 Gas Year. The figure also shows the winter and summer design flow requirements from the June 2008 design forecast for the 2008/09 Gas Year through the 2012/13 Gas Year.

Based on the June 2008 design forecast, the projected design and peak expected flow conditions are not expected to result in any new mainline facility requirements for Peace River Design Area during the period covered by this Annual Plan.

4.2 North and East Project Area

Based on the June 2008 design forecast, the projected 'flow through' design and peak expected flow conditions are not expected to result in any new mainline facility requirements for this design area during the period covered by this Annual Plan.

The 'flow within' condition governs the design flow requirements in the North and East Project Area as described in Section 2.6.1. This design flow requirement is the net effect of localized minimum available supply less the maximum deliveries expected within the North and East Project Area. As outlined in Chapter 3, Alberta deliveries to the North and East Project Area are forecast to increase in the future. The FS productive capability required to meet the maximum day delivery draws from available FS productive capability in the North and East Project Area plus the FS productive capability that is brought into the area, via the North Central Corridor, the Marten Hills Design Area through the Slave Lake compressor, the Rimbey-Nevis design area via the Gadsby crossover and the Eastern Alberta System Mainline Design Sub Area at the Princess Compressor Station.

Figure 4.2 illustrates the historical actual flows between November 2003 and December 2008, the historical design flow requirements between the 2005/06 and 2007/08 Gas Years and the design flow requirements currently forecast between the 2008/09 and 2012/13 Gas Years. The actual flows experienced during the recent cold snap in December 2008 show that the net flow shortfall within the North and East Project Area increased significantly over what was experienced in 2007/08.

Figure 4.2
North and East Project Area
Flow Within Design Flow Requirements

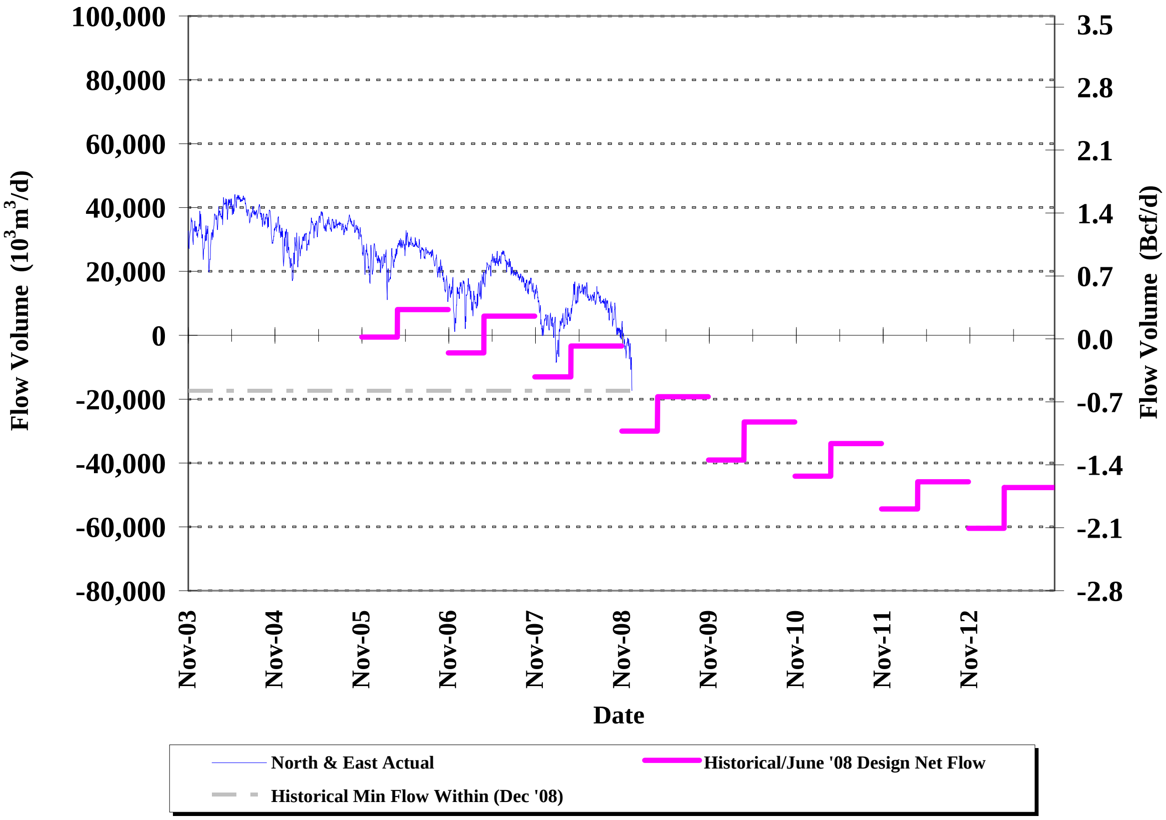


Table 4.2 shows the winter and summer design flow requirements for the Planning Period.

Table 4.2
North and East Project Area
Flow Within Design Flow Requirements
June 2008 Design Forecast
Design Flow Requirements

Gas Year and Season	Design Flow Requirements	
	Bcf/d	$10^6m^3/d$
2009/10 Winter	-1.38	-39.0
2009/10 Summer	-0.96	-27.1

CHAPTER 5 – MAINLINE FACILITY REQUIREMENTS

5.1 Introduction

This chapter details the proposed natural gas transportation mainline facilities required to be in-service on the Alberta System to transport the design flow requirements and peak expected flows shown in Chapter 4 for the Planning Period. Where applicable, information is included regarding size, routes, locations and cost estimates for the proposed facilities together with descriptions of the next best alternative facilities.

An overview of the facilities requirements for the Planning Period was presented at the TTFP meeting on November 18, 2008.

In this Annual Plan, design capability is determined using the design flow requirements and peak expected flows with facilities that are currently in-service and the facilities that are being constructed for the previous Planning Period. The design capability with proposed facilities is based on the June 2008 design forecast for the Planning Period.

Where new facilities are proposed, a table comparing proposed facilities and next best alternative facilities has been included, where applicable. Flow schematics, based on design flow requirements for the design areas requiring facilities, with and without the proposed facilities, are provided in Appendix 3.

5.2 System Optimization Update

As described in Section 2.8.1 of this Annual Plan, system optimization continues to be an integral part of the regular facility design review and planning to meet the system design flow requirements.

There are no facilities identified for retirement for the Planning Period resulting from the 2008 design review.

5.3 Facilities Requirements

In this Annual Plan only the design areas where facilities are required for the Planning Period are included.

5.3.1 North and East Project Area

The North and East Project Area comprises the North of Bens Lake Design Area and the South of Bens Lake Design Area as described in Section 2.3.2. The proposed facilities for the North and East Project Area are identified in Figure 5.3.1.

Figure 5.3.1
North and East Project Area
Proposed Facilities

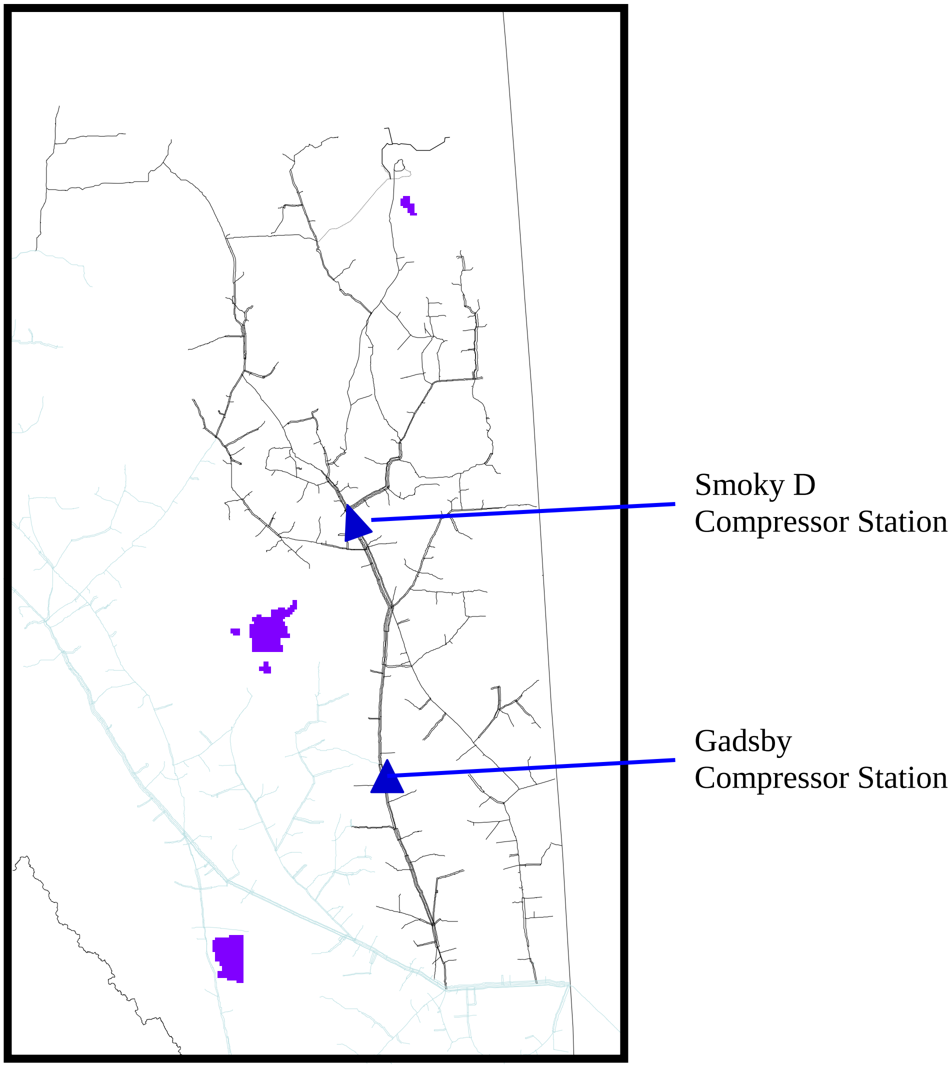


Table 5.3.1

North & East Project Area
Proposed Facilities

Proposed Facility	Description	Required In-Service Date	Capital Cost ($millions)	Facility Status
Miscellaneous[1]		November 2009	12.1	
TOTAL			**12.1**	

Note:
1 Miscellaneous represents compressor station yard modifications at Gadsby and Smoky D Compressor Stations.

In the North and East Project Area, there are two distinct flow conditions evaluated to determine facilities requirements. The two flow conditions used for design are the called "flow through" and "flow within" as described in Section 2.6.1.2. The flow through the area condition uses the North and East Project Area delivery assumption. The flow within the area condition uses the North and East Project Area maximum day delivery flow assumption.

Additional facilities are required to be placed in-service based upon the June 2008 design forecast to transport the Planning Period design flow requirements, based on the flow within the area design flow assumption, shown in Table 4.2 for the North and East Project Area.

Compressor station yard modifications are proposed at each of the following compressor stations: Gadsby and Smoky D for the Planning Period. Without the modifications at the Gadsby and Smoky D Compressor Stations, capability to meet the maximum day delivery within the North and East Project Area will have a shortfall of approximately 4597 $10^3m^3/d$ (163 MMcf/d). Alternative facilities to meet maximum day delivery in the North and East Project Area would consist of compressor unit additions at each of the Gadsby and Smoky D compression station sites at a significantly greater cost. The proposed compressor station yard modifications are the most economic way to transport additional gas to meet the North and East Project Area requirements.

The installation of the proposed facilities will provide the design capability to transport 100% of the forecast North and East Project Area requirements for the Planning Period as shown in Table 5.3.1.1.

Table 5.3.1.1
North and East Project Area
Maximum Day Delivery June 2008 Design Forecast
Design Capability vs. Design Flow Requirements

Gas Year and Season	Design Capability without Proposed Facilities (% of Maximum Day Delivery)	Design Capability with Proposed Facilities (% of Maximum Day Delivery)
2009/10 Winter	94	100
2009/10 Summer	100	100

CHAPTER 6 – EXTENSION FACILITIES AND LATERAL LOOPS

6.1 Introduction

As previously discussed (Section 2.1), receipt and delivery meter stations, extension facilities and lateral loops are designed and constructed independently of the construction of mainline facilities. 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 term and 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).

In accordance with the ERCB's *Guide 56, Energy Development Applications and Schedules*, October 2003, permit applications to construct new meter stations are no longer submitted to the regulator. Consequently, proposed meter stations are not included in this Chapter.

A summary of all pipeline applications that were filed with the regulator since the filing of the December 2007 Annual Plan is included under Appendix 4. In addition, a summary of all meter stations filed with the regulator from December 1, 2007 to November 30, 2008 is included under Appendix 4.

Proposed lateral loops (expansions) are listed in Table 6.1.

Table 6.1
Lateral Loops

Proposed Facility	Description	Required In-Service Date	Estimated Cost (2008 $millions)
Doe Creek South Lateral Loop	5 km x NPS 12 pipeline	November 2009	4.5
Sneddon Creek Lateral Loop #2	5 km x NPS 16 pipeline	November 2009	6.0
TOTAL			**10.5**

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 Receipt Forecast

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

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.

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.

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 Flow Requirements

The forecast of Firm Requirements 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 FS productive capability and gas delivery over a five year design horizon.

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.

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.

Field Deliverability

Field deliverability is the forecast peak rate at which gas can be received onto the pipeline system at each Receipt Point. NGTL forecasts field deliverability through an assessment of reserves, flow capability and the future supply development at each Receipt Point. This information is gathered from Board and industry sources, NGTL studies and through interaction with producers and Customers active in the area.

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.

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.

FS Productive Capability

FS productive capability is the lesser of forecast field deliverability and the forecast of aggregate Receipt Contract Demand under Service Agreements for Rate Schedule FT-R, Rate Schedule LRS, Rate Schedule LRS-2, Rate Schedule LRS-3, Rate Schedule FT-P and Rate Schedule FT-RN held at each Receipt Point.

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.

Green Area

Defined by Alberta Environment as non-arable lands.

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

The peak flow that is expected to occur within a design area or design sub area on the Alberta System.

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 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.

Receipt Area

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

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 Field Deliverability

System field deliverability is the sum of all individual Receipt Point field deliverability.

System FS Productive Capability

System FS productive capability is the sum of all individual Receipt Point FS productive capability.

System Maximum Day Deliveries

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

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.

White Area

Defined by Alberta Environment as arable lands.

Winter Season

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

APPENDIX 2

DESIGN FLOW REQUREMENTS

The following tables present both the winter and summer design flow requirements for design areas where additional facilities are required for the Planning Period. The values are derived, as discussed in Chapters 2 and 4, through application of the mainline design assumptions to the June 2008 design forecast.

Design flow requirements, described as Area Design Flow Requirements in the tables, are calculated by subtracting the Area Minimum Deliveries and area fuel (not shown) from the Area Required Receipts. In some areas, Flow Into Area is added to the Area Required Receipts and represents the flow from other design areas. Area Minimum Deliveries are determined based on the design flow assumption discussed in Section 2.6.

Area FS Productive Capability represents the sum of the FS productive capability at each Receipt Point in the design area. The Area Required Receipts are determined through application of the design area delivery, equal prorationing and FS productive capability assumptions.

Area Peak Productive Capability represents the expected coincidental peak receipts received from all receipt points with the design area as described in Section 2.6.2. The Area Peak Receipts are determined through application of the design area delivery and equal prorationing assumptions against the assessed peak productive capability on the Alberta System.

The design flow requirements may differ from the flow schematics shown in Appendix 3. This is because the detailed flow schematic information is taken directly from the hydraulic simulations whereas design flow requirements are estimated for the entire design area.

Design Flow Requirements

N&E Project Area Flow Within

$10^3m^3/d$

PW

Gas Year	2008/09	2009/10	2010/11	2011/12	2012/13
FS Productive Capability	33753	31723	33829	36682	39300
Flow Into Area	0	0	0	0	0
Area Required Receipts	33753	31723	33829	36682	39300
Area Deliveries	-63457	-70471	-77682	-90739	-99441
Area Design Flow Req'mts	-30005	-39032	-44155	-54384	-60492

mmcf/d

PW

Gas Year	2008/09	2009/10	2010/11	2011/12	2012/13
FS Productive Capability	1198	1126	1201	1302	1395
Flow Into Area	0	0	0	0	0
Area Required Receipts	1198	1126	1201	1302	1395
Area Deliveries	-2252	-2501	-2757	-3221	-3530
Area Design Flow Req'mts	-1065	-1385	-1567	-1930	-2147

$10^3m^3/d$

PS

Gas Year	2008/09	2009/10	2010/11	2011/12	2012/13
FS Productive Capability	35738	33589	35819	38840	41612
Flow Into Area	0	0	0	0	0
Area Required Receipts	35738	33589	35819	38840	41612
Area Deliveries	-54709	-60400	-69412	-84381	-88953
Area Design Flow Req'mts	-19290	-27111	-33912	-45887	-47713

mmcf/d

PS

Gas Year	2008/09	2009/10	2010/11	2011/12	2012/13
FS Productive Capability	1268	1192	1271	1379	1477
Flow Into Area	0	0	0	0	0
Area Required Receipts	1268	1192	1271	1379	1477
Area Deliveries	-1942	-2144	-2464	-2995	-3157
Area Design Flow Req'mts	-685	-962	-1204	-1629	-1693

PS = Peak Summer
PW = Peak Winter

APPENDIX 3

FLOW SCHEMATICS

Flow schematics for each of the design areas where additional facilities are required for the Planning Period.

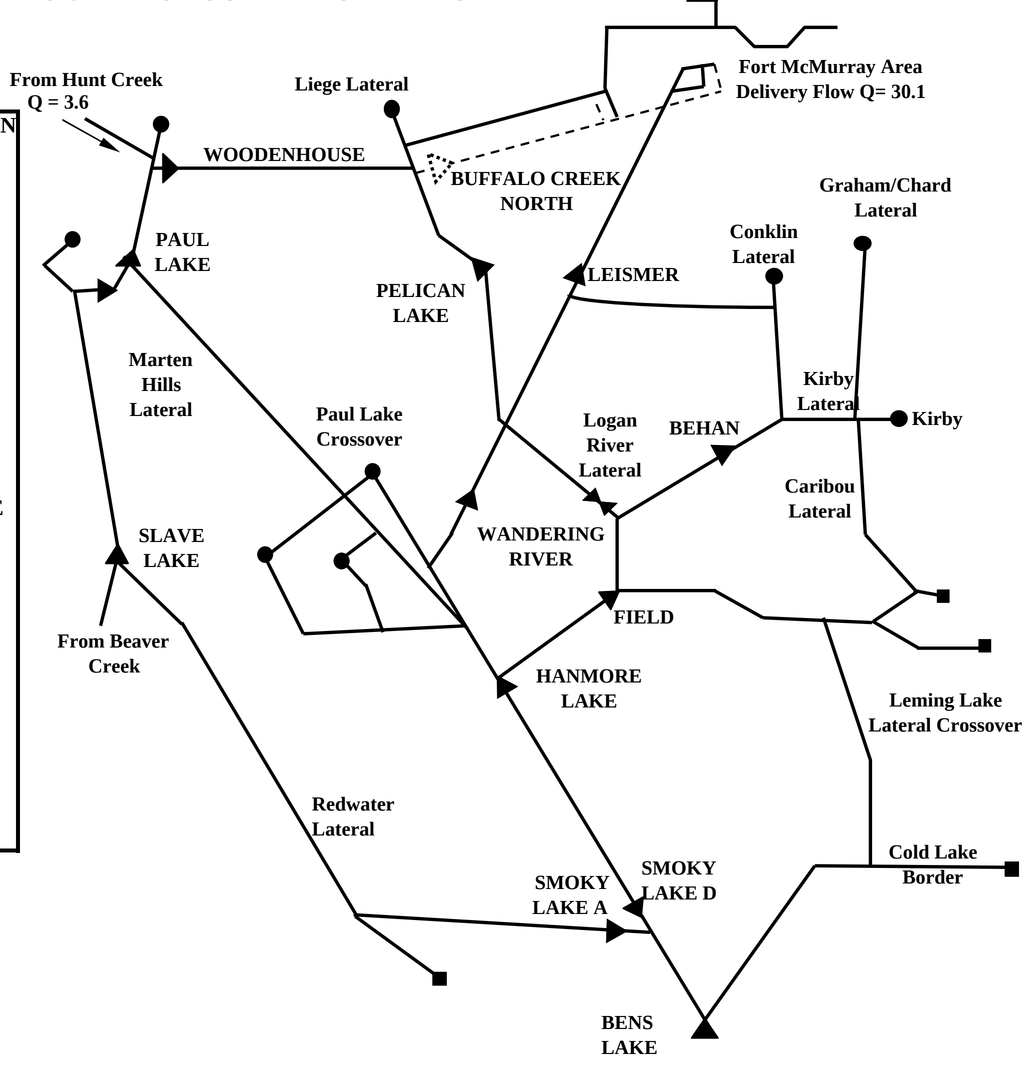
The flow schematics may differ from the design flow requirements shown in Appendix 2. This is because the detailed flow schematic information is taken directly from the hydraulic simulations whereas design flow requirements are estimated for the entire design area.

2009/10 GAS YEAR
NORTH OF BENS LAKE DESIGN AREA
WITH MAXIMUM DELIVERIES TO THE NORTH & EAST PROJECT AREA
WINTER CAPABILITY WITHOUT PROPOSED FACILITIES

COMPRESSOR STATION SUMMARY

	FIELD LK	HANMORE LK B,C	BENS LK A	BENS LK B	BENS LK C,D	SMOKY LK D	PELICAN LK
P_{sct}(kPa$_g$)	5925	6036	6896	6896	6323	6473	5392
P_{dis}(kPa$_g$)	7949	6961	8188	8193	6952	6472	8441
Flow (10^6m^3/d)	14.2	31.9	0.0	10.6	42.6	-31.8	3.7
Fuel (10^3m^3/d)	55.4	59.9	0.0	27.9	65.1	0.0	23.2
Power Avail (MW)	6.3	6.6	3.5	3.2	7.4	15.2	3.2
Power Req (MW)	6.0	6.6	0.0	3.1	7.4	0.0	2.4
Compression Ratio	1.3	1.2	N/A	1.2	1.1	N/A	1.6
T_{sct} (˚C)	4.5	6.0	5.0	23.0	13.0	10.0	5.0
T_{dis} (˚C)	30.5	18.5	5.0	40.0	23.0	10.0	44.0
T_{amb} (˚C)	2.0	2.0	2.0	2.0	2.0	2.0	2.0

	PAUL LK B2	WOODENHOUSE #1	WOODENHOUSE #2	BUFFALO NORTH	WAND. RIVER	LEISMER	SLAVE LK
P_{sct}(kPa$_g$)	5798	4993	4981	7606	5457	5510	5000
P_{dis}(kPa$_g$)	7614	7783	7784	7602	7657	5509	6179
Flow (10^6m^3/d)	19.0	0.0	22.8	13.3	4.8	1.7	2.8
Fuel (10^3m^3/d)	54.2	0.0	87.5	0.0	29.3	0.0	10.2
Power Avail (MW)	14.5	10.6	14.7	5.0	2.9	0.9	3.8
Power Req (MW)	6.3	0.0	12.5	0.0	2.3	0.0	0.9
Compression Ratio	1.3	N/A	1.6	N/A	1.4	N/A	1.2
T_{sct} (˚C)	3.0	1.0	1.0	10.0	2.0	5.0	10.0
T_{dis} (˚C)	24.0	1.0	35.0	10.0	32.0	5.0	31.0
T_{amb} (˚C)	2.0	2.0	2.0	2.0	2.0	2.0	3.0



LEGEND
- ● EXISTING RECEIPT POINTS
- ■ EXISTING DELIVERY POINTS
- ▲ EXISTING COMPRESSION
- — EXISTING PIPELINE (NGTL)
- ⧓ EXISITING CONTROL VALVE
- - - OTHER PIPELINE SYSTEMS

NOTE:
- NOT ALL EXISTING RECIPT POINTS, DELIVERY POINTS, INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERE
- FLOW AND FUEL IS @ STP (101.325 kPa AND 15° C)
- POWER IS AT SITE CONDITIONS
- COMPRESSOR CONDITIONS FOR COMPRESSION AT PAUL LAKE, SMOKY LAKE ‘A’, HANMORE LAKE ‘A’, AND BEHAN NOT SHOWN
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- Q, FLOW IS IN 10^6 m^3/d

2009/10 GAS YEAR
NORTH OF BENS LAKE DESIGN AREA
WITH MAXIMUM DELIVERIES TO THE NORTH & EAST PROJECT AREA
WINTER DESIGN WITH PROPOSED FACILITIES

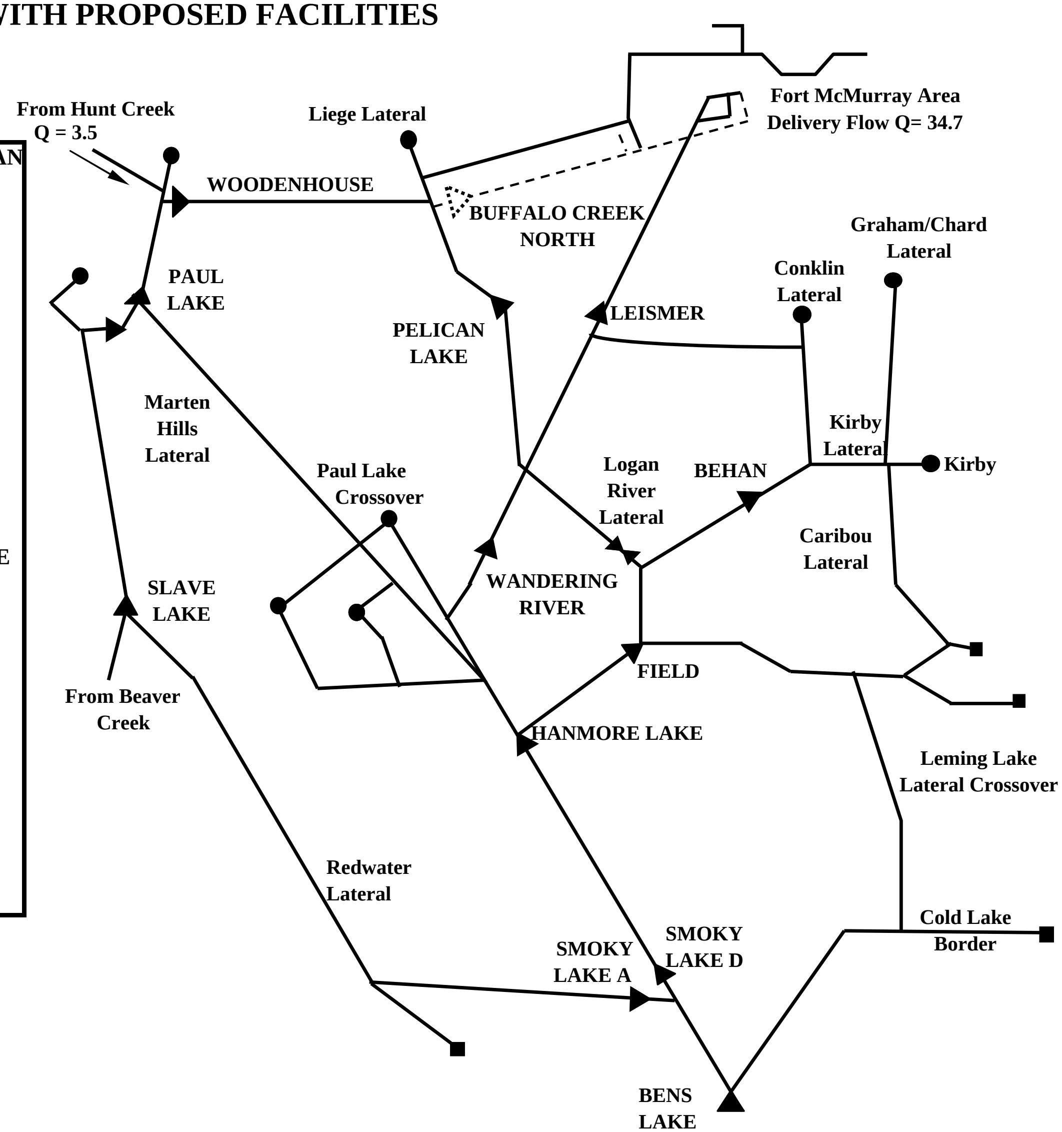
COMPRESSOR STATION SUMMARY

	FIELD LK	HANMORE LK B,C	BENS LK A	BENS LK B	BENS LK C,D	SMOKY LK D	PELICAN LK
P_{sct}(kPa$_g$)	7102	7830	6969	6969	6962	7384	7029
P_{dis}(kPa$_g$)	8271	8271	6969	7860	7894	8276	9930
Flow ($10^6 m^3$/d)	13.5	22.6	0.0	0.0	36.9	35.8	4.7
Fuel ($10^3 m^3$/d)	31.6	26.0	0.0	0.0	64.1	73.0	21.9
Power Avail (MW)	6.3	6.6	3.5	3.2	7.4	15.2	3.2
Power Req (MW)	2.9	1.1	0.0	0.0	7.4	5.6	2.2
Compression Ratio	1.2	1.1	N/A	N/A	1.1	1.1	1.4
T_{sct} (˚C)	4.5	13.0	5.0	5.0	13.0	11.0	5.0
T_{dis} (˚C)	17.5	18.5	11.0	5.0	25.0	21.0	34.0
T_{amb} (˚C)	2.0	2.0	2.0	2.0	2.0	2.0	2.0

	PAUL LK B2	WOODENHOUSE #1	WOODENHOUSE #2	BUFFALO NORTH	WAND. RIVER	LEISMER	SLAVE LK
P_{sct}(kPa$_g$)	6716	5530	5526	8794	6367	7185	5000
P_{dis}(kPa$_g$)	8800	9000	9000	9504	9650	7184	6179
Flow ($10^6 m^3$/d)	22.8	10.5	15.8	39.6	5.8	1.7	2.8
Fuel ($10^3 m^3$/d)	60.9	55.2	72.0	20.6	36.2	0.0	10.2
Power Avail (MW)	14.5	10.6	14.7	5.0	2.9	0.9	3.8
Power Req (MW)	7.5	6.4	9.8	1.8	3.3	0.0	0.9
Compression Ratio	1.3	1.6	1.6	1.1	1.5	N/A	1.2
T_{sct} (˚C)	6.0	2.0	1.0	13.0	1.0	5.0	10.0
T_{dis} (˚C)	26.0	39.0	39.0	22.9	36.0	5.0	31.0
T_{amb} (˚C)	2.0	2.0	2.0	2.0	2.0	2.0	3.0

LEGEND
- ● EXISTING RECEIPT POINTS
- ■ EXISTING DELIVERY POINTS
- ▲ EXISTING COMPRESSION
- EXISTING PIPELINE (NGTL)
- EXISITING CONTROL VALVE
- OTHER PIPELINE SYSTEMS

NOTE:
- NOT ALL EXISTING RECIPT POINTS, DELIVERY POINTS, INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERE
- FLOW AND FUEL IS @ STP (101.325 kPa AND 15° C)
- POWER IS AT SITE CONDITIONS
- COMPRESSOR CONDITIONS FOR COMPRESSION AT PAUL LAKE, SMOKY LAKE 'A', HANMORE LAKE 'A', AND BEHAN NOT SHOWN
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- Q, FLOW IS IN 10^6 m^3/d

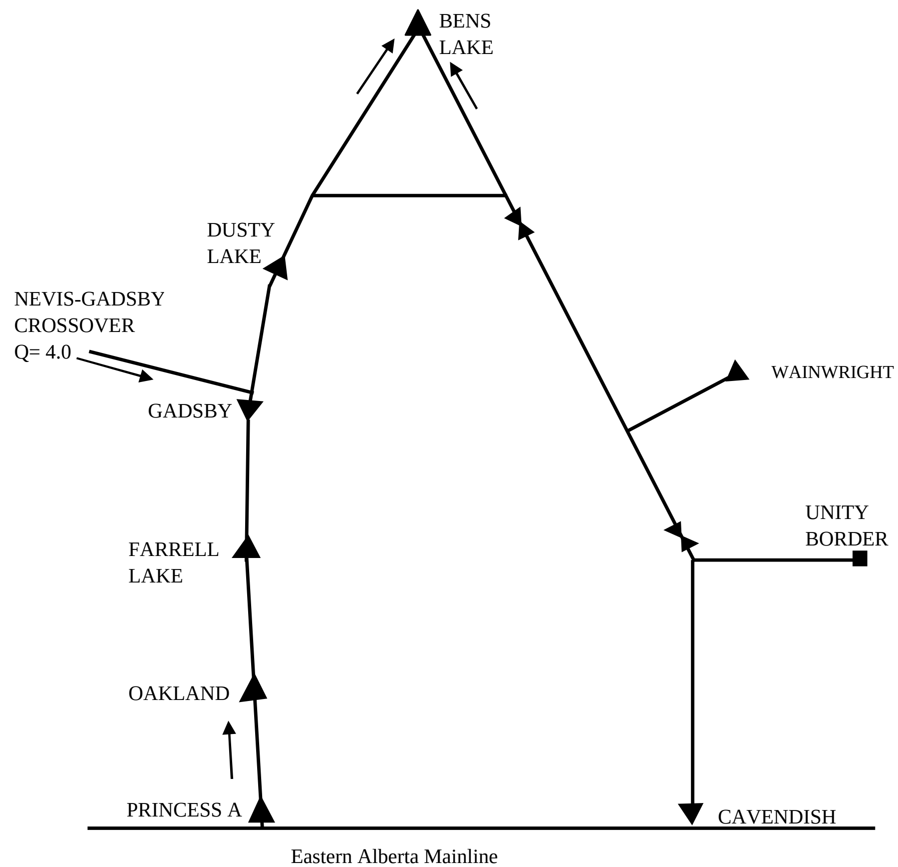


2009/10 GAS YEAR
SOUTH OF BENS LAKE DESIGN AREA
WITH MAXIMUM DELIVERIES TO THE NORTH & EAST PROJECT AREA
WINTER CAPABILITY WITHOUT PROPOSED FACILITIES

COMPRESSOR STATION SUMMARY

	DUSTY LAKE	GADSBY	FARRELL LAKE	OAKLAND
$P_{sct}(kPa_g)$	5547	6993	5292	5053
$P_{dis}(kPa_g)$	8227	6992	7797	6128
Flow ($10^6 m^3/d$)	41.3	-37.2	35.4	34.7
Fuel ($10^3 m^3/d$)	177.6	0.0	163.2	82.7
Power Avail (MW)	29.0	28.8	27.6	13.8
Power Req (MW)	21.6	0.0	19.0	12.2
Compression Ratio	1.5	N/A	1.5	1.2
T_{sct} (˚C)	9.0	5.0	9.0	7.0
T_{dis} (˚C)	41.0	5.0	42.0	28.0
T_{amb} (˚C)	2.0	3.0	4.0	4.0

	PRINCESS A	CAVENDISH
$P_{sct}(kPa_g)$	5000	4399
$P_{dis}(kPa_g)$	5695	5045
Flow ($10^6 m^3/d$)	29.6	4.0
Fuel ($10^3 m^3/d$)	29.8	7.1
Power Avail (MW)	17.0	4.5
Power Req (MW)	6.2	0.8
Compression Ratio	1.1	1.1
T_{sct} (˚C)	5.6	4.0
T_{dis} (˚C)	23.0	17.0
T_{amb} (˚C)	6.0	5.0



LEGEND
- ■ EXISTING DELIVERY POINTS
- ▲ EXISTING COMPRESSION
- — EXISTING PIPELINE (NGTL)
- ⧓ EXISTING CONTROL VALVE

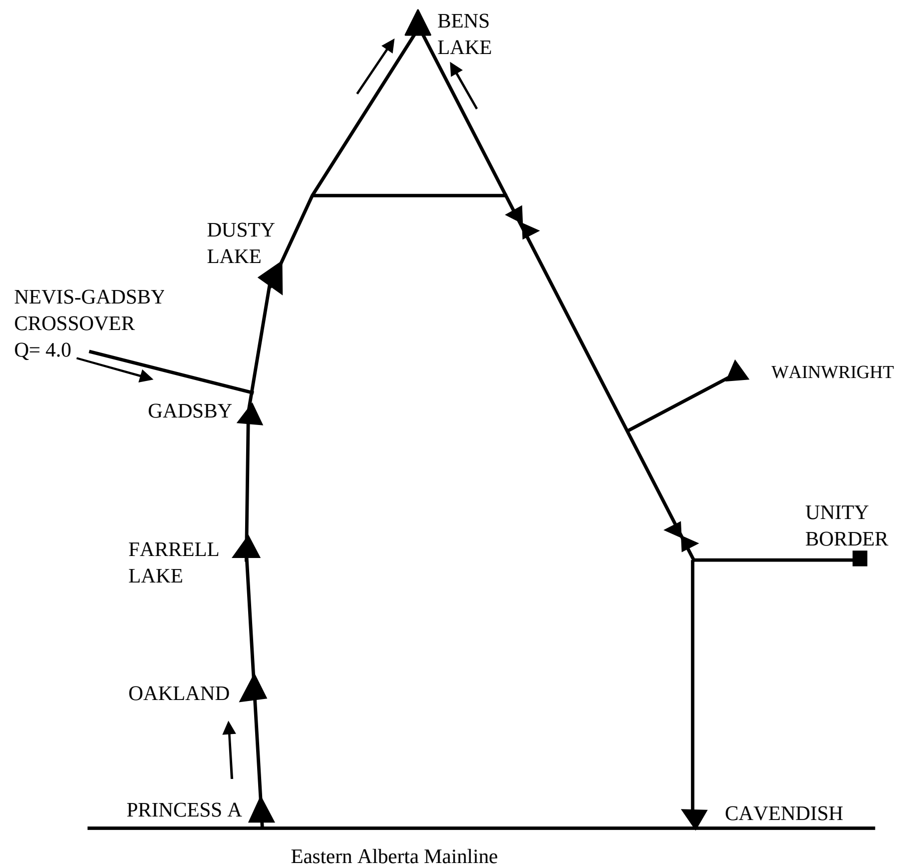
NOTE:
- NOT ALL EXISTING RECIPT POINTS, DELIVERY POINTS, INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERE
- FLOW AND FUEL @ STP (101.325 kPa AND 15° C)
- POWER IS AT SITE CONDITIONS
- COMPRESSOR CONDITIONS FOR LATERAL COMPRESSION AT WAINWRIGHT NOT SHOWN
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- Q, FLOW IS IN 10^6 m^3/d

2009/10 GAS YEAR
SOUTH OF BENS LAKE DESIGN AREA
WITH MAXIMUM DELIVERIES TO THE NORTH & EAST PROJECT AREA
WINTER DESIGN WITH PROPOSED FACILITIES

COMPRESSOR STATION SUMMARY

	DUSTY LAKE	GADSBY	FARRELL LAKE	OAKLAND
P_{sct}(kPa$_g$)	6871	6229	5033	4828
P_{dis}(kPa$_g$)	8364	8450	7389	6147
Flow ($10^6 m^3$/d)	46.0	41.8	40.7	39.7
Fuel ($10^3 m^3$/d)	130.0	161.6	174.0	90.4
Power Avail (MW)	29.0	28.8	27.6	13.8
Power Req (MW)	12.4	18.7	21.3	13.8
Compression Ratio	1.2	1.4	1.5	1.3
T_{sct} (˚C)	21.0	19.0	9.0	7.0
T_{dis} (˚C)	38.0	45.0	41.0	28.0
T_{amb} (˚C)	2.0	3.0	4.0	4.0

	PRINCESS A	CAVENDISH
P_{sct}(kPa$_g$)	5000	4399
P_{dis}(kPa$_g$)	5695	5045
Flow ($10^6 m^3$/d)	34.6	4.0
Fuel ($10^3 m^3$/d)	33.9	7.1
Power Avail (MW)	17.0	4.5
Power Req (MW)	7.2	0.8
Compression Ratio	1.1	1.1
T_{sct} (˚C)	5.6	4.0
T_{dis} (˚C)	23.0	17.0
T_{amb} (˚C)	6.0	5.0



LEGEND
- ■ EXISTING DELIVERY POINTS
- ▲ EXISTING COMPRESSION
- — EXISTING PIPELINE (NGTL)
- ⋈ EXISTING CONTROL VALVE

NOTE:
- NOT ALL EXISTING RECIPT POINTS, DELIVERY POINTS, INTERCHANGES AND PIPELINE LOOPS ARE SHOWN HERE
- FLOW AND FUEL @ STP (101.325 kPa AND 15° C)
- POWER IS AT SITE CONDITIONS
- COMPRESSOR CONDITIONS FOR LATERAL COMPRESSION AT WAINWRIGHT NOT SHOWN
- COMPRESSION RATIO REPRESENTS UNIT CONDITIONS
- Q, FLOW IS IN 10^6 m^3/d

APPENDIX 4

PIPELINES

This Section describes facilities that were applied for following the issuance of the December 2007 Annual Plan which were not identified or were significantly revised from the facilities identified in the December 2007 Annual Plan.

METER STATIONS

This Section describes meter stations that were proposed from December 1, 2007 to November 30, 2008.

PIPELINES		
FACILITIES	**PROJECT SCOPE**	***FILED FOR CAPITAL COST**
Christina Lake North Sales Connection Pipeline	100 m of NPS 12 pipe	$0
Collicutt Connection Pipeline	1.33 km of NPS 8 pipe	$0
Lobstick Connection Pipeline	170 m of NPS 6 pipe	$0
Shady Oak Conneciton Pipeline	90 m of NPS 12 pipe	$0
Sherri Vail Connecion Pipeline	60 m of NPS 6 pipe	$0
Wembley South Sales Connection Pipeline	610 m of NPS 6 pipe	$0
Total		**$0**

NOTE: The capital costs for the Christina Lake North Sales and Wembley South Sales Connection pipelines were included in cost of the Meter Stations

* After a Contribution in Aid of Construction

METER STATIONS		
FACILITIES	**PROJECT SCOPE**	**CAPITAL COST**
Brainard Lake Meter Station	1212 ultrasonic bi-directional meter	$3,700,000
Canoe Lake Sales No. 2 Meter Station	2-1612 turbine meter	$1,800,000
Christina Lake North Sales Meter Station	2-1280 turbine meter	$1,970,000
Collicutt Sales Meter Station	2-640 turbine meter	$1,466,000
Egg Lake Sales Meter Station	2-860 turbine meter	$1,429,000
Hamburg Meter Station	type 440-2 meter	$1,142,000
Jackpine Creek Sales Meter Station	2-2016 ultrasonic meter	$5,600,000
Moorehead Sales Meter Station	2-1612 turbine meter	$1,880,000
Oldman Meter Station	type 660-2 meter	$1,006,000
Sherri Vail Meter Station	type 442 meter	$2,084,000
Wembley South Sales Meter Station	2-640 turbine meter	$1,400,000
Total		**$23,477,000**

Note: List as of November 30, 2008

APPENDIX 5

The Alberta System map is not included in this Annual Plan.

Upon completion of an updated map, estimated to be in Q1 2009, a copy can be mailed on request by calling the Customer Service Call Centre at (403) 920-PIPE (7473) and will be accessible on TransCanada's Web site at:
http://www.transcanada.com/Alberta/info_postings/system_map.html