Alberta NGL Extraction Conventions

Prepared for:

EUB Inquiry into NGL Extraction Matters Application No. 1513726

Calgary, Alberta

November 2007

25th Anniversary
ziff
ENERGY GROUP
Global Energy Advisors
1982-2007

07GC-2020-05

1117 Macleod Trail S.E. Calgary, Alberta T2G 2M8
Tel: (403) 234-4299 Fax: (403) 261-4631
E-mail: bill.gwozd@ziffenergy.com
Toll Free 1-800-853-6252 ext.299

4295 San Felipe, Suite 350 Houston, Texas 77027
Tel: (713) 627-8282 Fax: (713) 627-9034
E-mail: paul.ziff@ziffenergy.com
Toll Free 1-888-736-5780

RESTRICTIONS

ALBERTA NGL EXTRACTION CONVENTIONS

TABLE OF CONTENTS

Section **Page**

1. INTRODUCTION

In June 2007, the Alberta Energy and Utilities Board ("EUB" or "Board") made a request for proposals ("RFP") for an expert report on issues related to an Inquiry into the Review of Alberta Natural Gas Liquid ("NGL") Extraction Conventions, EUB Application Number 1513726 (the "Inquiry"). Appendix 1 includes a copy of the RFP. Ziff Energy Group responded to the RFP and was selected as the expert. The deliverables of the RFP include:

1. Review of existing NGL contraction conventions, related tariffs and practices on regulated Alberta pipelines including NGTL, ATCO Pipelines and AltaGas Utilities Inc., as well as proposed conventions and practices for the proposed Aux Sable Canada Ltd. North Sable Extraction Plant –Fort Saskatchewan.

2. Analysis of decisions or approaches used by other relevant jurisdictions for NGL recovery from main transmission pipelines.

3. Review of reserve, supply and demand forecasts of natural gas and NGLs provided by Inquiry participants ("Participants"), to provide the Board a comprehensive view of 1, 10 and 20 year forecasts of Alberta NGL supply and demand by component. The consultant is to comment on forecasts provided by participants, identify omissions or inappropriate assumptions, and supplement these forecasts to address gaps and concerns.

4. Review of evidence provided by the Participants to submit information requests (IRs) to provide greater clarity, understanding and to address information gaps.

5. Analysis of each Participant's direct evidence, information responses and rebuttal evidence, including comments on strengths and weaknesses of each of the Participant's positions where the Participant's evidence is in significant conflict.

6. Identification and assessment of one or more possible alternative approaches or modifications to those proposed by the Participants to address the matters before the Inquiry and that meet the overall Alberta public interest. The consultant is to assess the benefits, limitations, and market impacts of the alternatives.

7. Prepare and submit a report which includes the preceding items, respond to IRs from Participants on the report, and appear at the Inquiry for cross-examination by the Participants.

49 parties registered as interested parties to the Inquiry with almost all indicating they expected to be active participants. The EUB provided a procedural schedule and final list of issues to be addressed in the Inquiry in correspondence to the interested parties dated July 6, 2007. Appendix 2 provides a summary of Ziff Energy's understanding of participant's comments provided in their letters of interest.

This page intentionally left blank.

2. EXECUTIVE SUMMARY

2.1 NGL Extraction Conventions on Alberta Pipelines versus Other Jurisdictions

Ziff Energy reviewed NGL extraction conventions on regulated Alberta pipelines, in other provinces, and in the United States with respect to how NGL rights are determined, administered, and reflected in the tariffs of regulated transmission pipelines. From comparing Alberta to other jurisdictions, Ziff Energy notes that Alberta's NGL extraction conventions and straddle plant system are unique in that:

- most of the gas in the province is processed at field plants and then reprocessed at straddle plants located on the Atco Pipelines and NGTL systems

- almost all gas leaving the province moves on the NGTL transmission system and through the border straddle plants before being exported

- NGTL has a two part toll with separate rates for receipt and delivery, with a major natural gas trading point (NIT) notionally in the middle of the system (after the receipt toll has been paid but before the gas is delivered to a market and the delivery toll paid). This leads to varying views as to appropriate NGL extraction rights and extraction conventions[1].

There is only one other straddle plant in Canada, the Younger plant near Taylor, British Columbia, operated by Taylor NGL Limited Partnership. This plant is not regulated and extraction conventions/NGL rights are determined in commercial arrangements between the shippers delivering gas to the plant and the plant operator.

In the United States, the only straddle plants Ziff Energy is aware of are located in the Gulf Coast area near the shoreline. Offshore transmission lines move gas from marine production platforms in the Gulf to straddle plants on the shoreline. These straddle plants are not regulated and processing arrangements are determined between the owners of the NGLs and the straddle plants. The regulated pipelines that transport the gas to the plants do not appear to take an active role in determining how NGLs are allocated among shippers. Ziff Energy assumes that the common stream operators of the offshore production platforms determine natural gas and NGL allocations, and provide these allocations to the straddle plants/shippers/pipeline to facilitate this. As a result, processing and NGL extraction arrangements and conventions are determined between the shippers and straddle plants, with the regulated pipelines facilitating movement of the gas and entrained NGLs from the field to the plant. Disputes dealing with extraction rights are determined by the courts.

[1] as the gas moves in a common stream on NGTL, ownership of the gas can change numerous times via NIT, parties have different opinions on whether the NIT price reflects the value of extraction rights, and different parties hold receipt and delivery service on NGTL

Table 1 summaries tariff provisions related to NGL extraction rights for Alberta gas pipelines.

Table 1
Provisions in Alberta Pipeline Tariffs Related to NGL Extraction Rights

Pipeline	Pipeline Control of Gas	Title to Natural Gas shipped	Pipeline Gas Delivery Commitment	Title to NGLs in Common Stream	Other Related Provisions
Alliance Pipelines	Alliance deemed to be in possession and control of gas being shipped	Not specific, but tariffs appear to support that shipper retains title (alliance allows Title Transfers)	Energy equivalent amount to that provided by shipper at receipt point, net of fuel requirement	Shipper gives Alliance (or its designate, which is Aux Sable) the right to extract NGLs in return for an energy equivalent quantity of gas at delivery point	
AltaGas Utilities	Gas being shipped is under exclusive control of AltaGas	shipper retains title	Energy equivalent amount to that provided by customer at receipt point, net of unaccounted for gas	AltaGas retains title to any hydrocarbons removed from common stream during shipping	
ATCO Pipelines	Gas being shipped is under exclusive control of ATCO	shipper retains title	Quantity of gas tendered for transportation (net of unaccounted for gas)	ATCO retains title to any hydrocarbons removed from common stream during shipping	Rate SPD covers delivery of gas to straddle plants to makeup energy removed at plant
NGTL	NGTL deemed to be in custody and control of gas shipped	Not specific but tariff provisions appear to support that shipper retains title (NGTL allows Title Transfers)	Energy equivalent quantity to that provided by customer at receipt point, net of gas used, lost, & variance	Not specific in tariffs although NGTL recognize current convention under which export shippers retain title to NGLs	Rate FT-X covers delivery of gas to straddle plant and return of stripped gas at plant outlet
Foothills Pipelines	Foothills deemed to be in custody and control of gas shipped	remains with shipper	Energy equivalent quantity to that provided by shipper at receipt point, net of fuel, & variance	Not specific in tariffs	

From review of the various Alberta pipeline tariffs:

- all of the pipeline companies maintain control of the gas being shipped on their systems, and although not clear in all pipeline's tariffs, Ziff Energy believes that the shipper retains title to the gas being shipped on all of these pipelines.
- rights to NGLs in the common stream vary by pipeline, with AltaGas and ATCO both retaining title to NGLs extracted on their systems during shipping of the gas. ATCO transfers these rights to extraction plants on their system under rate SPD. Alliance's tariffs are the most specific, giving Alliance's designate (Aux Sable) the right to all NGLs in the shipper's gas, with an energy equivalent quantity of gas returned to the shipper at the delivery point. NGTLs tariffs appear silent on NGL extraction rights, although the current convention recognized by NGTL is that the export shippers retain NGL extraction rights. NGTL facilitates gas delivery to extraction plants under rate FT-X.
- Foothills do not have anything in their tariff related to NGL extraction rights. Zones 6 and 7 are connected to the Empress and Cochrane straddle plants and as NGTL holds 100% of this capacity to provide transportation services to its shippers, any related extraction rights would flow to export shippers via the NGTL convention.

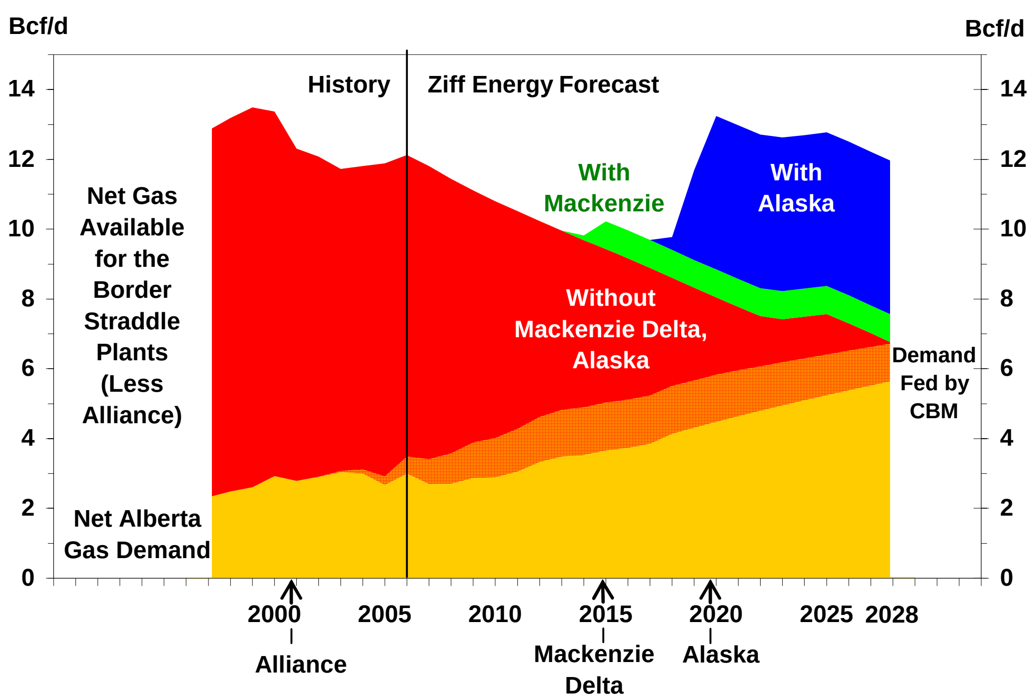
2.2 Natural Gas Outlook

The gas outlook analyses Alberta natural gas reserves, supply, and demand to 2028 to determine gas supplies available for processing. Gas reserves assessed include reserves from economic conventional gas, tight gas, CBM, shale gas, and reserves that may be transported into Alberta in the future (Mackenzie Delta and Alaska). Gas supply forecasts reflect new gas well completions, productivity, and decline rates; and include volumes for tight gas, CBM, shale gas, and potential production from the Mackenzie Delta and Alaska flowing into the province. Growing gas demand within Alberta includes Ziff Energy's analysis of gas demand for residential, commercial, power, industrial, pipeline/lease fuel, and for oil sands.

The report provides major assumptions, graphical outlooks (by year) plus tabular summaries of the data utilised in the charts.

Overall, Ziff Energy's assessment is that Alberta gas supply production is declining and coupled with growing Alberta gas demand driven by oilsands growth, natural gas available for processing and NGL production will decline. Figure 1[2] shows the total gas supply by source (Alberta, Mackenzie, and Alaska), and the Alberta gas demand fed by that supply (including the portion of demand assumed to be fed by growing CBM supply). The portion in red is the amount of gas available to the border straddle plants after Alberta demand is met, and is forecast to decline to zero by 2028 if Alaska and Mackenzie do not flow.

Figure 1
Net Natural Gas Supply Available for NGL Extraction



Source: Ziff Energy

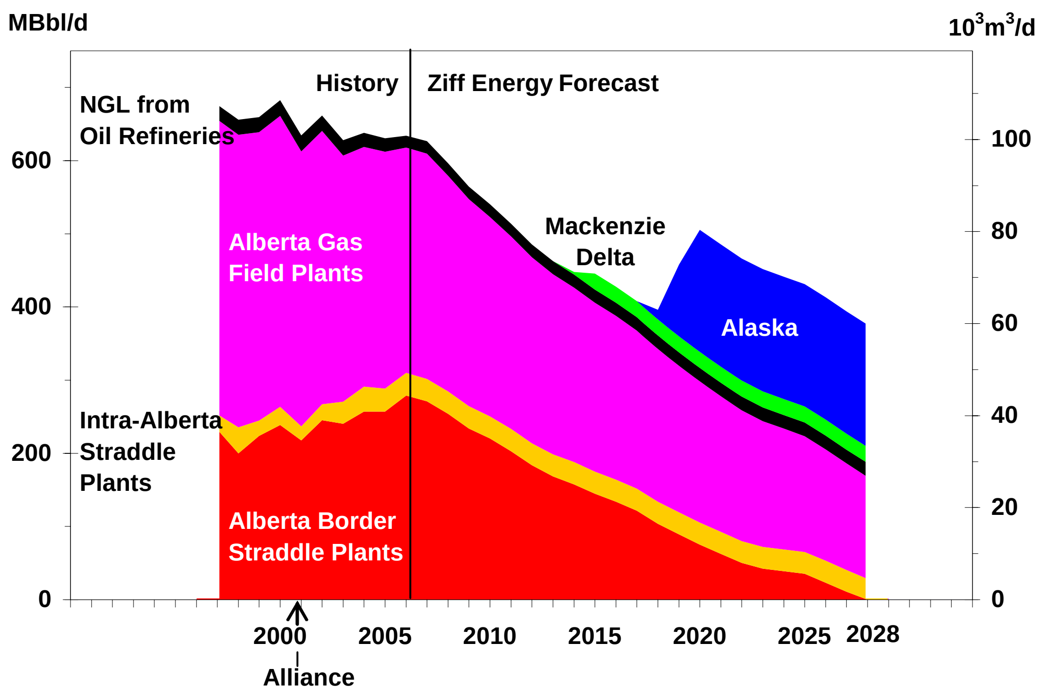
[2] copied from Figure 11 of the Ziff Energy Gas Reserve, Supply, Demand section

2.3 NGL Outlook

The NGL outlook analyses Alberta NGL reserves, supply, and demand to 2028. Key emphasis focuses upon NGL supply from 5 sources: Alberta straddle plants, intra-Alberta straddle plants, field gas processing plants, oil refineries, and future NGL supply from Mackenzie Delta and Alaska. To add clarity, Ziff Energy illustrates NGL supply by source and by composition (ethane, propane, butane, pentanes plus, and NGL mix). Tabular data for each chart and major assumptions are outlined and explained.

Figure 2[3] shows the declining NGL supply from the various sources.

Figure 2
Alberta NGL Production Outlook by Source to 2028



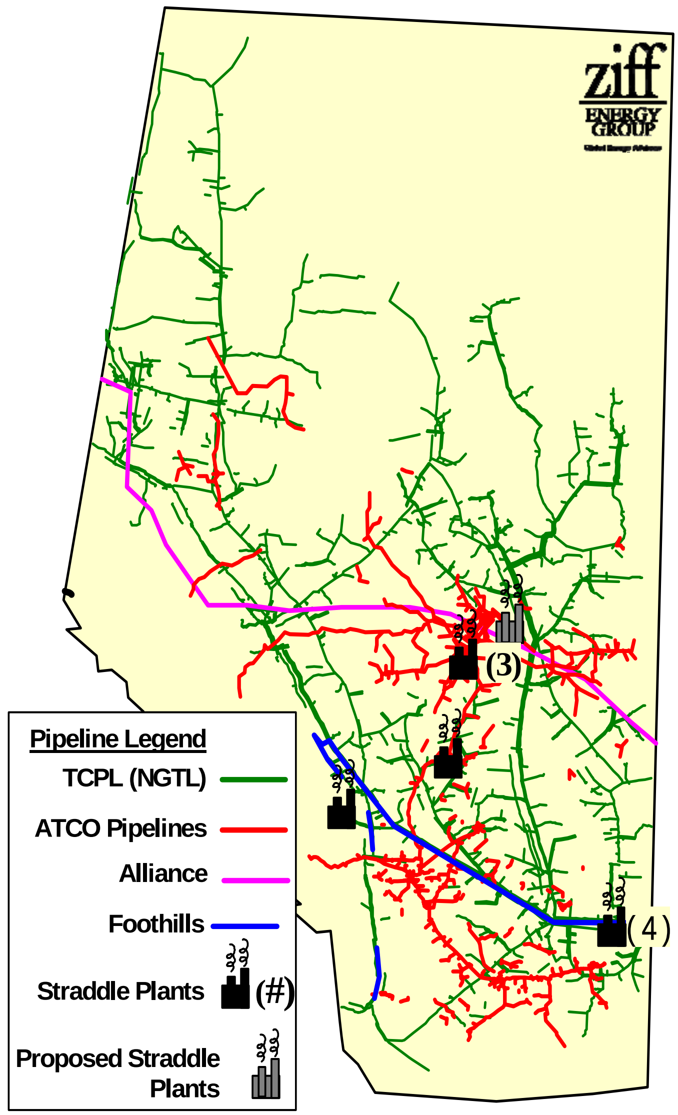
Source: Ziff Energy and AEUB

[3] copied from Figure 1 of the Ziff Energy NGL Reserve, Supply, Demand section

3. EXISTING NGL EXTRACTION CONVENTIONS ON ALBERTA PIPELINES

This section describes existing Natural Gas Liquids (NGL) extraction conventions on major Alberta gas pipelines. Figure 1 shows a map of the major regulated pipelines in Alberta for which Ziff Energy reviewed NGL extraction conventions:

Figure 1
Major Alberta Natural Gas Pipelines and Extraction Plants



- NGTL is the main Alberta transmission pipeline transporting producer gas from 976 receipt points[4] to Alberta markets and export points. 6 of the 9 straddle plants are on the NGTL system, with 5 processing most of the gas destined for export and 1 (Joffre Extraction Plant) processing gas to the Nova Chemicals petrochemical plant near Joffre

- ATCO Pipelines is a transmission system transporting on system producer gas and NGTL sourced gas to end-use customers on their pipeline and on the Atco Gas system, the largest LDC in Alberta. There are 3 straddle plants on those systems

- AltaGas Utilities. serves various towns and rural communities and have producer gas supplies on the system and no extraction plants

- Foothills Pipelines is integrated with the NGTL system in Alberta and delivers gas to export markets via Foothills BC and Foothills Saskatchewan

- Alliance Pipelines transports NGL rich gas from Alberta and B.C. to the Chicago area. Aux Sable Canada have the right to NGLs in the Alliance common stream[5] and plan to build a straddle plant on the Alliance Pipeline near Fort Saskatchewan to remove ethane.

[4] source: NGTL December 2006 Annual Plan, page 2-3
[5] see discussion in following section on these rights

3.1 NOVA Gas Transmission Ltd. (“NGTL”)

3.1.1 Provisions in NGTL Tariffs Related to NGL Extraction

Ziff Energy has reviewed NGTL’s tariffs to identify provisions related to NGL extraction. NGTL’s General Terms and Conditions indicate NGTL is deemed to be in the custody and control of a Customer’s gas while it remains on the NGTL system[6], and obligate NGTL to deliver an energy equivalent quantity of gas to Customer based on the gas provided by the Customer at receipt points, net of Customers share of Gas Used, Gas Lost, and Measurement Variance[7].

Ziff Energy could not find specific provisions in NGTL’s tariff that confirms title to gas or entrained NGLs remains with the Customer (shipper), nor provisions on tracking and return of NGLs to Customers at the delivery point. Despite this, Ziff Energy believes the provisions described above support that the shipper retains title to the Gas, given the provisions on custody and control. In addition, NGTL offers Title Transfer services under which shippers can transfer their gas inventory to other shippers (shippers would need to have title to transfer title), and NGTL shippers (not NGTL) make arrangements with the straddle plants for NGL rights[8].

NGTL rate schedule FT-X titled “Firm Transportation – Extraction” provides for delivery of a Customer’s gas by NGTL to an Extraction Plant[9], and receipt of gas by NGTL for the Customer at the outlet of an Extraction Plant. This service appears to be available to any customer prepared to execute a Service Agreement and Rate Schedule FT-X, as well as a valid FCS Rate Schedule for related facilities.[10] Ziff Energy could not find any wording restricting FT-X service to export shippers, so presumably receipt shippers can hold FT-X service. Section 4 of the FT-X Service Agreement (and most NGTL Service Agreements for other rates) requires the Customer to provide NGTL assurances that it has the necessary arrangements with other parties (such as common stream operators, buyers /sellers, and extraction plant owners) to facilitate the service provided by NGTL under the rate schedule. This implies that Customers who wish to hold FT-X service would need to make commercial arrangements with an Extraction Plant.

3.1.2 Current NGTL NGL Extraction Convention

At present the NGTL convention is that only export shippers or parties designated by these shippers hold NGL extraction rights, and to Ziff Energy’s knowledge the extraction plants only contract with those shippers (or their designate) for those rights. The current convention is described in more detail in the TTFP NGL Extraction Convention Task Force report and the vast majority of the participants in the proceeding agree that the report provides a reasonable characterization of the convention.

---

[6] Paragraph 6.1 of NGTL General Terms and Conditions, provided in Appendix 4

[7] Appendix 4 provides excerpts from NGTL’s General Terms and Conditions, paragraphs 8.1 and 9.1.

[8] confirmed in the Natural Gas Liquid Extraction Convention Report, NGTL TTFP Resolution T2004-04

[9] Appendix 4 provides an excerpt of NGTL’s General Terms and Conditions, page 8 which defines Extraction Plants as a facility where Gas liquids are extracted, and which is connected to NGTL’s facilities

[10] Appendix 4 provides a copy of Rate Schedules FT-X , FCS and Service Agreements for these rates

3.1.3 NGTL Design Policy with respect to NGL Recovery

From a cursory review of NGTL's annual plan, Ziff Energy could not find any design criteria related to maximizing NGL recoveries at extraction plants. NGTL's Annual Plan states that their facility design must meet two important objectives:

- provide fair and equitable service to customers requesting new firm transportation Service Agreements
- prudently size facilities to meet peak day firm transportation delivery requirements[11].

Their Annual Plan states:

> *"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. 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 cumulative present value cost of service ("CPVCOS")."*[12]

NGTL considers expected gas delivery requirements in their design, which includes new natural demand from the various gas markets in Alberta including gas liquids extraction plants.[13]

Ziff Energy notes that NGTL in its evidence and information responses indicated that options to route lean gas to intra Alberta markets and richer gas to straddle plants could be considered and included it its design criteria, if supported by its customers.

[11] Appendix 3 provides an excerpt of NGTL December 2006 Annual Plan, page 2-4
[12] Appendix 3 provides an excerpt of NGTL December 2006 Annual Plan, page 2-14
[13] Appendix 3 provides an excerpt of NGTL December 2006 Annual Plan, pages 2-31 to 2-32

3.2 ATCO Pipelines ("AP")

3.2.1 Provisions in Atco Pipeline's Tariffs Related to NGL Extraction

ATCO Pipeline's tariffs include provisions specifying AP maintains control of the shipper's gas on the AP system, do not acquire title to Gas transported under a transportation Agreement, but do retain title to hydrocarbon components that may be extracted from the gas stream as a result of commingling, exchanging or removal of such hydrocarbon components in the course of transporting the Gas[14].

AP's rates also include delivery service to straddle plants under Rate SPD, which applies to the total energy removed in the straddle plant. This rate appears to be available to any customer served off AP's Gas Pipeline system, and provides delivery service to those selling gas to the extraction plants to replace the energy removed from the gas stream. Article 7.1 of the SPD Transportation Agreement indicates that title to NGLs extracted at the straddle plant pass from AP to the Customer.[15]

Ziff Energy could find no other references to NGL rights or extraction conventions in AP's rates.

AP confirms in their evidence that:

- title to hydrocarbons removed on their system pass to AP
- AP permits third parties to construct and operate NGL extraction facilities on their system
- AP transfers the NGL rights to the straddle plant customer under Rate SPD
- straddle plant customers compensate Atco Pipelines for the extraction rights by payment of the SPD toll.

With respect to the last point, Ziff Energy notes that the SPD toll reflects AP's average system delivery cost, that the SPD service has the attributes of delivery service to other pipelines, and was not directly designed to reflect the value of the NGLs extracted.[16]

[14] Appendix 5 provides an excerpt of Atco Pipelines Transportation Service Regulations, Article 2.5
[15] provided in Atco Pipelines' August 28, 2007 submission
[16] based on Atco responses to BR-AP-2(d), Ziff-AP-7.2 and Ziff-AP-7.4

3.3 AltaGas Utilities

AltaGas Utilities is the second largest LDC in Alberta after ATCO Gas and serves 64,000 customers in 76 municipal and rural franchise areas[17]. Figure 2 shows the rural and municipal areas served.

Figure 2
AltaGas Utilities Franchise Areas

Source: AltaGas

About 36 MMcf/d of producer gas flowed on to the AltaGas system in 2006 and 2007 of which 85% of the gas came from four receipt points.[18] The remainder of AltaGas gas comes from the NGTL, ATCO Pipelines, and other distribution systems. There are no natural gas processing plants or

[17] provided by AltaGas
[18] based on AltaGas response to BR-AUI-1(a), about 14 million GJ/yr of gas comes from on-system supplies (14,000,000 GJ/365/1054 GJ/MMcf/d = 36 MMcf/d)

straddle plants on their transmission lines. Minor amounts of NGLs are removed at separators on the system for quality control purposes.[19]

AltaGas current and proposed transportation tariffs give AltaGas control of the shipper's gas on their system[20], although they do not acquire any title or interest in the Gas transported.[21] While this appears to suggest that shippers retain title to their gas, AltaGas current Transportation Service Regulations[22] and proposed Transportation Service Regulations[23] contain a section on Gas Commingling which states AltaGas retains title to hydrocarbon components removed from the gas stream in the course of transporting the gas. This is similar to ATCO Pipeline's rates and suggests that shippers have transferred their NGL extraction rights to AltaGas. In any case, such rights likely have limited value given the small quantities of gas transported on the AltaGas system and the fact it is not likely possible to process all on system supplies in one or even several straddle plants[18].

AltaGas commits to deliver to the shipper an amount of gas with equivalent energy to that provided by the shipper, net of Unaccounted For Gas[24], so to the extent NGLs are removed, AltaGas must makeup the energy difference.

[19] AltaGas response to BR-AUI-1(c) shows that the 4 largest sources represent 85% of the volumes, and only 57% (Barrhead and Westlock) may be able to be processed at one plant, assuming Barrhead and Westlock are connected to a common AltaGas pipeline

[20] Appendix 6 provides Article 2.2 of AltaGas' current Transportation Service Regulations, and Article 2.6 of AltaGas' proposed Transportation Service Regulations, AltaGas 2005/2006 General Rate Application, Phase 2

[21] Appendix 6 provides Article 2.1 of AltaGas' current Transportation Service Regulations, and Article 2.1 of AltaGas' proposed Transportation Service Regulations, AltaGas 2005/2006 General Rate Application, Phase 2

[22] Appendix 6 provides Article 2.4 of AltaGas' current Transportation Service Regulations

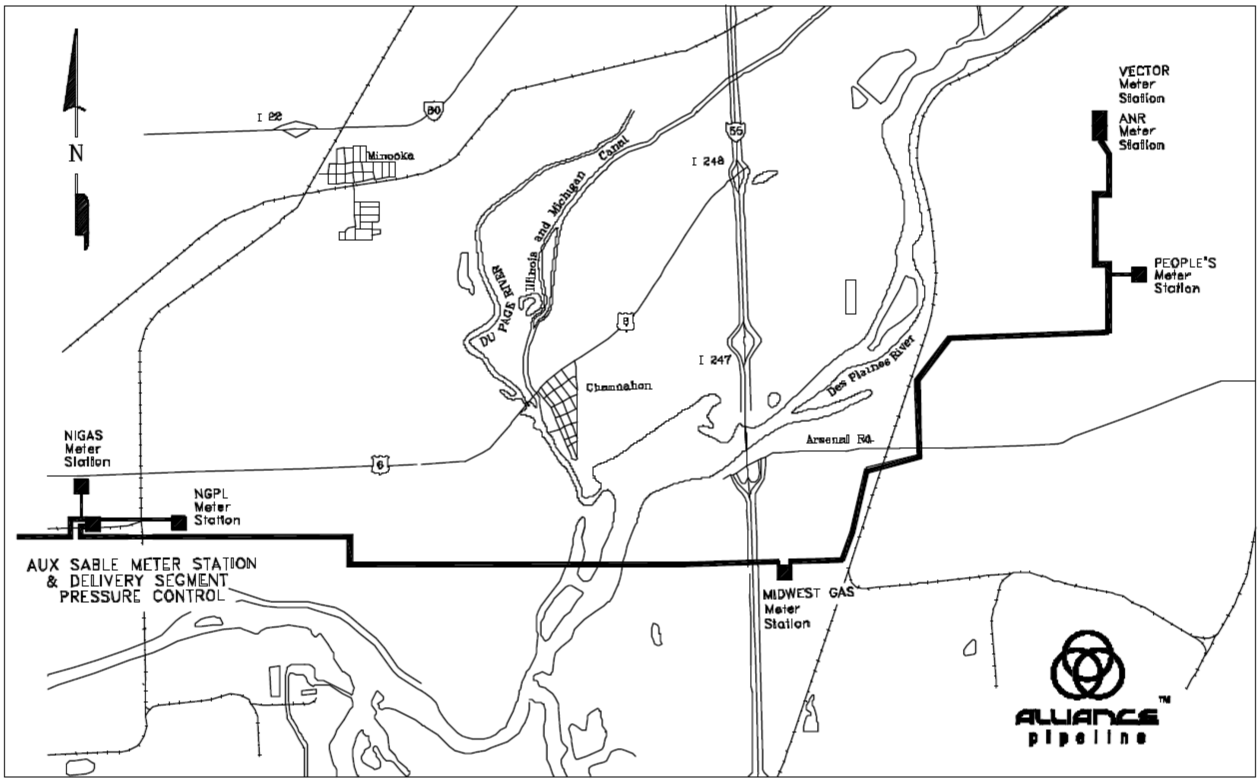
[23] Appendix 6 provides Article 2.8 of proposed Transportation Service Regulations, AltaGas 2005/2006 General Rate Application, Phase 2

[24] Appendix 6 provides Article 5.1 of AltaGas' current Transportation Service Regulations, and Article 5.1 of AltaGas' proposed Transportation Service Regulations, AltaGas 2005/2006 General Rate Application, Phase 2

3.4 Alliance Pipelines/Aux Sable Canada North Sable Extraction Plant

Alliance Pipelines ("Alliance") transports NGL rich gas from Alberta and British Columbia to Channahon, Illinois, near Chicago. This gas bypasses Alberta extraction plants. NGLs are removed at an NGL Extraction Plant at the end of the pipeline and owned by Aux Sable Liquid Products LP's (Aux Sable L.P.). Figure 3 shows the pipeline delivery points in the Chicago region.

Figure 3
Alliance Pipeline Delivery Points



Source: http://www.alliance-pipeline.com/inside.jsp?cid1=6&cid2=301&cid3=0

Under Alliance's tariffs, Alliance is deemed to be in possession and control of gas being transported on their system.[25] It is Ziff Energy's opinion that Alliance has the right to give a designated party (Aux Sable) the right to extract liquids from the shipper's commingled gas stream. In exchange for the NGLs removed, Alliance provides shippers an energy equivalent amount of natural gas at the U.S. delivery points[26]. This arrangement was agreed to by shippers as part of the initial commitments made to build the Alliance Pipeline, and approved by the NEB.

[25] Appendix 7 includes a copy of Article 18 of Alliance's General Terms and Conditions
[26] Appendix 7 includes a copy of Article 5 of Alliance Transportation Service Agreements for Firm Transportation and Interruptible Transportation

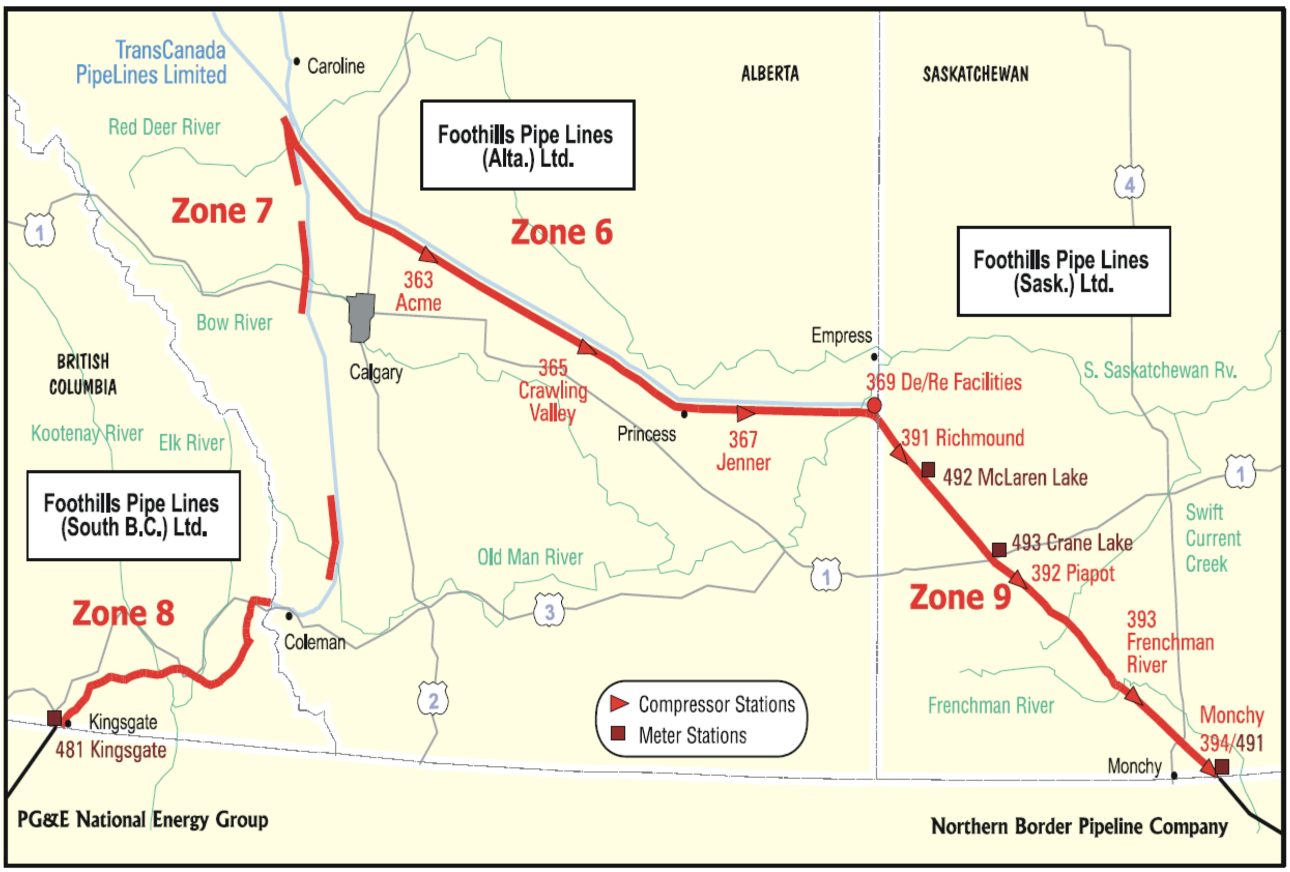
Aux Sable Canada plans to build a straddle plant near Fort Saskatchewan by 2010, which would remove ethane from the Alliance Pipeline[27]. Under this arrangement, Alliance plans to designate Aux Sable Canada as the party with the right to extract liquids at the plant.[28]

3.5 Foothills Pipelines

Foothills Pipe Lines, a subsidiary of TransCanada Pipelines, was originally built to transport Alaska gas through Alberta, BC, and Saskatchewan to downstream markets. Parts of the system (Zones 6 and 7) are integrated into the NGTL system. Figure 4 provides a map of the Foothills system which currently provides transmission service from Alberta to:

- Kingsgate, BC, to facilitate exports to the US Pacific Northwest/California via GTN
- Monchy Saskatchewan to facilitate exports to the US Midwest via Northern Border.

Figure 4
Foothills Pipeline System



Source: Foothills website

[27] Appendix 8 provides a Fact Sheet from Aux Sable Canada's website describing the project
[28] Alliance indicated in their June 15, 2007 intervention letter that their prevailing transportation service agreements are flexible enough to allow Alliance to give Aux Sable the right to extract NGLs at Fort Saskatchewan. From a cursory review of Alliance's tariffs, Ziff Energy agrees with Alliance's assessment

Under Foothills tariffs, Foothills does not acquire title to the shipper's gas, although Foothills is deemed to have custody and control of the gas on its system[29]. Foothills commits to deliver to the Customer an energy equivalent quantity of gas based on customer gas provided at receipt points, less Company Use Gas (fuel, measurement variance)[30]. Ziff Energy could not find any specific reference in these tariffs to rights to NGLs.

As Alaska gas deliveries have been delayed, NGTL has contracted 100% of the capacity on zones 6 and 7 to meet its Alberta customers' needs and rolled these costs into NGTL's toll. Zone 8 tolls are rolled into Foothills BC tolls and Zone 9 tolls are the tolls payable for service on Foothills Saskatchewan.

Foothills Zone 6 is connected to the three of the Empress straddle plants and Foothills Zone 7 is connected to the Cochrane straddle plant. NGTL have indicated that they do not hold extraction rights related to this capacity[31]. However, as this capacity is used and paid for by NGTL shippers, Ziff Energy assumes the related extraction rights are allocated to the NGTL export shippers under the current NGTL extraction convention.

NGL extraction rights would have little value to shippers on the Foothills BC and Saskatchewan systems, as gas is processed at the major Alberta straddle plants before it enters those systems.

3.6 Rural Gas Co-Ops and Municipally Owned Systems

These smaller natural gas distribution systems serve areas not otherwise served by ATCO and AltaGas Utilities. Most are members of the Federation of Alberta Gas Co-ops ("Federation"), which includes 59 rural gas co-ops, 19 towns and municipalities, 4 counties and 6 Native Bands[32]. Gas for these systems is primarily sourced by pipeline gas from the NGTL, ATCO Pipelines, and AltaGas Utilities' systems, although some may have producer wells tied directly to their systems.

The town of Medicine Hat, who are not members of the Federation, operate the largest municipally owned natural gas utility in Alberta. Some of their supply is sourced from their own natural gas wells in and adjacent to the town.

There are no straddle plants on these systems due to the small volumes, although some may remove small quantities of natural gas liquids for quality control. Ziff Energy's NGL forecasts do not reflect any volumes for these systems.

[29] Appendix 9 provides excerpts of Foothills Service Agreements FT, STFT, SGS and IT, Article 5
[30] Appendix 9 provides excerpts of Foothills Rate Schedule FT, section 7.2.2, and Rate Schedule STFT, section 7.2, Rate Schedule SGS, section 6.2.2, Rate Schedule IT, section 4.2.2
[31] response to Ziff-NGTL-1
[32] per Federation of Alberta Gas Co-ops website

This page intentionally left blank.

4. APPROACHES IN OTHER JURISDICTIONS

This section summarizes how NGL extraction rights are dealt with in other provinces and the United States.

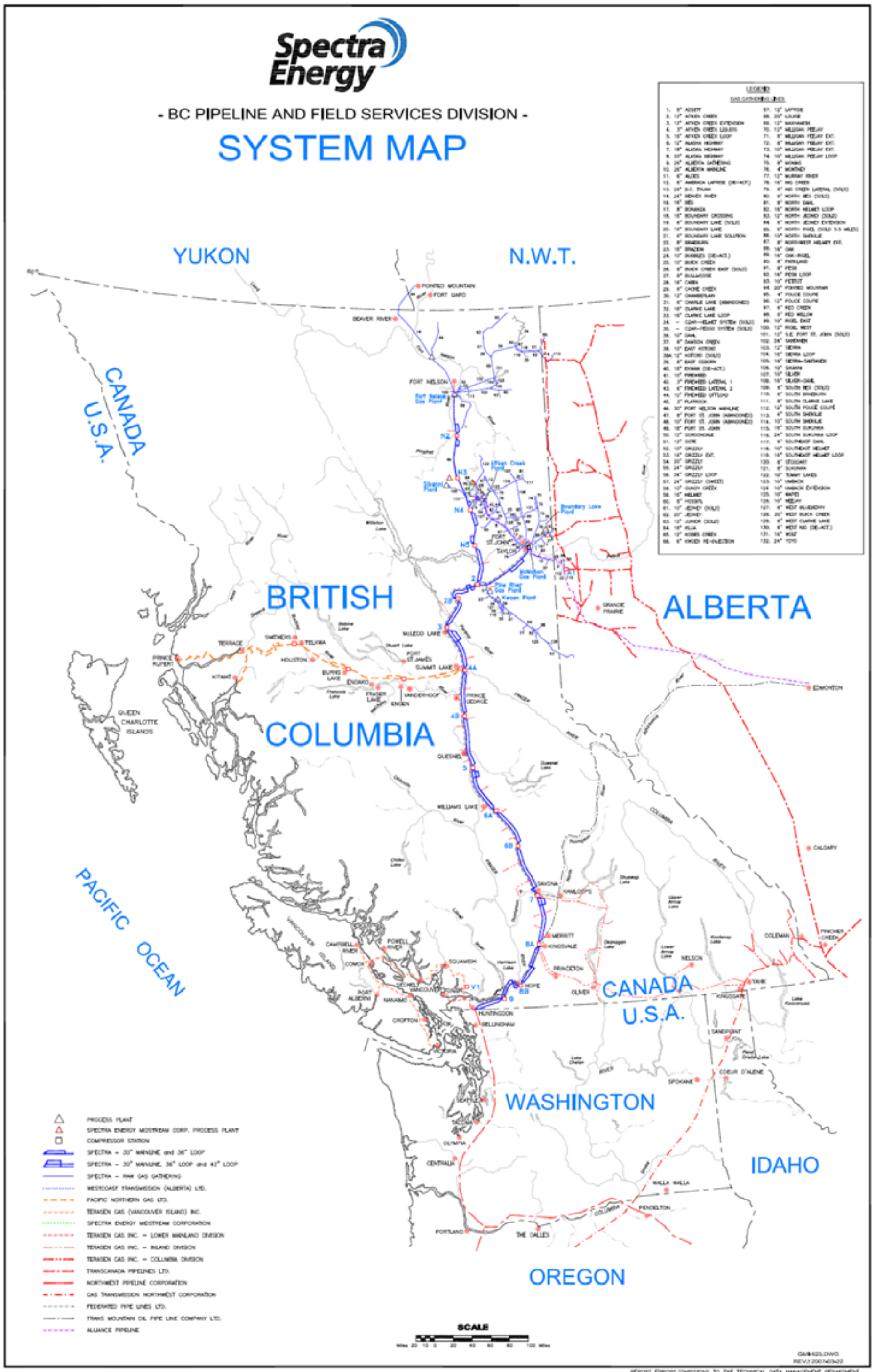
4.1 British Columbia (BC)

Gas produced in British Columbia flows into the Spectra Energy (Westcoast Energy) system. Westcoast provides gas gathering, processing, and transmission services to transport pipeline quality gas to markets in BC, Alberta, and U.S. markets. BC producers can build their own gathering and processing facilities or contract with third party processors for capacity, then flow their gas into the Westcoast transmission system or into non Westcoast gas gathering systems that flow into Alberta.

Figure 1 is a map of Spectra's B.C. system which provides regulated services under Westcoast Energy tolls regulated by the NEB. The system is divided into four toll zones:

- Zone 1 covers raw/sour gas gathering services in Northeast B.C.
- Zone 2 covers processing services of both wet and dry gas, primarily at gas plants known as McMahon, Pine River, Fort Nelson, and Sikanni
- Zones 3 and 4 cover transmission services of pipeline spec gas for delivery to Alberta, export markets and B.C. markets.

Figure 1
Westcoast System Map



Source: https://noms.wei-pipeline.com/weihtml/companyinfo/tariff/maps/pipeline_systems_map.pdf

Westcoast's tolls entitle shippers to natural gas liquids recovered from the shipper's gas at Westcoast's processing plants.[33] If shippers have their gas processed at upstream third party facilities, NGL rights would depend on their negotiated arrangements with those third parties.

The only straddle plant in B.C. is the Younger extraction plant located at Taylor, B.C.. Taylor NGL Limited Partnership operate the plant and own a majority share.[34] The Taylor plant is connected to Westcoast's system adjacent to the Westcoast McMahon plant and can deliver residue gas to Westcoast or to the Alliance system. As the Taylor plant processing fees are not regulated, rights to NGLs would be determined by negotiation between the shipper and the plant.

British Columbia does not have a specific policy on natural gas liquids rights or recovery of NGLs from transmission pipelines.[35] However in the BC Energy Plan released by the province on February, 27, 2007, Policy # 50 directs the development of business cases and promotion of opportunities for new refining and petrochemical investment in BC, given the numerous proposals for condensate and crude oil pipelines and LNG regasification terminals.[36] If such investment occurs, this could lead to increased BC NGL production and demand, and future opportunities for NGL producers to market and ship their NGL production.

[33] Article 16 of Westcoast Energy Inc. Terms and Conditions, provided in Appendix 10
[34] based on information on the Taylor NGL Limited Partnership website
[35] based on discussions with BC Ministry of Energy, Mr. Stirling Bates, Director, Regulatory Policy, Major Initiatives Branch, Oil and Gas Division
[36] Appendix 11 provides the text of Policy 50 titled "Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province."

4.2 Saskatchewan

TransGas is the major intra-provincial pipeline system in Saskatchewan. Figure 2 includes a map of the TransGas system showing receipt points where gas enters the system, and delivery points to Saskatchewan markets and to the TransCanada Pipelines system for export.

Natural gas produced in Saskatchewan is processed at 32 gas plants upstream of the TransGas system owned by parties other than TransGas[37]. Appendix 12 provides a list of Posted Heating Values[38] at various receipt points for August, 2007 on the TransGas system, showing that gas moving on the system is fairly lean, averaging 36.7 MJ/m3.

There is only one gas plant midstream on the TransGas transmission system, the Coleville Plant. The plant is owned and operated by TransGas and designed to handle 60 MMcf/d and 226 Bbl/d of ethane. TransGas custom processes gas from several producers behind the plant with rates and terms (including NGL rights) determined by negotiation.

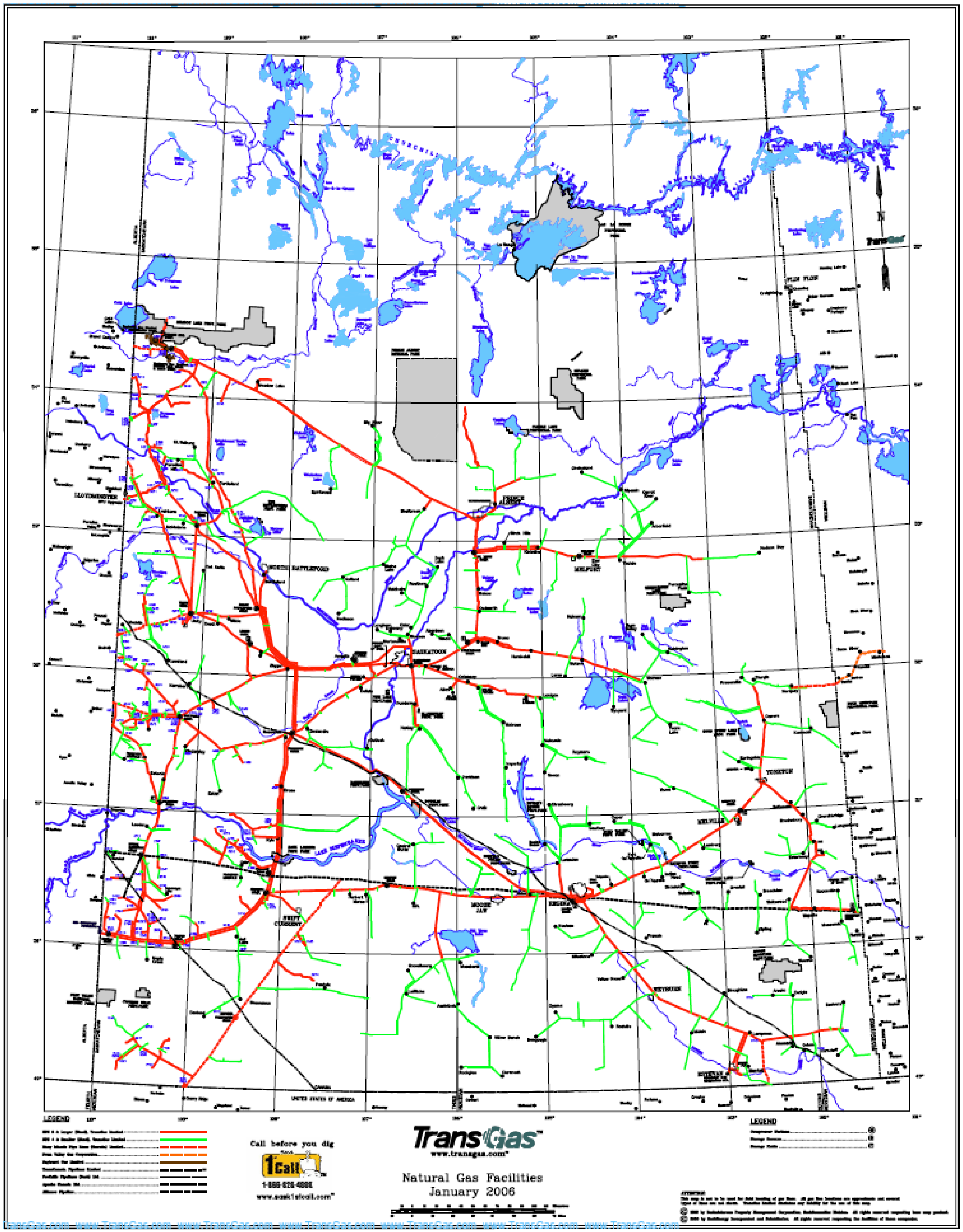
TransGas owns and operates the Many Islands Pipeline which is NEB regulated and allows TransGas to ship gas from Alberta and Montana into Saskatchewan.

There are no straddle plants on the Transgas or Many Islands systems, so NGL extraction rights are not an issue. TransGas' tariffs do not have specific provisions related to NGL extraction rights, although TransGas commits to ship and return equivalent energy amounts to shippers (net of Fuel Gas and Line Loss) pursuant to its tariff.[39]

From discussions with Saskatchewan Industry and Resources, there is not any specific policy dealing with NGL extraction rights.[40]

[37] source: The Canada Gas Plant Directory, Volume XI – 2007, excludes compressor and gas liquids storage plants
[38] TransGas' estimate of heating value for the current month at a Receipt Point or Delivery Point
[39] Article 2.1 of TransGas General Terms and Conditions, see Appendix 13
[40] discussion with Rick McLean, Senior Engineer, Engineering Services Branch on July 25, 2007

Figure 2
TransGas System



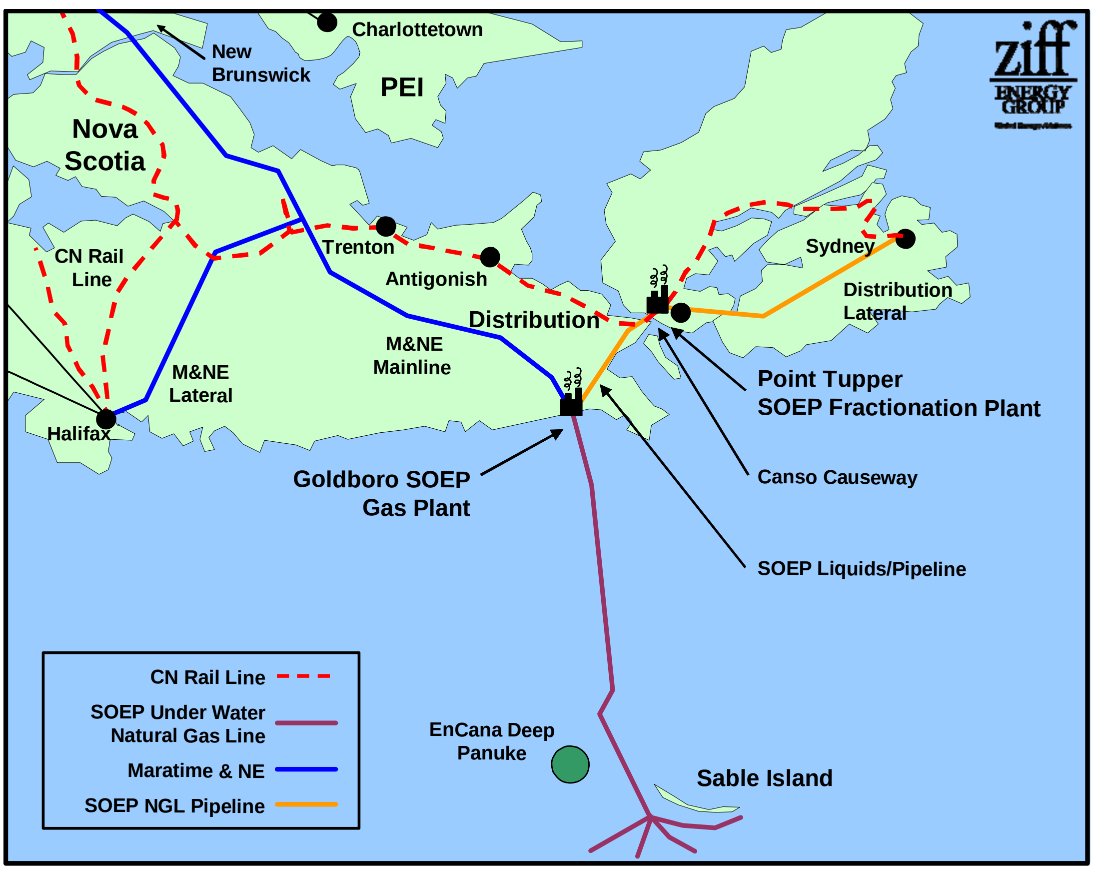
4.3 Manitoba

There is no natural gas production[41] nor gas plants in Manitoba, so NGL policy is not an issue.

4.4 Nova Scotia

Figure 3 shows a map of Nova Scotia pipelines and production areas. All natural gas production in Nova Scotia comes from the Sable Island area and is produced by a consortium company known as the Sable Offshore Energy Project ("SOEP"), owned by ExxonMobil (50.8%), Imperial Oil Ltd. (9.0%), Shell Canada Ltd. (31.3%), Pengrowth Corporation (8.4%) and Mosbacher Operating Ltd. (0.5%). Gas is transported via underwater pipeline to an onshore gas plant at Goldboro, Nova Scotia where NGLs are removed. About 400 MMcf/d of processed gas flows from the plant into the Maritime and Northeast Pipeline.[42]

Figure 3
Nova Scotia Natural Gas and NGL Pipelines



Source: Ziff Energy multiclient study, Beyond the Midwest, page 2-6

[41] per CAPP website
[42] SOEP website: http://www.soep.com/cgi-bin/getpage?pageid=1/0/0

As the same owners of the natural gas production have interests in the gas plant, NGL rights are likely dealt with in commercial arrangements among the owners. There are no other gas processing or straddle plants in the Maritime provinces[43].

Under the Nova Scotia Petroleum Resources Removal Permit Act, natural gas and NGLs cannot be removed from the province without a removal permit or unless the producer has a Petrochemical Supply Agreement with the province governing their commitments to the province related to their oil and gas production. The Nova Scotia government's objective is to provide access to NGLs for petrochemical manufacture in Nova Scotia, and have undertaken several studies to identify opportunities to develop a petrochemical industry. The SOEP Petrochemical Supply Agreement commits the Sable Island producers to remove NGLs in Nova Scotia, and to remove or allow third parties to remove ethane from their natural gas. Nova Scotia expects future offshore developers to sign similar agreements.[44]

[43] Canada Gas Plant Directory Volume XI – 2007, CD, shows Goldboro as the only plant in Nova Scotia

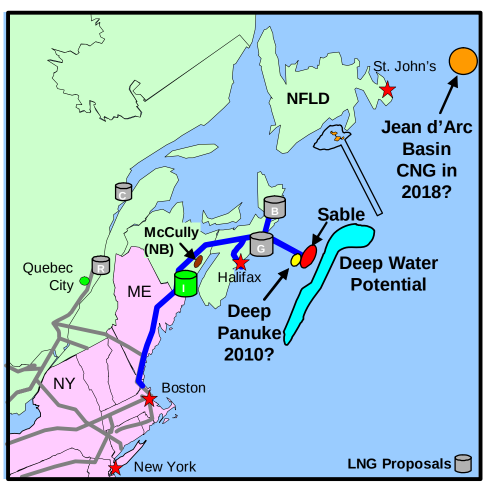
[44] Appendix 14 provides a press release and page 9 of Part II, Volume 2 of the Nova Scotia energy strategy report "Seizing the Opportunity" published by the Nova Scotia Government in December, 2001.

4.5 Newfoundland

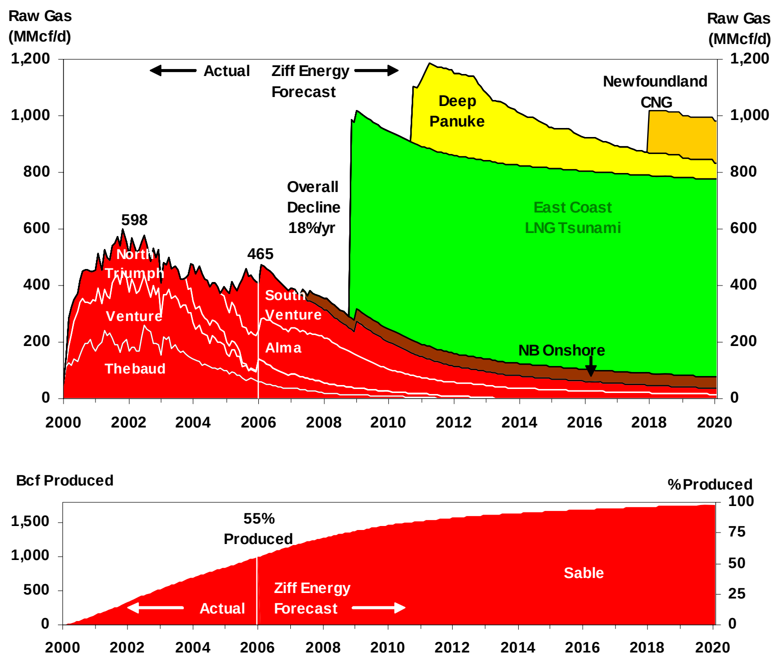
While natural gas is produced with oil in the offshore Newfoundland Jean d'Arc basin (Hibernia, Terra Nova, and White Rose), the gas is reinjected into the oil reservoirs, used as fuel or flared as there are no commercial means to bring the gas onshore. Ziff Energy forecasts commercial natural gas production in the Jean d'Arc basin by 2018, with gas delivered via Compressed Natural Gas ("CNG") to pipelines along the St. Lawrence River.

Newfoundland does not have policy on NGL rights, although is working on developing royalty policy for natural gas.[45] As there are a limited number of producers operating in the areas mentioned[46], Ziff Energy expects that NGL rights/processing arrangements would be determined by negotiations between the producers, owners of processing facilities, and the Newfoundland Government, similar to Nova Scotia. Figure 4 provides an overview of the East Coast gas production outlook.

Figure 4
East Coast Oil and Gas Production Areas



Jean d'Arc Basin: Hibernia, Terra Nova, Whiterose



Sable Cumulative Raw Gas Production

Source: Ziff Energy North American Natural Gas Strategy Retainer Service, Topic report Ziff Energy Canadian Natural Gas Exports to 2020, page 3

---

[45] based on discussion with Fred Allen, Director, Policy and Strategic Planning, Newfoundland Mines and Energy during 3rd quarter 2007. Mr. Allen indicated royalty policy development is confidential at this time

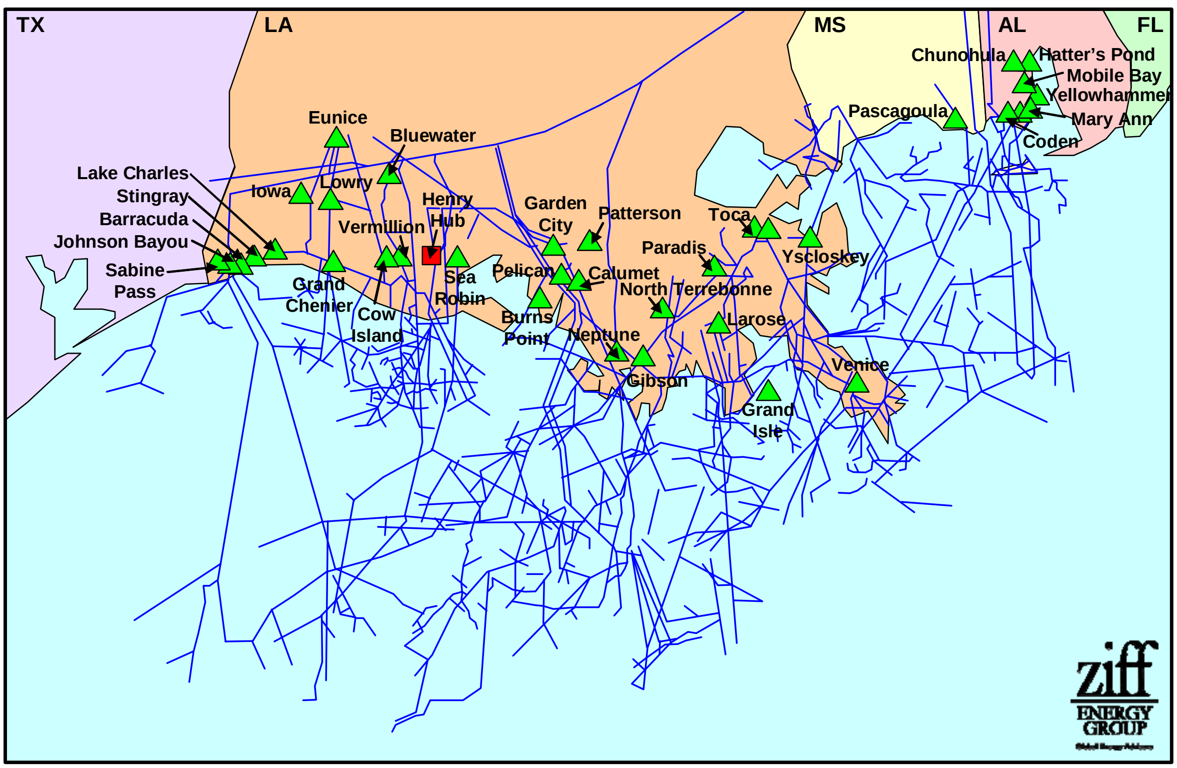
[46] PetroCanada, Husky Oil, and ExxonMobil

4.6 United States

4.6.1 Location of U.S. Straddle Plants

From Ziff Energy's research, there are a limited number of straddle plants in the United States that process gas midstream on an interstate pipeline. The majority of these plants are located in the onshore Gulf Coast region of Texas and Louisiana near the shoreline. Offshore natural gas transmission lines carry wet gas (methane with entrained NGLs) from wells/production platforms in the Gulf to the shoreline; where the gas must be processed to meet pipeline specifications prior to redelivery to transmission pipelines. Figure 5 shows natural gas pipelines and onshore processing plants in the Gulf of Mexico. Some of the pipelines are not transmission lines and are owned by producers or others, and also feed into onshore processing plants. NGL conventions on these non-regulated pipelines would be subject to commercial arrangements between the producers and the plants, in the same fashion as exists in Alberta for producers and field processing plants. Given the lack of publicly available information and the multitude of pipelines, it was not practical to identify which of the lines were regulated transmission lines versus non-regulated pipelines.

Figure 5
Gulf of Mexico Wet Transmission Lines and Onshore Processing Plants



Source: INGAA Report "Gulf of Mexico Natural Gas Resources and Pipeline Infrastructure 2001"
Ziff Energy

A Report issued June 2004[47] by the Mineral Management Service ("MMS") a Division of the US Department of the Interior, provides an example of a straddle plant operation in the Gulf Coast area:

> *"Also, responding to the recent successes of deepwater exploration and production in the Gulf of Mexico, the Destin pipeline and Pascagoula gas processing plant have come online. The Destin pipeline originates at a junction platform at Main Pass 260 and, after coming ashore near Pascagoula, Mississippi, connects with 5 interstate gas transmission pipelines. The line has a 121-mile offshore segment and a 134-mile onshore segment. The gas processing plant is located where the pipeline comes ashore, just before the first compressor station. The Pascagoula plant straddles the Destin pipeline adjacent to slug-catching facilities that are designed to remove retrograde condensate that may form in the pipeline. The slug catcher holds 5,000 bbl of liquids from the pipeline. Gas handling capacity is 1 bcf/d. Liquid from the slug catcher feeds into the condensate stabilizer. Gas from the slug catcher is dehydrated, then processed in two identical trains, each with a capacity of 500 MMscf/d. Each train provides inlet-gas cooling, dehydration, expansion, demethanization, NGL recovery and residue-gas compression."*

While a complete list of straddle plants on interstate pipelines is unavailable, Table 1 provides straddle plants in the U.S. Gulf Coast area identified from Ziff Energy's research.

Table 1
U.S. Gulf Coast Straddle Plants

Operator	Location	Pipeline Straddled	Capacity (Bcf/d)
Enterprise Products Partners	Toca, LA	Southern Natural Transmission Pipeline	1.1
Williams Energy Services Company	Cameron, LA	North High Island, UTOS Pipeline and West Cameron	0.5
Targa Louisiana Field Services LLC	Lake Charles, LA	Enbridge Stingray Pipeline	0.3
BP and Enterprise Products Partners	Pascagoula, Mississippi	Destin Gas Pipeline	1.0

source: Ziff Energy research, Sulpetro plant database

A report issued by the Energy Information Agency ("EIA") in January 2006 provides a summary of U.S. processing plant capacity and numbers by state, showing that 53% of natural gas processing capacity (which includes both straddle and field plants) exists in Louisiana and Texas.[48]

[47] Minerals Management Service of the U.S. Department of the Interior published June 2004 Study titled "OCS-Related Infrastructure in the Gulf of Mexico Fact Book" Crucial Link between Natural Gas Production and Its Transportation to Market" (http://www.gomr.mms.gov/PI/PDFImages/ESPIS/2/2984.pdf)

[48] Appendix 15 provides EIA Report issued Jan 2006, "Natural Gas Processing: The Crucial Link between Natural Gas Production and Its Transportation to Market" (http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2006/ngprocess/ngprocess.pdf)

4.6.2 Ownership of Straddle Plants

Ziff Energy understands that nearly all straddle plants are non-regulated and typically owned by midstream companies.[49] After the Federal Energy Regulatory Commission ("FERC") Order 636 was enacted in April 9, 1992; most interstate pipelines divested their non-essential assets.[50] Some of the straddle plants in the Gulf Coast region where sold to "midstream" companies[51]; others were sold or transferred to the pipelines' non-regulated *'sister'* companies.

Section 5.1.5 of The FERC issued White Paper on Hydrocarbon Drop Out[51] and page 9 of the EIA Report[48] discuss the consolidation of plants under midstream operating companies such as Duke Energy, Enterprise Products, Targa Resources, Williams, and others.

Some onshore straddle plants in Louisiana and Texas do not straddle one interstate pipeline. These are connected to offshore and onshore gathering facilities and numerous interstate pipelines at the tailgate of the plants. In each of these instances a third party owns the facilities. One such facility is the newly constructed Pascagoula Processing Facility referred to in the above cited MMS 2004 Study[1]. Table 2 shows the connecting pipelines at its tailgate for the Pascagoula Processing Facility that straddles the Destin Offshore Pipeline owned by BP Americas and Enbridge.

Table 2
Connecting Pipelines for the Pascagoula Processing Plant

Connecting Pipeline	Location	Capacity (Bcf/d)
Gulf South Pipeline	Jackson County, Mississippi	0.2
Gulfstream	Jackson County, Mississippi	1.0
Florida Gas Transmission Company	Georgia County, Mississippi	0.5
Transcontinental Gas Pipeline	Clarke County, Mississippi	0.8
Tennessee Gas Pipeline Company	Clarke County, Mississippi	0.2
Southern Natural Gas Company	Jackson County, Mississippi	0.8

4.6.3 Regulation of Straddle Plants and NGL Rights

Before 1992 the interstate pipelines and their various assets and services were provided under bundled regulated rates. Since the FERC issued Order 636 in 1992, the regulated pipelines were required to "*unbundle*" their assets (including processing) and related services. Recent conversation with FERC staff[52] indicate that immediately after the issuance of Order 636 in 1992, a few straddle plants owned by regulated pipelines (for various quality reasons) continued to be included in their rate base. This practice however is no longer in effect. As pipelines divested straddle facilities,

---

[49] per discussion with James Tobin, author of EIA Report on Natural Gas Processing referred to in above footnote, who indicated he found no evidence of straddle plants owned by interstate pipelines
[50] FERC Order 636 mandated unbundling of U.S. pipeline transmission and merchant functions
[51] Appendix 16 provides the White Paper on Liquid Hydrocarbon Drop Out in Natural Gas Infrastructure, NGC+ Liquid Hydrocarbon Drop Out Task Group, February 28, 2005, Docket # PL04-3-000. http://www.ferc.gov/industries/lng/indus-act/issues/gas-qual/liquid-hydrocarbon.pdf
[52] per discussion with Berne Mosley, Division Director of Pipeline Certification, FERC

selling them to independent third parties, the facilities by the very nature of their disconnect from the regulated entity became non-jurisdictional and excluded from pipeline rate base. As an example of this, the FERC indicated that jurisdictional issues with respect to processing plants arose in the events related to Hurricane Katrina in the Gulf of Mexico region. Reconstruction costs to replace destroyed processing plants necessary for pipeline operation were not allowed to be included in the affected pipelines emergency blanket authority for rate base expenditures.[53]

Texas has enacted a Code of Conduct[54] to loosely regulate the treatment of processing facilities owned by midstream companies doing business in their state. The Gas Processors Association ("GPA"),[55] indicates that several other states such as Kansas and Oklahoma have issued similar light handed regulation. Review of this Code indicates it appears to do very little to regulate transportation or processing rights in Texas, but rather shifts the governance of NGL rights to the domain of the legal system.

The Louisiana Conservation Commission's Regulation Division,[56] indicates that Louisiana exerts no jurisdiction on interstate pipelines or processors. The State regards problems concerning rights to NGLs to be of a legal nature strictly controlled by contractual arrangements.

4.6.4 State or Federal Policy Regarding Rights to NGLs in the Common Stream

Ziff Energy's Interviews with State regulatory agencies, FERC officials, EIA administrators, GPA staff members, and Interstate Natural Gas Pipeline Association, ("INGAA") officials conclude that no State or Federal regulation of the ownership of NGLs in the combined gas stream exists. It is clear from the review of the various documents referenced and the information obtained from the various state and federal agencies that NGL rights are determined by contract, and that disputes regarding NGLs are resolved in the judicial system.

4.6.5 Commercial Arrangements for Straddle Plants and NGLs

In the Gulf Coast region the typical contracting parties involved are:

- offshore producer and the owner of the Onshore Processing Facility
- owner of the gas stream transported through the offshore pipeline and the onshore processing facility.

In addition to gas transportation contracts, producers or owners of the offshore gas stream must execute a Plant Thermal Reduction "PTR" Contract with the gas pipeline. This compensates the transmission line for the transportation of the entrained NGLs from the offshore wellhead/platform to the shore, and clarifies how the pipeline administers the party's processing rights. The PTR

[53] Order Extending Deadline for Construction of Facilities Pursuant to Temporary Waiver of Regulations Raising Blanket Certificate Limits, 114 FERC 61,186 (2006)
[54] Appendix 17 provides a copy of the Texas Code of Conduct
[55] discussion with Director of Industry Affairs, Mr. Johnny Dreyer
[56] per discussion with Mr. Fred Dedon, Assistant Director, Louisiana Office of Conservation – Regulatory Division

contract sets out how the residue gas that exits the straddle plants will be re-delivered for the transporter's account.

To confirm some of these arrangements, Ziff Energy reviewed the tariffs of two offshore transmission pipelines, Tennessee Gas Pipeline and Southern Natural Gas Company.

From review of Tennessee Pipelines tariffs, it appears that Shippers retain title to NGLs entrained in the common stream on the pipeline, and have the right to make arrangements with straddle plants to process their gas. However, it is not clear how NGL or processing rights are allocated among shippers. Ziff Energy believes this is based on commercial arrangements between the shippers/their designate and the gas processing plant. The gas processing plants may have access to gas composition data at the receipt point (where the gas leaves the offshore production platform and enters the transmission pipeline). This data may be used by the processing plants to allocate liquids to shippers taking NGLs in kind, to determine processing fees, for purchase of the gas by the processing plant, or used for other commercial arrangements made between the processor and the shipper.

Ziff Energy came to the conclusion that shippers retain rights to liquids based on the following:

- the shipper retains title to the gas on the pipeline as title to the gas received by the pipeline at the Receipt Points does not pass to Transporter (except for gas delivered for fuel and use quantities)[57]
- the tariffs indicate that shippers receive thermally equivalent quantities of gas at the delivery point, net of pipeline fuel, gas lost and unaccounted for gas, and gas subject to a PTR agreement[58]
- a Plant Thermal Agreement or PTR Agreement is required to transport entrained NGLs in the gas stream that are removed at a downstream straddle plant (it covers transportation of the shrinkage gas[59]
- title to the NGLs removed on the pipeline remains with the party who has contracted for the processing rights, and if no such party has the rights, the pipeline (Transporter) retains the rights[60].

As with Tennessee Gas Pipeline, Southern Natural Gas Company ("SONAT"), provides for the transportation of NGLs to a processing facility for Shipper. Similar to the PTR contract used by Tennessee, SONAT has a Liquefiable Transportation Contract for the transportation of entrained NGLs to the processing facility, and to set out methodology for allocating NGL extracted to the Shipper. The following information is set out in the SONAT Tariff:

- the tariff clarifies the Shippers rights to process and the procedures required by SONAT to enable the initiation of shipper's intention[61]

[57] Tennessee General Terms and Conditions, Article IX in Appendix 18
[58] Tennessee FTA Gas Agreement, Article II and General Terms and Conditions, definition of equivalent quantity, Article 1, point 15, all in Appendix 18
[59] Tennessee General Terms and Conditions, Article II, part 9 in Appendix 18
[60] Tennessee General Terms and Conditions, Article II, part 1 in Appendix 18

- SONAT states that if shipper does not properly elect to process, that SONAT will have the right to act as agent for shipper and either charge shipper an allocated share of plant volume reduction and credit shipper with for its allocated share of Liquefiables, or keep shipper whole – that is, redeliver equivalent MMBtu, at the delivery point.[62] These provisions are the same in the IT contract details in the Tariff
- SONAT's tariff commits the pipeline to deliver gas to Shipper for processing which contains as nearly as practical the same NGL content received from the Shipper at the receipt point[63]
- a Liquefiable's Transportation Agreement set out the terms and conditions for the transportation of the NGLs entrained in Shippers gas[64].

4.6.6 Legal Decisions Pertaining to NGL Rights

There have been a number of lawsuits filed and prosecuted regarding producer rights to NGLs in the common gas stream at the Gas Processing facility at Bushton, Kansas. This plant is fairly large and processes gas from many producers in the Hugoton Field, Kansas.

One such claim was made by ExxonMobil against Kinder Morgan and its predecessors in interest at the Bushton Plant in 2005. ExxonMobil claimed that the plant made an egregious error in the calculation of the amount of propane credited to their account pursuant to the gas processing agreement. Although this complaint centered around the calculation of propane proceeds and not the actual inherent rights to NGLs, the Court did upon re-hearing point out that ExxonMobil had rights to the NGLs detailed in the Gas Processing Agreement; not all propane extracted at the plant[65]. The point here is that NGL rights were determined on the basis of the contract between the processor and the party who had legal ownership of the gas being delivered for processing. Following is an excerpt from the opinion:

> *"The GPA defined plant products as the hydrocarbons in liquid and liquefiable form extracted and saved from Gas processed at Plant. Propane is the only plant product that ExxonMobil contends it was entitled to but did not receive in the correct quantity. Under paragraph 10.03, Exxon Mobil was entitled to as much as 88% of the propane theoretically produced from its gas minus the amount that would be required to enhance the BTUs of the residue gas.*
>
> *Exxon Mobil's theory is that appellees breached the GPA by using methane instead of propane to enhance BTUs in the residue gas stream, retaining the propane that should have been used for BTU control, and selling that propane for a profit. The charge did not permit the jury to find a breach of contract simply on evidence that methane was used instead of Exxon Mobil's propane to control BTUs in the residue*

---

[61] Southern Natural Gas Company, Rate Schedule FT, Section 5, Appendix 19
[62] Southern Natural Gas Company, Rate Schedule FT, Section 5(b), Appendix 19
[63] Southern Natural Gas Company General Terms and Conditions, Section 19.2, Appendix 19
[64] Appendix 19 provides a copy of the Liquefiables Transportation Agreement
[65] Affirmed and Opinion filed February 21, 2006, Fourteenth Court of Appeals Docket. 14-04-01060-CV
http://www.14thcoa.courts.state.tx.us/opinions/htmlopinion.asp?OpinionId=81833#_ftnref13

> *gas stream. Under Exxon Mobil's own theory, the jury could have logically concluded that ExxonMobil would not have been entitled to any more propane as a plant product than what it received. Accordingly, we find that the jury's answer to Question 2 was not against the great weight and preponderance of the evidence. We overrule ExxonMobil's second issue."*

The Judge upheld the lower courts verdict and found for Kinder Morgan.

4.6.7 Interstate Natural Gas Pipelines Demand Specific Gas Quality Guidelines

In the past few years as new LNG re-gas facilities have connected to the pipeline grid, interstate gas pipelines and the FERC have given specific attention to gas quality specifications of the commingled gas stream. Although gas quality has always been a concern to pipelines, particularly as it relates to delivery to end users, this new emphasis may effect changes to NGL extraction practices. In 2005, an industry committee known as the Natural Gas Council[66] published a *white paper*[67] on importance of regulating the gas quality of any gas entering the interstate pipeline grid. That *white paper* has become the closest step taken thus far toward the regulation of liquid extraction and intended to:

> "2.1..... define acceptable ranges of natural gas characteristics that can be consumed by end users while maintaining safety, reliability, and environmental performance. It is important to recognize that this objective applies equally to imported LNG and domestic supply."

The *white paper* sets out industry concerns regarding the management of NGL extraction. In 7.2.10 "Management" it states:

> "It is important to note that following implementation of FERC Order 636, significant numbers of producers have entered into contracts with pipelines to transport their gas without prior NGL removal. This situation resulted as the production sources developed near the existing pipeline infrastructure and producers determined that it was either infeasible nor economically attractive to extract NGLs. The volume of any one source tended to be small, approximately less than 10 MMscf, and pipelines were often able to take advantage of incidental blending to achieve a delivered gas that was acceptable."

[66] Natural Gas Council members are senior executives representing the major North American natural gas trade associations such as American Gas Association, American Petroleum Institute, Independent Petroleum Association of America, Interstate Natural Gas Association of America, and the American Gas Supplier's Association

[67] White Paper on Natural Gas Interchangeability and Non-Combustion End Use, NGC+ Interchangeability Work Group, February 28, 2005 (http://ferc.gov/industries/lng/indus-act/issues/gas-qual/natural-gas-inter.pdf)

This statement is important because it reveals the suppliers prior lack of interest in NGL recovery shifting the management of NGL extraction to downstream parties. In Section 8.0 “Findings”, the Study sets out parameters for overall NGL recovery prior to the entrance into the pipeline as well as the city-gate.” It states:

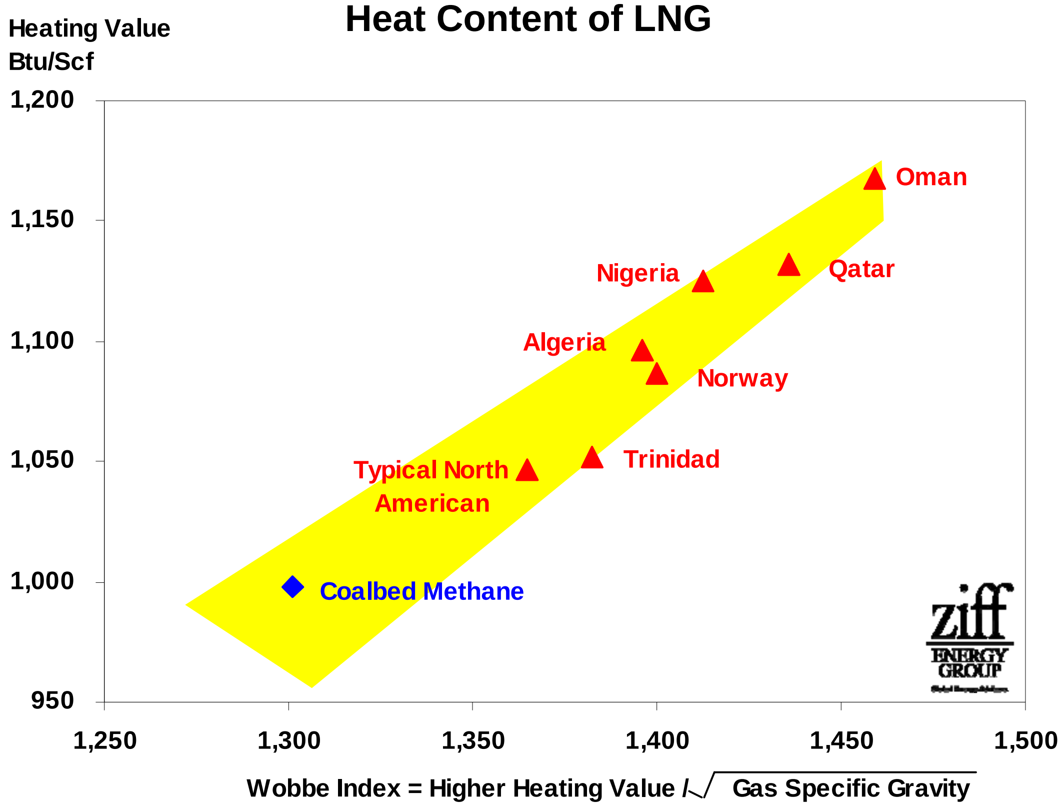
> “In the majority of cases, interchangeability is best managed at two key points along the value chain, at the origin of supply or prior to delivery into the existing pipeline infrastructure.”

As Ziff Energy expects a larger part of the future North American gas supply will come from LNG supplies, interchangeability management at the supply end would require processing of rich LNG supplies. Future LNG expansion is expected to predominantly occur on the east cost of the U.S. and in the Gulf Coast, and since LNG processing is not practical on the east coast due to lack of NGL infrastructure, Ziff Energy expects the bulk of LNG to be delivered and processed in the Gulf of Mexico area which could result in increased NGL production there. This in turn could depress NGL prices and provide lower priced feedstock for Gulf coast area petrochemical plants, improving their competitiveness compared to petrochemical plants in Alberta.

4.7 Foreign Jurisdictions

Figure 6 shows the heat content of LNG delivered from various countries as compared to typical North American supplies and coalbed methane.

Figure 6
Heat Content of LNG



Sources: NGTL evidence, Page 23, ENVIRON Oct. 12, 2005

- LNG from many countries exhibits high heat values as NGLs are not removed from their gas streams due to lack of local demand or low value of NGLs in these countries. This necessitates NGL removal in North America to meet pipeline specifications

- coalbed methane has a low heating value as it contains very little NGLs.

This page intentionally left blank.

5. ALBERTA NATURAL GAS RESERVES, SUPPLY, AND DEMAND

In this section Ziff Energy will outline how Alberta gas fits into North America, review available gas reserves, provide a technical review of expected new Alberta gas well completions, access new Alberta gas well productivity, evaluate new Alberta gas well decline rates, and forecast Alberta gas production expectations to 2028. This gas production forecast provides a basis for Ziff Energy's insight as to the amount of NGLs available for the province.

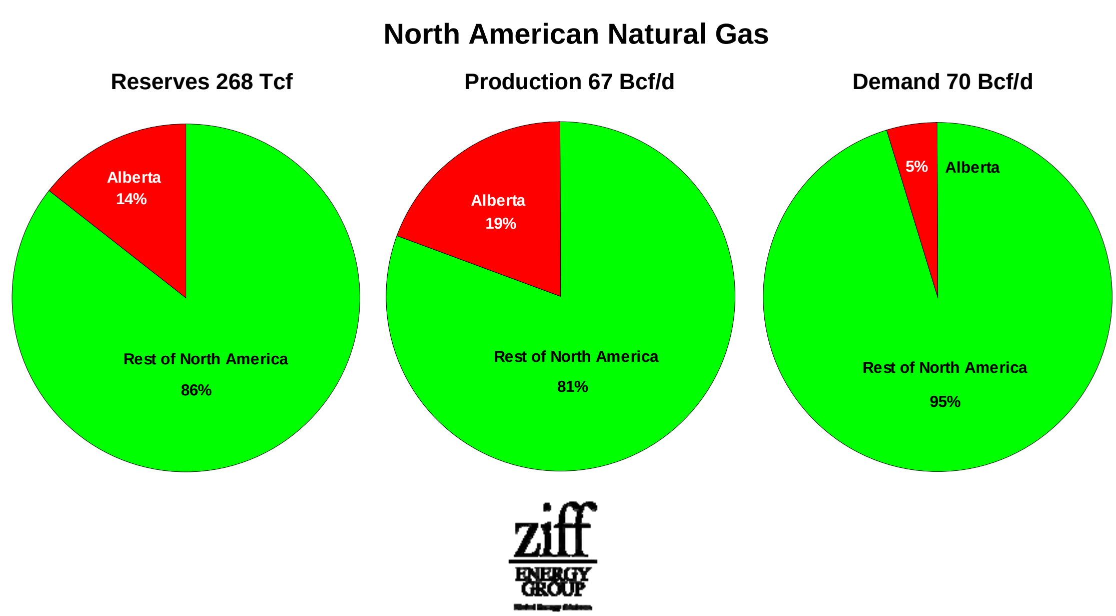
5.1 How Alberta Gas Fits Into North American Gas Supply

5.1.1 Overview

5.1.2 Alberta Size of the Gas Pie

Figure 1 demonstrates how Alberta fits into the North America natural gas industry[68]. North America has 268 Tcf of gas reserves and produces 67.4 Bcf/d to meet 69.9 Bcf/d of gas demand[69]. Alberta has 39 Tcf of gas reserves, produces 13.1 Bcf/d and consumes 3.3 Bcf/d of gas demand. In summary, Alberta has 14% of gas reserves, 19% of gas production, and 5% of gas demand.

Figure 1
Alberta Size of the Gas Pie, 2007



[68] source: Ziff Energy, EIA
[69] to balance supply and demand, North America will import about 2.5 Bcf/d of LNG

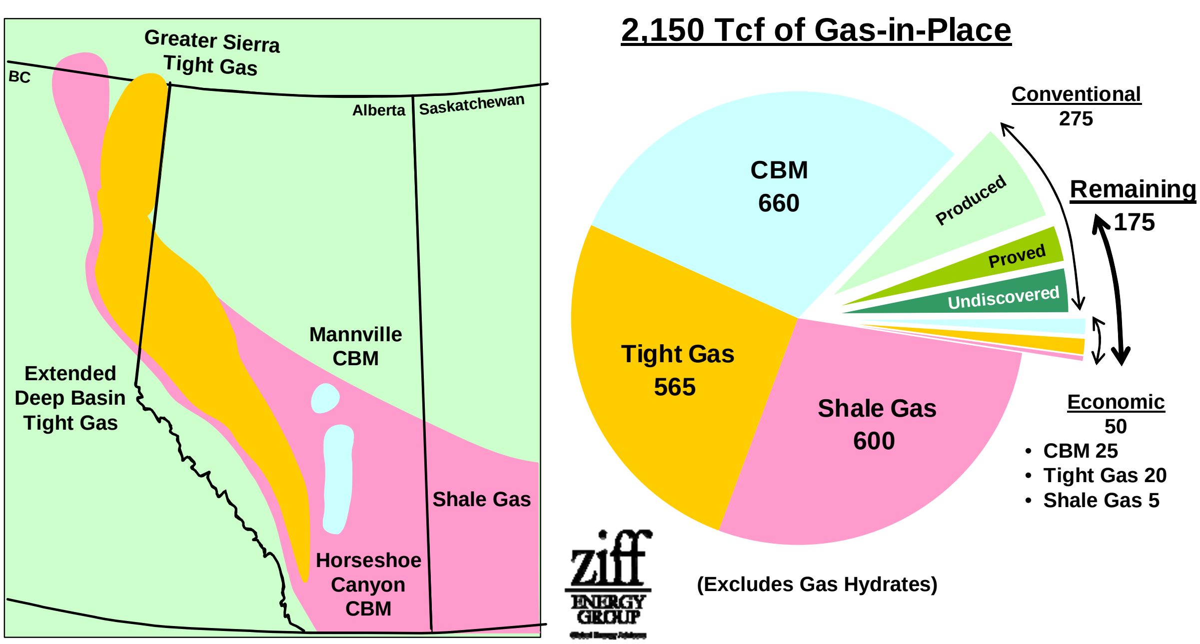
5.2 Natural Gas Resources

5.2.1 Western Canada

While this Alberta Energy and Utilities Board Hearing is focused upon Alberta, it is important to consider gas resources in Western Canada, NWT, and Alaska as this gas supply may be used in Alberta or used as a supply source for Alberta NGL extraction. Southeast Yukon and Southern NWT resources are included in the Western Canada resource estimate. A portion of Alberta's natural gas production flows out of Alberta to BC gas export points and some northwest Alberta gas flows directly out of the Province on the Alliance pipeline, and so this gas is currently not available for processing to extract NGLs in Alberta.

Figure 2 shows a pie chart of Western Canada natural gas-in-place resources for 2007, and a map showing the location of the unconventional gas resources. It is important to realize that only a small fraction of these gas resources are recoverable and an even smaller fraction will be economic. The broken out wedge on the right represents the 325 Tcf[70] of resources that are ultimately recoverable out of the ultimate potential of 2,150 Tcf gas in place.

Figure 2
Western Canada Ultimate Gas Potential



Source: Ziff Energy, Canadian Gas Potential Committee, Alberta Energy and Utilities Board, BC Ministry of Energy and Mines

[70] other Canadian resources include Mackenzie Delta, east coast offshore resources, and other provinces

5.2.2 Alberta

As of January 1, 2007, Alberta's initial conventional gas resources are estimated to be 223 Tcf, (81% of the 275 Tcf in Western Canada) with 93 Tcf remaining. Alberta has additional unconventional marketable gas resources of 39 Tcf. Table 1 summarises Alberta's natural gas resources. On going natural gas production will reduce the remaining gas reserves and resources from 132 Tcf in 2007 to 82 Tcf in 2018 and 53 Tcf in 2028.

Table 1
Alberta's Marketable Natural Gas Resource Estimates (Tcf)

	Jan 1, 2007	Jan 1, 2018	Jan 1, 2028
Conventional Gas			
Produced	130	169	189
Remaining Reserves	39	30	20
Undiscovered	54	25	13
Unconventional Gas			
Produced	2	13	22
Remaining Resource			
Coalbed Methane	20	15	10
Tight Gas	18	12	8
Shale Gas	1	1	2
Total	264	264	264

Source: Ziff Energy, Alberta Energy and Utilities Board

5.3 Natural Gas Production[71] Forecast Procedure

Alberta natural gas production includes supply from several sources including: Conventional Gas, Solution Gas, Tight Gas, and Coalbed Methane. Ziff Energy has forecast annual gas supply to 2028 as follows:

1. current gas production is obtained and declined annually using established decline rates
2. natural gas production from new wells is estimated annually to 2028 based on:
   - number of gas well completions by year considering natural gas prices, costs, economics, and basin maturity
   - productivity trends
   - historic and projected decline rates
3. using actual production, the amount of gas from oil wells (Solution Gas) is estimated annually
4. natural gas from Coalbed Methane wells is estimated annually by adding existing Coalbed Methane production to new Coalbed Methane production considering:
   - number of annual gas well completions considering natural gas prices, costs, economics, and play maturity
   - productivity trends
   - historic and projected decline rates
5. natural gas from Tight Gas wells is estimated by adding existing Tight Gas production to new Tight Gas production reflecting:
   - number of gas well completions by year considering natural gas prices, costs, economics, and play maturity
   - productivity trends
   - historic and projected decline rates

The various gas supply sources have differing characteristics:

- Western Canada Conventional Gas production is declining due to basin maturity; production peaked in 1999 at 16.6 Bcf/d (Alberta at 13.7 Bcf/d)
- Solution Gas is declining due to a decline in conventional oil production and is not related to gas well activity
- Coalbed Methane has a lower gas heating value (contains little Natural Gas Liquids) and Coal Bed Methane production will grow
- Tight Gas is a newer gas supply source that is expected to grow in quantity.

By forecasting the gas supply available by source, Ziff Energy is better able to estimate Natural Gas Liquids production which varies by source.

[71] this methodology is used to forecast natural gas production from natural gas, oil, and bitumen wells; it does not include the off-gas produced and consumed during the upgrading of bitumen to synthetic crude oil

5.3.1 Total Alberta Natural Gas Supply

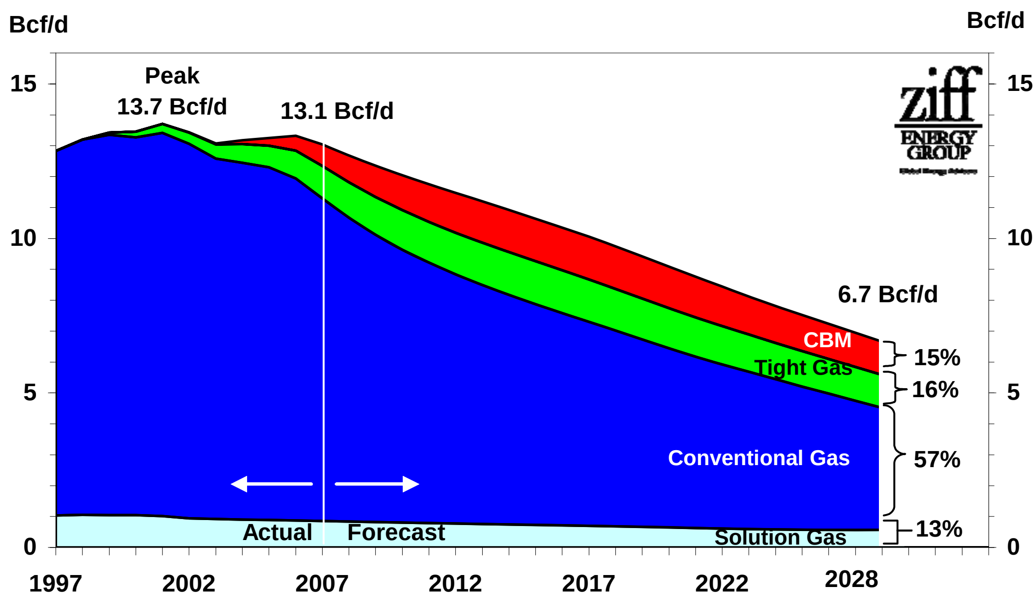
Figure 3 provides a decade of historical gas production and forecast gas production to 2028 by Alberta natural gas supply type. The types of gas supply modelled include:

- Solution Gas – gas from oil production
- Conventional Gas
- Tight Gas – gas from formations with low permeability
- Coalbed Methane – natural gas from coal formations.

Gas production declined from the 13.7 Bcf/d peak in 2001 despite record levels of gas well completions following 2001. Ziff Energy expects marketable gas production to shrink to 6.7 Bcf/d by 2028, an almost 50% decline from current gas production (13.1 Bcf/d). Conventional gas will represent more than half and unconventional gas a third of Alberta natural gas production in 2028.

Note that gas from Alaska and the Mackenzie Delta is not included in Alberta natural gas production.

Figure 3
Alberta Gas Production



Source: Ziff Energy

Appendix A provides insight to Ziff Energy's views on new Alberta gas well completions, new gas well productivity, new gas well decline rates, additional detail on the new Coalbed methane gas production outlook, new Tight Gas production outlook, and gas from Alaska and Mackenzie Delta.

Table 2 provides Alberta's natural gas production for each supply type by year. Conventional gas has peaked and is declining. Tight Gas in Alberta peaks at 1.39 Bcf/d in 2014, CBM peaks at 1.38 Bcf/d in 2016. The maximum Alberta gas supply has already occurred and by 2018 (a decade from now) total gas production is under 10 Bcf/d. By 2028 (20 years from now) Alberta gas production merely equals Alberta expected gas demand, consequently, the gas flows through the Alberta border straddle plants will be nil[72].

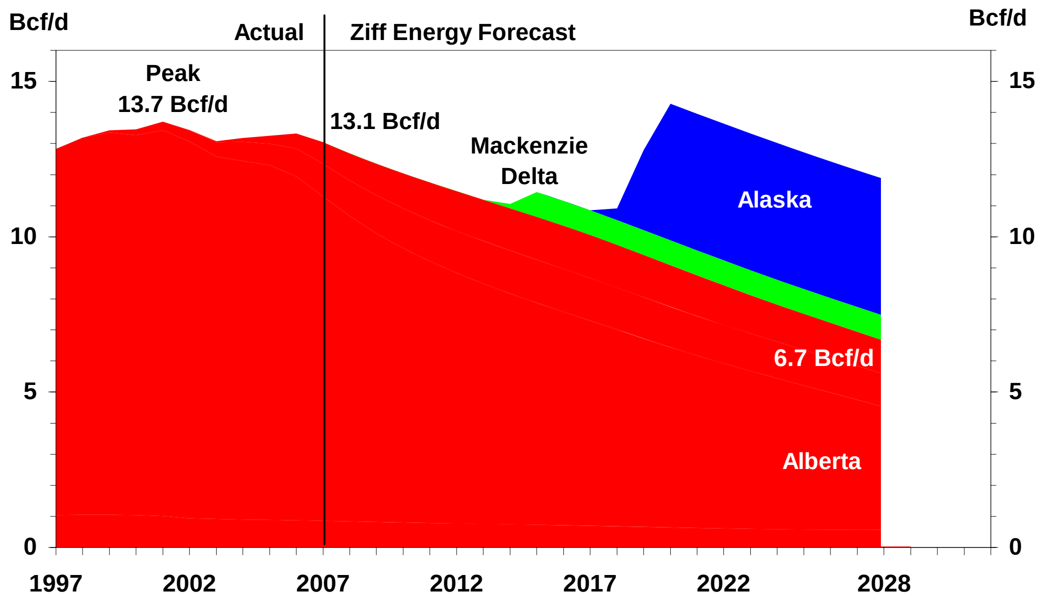
Table 2
Alberta Natural Gas Production (Bcf/d)

Year	Solution Gas	Conventional Gas	Tight Gas	CBM	Total Gas
1997	1.04	11.79	0.00	0.00	12.83
1998	1.05	12.14	0.00	0.00	13.19
1999	1.05	12.30	0.07	0.00	13.42
2000	1.04	12.23	0.18	0.00	13.45
2001	1.01	12.41	0.28	0.00	13.71
2002	0.94	12.13	0.36	0.01	13.44
2003	0.92	11.67	0.46	0.03	13.07
2004	0.90	11.54	0.62	0.13	13.18
2005	0.89	11.41	0.70	0.25	13.25
2006	0.87	11.07	0.90	0.48	13.32
2007	0.85	10.45	1.04	0.71	13.05
2008	0.84	9.83	1.14	0.87	12.68
2009	0.82	9.30	1.22	1.01	12.35
2010	0.80	8.83	1.28	1.13	12.04
2011	0.79	8.43	1.31	1.22	11.75
2012	0.77	8.07	1.34	1.29	11.47
2013	0.76	7.74	1.37	1.33	11.19
2014	0.74	7.44	1.39	1.36	10.92
2015	0.73	7.14	1.39	1.37	10.64
2016	0.71	6.87	1.39	1.38	10.35
2017	0.70	6.60	1.37	1.38	10.05
2018	0.68	6.33	1.35	1.37	9.74
2019	0.67	6.06	1.33	1.36	9.42
2020	0.65	5.79	1.30	1.35	9.09
2021	0.63	5.54	1.28	1.32	8.76
2022	0.61	5.31	1.24	1.27	8.44
2023	0.59	5.09	1.21	1.24	8.13
2024	0.57	4.87	1.18	1.20	7.82
2025	0.57	4.63	1.15	1.17	7.52
2026	0.57	4.41	1.12	1.13	7.23
2027	0.57	4.18	1.09	1.10	6.94
2028	0.57	3.95	1.06	1.07	6.66

[72] Ziff Energy did not reflect the Alberta Gas Resources Preservation Act which indicates the EUB may authorise new gas exports when the gas is surplus (exceeds 15 years) to Albertan's needs. Thus the volumes through the Alberta border straddle plants (for subsequent export) may be reduced by government order prior to the forecast provided by Ziff Energy

Figure 4 illustrates the declining Alberta gas production, and the potential incremental supply from the north. Mackenzie Delta is projected to provide 0.8 Bcf/d[73] in 2015, and Alaska will start[74] at 50% flows (2.2 Bcf/d) in November 2018, and ramp up to full volumes (4.4 Bcf/d) in November 2019.

Figure 4
Alberta, Mackenzie Delta, and Alaska Gas Production



Source: Ziff Energy

---

[73] various gas supply forecasts are available in industry. Ziff Energy has chosen the lowest gas production volume although at an optimistic start date. Notwithstanding, gas flows from the Mackenzie delta may simply not happen at all as estimated transport costs to connect this gas supply appear costly. Thus by using a low estimate, the Ziff Energy analysis provides a middle position

[74] gas flows from Alaska may be challenged to flow primarily due to the anticipated high cost to connect this gas supply source. Additionally, the expected timetable to connect this Alaska gas has slipped by more than a decade, and further potential timing slippage is a very real possibility. However, Ziff Energy has chosen to model Alaska gas supply start up prior to 2020.

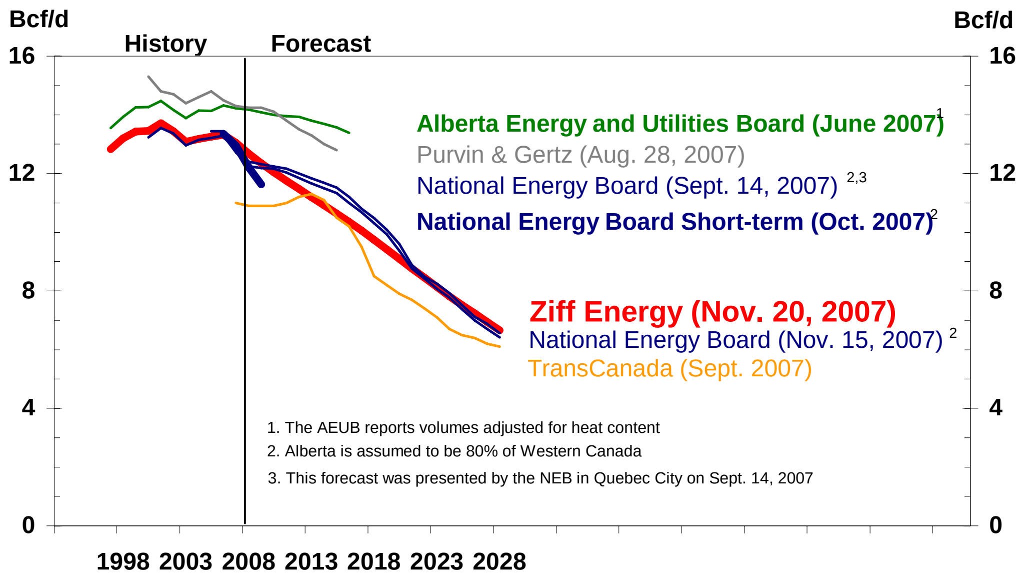
Table 3 illustrates Alberta natural gas production and potential incremental natural gas production from Mackenzie Delta and Alaska. Gas supply would peak at over 14 Bcf/d in 2020. Note that Table 3 excludes Alberta gas demand.

Table 3
Alberta, Mackenzie Delta, and Alaska Natural Gas Production (Bcf/d)

Year	Alberta	Mackenzie Delta	Alaska	Total Gas
1997	12.83			12.83
1998	13.19			13.19
1999	13.42			13.42
2000	13.45			13.45
2001	13.71			13.71
2002	13.44			13.44
2003	13.07			13.07
2004	13.18			13.18
2005	13.25			13.25
2006	13.32			13.32
2007	13.05			13.05
2008	12.68			12.68
2009	12.35			12.35
2010	12.04			12.04
2011	11.75			11.75
2012	11.47			11.47
2013	11.19			11.19
2014	10.92	0.13		11.05
2015	10.64	0.80		11.44
2016	10.35	0.80		11.15
2017	10.05	0.80		10.85
2018	9.74	0.80	0.37	10.91
2019	9.42	0.80	2.57	12.78
2020	9.09	0.80	4.40	14.29
2021	8.76	0.80	4.40	13.96
2022	8.44	0.80	4.40	13.64
2023	8.13	0.80	4.40	13.33
2024	7.82	0.80	4.40	13.02
2025	7.52	0.80	4.40	12.72
2026	7.23	0.80	4.40	12.43
2027	6.94	0.80	4.40	12.14
2028	6.66	0.80	4.40	11.86

Figure 5 shows 7 declining Alberta gas production forecasts[75].

Figure 5
Alberta Gas Production Forecasts



Source: Ziff Energy

The gas production forecasts used some assumptions:

- the EUB determines gas supply at a standard heating value (37.5 MJ/m^3) and includes gas from bitumen wells
- Ziff Energy removed eastern Canadian gas supply from the NEB gas supply forecast for Canada and took 80% of Western Canada supply as Alberta
- TransCanada excludes Alberta Alliance supply (1.31 Bcf/d in 2008, 1.21 Bcf/d in 2018, and 0.0 Bcf/d in 2028) and excludes very small quantities of Atco gas supply sourced and consumed on the Atco pipeline system. Their forecast appears to be based on a 'gas year' starting each Nov. 1 through to Oct.31
- Ziff Energy excludes gas from bitumen wells as this is netted from the growing gas demand for oil sands.

[75] there are seven sources:
- TransCanada Pipeline, "Alberta Systems Receipts and Deliveries (Base Case with Northern Gas)", Sept. 2007
- National Energy Board, "Natural Gas Production Outlook", Canada's Energy Future reference case scenarios to 2030, Figure 5.18, Nov. 15, 2007
- Ziff Energy, "Reserves and Supply", EUB Natural Gas Liquids Extraction Conventions, Fig. 4, Nov. 20, 2007
- National Energy Board, "Short-term Canadian Natural Gas Deliverabilities 2007-2009", An Energy Market Assessment, Oct. 2007
- National Energy Board, "Industrial Gas Users Association's", 2007 Natural Gas Conference in Quebec City, Sept. 14, 2007
- Purvin & Gertz, "Alberta Natural Gas Supply", The Straddle Plant Group, Pg. III-2, Aug. 28, 2007
- Alberta Energy and Utilities Board, "Alberta's Energy Reserves and Supply/Demand outlook 2007", Total Gas Production in Alberta, Figure 5.27, June 2007

Table 4 illustrates industry Alberta natural gas production forecasts.

Table 4
Alberta Natural Gas Production Forecasts (Bcf/d)

Year	Purvin & Gertz (Aug. 28 2007)	Alberta Energy and Utilities Board (June 2007)	National Energy Board (Short-term, Oct.2007)	National Energy Board (Quebec, Sept. 14, 2007)	National Energy Board (Long-term, Nov. 15, 2007)	Ziff Energy (Nov. 20, 2007)	TransCanada (Sept. 2007)
1997		13.55				12.83	
1998		13.93				13.19	
1999		14.25				13.42	
2000	15.30	14.27			13.23	13.45	
2001	14.80	14.47			13.55	13.71	
2002	14.70	14.16			13.36	13.44	
2003	14.40	13.88			12.96	13.07	
2004	14.60	14.15			13.14	13.18	
2005	14.80	14.14		13.44	13.20	13.25	
2006	14.50	14.32	13.35	13.44	13.29	13.32	
2007	14.30	14.22	12.95	12.80	12.72	13.05	11.00
2008	14.25	14.18	12.21	12.40	12.25	12.68	10.90
2009	14.25	14.08	11.63	12.32	12.19	12.35	10.90
2010	14.10	13.99		12.24	12.17	12.04	10.90
2011	13.80	13.95		12.16	12.04	11.75	11.00
2012	13.50	13.93		12.00	11.84	11.47	11.20
2013	13.30	13.80		11.84	11.66	11.19	11.30
2014	13.00	13.69		11.68	11.49	10.92	11.10
2015	12.80	13.57		11.52	11.34	10.64	10.50
2016		13.38		11.20	11.00	10.35	10.20
2017				10.80	10.68	10.05	9.50
2018				10.48	10.31	9.74	8.50
2019				10.08	9.93	9.42	8.20
2020				9.60	9.38	9.09	7.90
2021				8.88	8.76	8.76	7.70
2022				8.48	8.41	8.44	7.40
2023				8.24	8.07	8.13	7.10
2024				7.92	7.77	7.82	6.70
2025				7.52	7.38	7.52	6.50
2026				7.12	7.00	7.23	6.40
2027				6.88	6.70	6.94	6.20
2028				6.56	6.42	6.66	6.10

5.4 Alberta Gas Demand

Gas demand includes: 5 sectors: Residential, Commercial, Industrial, gas for Power, and pipeline fuel/lease fuel. Table 5 summarises the major factors that influence the gas demand categories.

Table 5
Major Factors that Influence Gas Demand, by Sector

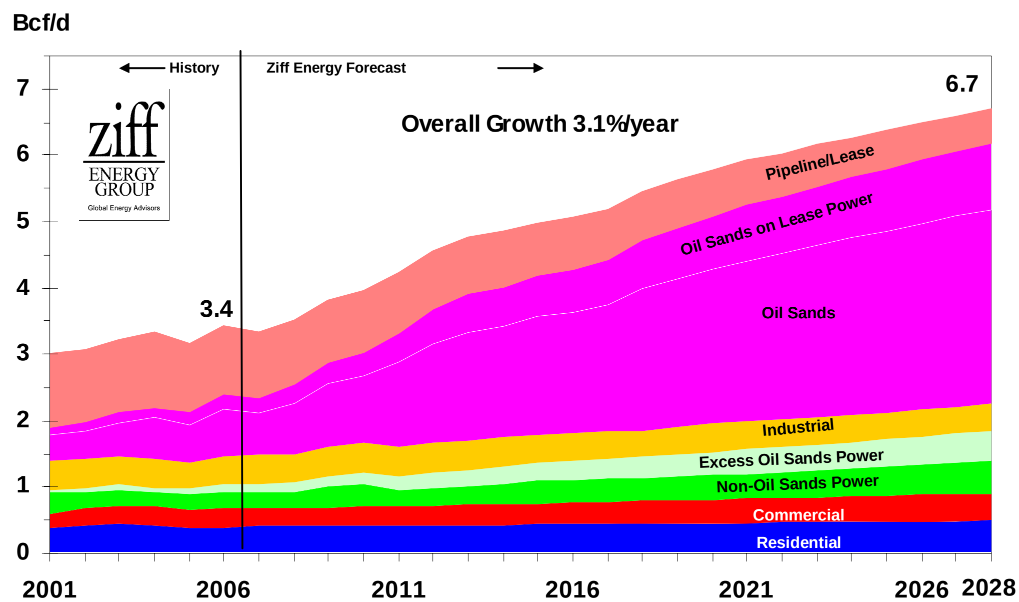
Alberta Sector	Influencing Factor
Residential	Change in customer count Change in gas consumption per customer
Commercial	Change in customer count Change in gas consumption per customer
Industrial	Price of gas Price of Industrial product Growth of oil sands projects
Gas for Power Generation	Alternative fuel availability
Pipeline Fuel/Lease Fuel	Change of gas volume in a basin

5.4.1 Summary of Alberta Gas Demand

Figure 6 provides a summary of gas demand by sector for Alberta (currently 40% of overall Canadian gas demand). Ziff Energy expects Alberta gas demand to grow at 3.1%/year over the forecast period. By 2028, gas demand is anticipated to have doubled to 6.7 Bcf/d from current requirements of 3.4 Bcf/d. Ziff Energy's forecast includes an assessment of gas demand requirements by year for the growing oil sands projects. Going forward, gas fired generator requirements are expected to grow. Three types of gas-fired uses considered are:

- traditional non-oil sands power requirements, power generators operating on the margin to supply MWh into the power market, shown in green
- oil-sands on lease power/steam requirements used in the process to extract and upgrade bitumen, shown in the upper pink band
- excess oil sands power, power produced on-lease and delivered into the Alberta power grid as a consequence of extracting bitumen and/or to meet marginal power opportunities, shown in light blue.

Figure 6
Alberta Natural Gas Demand



Source: Ziff Energy

5.4.2 Gas Demand Tabulation

Table 6 provides the Alberta Gas Demand by sector and by year. Note that total gas demand doubles by 2028 (6.69 Bcf/d in 2028 vs. 3.34 Bcf/d in 2007).

Table 6
Alberta Gas Demand (Bcf/d)

Year	Residential	Commercial	Industrial	Gas for Power Generation	Oil Sands	Lease Fuel / Pipeline Fuel	Total
2002	0.42	0.27	0.30	0.44	0.57	1.06	3.06
2003	0.43	0.29	0.31	0.42	0.68	1.06	3.21
2004	0.43	0.29	0.28	0.44	0.78	1.11	3.33
2005	0.39	0.27	0.32	0.38	0.79	1.01	3.17
2006	0.40	0.27	0.36	0.43	0.95	1.00	3.41
2007	0.40	0.28	0.36	0.44	0.88	0.98	3.34
2008	0.41	0.28	0.37	0.42	1.08	0.95	3.51
2009	0.41	0.29	0.47	0.45	1.28	0.93	3.82
2010	0.41	0.29	0.50	0.46	1.38	0.90	3.95
2011	0.42	0.30	0.44	0.46	1.72	0.88	4.21
2012	0.42	0.30	0.48	0.46	2.03	0.86	4.56
2013	0.43	0.31	0.52	0.45	2.21	0.84	4.76
2014	0.43	0.32	0.56	0.44	2.28	0.82	4.84
2015	0.44	0.32	0.60	0.44	2.39	0.80	4.98
2016	0.44	0.33	0.62	0.42	2.47	0.78	5.06
2017	0.44	0.34	0.65	0.41	2.60	0.75	5.18
2018	0.45	0.34	0.67	0.40	2.87	0.73	5.46
2019	0.45	0.35	0.70	0.41	3.01	0.71	5.62
2020	0.46	0.35	0.72	0.44	3.14	0.68	5.79
2021	0.46	0.36	0.74	0.43	3.26	0.66	5.91
2022	0.47	0.37	0.76	0.42	3.37	0.63	6.03
2023	0.47	0.38	0.79	0.42	3.48	0.61	6.15
2024	0.47	0.38	0.82	0.41	3.59	0.59	6.26
2025	0.48	0.39	0.85	0.40	3.68	0.56	6.37
2026	0.48	0.40	0.88	0.40	3.77	0.54	6.48
2027	0.49	0.40	0.91	0.41	3.86	0.52	6.59
2028	0.49	0.41	0.94	0.41	3.94	0.50	6.69

5.4.3 Residential and Commercial Gas Demand

Ziff Energy forecasts that these two sectors will grow by 1.4% per year in North America. The customer count grows and the consumption per customer declines, although results in a net increase.

Residential consumption in 2006 makes up 21% of total North America gas demand and residential gas demand is only 12% of Alberta demand. Ziff Energy calculates Alberta residential demand growth to be 1.0%/year over the outlook period, which is lower than the previous ten-year period (1.7%). On a normalised basis (Mcf/customer/HDD), residential consumers are continuing to make efficiency gains reducing the average consumption per residential unit.

Current North American commercial sector (schools, hospitals, stores, offices, and other) natural gas consumption of 8.8 Bcf/d represents 13% of total North American gas demand. Total Alberta commercial consumption is 0.3 Bcf/d or 8% of overall provincial demand. While commercial consumers are making efficiency gains, there has been almost no change in the average consumption per commercial user:

- commercial units cover a wide spectrum
- commercial consumption tends to track economic cycles more closely than residential consumption, with more focus on cost savings (turning off inefficient equipment when capacity is not required) during economic downturns, and more focus on revenues and less on cost control (operating less efficient equipment) in times of growth.

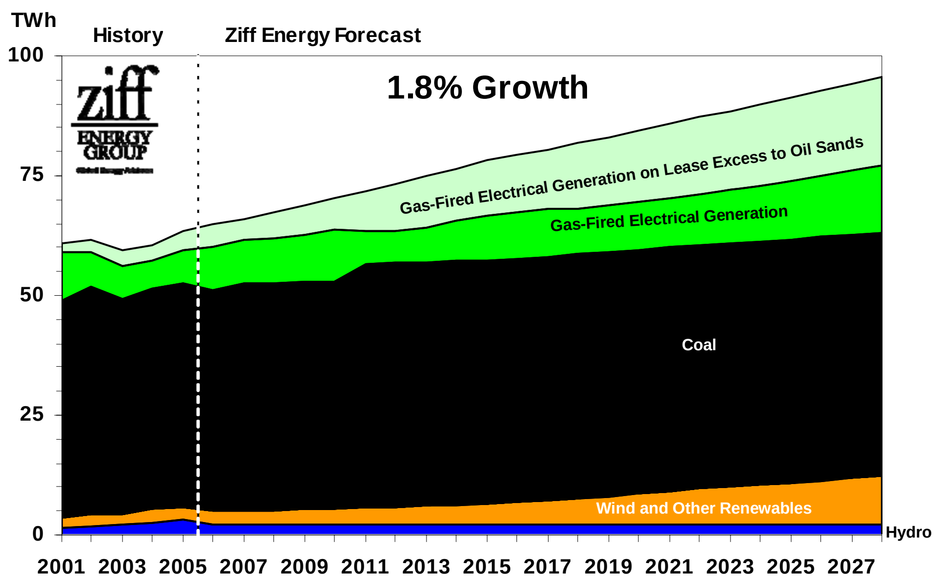
5.4.4 Gas for Power Generation

While Alberta's power generation uses several fuel types including coal, natural gas will play a key role in generating future power.

Figure 7 indicates Ziff Energy's outlook for gas-fired generation demand for the power generation market grows at 1.8%/yr. Although Ziff Energy believes load factors for coal generation will creep upwards early in the forecast, gas-fired generation is the only real choice for incremental growth in power demand. Later in the forecast period:

- the opportunity to add new coal capacity tempers the growth in gas demand for power generation
- continued development of oil sands project continues to provide gas-fired electricity to the Alberta power market
- opportunities to grow wind power stations continue throughout the forecast.

Figure 7
Alberta Power Market



Source: Ziff Energy

5.4.5 Industrial Gas Demand

Due to lower cost gas availability in other parts of the world, gas demand for industrial processes in Alberta is challenged to grow. Currently, 80% of Alberta industrial activity falls in to two broad categories:

- chemical sector (52%) - fertilizer, methanol, and petrochemical industries are highly sensitive to swings in natural gas pricing as they consume natural gas as a feedstock in production and cannot easily substitute natural gas for a different energy source. Chemicals are also disadvantaged by the fact that natural gas composes a large percentage of their production cost. This results in the end product being less competitive when oil:gas prices tend toward parity (and *vice versa*) as the global market[76] uses crude oil and its derivatives as feedstocks for their petrochemical production
- other Manufacturing sector (27%) - the other manufacturing sector is more dependent on economic conditions and has been stagnant for the past decade. As most processes are not natural gas intensive, commodity price swings have a limited impact on final product costs. Utilizing new technologies to reduce the amount of energy required to fuel operations is prevalent throughout this sector. For example, food manufacturing has been striving to reduce natural gas and other energy costs by implementing efficient processing methods. Given the stable and consistent nature of this segment, future gas usage is forecast to be moderate although steady.

It is Ziff Energy's opinion that the outlook for industrial gas demand is flat, with the chemical sector in flat to slight decline and the other manufacturing sector to be flat to slight growth.

5.4.6 Pipeline Fuel/Plant Fuel

To produce gas at a well lease site, and to transport the gas on pipelines, gas is consumed. With less Alberta gas produced and thus less gas to transport, gas demand in this sector will decline. The production and transmission of gas to end user markets requires 35% (1.0 Bcf/d) of Alberta gas supply:

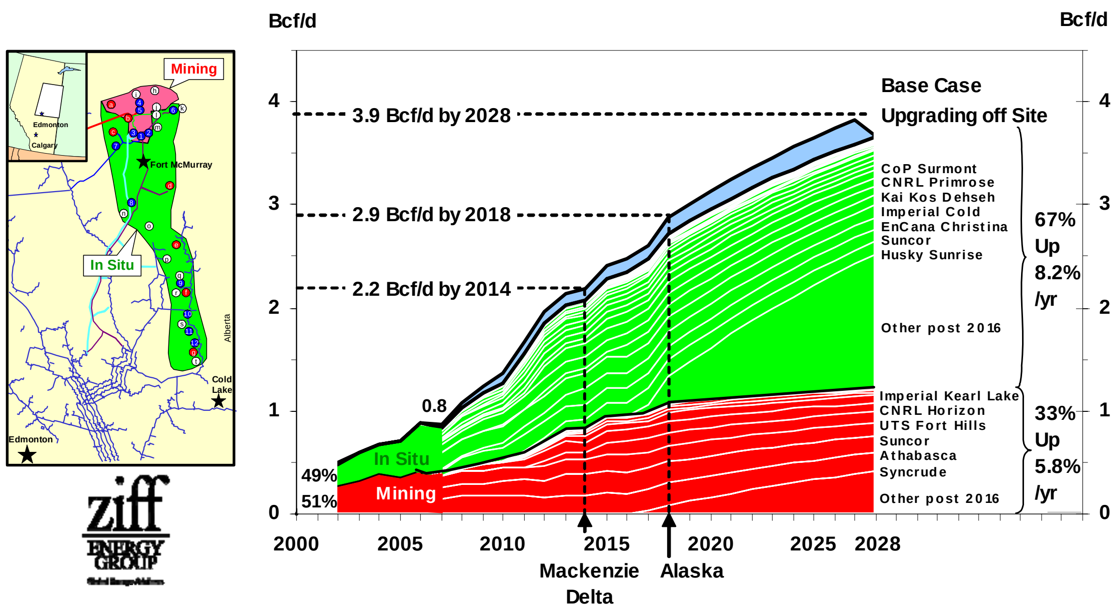
- *lease fuel*, natural gas is used in well, field, and lease operations such as gas used in drilling operations, heaters, dehydrators, and field gas compressors. Ziff Energy forecasts *plant gate* supply post lease, therefore *lease fuel is not* included as a demand
- *plant fuel*, natural gas is used as fuel in natural gas processing plants
- *pipeline fuel* consumed in pipeline compressor operations.

[76] significant portion of European and Asian producers use crude oil

5.4.7 Alberta Oilsands Natural Gas Demand

The Alberta oilsands are expected to consume more natural gas than any other gas demand sector in Alberta, growing to 3.9 Bcf/d by 2028, up from 0.8 Bcf/d in 2006 and 2.9 Bcf/d in 2018. This growth is driven by increasing oilsands production which Ziff Energy forecasts will increase to 5.8 MMBbl/d by 2028, up from 1.1 MMBbl/d in 2006[77] and 3.7 MMBbl/d in 2018. Gas is required for mining projects for process heat to separate bitumen from the mined material, to generate electricity, and to upgrade the bitumen into synthetic crude oil. In situ projects need gas to produce steam, generate electricity, and for upgrading. Figure 8 shows natural gas demand for the major oilsands mining and in-situ projects.

Figure 8
Alberta Oil Sands Gas Demand



Source: Alberta Energy and Utilities Board, Ziff Energy

5.4.8 Oil Sands Assumptions

Assumptions used in the Ziff Energy forecast are as follows:

- Bitumen production was forecast on an oilsands project by project basis based on capacities identified by operators, with adjustments as follows:
  - new projects were forecast to operate at 50% load factor in their first year
  - in situ projects and mining projects operate at 90% load factor after the first year
  - oilsands production was discounted by project based on regulatory status, to recognize that not all Oil Sands projects will proceed[78]

[77] from EUB ST98-2007
[78] discounted based on regulatory status, using the same methodology as in Oilsands Industry Update, June 2007, published by Alberta Employment, Immigration and Industry http://www.albertacanada.com/energyCommodities/files/pdf/oilSandsUpdate_June_2007.pdf

- as few new projects are identified after 2016, Ziff Energy assumed that 150 Bbl/d of new in situ capacity and 100 Bbl/d of new mining capacity will be added every year after 2016. These amounts were based on average capacity additions between 2006 and 2016 of about 150 Bbl/d for both in situ and mining projects. Ziff Energy's lower forecast for post 2016 mining additions reflects lower reserve life of mining reserves versus in situ reserves[79]

- gas demand for each oil sands project includes gas for related electrical generation, plus onsite upgrading. Figure 8 shows demand for offsite upgrading (light blue band), assuming 70% of all bitumen produced in Alberta is upgraded in Alberta[80]

- gas demand was based on the gas intensities shown in Table 7, and includes gas required for related electrical generation:

Table 7
Oil Sands Gas Use Intensities[81]

Project Type	Gas Intensity (Mcf/Bbl)
In Situ projects	1.18
Nexen/Opti Long Lake	0.28
Mining (includes upgrading)	0.64
Offsite Upgrading	0.25

- gas intensities assume that "off gas" produced in upgrading and in-situ production operations will continue to be produced and used as fuel for oilsands projects, in proportion to the amount of bitumen production. This off gas reduces the total amount of natural gas required. Section 5.5 provides more detail on off gas and the potential to process off gas to produce NGLs

- forecasts assume natural gas continues to be the fuel of choice for the oil sands projects, although gas intensities have been reduced 2%/year starting in 2010 assuming gradual adoption of technology that reduces reliance on natural gas. The following section provides more discussion in this regard

- both In Situ and Mining gas requirements are expected to grow, collectively averaging over 7.1%/year

- Ziff Energy expects 2.2 Bcf/d of gas required by Nov. 2014, when Mackenzie Delta gas deliveries are expected, rising to 2.9 Bcf/d by Nov. 2018 when Alaska gas is forecast to arrive, 3.6 times greater than the current gas requirements of 0.8 Bcf/d.

[79] mining reserve life is 50 years and in situ is 300 years, based on forecast 2015 production levels and 2007 reserves per EUB ST98-2007

[80] based on EUB ST98-2007, which forecasts 69 to 71% of bitumen produced is upgraded in Alberta from 2006-2016

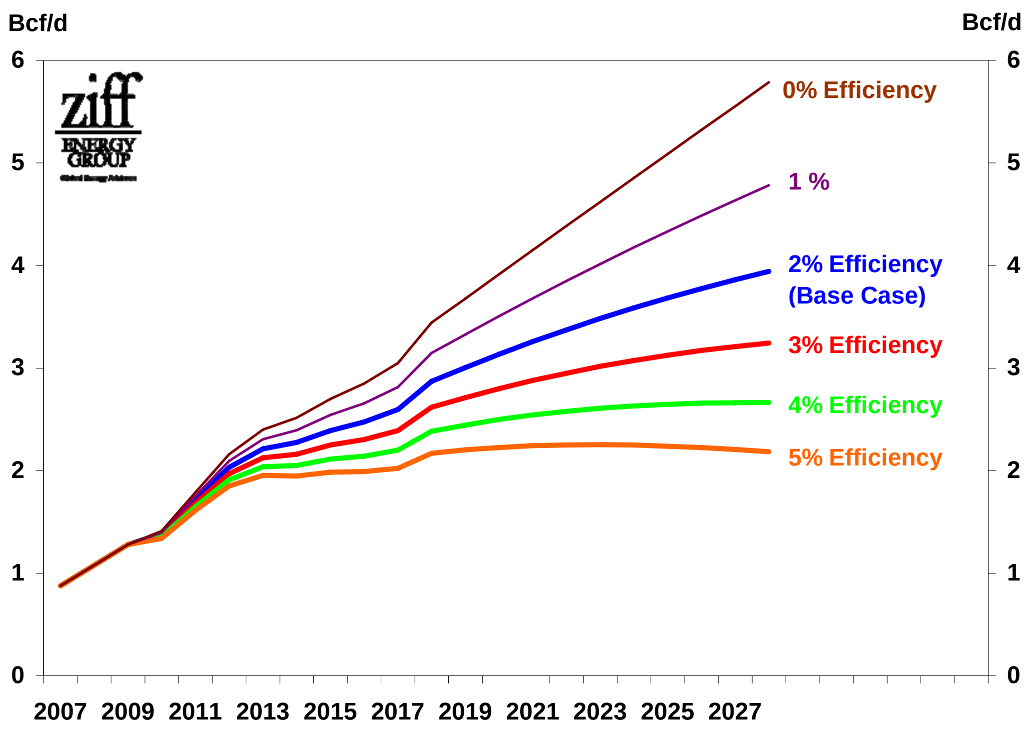
[81] intensities based on EUB ST98-2007. ST98 provides gas use/Bbl, with and without gas purchased for onsite electrical generation. Ziff Energy took 69% of the incremental gas use/Bbl for electrical generation, as the EUB projects oilsands projects will use 69% of total electricity they generate, with the remainder flowed to the grid

5.4.9 Impact of Technology Improvements

Alternative technologies are being developed to extract and upgrade bitumen in more energy efficient processes that decrease natural gas use. Some involve converting by-products of bitumen upgrading, such as coke and asphaltenes, into a syngas (for example, syngas contains 25% hydrogen) to replace natural gas. The Nexen/Opti Long Lake project uses this type of technology. Other technologies have been proposed that create heat and/or thin the bitumen in the formation without using natural gas.[82]

As most new commercial projects under construction have not yet adopted these technologies, Ziff Energy does not expect much benefit until 2010 as new projects yet to be designed and constructed come on stream. Ziff Energy's forecast assumes gas intensity in oilsands projects will decrease 2%/year starting in 2010 based on adoption of these technologies. This results in overall gas requirements being reduced by 17% by 2018 and 32% by 2028. Figure 9 shows the impact on natural gas requirements if technology further accelerates improvements, based on a range of annual percentage reductions in gas intensity starting as early as 2010.

Figure 9
Natural Gas Demand for Oilsands Projects
(Technology Improvement after 2010, %/Year)



Source: Ziff Energy

[82] Petrobank is operating a pilot using the THAI process (Toe to Heal Air Injection), where air is injected into the formation, causing combustion of the bitumen and heating the zone, which mobilizes and partially upgrades the bitumen in situ. Biological upgrading has been proposed where anaerobic organisms are introduced into the formation to upgrade the bitumen in-situ and allow it to flow without heating

5.4.10 Nuclear Energy as a Substitute for Natural Gas

Nuclear reactors have been considered as a substitute to natural gas to generate steam, hydrogen, and electricity for in situ processes and upgrading. From a cost basis, nuclear may have merit and may be a good match with oil sands energy requirements for high load factor steam and hydrogen, which could be provided by a nuclear plant without CO_2 emissions. However, there are a number of considerations that may make nuclear energy impractical for widespread use in the oilsands:

- a large part of the energy requirements are for generating steam for in situ projects. As it is not practical to transport steam long distances, and given economies of scale for nuclear plants, such plants may only be practical for the largest projects. For example, the Long Lake project has 170 MW of capacity (two 85 MW units), whereas the smallest nuclear plants are much larger.
- the industry may find it unacceptable to locate nuclear plants adjacent to production sites due to the risk of contamination of the oilsands reserves and operations in the event of a nuclear accident
- the long lead time to gain approval for nuclear and the time to construct may adversely impact the oil sands economics through long term delay
- plant proponents would likely want the ability to export excess power to the grid so may need significant electricity transmission upgrades to accommodate this.

5.5 Off Gas from Oilsands Operations

Off gas is a by-product of the production and upgrading of bitumen into synthetic crude oil. In addition, gas is produced with bitumen from in situ wells. For purposes of this report, both of these gas sources will be called off gas. Off gas is a mixture of hydrogen and light gases, including paraffin ethane, propane, butane, propylene, and butylene. The composition of off gas from upgrading operations depends on the technology and design of the upgrader.

Currently most off gas is used in oilsands operations as a fuel in upgraders, for producing electricity, and for process heat. As a result, off gas reduces the amount of natural gas otherwise purchased by oilsands projects and upgraders. Ziff Energy's gas demand forecasts assume that off gas will continue to be produced and used in oilsands operations as in the past, in proportion to total bitumen production. The EUB estimate that 1.4 Bcf/d of off gas will be produced by 2016.[83]

As off gas contains ethane and other heavier hydrocarbons as described above, this gas can be processed to extract NGLs, and the residue gas used as a fuel for oilsands projects as before. Williams Companies is the only company with an off-gas processing facility, which is at Fort McMurray and processes off gas from Suncor. Olefins are extracted there and then fractionated into propane and propylene at Williams' Redwater fractionation facility. In addition the following off gas plants or expansions have been proposed:

[83] from EUB ST98-2007, includes what the EUB call "process gas" from upgrading operations plus solution gas produced with bitumen from in situ wells

- addition of a de-ethanizer to the Williams' Redwater facility to start in 2010 to produce ethane to be sold to Nova Chemicals
- Aux Stable Canada plans to build an off gas plant by late 2008 to process up to 50 MMcf/d of off gas from the Heartland Upgrader in Fort Saskatchewan and produce up to 20,000 Bbl/d of NGL's.

Off gas processing reduces the heat content of the residue gas and hence reduces off gas available for oilsands operations, so this processing may result in increased natural gas demand for oilsands projects. Given the limited amount of off gas projects, Ziff Energy has not specifically reflected the impact of such processing in its oilsands gas demand forecasts. To give an idea of the potential impact, if 50% of off gas from upgrading operations was processed, Ziff Energy estimates that oilsands natural gas demand would increase about 4%, or would increase from 3.9 to 4.1 Bcf/d in 2028 if this were to occur.[84]

[84] assumes off gas provides about 35% of total gas requirements for oilsands, 65% of gas is purchased after 2006 (based on EUB ST98-2007), off gas shrinkage is 15%, and 50% of off gas is processed. Total shrinkage that needs to be made up by increased gas purchases is 2.3% (50%*35%*15% shrinkage) of total requirements. Given Ziff Energy's gas demand forecast represents 65% of total oilsands energy requirements, Ziff Energy's forecast would need to be increased by 3.5% (2.3%/65%). Ziff Energy's 2028 forecast is 3.94 Bcf/d so would become 4.1 Bcf/d in this scenario

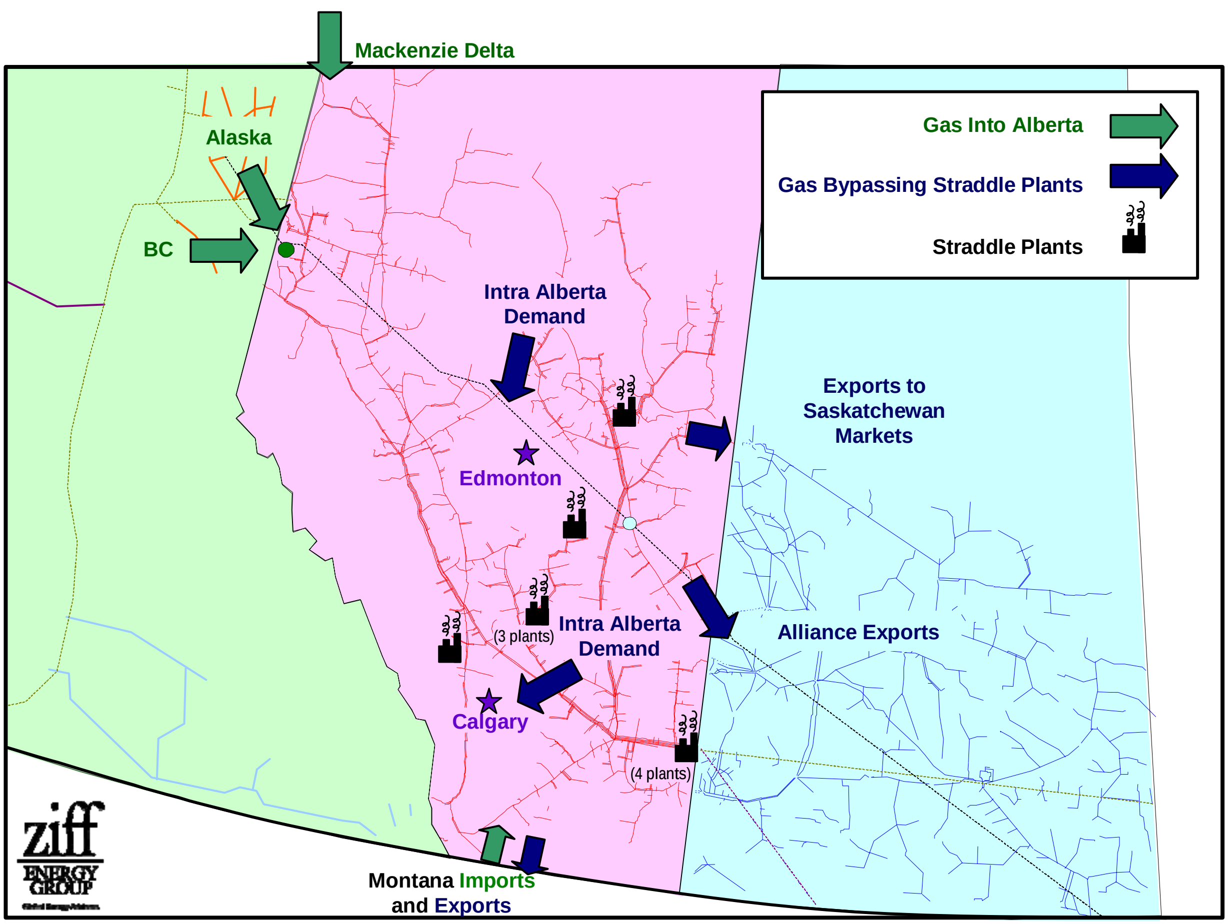
5.6 Alberta Natural Gas Supply Available for NGL Extraction

Ziff Energy assumes that Alberta gas markets (including gas for the growing oil sands) are met prior to export of gas. Natural gas liquids (NGL) from natural gas processing will come from:

- the Alberta field level plants, where NGL will decline with gas production declines
- the intra-Alberta straddle plants, where NGL production will be fairly stable as the plants process gas to the Alberta residential/commercial gas markets
- the Alberta border straddle plants, which like the Alberta field level plants, will see declining NGL production as gas production and exports decline.

Figure 10 illustrates factors considered in undertaking a NGL outlook from a gas supply and gas demand balance.

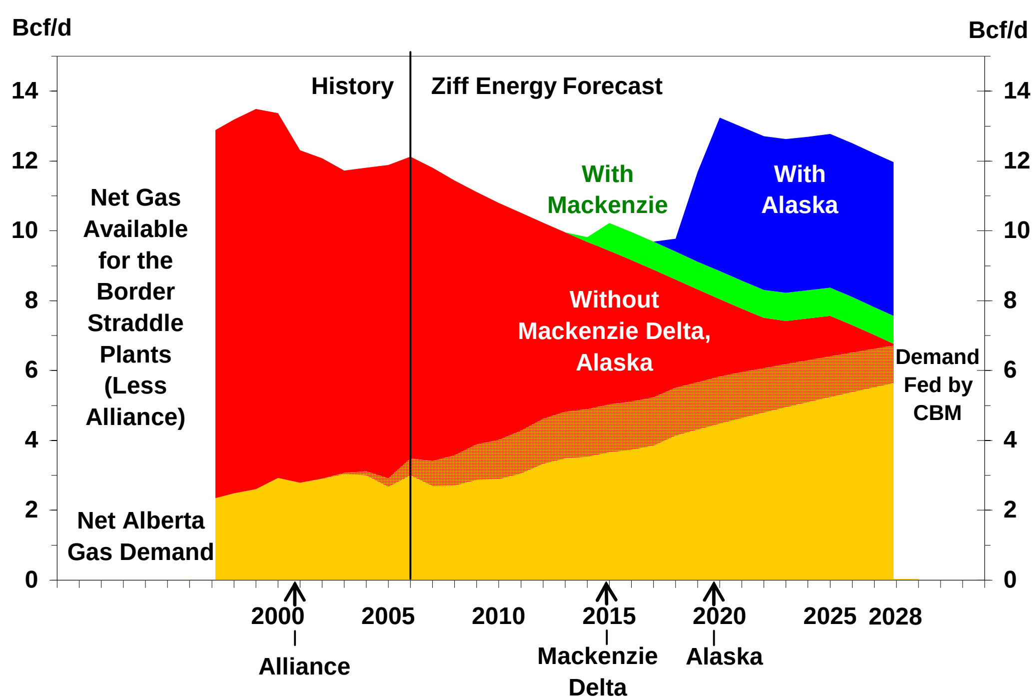
Figure 10
Factors Considered in Determining Gas Available for Processing



Source: Ziff Energy

Figure 11 depicts the total gas supply by source (Alberta, Mackenzie, and Alaska), and the Alberta gas demand fed from that supply. The supply includes 0.075 Bcf/d gas imports from BC at Gordondale. The skyline of the chart represents total supply moving through Alberta, made up of Alberta supplies (red and gold areas), gas from Mackenzie Delta (in green) and gas from Alaska (in blue). The gold portion represents intra-Alberta gas demand and includes the cross hatched area. The cross hatched area represents CBM supplies, that for purposes of modelling, are assumed to be diverted to intra-Alberta gas markets and so CBM is not available for gas processing at the Alberta border straddle plants. The portion in red is the amount of gas available to the Alberta border straddle plants after Alberta demand is met. To the extent Mackenzie and Alaska flow into the NGTL system, they will increase gas supply available to the border straddle plants, so total straddle plant supply would include the red, green, and blue gas volumes. By 2028, gas supply available to the straddle plants would be 5.2 Bcf/d with northern gas and zero without.

Figure 11
Net Natural Gas Supply Available for NGL Extraction



Source: Ziff Energy

Table 8 provides the net gas supply, net gas demand, and the gas supply remaining for straddle plant NGL extraction to 2028.

Table 8
Gas Available for Straddle Plant NGL Extraction (Bcf/d)

Year	Net Gas Demand	Demand Fed by CBM	Net Gas Supply Without Mackenzie, Alaska	Net Gas Supply With Mackenzie, Alaska	Net Gas Available for Straddle Plant Processing Without Mackenzie, Alaska	Net Gas Available for Straddle Plant Processing With Mackenzie, Alaska
	Bcf/d	Bcf/d	Bcf/d	Bcf/d	Bcf/d	Bcf/d
1997	2.33		12.83	12.83	10.50	10.50
1998	2.49		13.19	13.19	10.70	10.70
1999	2.61		13.49	13.49	10.88	10.88
2000	2.92		13.38	13.38	10.45	10.45
2001	2.79		12.31	12.31	9.53	9.53
2002	2.90	0.01	12.07	12.07	9.17	9.17
2003	3.04	0.03	11.69	11.69	8.65	8.65
2004	3.00	0.13	11.68	11.68	8.68	8.68
2005	2.67	0.25	11.64	11.64	8.97	8.97
2006	3.00	0.48	11.64	11.64	8.64	8.64
2007	2.70	0.71	11.10	11.10	8.40	8.40
2008	2.71	0.87	10.57	10.57	7.86	7.86
2009	2.88	1.01	10.10	10.10	7.22	7.22
2010	2.89	1.13	9.68	9.68	6.79	6.79
2011	3.06	1.22	9.30	9.30	6.24	6.24
2012	3.33	1.29	8.95	8.95	5.62	5.62
2013	3.49	1.33	8.63	8.63	5.14	5.14
2014	3.54	1.36	8.33	8.46	4.79	4.92
2015	3.66	1.37	8.05	8.85	4.39	5.19
2016	3.74	1.38	7.78	8.58	4.05	4.85
2017	3.85	1.38	7.51	8.31	3.66	4.46
2018	4.13	1.37	7.23	8.40	3.10	4.27
2019	4.31	1.36	6.96	10.32	2.65	6.02
2020	4.48	1.35	6.70	11.90	2.21	7.41
2021	4.64	1.32	6.46	11.66	1.82	7.02
2022	4.79	1.27	6.24	11.44	1.44	6.64
2023	4.95	1.24	6.19	11.39	1.24	6.44
2024	5.10	1.20	6.30	11.50	1.20	6.40
2025	5.24	1.17	6.41	11.61	1.17	6.37
2026	5.38	1.13	6.17	11.37	0.79	5.99
2027	5.52	1.10	5.91	11.11	0.39	5.59
2028	5.65	1.07	5.66	10.86	0.00	5.20

5.7 Appendix A

Ziff Energy forecasts total Western Canada marketable natural gas production from wells, then assumes 80% of that production comes from Alberta based on actual historical production. Alberta production of individual gas types is calculated separately.

5.7.1 Solution Gas

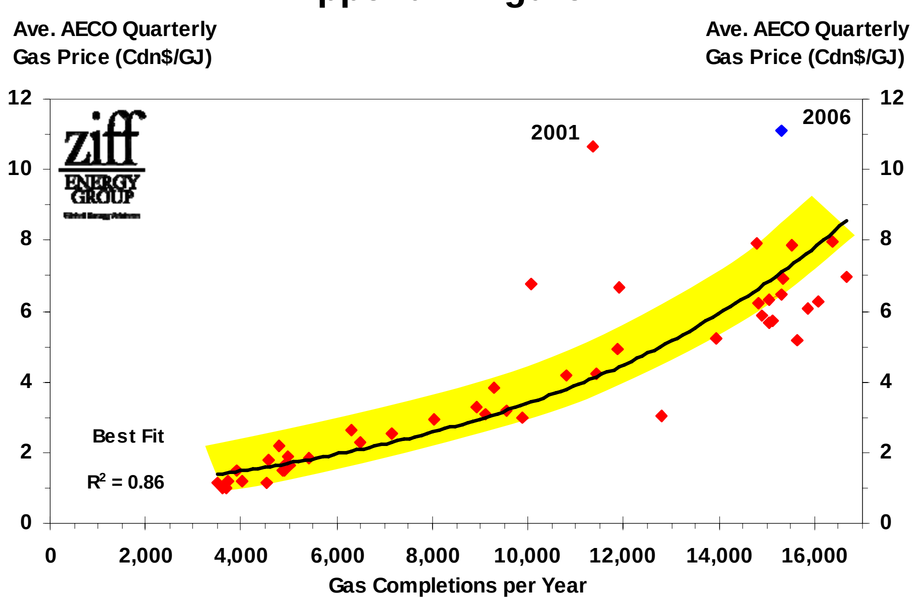
Alberta solution gas is natural gas recovered from oil production and contains NGL. Solution gas production declines at 2% per year, reflecting the long-term conventional oil production decline in Western Canada.

5.7.2 Gas Well Forecast Methodology

Figure A1 shows the relationship between gas price at AECO (previous quarter) and all Western Canada gas well completions (next 12 months). This figure, along with judgement of the impact of cost changes, royalties, and basin maturity, is utilized to assess the number of new gas well completions that will be undertaken through each year.

- Ziff Energy believes that the industry currently has a capacity to complete a maximum of 16,500 gas wells in Western Canada
- the more than three-fold increase in gas completions since 1998 corresponds with a similar increase in the AECO gas price
- in the first 10 months of 2007, 84% of gas completions were in Alberta.

Appendix Figure A1



Average 4th quarter 2006 gas price is correlated with expected completions for 2007

Source: Ziff Energy

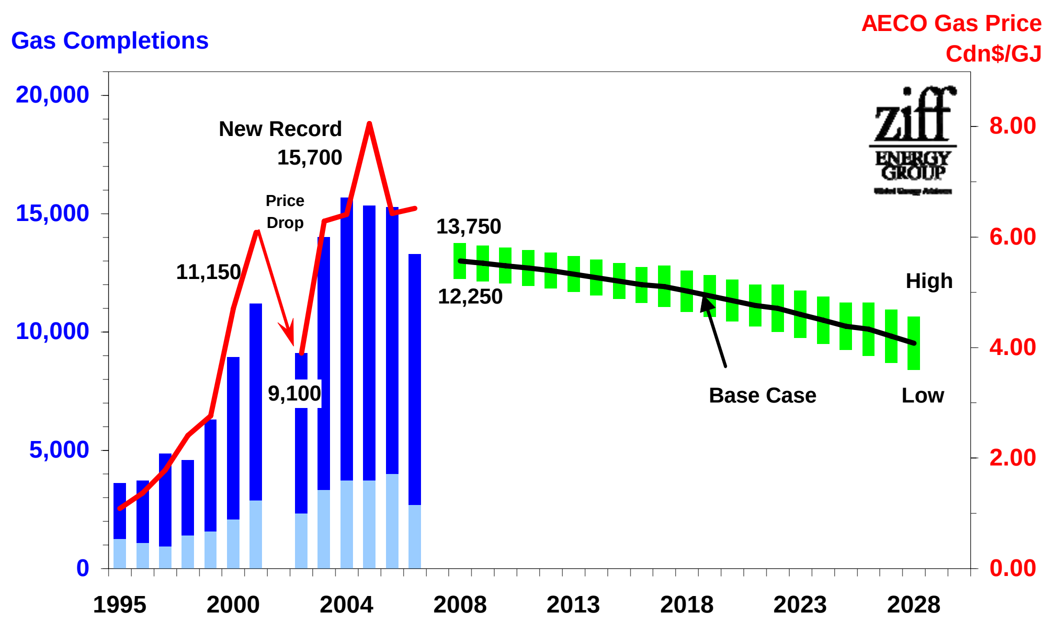
5.7.3 Gas Well Completions Outlook

Figure A2 shows the surge in gas directed completions since 1995 due to increasing gas prices and the completion outlook. Ziff Energy believes gas prices[85] through to 2015 will remain in a narrow range, of Cdn$6 to Cdn$8/GJ on an average year basis. The industry faces several challenges:

- currency exchange rate – the soaring Canadian dollar has decreased the price producers receive for their gas in Alberta (Cdn$ at AECO) compared to the US dollar based Henry Hub price
- falling new gas well productivity
- increasing gas finding and development costs
- escalating operating costs
- uncertainty of stable government royalties.

Ziff Energy's outlook shows gas well completions to 2028. While a low – high band is shown, Ziff Energy undertakes all analysis on the base case.

Appendix Figure A2
Western Canada Gas Well Completions Outlook to 2028



Source: Ziff Energy

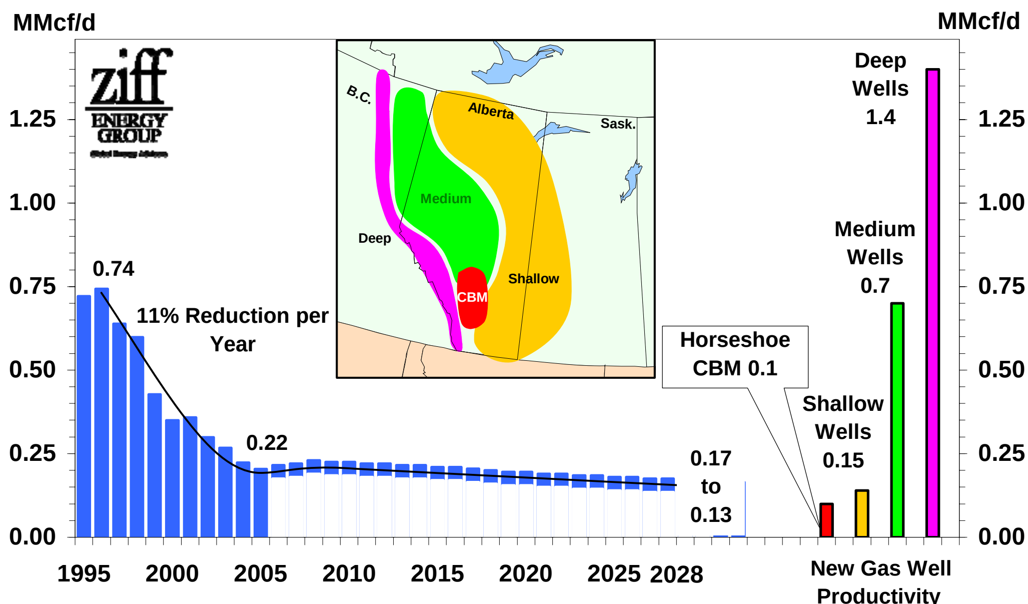
85 for a comparable reference, the EUB in its Alberta Energy Reserves 2006 and Supply/Demand Outlook 2007-2016 report ST98-2007 on p. 5-23 show an Alberta gas price outlook to 2016 in the Cdn$7 to $8+ level

5.7.4 New Gas Well Productivity

Figure A3 shows the continuous double digit reduction in new gas well maximum productivity since 1995. While each gas producing region has different characteristics, a key parameter is the typical declining new gas well productivity of the new well completions each year. Currently, a new gas well produces less than a third of what it produced in 1995, and that new gas well productivity will continue to shift downward by 2028, as the Western Canadian Sedimentary basin matures.

Ziff Energy believes it is important to indicate that the average new gas well productivity is an average of gas well productivities from various gas production strategies in Western Canada. For example, new deep gas wells may produce at an average of 1.4 MMcf/d, a medium depth gas well may produce at 0.7 MMcf/d and a new shallow gas well may produce at 0.15 MMcf/d. A typical new CBM well flows at 0.1 MMcf/d. Thus it is the weighted average of the all new gas wells that defines the average new gas well productivity.

Appendix Figure A3
New Gas Well Productivity

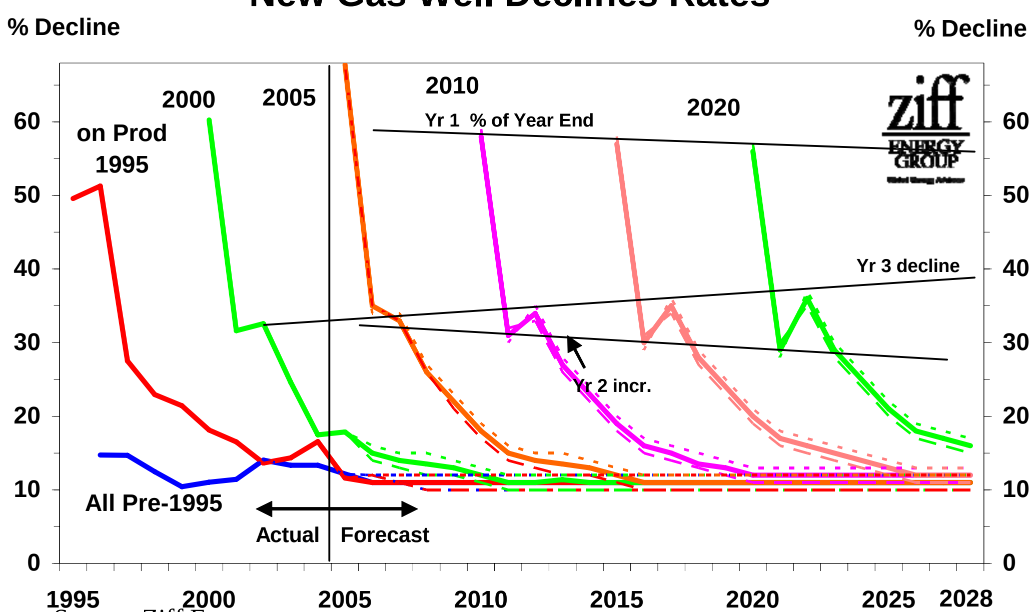


Source: Ziff Energy

5.7.5 Declines Rates

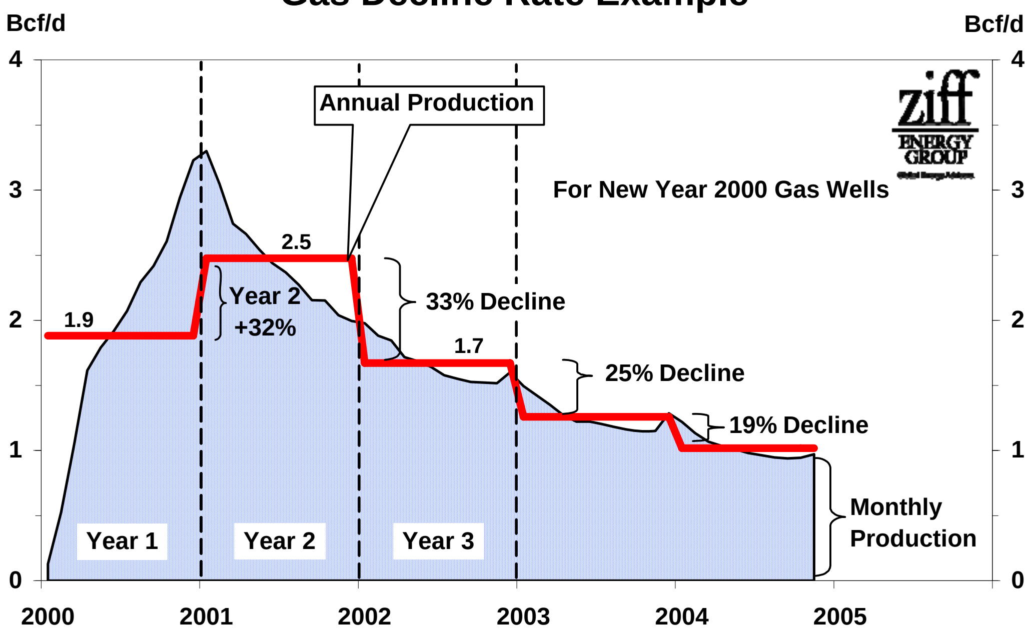
Figure A4 illustrates the new gas well decline rates which, over the past decade, have accelerated due to advances in completion technology and maximization of initial production rates. Figure A5 is an illustrative example of how decline rates are determined.

Appendix Figure A4
New Gas Well Declines Rates



Source: Ziff Energy

Appendix Figure A5
Gas Decline Rate Example



Source: Ziff Energy

5.7.6 Tight Gas Overview

Tight Gas is expected to grow in Alberta (and BC), thus Ziff Energy believes some additional insight is helpful to the inquiry. Investigation into Tight Gas and massive hydraulic fracturing began in the Deep Basin of Western Canada in the late 1970s when gas prices were high, although waned as gas prices fell with deregulation in the 1980s. Twenty-five years later, the Deep Basin remains an active area with only a fraction of its Tight Gas potential realized. Some insight:

General Comments

- in developing the gas production profiles and total production for each play, Ziff Energy used all wells placed on production after 1998 for the Jean-Marie and Cadomin, and applied a 5.3 MMcf/d (150,000 m3/d) maximum production rate to wells in the other tight gas plays
- Tight Gas wells tend to have higher initial decline rates than conventional wells; however, by the 3rd year, declines are generally lower, less than 20%.

Extended Deep Basin (Alberta and BC)

- previously, exploration has focused in the northwest, where Deep Basin plays extend into BC. Now, significant development is taking place much further south. The Extended Deep Basin stretches to the southeast past Calgary, and northwest to about 50 miles south of Fort Nelson in Northeast BC:
    - Tight Gas production comes from a thick section of Mesozoic sands and low permeability conglomerates including parts of the Cardium, Cadotte, Upper and Lower Mannville, and Cadomin, plus Triassic Doig and Halfway sands
    - some zones were previously by-passed in favour of conventional production and economics are improved by using the extensive existing infrastructure.

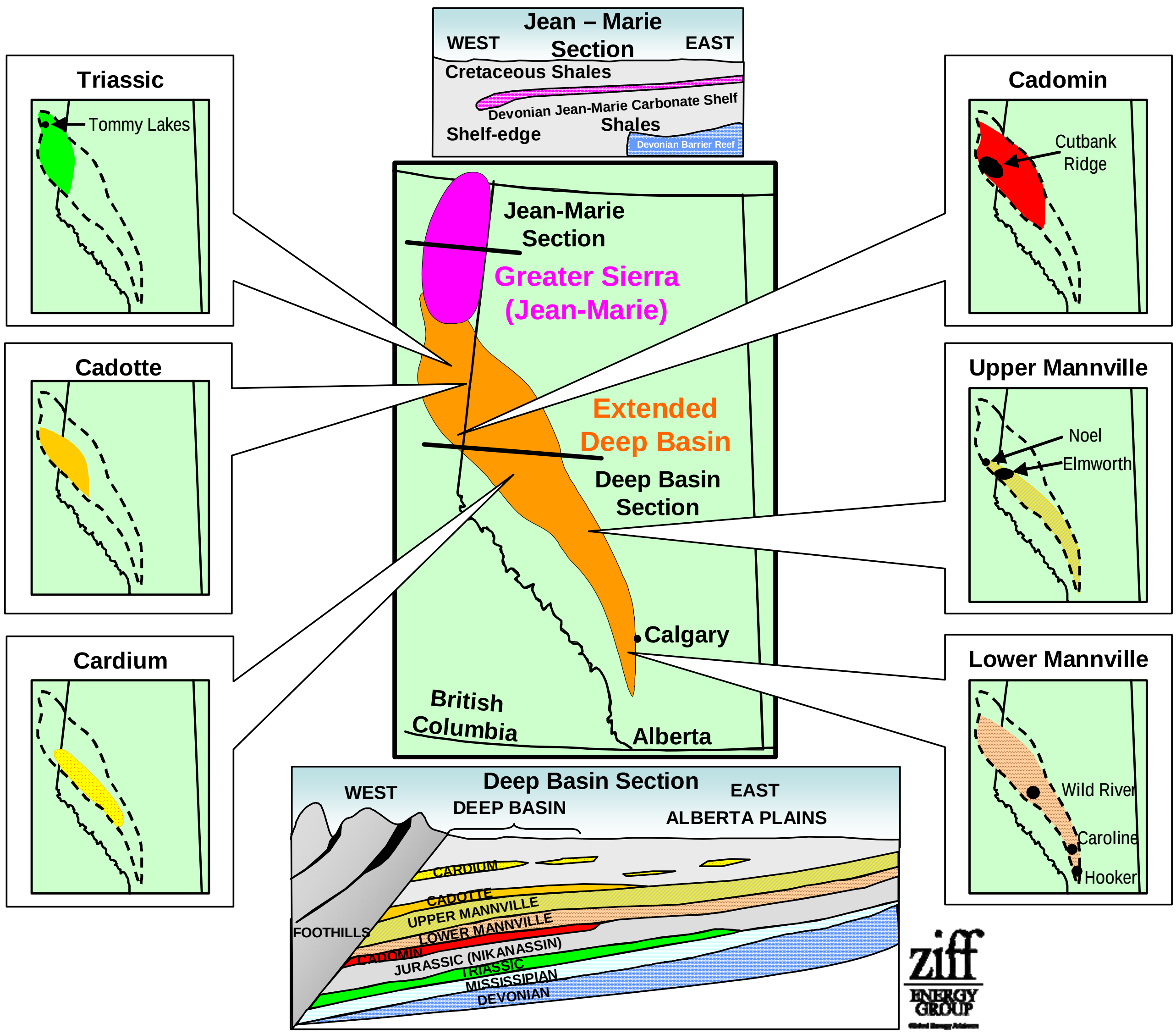
Greater Sierra (BC)

- sweet gas production comes from the Devonian Jean-Marie reef margin and lower productivity carbonate platform. EnCana exploited the potential using horizontal, under-balanced wells, and a low-impact, wooden mat system for roads and well sites for year-round drilling:
    - largest Tight Gas production increase has been in this play; however, production has likely peaked
    - 5 Tcf in place, with 50% recovery; better sections have 5-10 Bcf in place
    - initial gas well productivity is 1.4 MMcf/d, with over 40% early decline, and long term, lower declines of about 10%
    - EnCana’s Ekwan pipeline flows some of the gas production directly into Alberta
    - wells are commonly horizontal and drilled under-balanced.

5.7.7 Tight Gas Regions

Figure A6 illustrates the Tight Gas Regions and Plays.

Figure A6
Tight Gas Plays



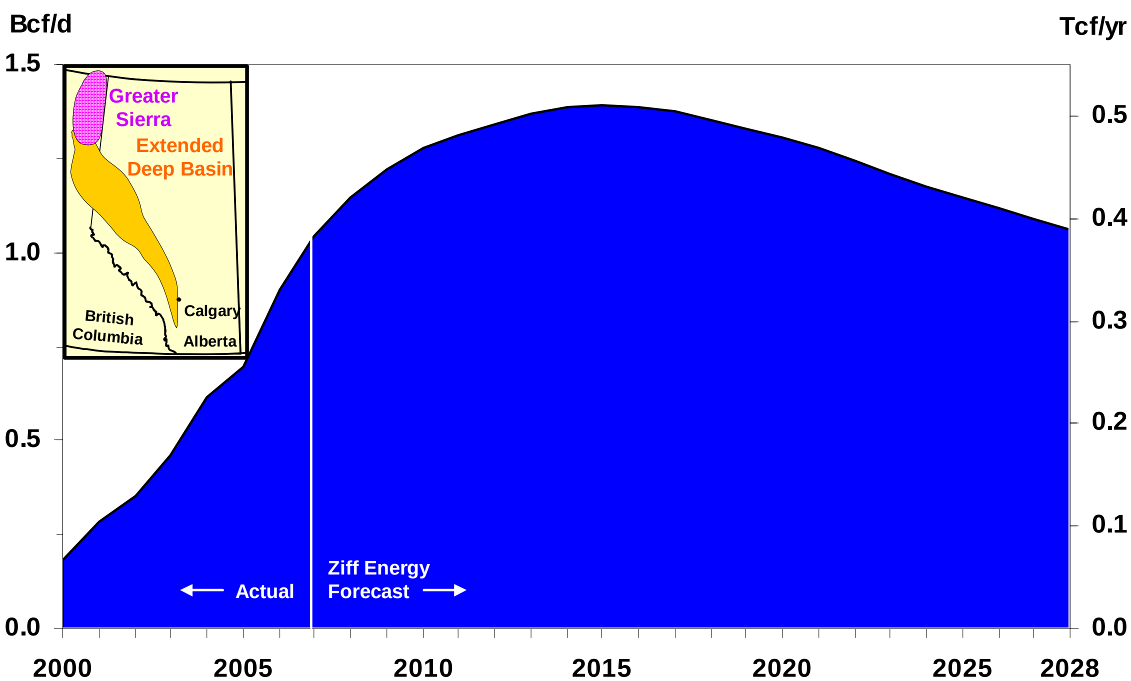
Source: Ziff Energy

5.7.8 Tight Gas Production Outlook

Figure A7 illustrates the Alberta Tight Gas Production Outlook. In developing the outlook for Alberta Tight Gas production, Ziff Energy used its Western Canada Tight Gas outlooks by play and included:

- all of the Upper Mannville and Cardium Tight Gas production
- 80% of the Cadotte and Lower Mannville
- 40% of the Cadomin
- none of the Jean-Marie (Greater Sierra) and Triassic plays as these are in British Columbia.

Figure A7
Alberta Tight Gas Production Outlook



Source: Ziff Energy

5.7.9 Coalbed Methane Parameters

Alberta Coalbed Methane (CBM), while expected to grow, contains lower quantities of Natural Gas Liquids. Some insight in to the 2 main CBM plays:

- the Horseshoe Canyon CBM fairway covers about 9,000 sections (square miles)
  - gas-in-place is estimated to be 66 Tcf (10% of Western Canada), though less than half may be economic
  - production from individual coal beds and intervening sands and silts is co-mingled
  - at 2 to 4 wells per section, this play has the potential for 20,000 to more than 30,000 wells
- Mannville CBM is largely at the pilot project stage
  - several companies have announced encouraging results
  - coals are typically deeper and wet, requiring costly water disposal
  - producing characteristics are speculative and will likely vary significantly across the basin
  - EnCana is believed to be developing dry Mannville gas which, without water disposal, will have lower operating costs
- over 600 MMcf/d will be produced from more than 7,000 wells by the end of 2007
- Ziff Energy expects CBM to grow to 1.4 Bcf/d in 2018, and decline to 1.0 Bcf/d in 2028.

Table A1 highlights key parameters of Ziff Energy's CBM production outlook:

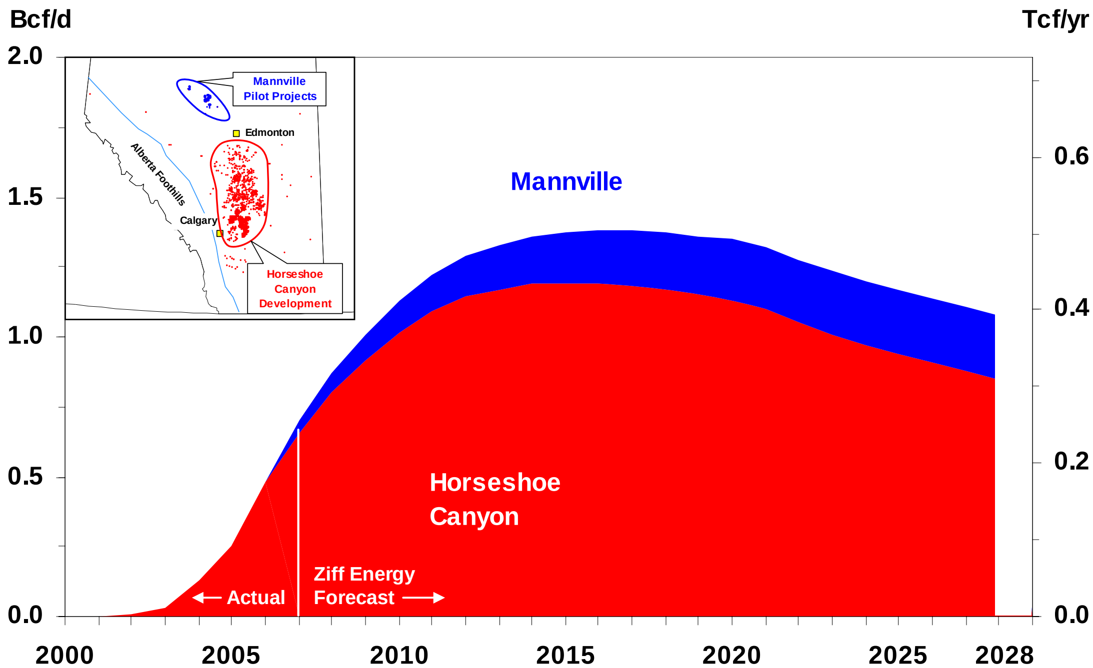
Table A1
Coalbed Methane Production Forecasting Parameters

Case	Gas Well Connections Per year	Total Production (Bcf/d)	Comment
2008	2,115	0.9	mostly Horseshoe Canyon development
2018	675	1.4	Horseshoe Canyon starts to decline; Mannville plateaus
2028	180	1.0	Horseshoe Canyon declining; Mannville flat

5.7.10 Coalbed Methane Production Outlook

Figure A8 provides Ziff Energy's Alberta Coalbed Methane outlook to 2028. At this time, Ziff Energy expects that CBM production from other Provinces will be minimal.

Figure A8
CBM Production Outlook



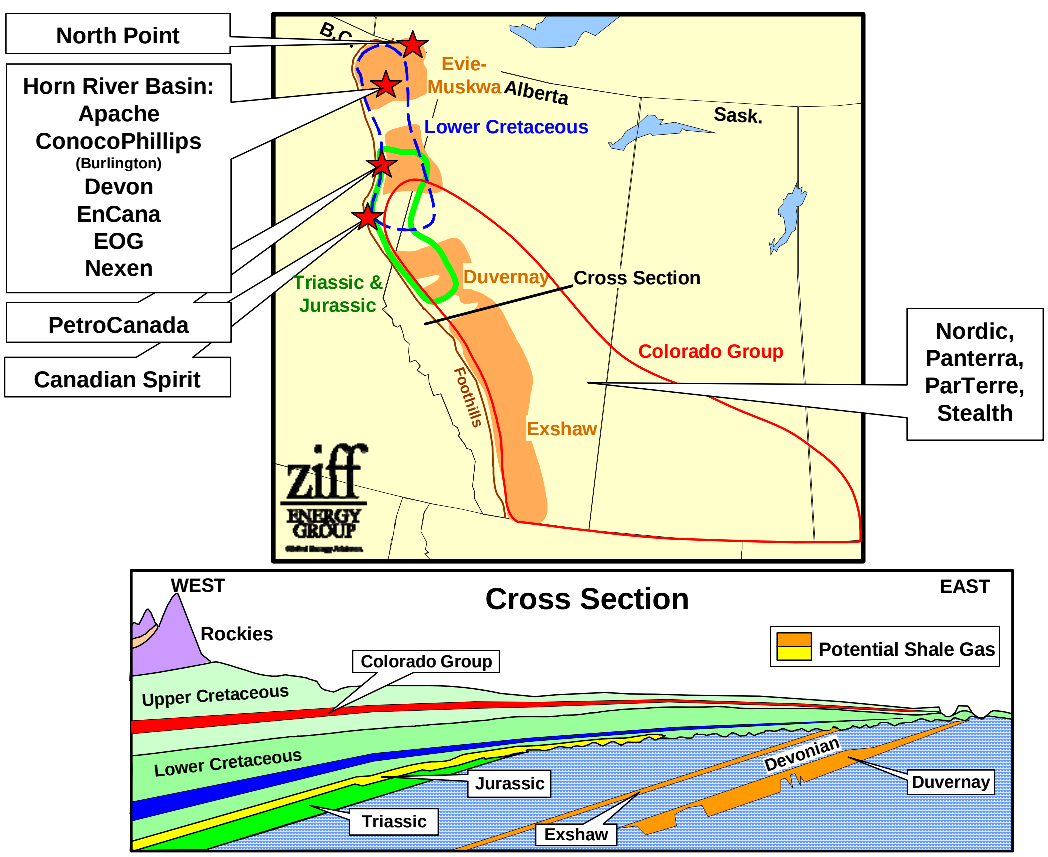
Source: Ziff Energy

5.7.11 Shale Gas Overview

Shale Gas was not a focus in Canada although there may be exploration break-through in the near future. Figure A9 provides an overview of the shale gas potential for Western Canada. While Ziff Energy does not explicitly include shale gas in its forecasts, some background may be helpful for the analysis:

- Canadian shale gas is at the early pilot stage of research. While shale occupies over 2/3rds of WCSB, only a small amount contain enough organic matter to be gas shales.
- there are two main types of shale gas:
  - deeper, thermogenic gas (sediments heated to gas window) thus potential is only in hotter, deeper, western parts of the basin; initial shale gas well productivity may be 0.5 to 1+MMcf/d; the Horn River Basin in NE BC has attracted several pilot and research projects
  - biogenic gas (produced by bacteria) in a mix of shallow low-pressure reservoirs (shale, sand, and silt) in the eastern parts of the basin, with low productivity, perhaps 0.1 to 0.2 MMcf/d per well.

Figure A9
Western Canada Shale Gas

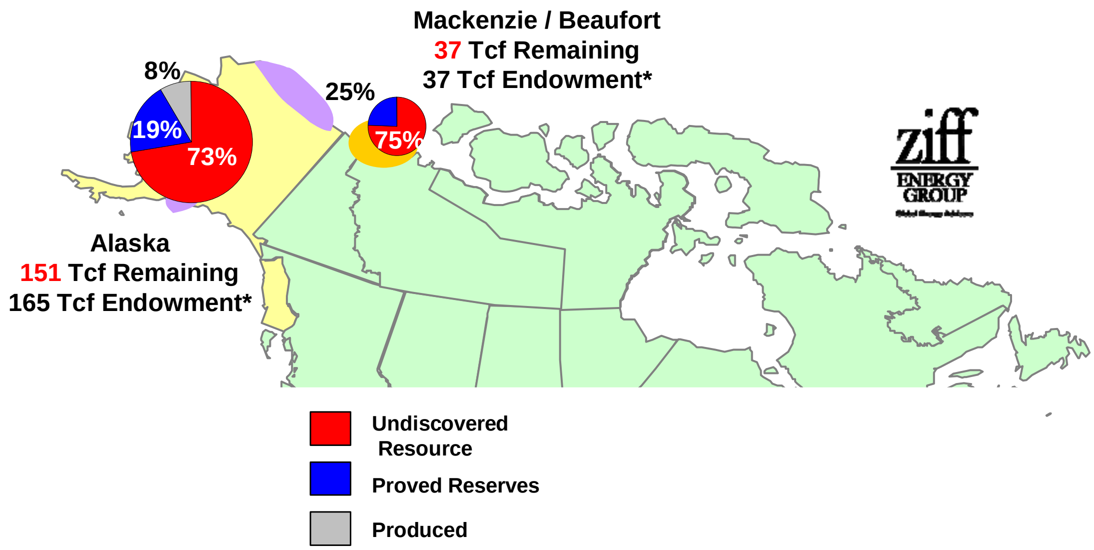


Source: Ziff Energy, Geological Survey of Canada, Daily Oil Bulletin

5.7.12 Alaska and Mackenzie Delta

Alaska contains 165 Tcf of gas endowment, half that of Western Canada. The Mackenzie / Beaufort contain an additional 37 Tcf. While 10% of the Alaska resource has been produced, little has been produced in the Mackenzie / Beaufort, thus an estimated 188 Tcf resource remains in the north, more than the remaining resource of Western Canada. Additional northern exploration and development may result in these estimates rising. Figure A10 illustrates the Northern gas Resource.

Figure A10
Northern Gas Resource (Tcf)



Source: EIA, NEB, PGC, CGPC, and Ziff Energy, as of Jan. 1, 2007
* Endowment = Produced + Reserves + Yet to be found Resource

Current industry plans are to eventually connect this northern gas into the North American gas markets although planning timetables suggest this is in the distant future. Industry estimates of the exact timing have evolved over the past half dozen years. Some early estimates indicated that the Mackenzie / Beaufort and the Alaska resource could have been connected already, thus indicating considerable uncertainty. Notwithstanding the uncertainty, it is estimated that the Mackenzie Delta could be connected perhaps as early as Nov. 2014, and Alaska, perhaps a few years later in Nov. 2018/ Nov. 2019. History has indicated the timetable estimates tend to be delayed. While the giant prize of over 4 Bcf/d from Alaska seems very appealing in a gas declining North America, the price tag for connecting Alaska gas is expected to exceed $35 Billion. The Canadian Mackenzie Delta may be even more economically challenged, with its costs escalating to $16 Billion for a small 0.8 Bcf/d, essentially pushing this gas supply somewhere deep into the future.

Ziff Energy has chosen to use the earliest possible dates for the connection – that is 0.8 Bcf/d in Nov. 2014 for Mackenzie / Beaufort and 2.2 Bcf/d in Nov. 2018 and rising to 4.4 Bcf/d for Alaska.

Table A2 provides a gas supply outlook for Mackenzie Delta and Alaska. As the Mackenzie Gas Project is assumed to only consider onshore gas developments, Ziff Energy does not anticipate the total initial production to exceed 0.8 Bcf/d. The Mackenzie Valley Pipeline has been designed for an initial flow of 1.2 Bcf/d; however, it can be expanded to 1.9 Bcf/d with additional compression. Based on proven reserves[86] of 34 Tcf on the North Slope and using the parameters discussed earlier, the initial production is 4.7 Bcf/d, and the average daily production is 4.4 Bcf/d using a 95% load factor for the pipeline. Due to the impact that such a large volume may have on markets, the Alaska gas production may be staged over two years: 2.2 Bcf/d in Nov. 2018, and 4.4 Bcf/d in Nov. 2019.

Table A2
Gas Supply Outlook for Mackenzie Delta/Beaufort and Alaska (Bcf/d)

Year	Mackenzie Delta	Alaska	Total Northern Gas	Alberta Total	Total with Northern Gas[87]
1997	0.00	0.00	0.00	12.83	12.83
1998	0.00	0.00	0.00	13.19	13.19
1999	0.00	0.00	0.00	13.42	13.49
2000	0.00	0.00	0.00	13.45	13.38
2001	0.00	0.00	0.00	13.71	12.31
2002	0.00	0.00	0.00	13.44	12.07
2003	0.00	0.00	0.00	13.07	11.69
2004	0.00	0.00	0.00	13.18	11.68
2005	0.00	0.00	0.00	13.25	11.64
2006	0.00	0.00	0.00	13.32	11.64
2007	0.00	0.00	0.00	13.05	11.10
2008	0.00	0.00	0.00	12.68	10.57
2009	0.00	0.00	0.00	12.35	10.10
2010	0.00	0.00	0.00	12.04	9.68
2011	0.00	0.00	0.00	11.75	9.30
2012	0.00	0.00	0.00	11.47	8.95
2013	0.00	0.00	0.00	11.19	8.63
2014	0.13	0.00	0.13	10.92	8.46
2015	0.80	0.00	0.80	10.64	8.85
2016	0.80	0.00	0.80	10.35	8.58
2017	0.80	0.00	0.80	10.05	8.31
2018	0.80	0.37	1.17	9.74	8.40
2019	0.80	2.57	3.37	9.42	10.32
2020	0.80	4.40	5.20	9.09	11.90
2021	0.80	4.40	5.20	8.76	11.66
2022	0.80	4.40	5.20	8.44	11.44
2023	0.80	4.40	5.20	8.13	11.39
2024	0.80	4.40	5.20	7.82	11.50
2025	0.80	4.40	5.20	7.52	11.61
2026	0.80	4.40	5.20	7.23	11.37
2027	0.80	4.40	5.20	6.94	11.11
2028	0.80	4.40	5.20	6.66	10.86

[86] State of Alaska indicated 35 Tcf in a presentation at the Ziff Energy conference in Houston in April 2004. ExxonMobil indicated 34 Tcf in their 2004 Annual Report

[87] excludes gas exported from Alberta on the Alliance Pipeline

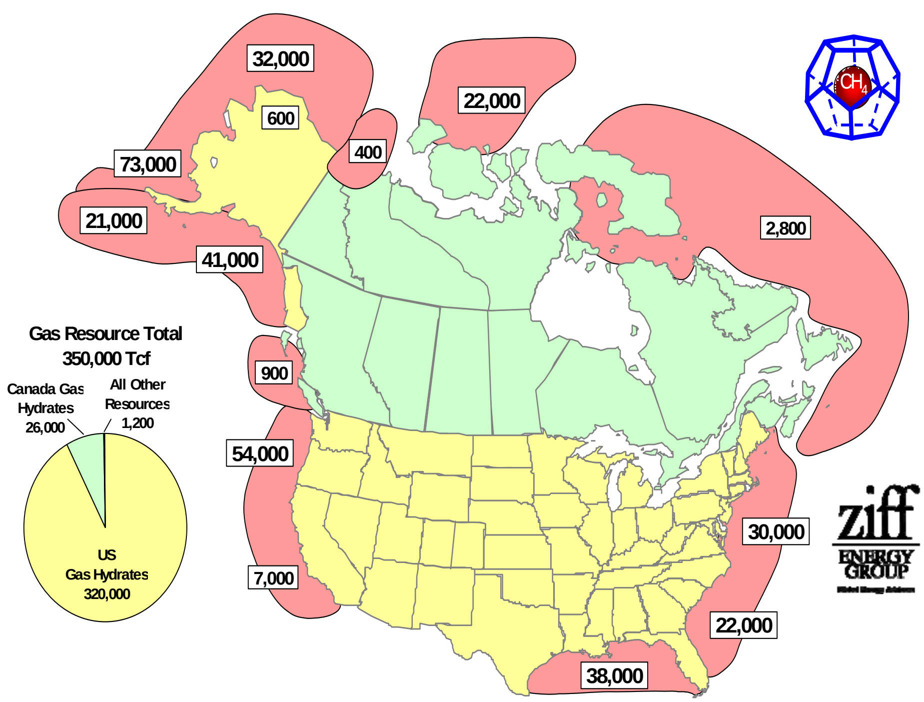
5.7.13 Gas Hydrates Overview

Gas hydrates are solid, crystalline, ice like substances containing methane trapped in a water-ice lattice. Hydrates form under moderately high pressure at temperatures near freezing, in permafrost areas, on the sea bottom or under sea beds. Figure A11 provides a map of North American gas hydrate potential for Canada and the U.S.

- pie chart in the lower left corner shows that gas hydrate potential dwarfs all other natural gas resources for the Canada and the U.S.
- recoverable reserves are likely a small percentage of the total hydrate resource (less than 1%)
- no commercial technology exists to recover the resource – a number of test projects have produced small quantities
- first production is most likely in onshore permafrost (Alaska, Mackenzie Delta), and would not likely be commercialized unless the Mackenzie or Alaska pipelines proceed
- producing hydrates has many technical challenges related to decomposing hydrates to release methane, and hydrate collection/stabilization of the seabed in marine locations.

Given the technical and infrastructure challenges of producing and bringing this supply to market, Ziff Energy has not included this gas supply source in its forecasts.

Figure A11
North American Gas Hydrate Potential (Tcf)



Source: U.S. Geological Survey, Canadian Gas Potential Committee, Ziff Energy

This page intentionally left blank.

6. ALBERTA NGL RESERVES, SUPPLY, AND DEMAND

6.1 Introduction

To forecast NGL supply from Alberta, Ziff Energy calculates the NGLs available from five[88] Alberta supply sectors and then sums the sector NGL supply to develop the aggregate Alberta NGLs forecast. The five NGLs sectors in Alberta that Ziff Energy considered are:

- NGLs from the Alberta border Straddle plants
- NGLs from the intra-Alberta Straddle plants
- NGLs from the 885 Alberta field gas processing plants[89] in Alberta
- NGLs from oil refineries
- future NGLs from proposed Mackenzie Delta and Alaska pipeline projects (included in Ziff Energy's analysis of the border Straddle plants), by component.

By forecasting NGLs from each sector, a more detailed view of Alberta NGLs production is available to allow meaningful comparison to the inquiry participants' forecasts. Ziff Energy uses existing estimates of NGL demand in Alberta by feedstock (ethane, propane, butane, and pentanes plus) prepared by the EUB, and extends those forecasts to 2028. An Alberta NGL supply / demand balance is then prepared for each component.

Forecasts for each of the five sectors were prepared using the gas supply forecasts generated in the previous section and representative gas compositions for the various streams. Later in this section, this is explained in more detail.

[88] this is not a complete list. Other sources may include:

- NGLs returns from miscible floods (Ziff Energy assumes this liquid would be recovered initially at the Alberta field gas plant and subsequently at the Alberta straddle plants. The EUB estimates 5.2 10^6 m3 (32,700 MBbl or 4.5 MBbl/d for 20 years or equivalent to a quarter of the intra-Alberta Straddle plant ethane production) of recoverable ethane is available. The EUB indicates that only 6 pools were still active in 2006 (Rainbow Keg River F, and Judy Creek Beaverhill Lake A pools are the 2 largest). Reference page 6-1 ST98-2007
- NGLs imported into Alberta could include condensate (and perhaps very small percentages of butane) for use as a diluent to assist with transport of bitumen and heavy oil
- NGLs from gas for proposed plants (Aux Sable)
- NGLs from gas for incremental ethane recovery projects

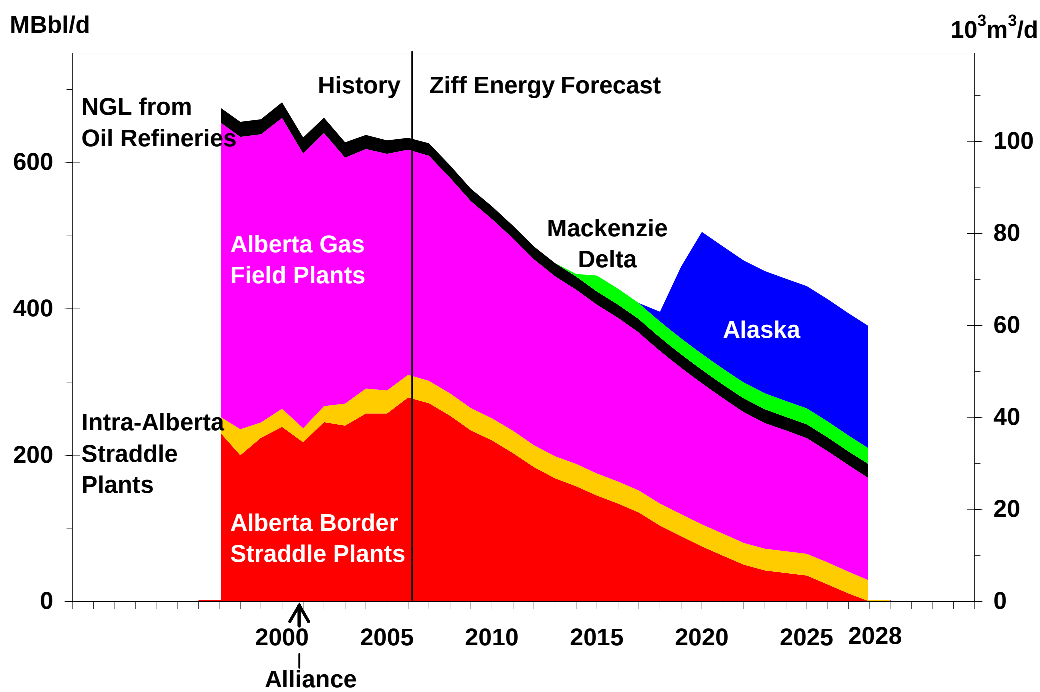
[89] of the total 903 gas field processing plants in Alberta, 885 plants receive gas, and 668 plants provide NGLs

6.1.1 NGL Production Outlook for Alberta

Figure 1 provides a summary of the Alberta NGL production[90] from the various NGLs sources[91] in Alberta to 2028:

- NGLs from the Alberta border Straddle plants
- NGLs from the intra-Alberta Straddle plants
- NGLs from gas processing field plants in Alberta
- NGLs from oil refineries
- NGLs from Mackenzie Delta and Alaska (included in Ziff Energy's analysis of the border Straddle plants).

Figure 1
Alberta NGL Production Outlook by Source to 2028



Source: Ziff Energy and AEUB

These represent average annual NGL volumes. Seasonal, monthly, daily, and hourly rates would fluctuate based on actual gas demand and gas supply. For example, gas demand is typically greater in the winter months.

[90] excludes NGLs produced from Alberta field plants connected to the Alliance pipeline
[91] excludes NGLs from new liquid plants such as Aux Sable Alliance plant.

Table 1 provides a tabular summary of the Alberta NGL production from the various Alberta NGLs sources in Alberta to 2028.

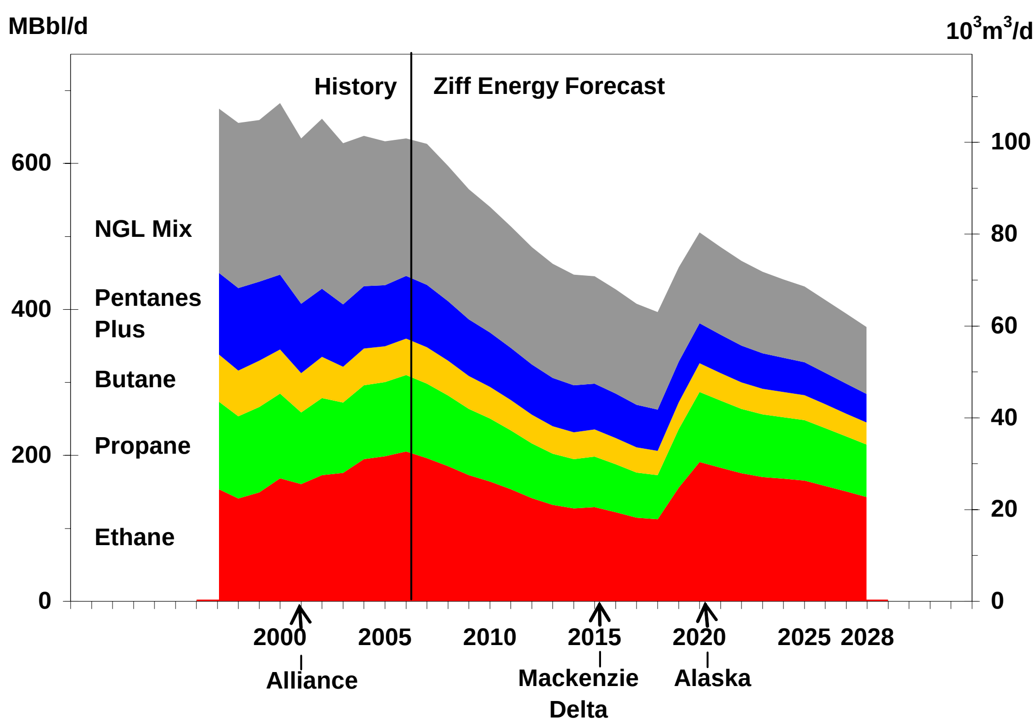
Table 1
Summary of Alberta NGL Production by Source

Year	NGLs from the Border Straddle Plants	Mackenzie Delta	Alaska	NGLs from Intra-Alberta Straddle Plants	NGLs from Alberta Gas Field Plants	NGLs from Oil Refineries	Total
	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d
1997	232.6	0.0	0.0	20.9	402.8	20.4	676.7
1998	199.8	0.0	0.0	35.8	399.9	20.4	655.9
1999	224.0	0.0	0.0	20.9	394.1	20.7	659.7
2000	238.9	0.0	0.0	24.6	397.5	21.7	682.8
2001	217.8	0.0	0.0	19.2	375.6	22.0	634.6
2002	245.4	0.0	0.0	22.0	373.4	20.8	661.6
2003	240.3	0.0	0.0	30.4	336.2	20.8	627.9
2004	257.1	0.0	0.0	34.0	327.6	19.4	638.0
2005	257.1	0.0	0.0	31.7	323.6	18.1	630.4
2006	279.2	0.0	0.0	30.7	308.1	16.1	634.2
2007	271.1	0.0	0.0	30.7	307.8	17.2	626.8
2008	254.1	0.0	0.0	30.6	294.5	17.3	596.6
2009	234.0	0.0	0.0	30.5	282.7	17.4	564.7
2010	220.3	0.0	0.0	30.5	272.2	17.5	540.4
2011	203.1	0.0	0.0	30.4	262.7	17.5	513.8
2012	183.5	0.0	0.0	30.4	254.0	17.6	485.6
2013	168.4	0.0	0.0	30.3	246.0	17.7	462.5
2014	157.5	3.5	0.0	30.3	238.6	17.8	447.8
2015	144.7	21.8	0.0	30.3	231.0	17.9	445.6
2016	133.8	21.8	0.0	30.2	223.7	18.0	427.5
2017	121.5	21.8	0.0	30.2	216.3	18.1	407.8
2018	103.6	21.8	13.9	30.1	208.7	18.2	396.4
2019	89.2	21.8	97.4	30.1	200.9	18.3	457.7
2020	75.2	21.8	167.0	30.1	193.0	18.3	505.5
2021	62.5	21.8	167.0	30.0	185.6	18.4	485.4
2022	50.2	21.8	167.0	30.0	178.8	18.5	466.4
2023	42.2	21.8	167.0	30.0	171.9	18.6	451.6
2024	38.7	21.8	167.0	30.0	165.1	18.7	441.3
2025	35.3	21.8	167.0	29.9	158.4	18.8	431.3
2026	23.3	21.8	167.0	29.9	152.1	18.9	413.1
2027	10.8	21.8	167.0	29.9	145.6	19.0	394.1
2028	0.0	21.8	167.0	28.4	139.2	19.1	375.5

Figure 2 provides a summary of the Alberta NGL production by component from the various NGL sources in Alberta to 2028.

- NGLs from the Border Straddle plants, by component
- NGLs from the intra-Alberta Straddle plants, by component
- NGLs from the gas processing plants in Alberta, by component
- NGLs from oil refineries
- NGLs from proposed Mackenzie Delta and Alaska pipeline projects (included in Ziff Energy's analysis of the border Straddle plants), by component
- the forecast excludes ethane that may be extracted at the proposed Aux Sable Fort Saskatchewan ethane extraction plant. Aux Sable plans to process 1.2 Bcf/d from the Alliance pipeline starting in mid-2010 and recover 40,000 Bbl/d of ethane[92]. If this project proceeds, ethane production would increase 18% in 2011. Note that in Ziff Energy's gas supply model, the Alberta Alliance gas volumes[93] show an initial decline starting in 2015 at 2%/yr, and 5% decline by 2020. The Ziff Energy gas supply models show zero Alliance Alberta exports in 2025/26. Consequently, the ethane supply from this plant, if it proceeds, would produce ethane for 14 years from the Alberta Alliance gas volumes.

Figure 2
Alberta NGL Production by Component to 2028



Source: Ziff Energy and AEUB

[92] Appendix 8 provides a copy of the Aux Sable Fact Sheet for the project
[93] Ziff Energy did not model the Alliance BC gas supply portion

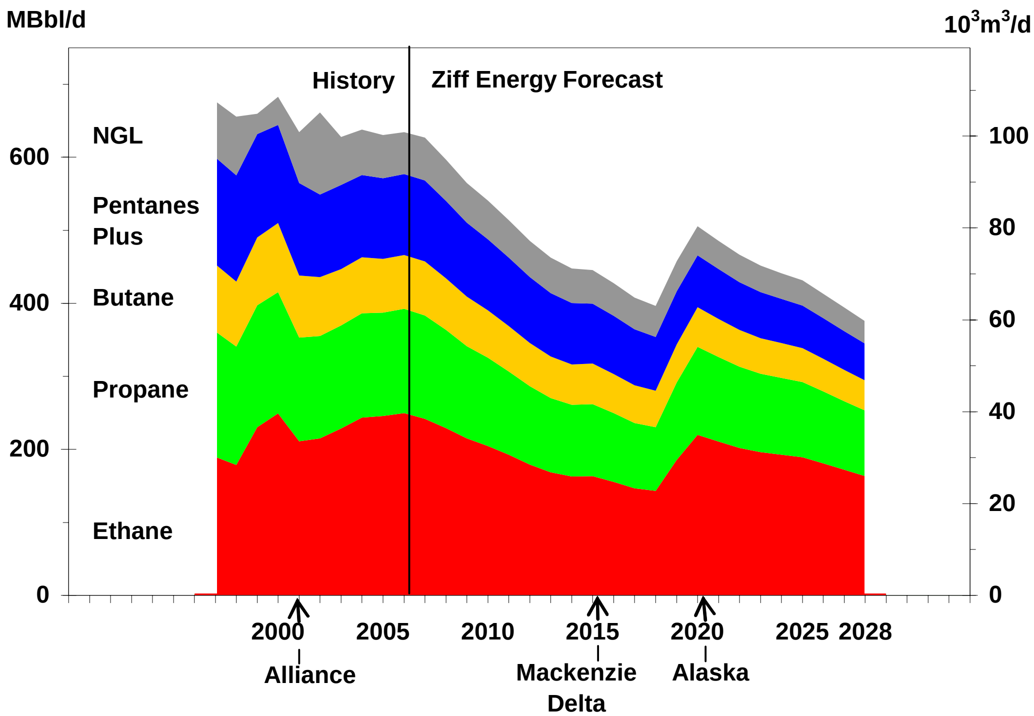
Table 2 provides a tabular summary of the Alberta NGL production by component from the various NGLs sources in Alberta to 2028.

Table 2
Summary of Alberta NGL Production by Component

Year	Ethane	Propane	Butane	Pentanes Plus	NGLs Mix	Total
	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d
1997	154.7	120.4	64.8	111.8	224.9	676.7
1998	141.2	112.7	62.6	112.9	226.5	655.9
1999	149.3	117.2	63.3	108.1	221.7	659.7
2000	168.8	116.0	60.3	102.5	235.1	682.8
2001	160.7	98.3	53.7	95.2	226.6	634.6
2002	173.2	105.4	56.5	93.4	233.0	661.6
2003	176.1	96.3	49.1	85.7	220.7	627.9
2004	194.9	101.1	50.7	85.2	206.1	638.0
2005	198.9	101.5	49.2	83.8	197.0	630.4
2006	205.3	104.7	50.1	85.8	188.2	634.2
2007	196.2	102.4	49.8	85.2	193.3	626.8
2008	185.4	96.8	47.6	81.3	185.3	596.6
2009	172.9	90.6	45.2	77.7	178.2	564.7
2010	164.3	86.1	43.5	74.7	171.9	540.4
2011	153.6	80.8	41.5	71.7	166.2	513.8
2012	141.6	74.9	39.3	68.9	161.0	485.6
2013	132.2	70.2	37.5	66.4	156.1	462.5
2014	127.3	67.8	36.6	64.3	151.7	447.8
2015	129.1	69.2	37.3	63.0	147.1	445.6
2016	122.3	65.7	36.0	60.8	142.7	427.5
2017	114.6	61.9	34.5	58.5	138.3	407.8
2018	112.4	60.5	33.3	56.3	133.7	396.4
2019	156.0	80.2	36.7	55.8	129.1	457.7
2020	191.1	95.9	39.2	55.0	124.3	505.5
2021	183.2	92.0	37.7	52.7	119.9	485.4
2022	175.6	88.2	36.3	50.6	115.8	466.4
2023	170.5	85.6	35.3	48.6	111.7	451.6
2024	168.1	84.2	34.7	46.8	107.6	441.3
2025	165.8	82.8	34.1	45.0	103.6	431.3
2026	158.4	79.1	32.8	43.1	99.8	413.1
2027	150.6	75.3	31.3	41.0	95.9	394.1
2028	142.9	71.9	30.1	39.1	91.6	375.5

Figure 2a illustrates the same summary as shown in Figure 2, except NGL mix production is allocated into ethane, propane, butane, pentanes plus, and some NGL mix, based on a representative product mix produced at fractionation plants in Alberta.

Figure 2a
Alberta NGL Production by Component to 2028



Source: Ziff Energy and AEUB

Table 2a provides same information as Table 2, with incremental allocation of the NGL mix into ethane, propane, butane, pentanes plus, and some NGL mix.

Table 2a
Summary of Alberta NGL Production by Component

Year	Ethane	Propane	Butane	Pentane Plus	NGL Mix	Total
	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d
1997	189.9	171.3	92.4	146.3	76.8	676.7
1998	178.8	162.0	88.9	145.7	80.6	655.9
1999	230.5	167.0	92.8	141.3	28.1	659.7
2000	249.4	166.0	94.6	134.3	38.5	682.8
2001	211.0	142.2	84.8	126.7	69.9	634.6
2002	214.9	140.3	80.7	113.1	112.5	661.6
2003	228.6	141.2	77.0	115.2	65.8	627.9
2004	243.7	142.8	76.6	112.7	62.2	638.0
2005	245.6	141.4	74.0	110.1	59.3	630.4
2006	249.8	142.7	73.7	110.8	57.1	634.2
2007	241.9	141.5	74.1	110.9	58.4	626.8
2008	229.2	134.3	70.9	106.0	56.3	596.6
2009	215.0	126.5	67.5	101.4	54.4	564.7
2010	204.7	120.7	65.0	97.4	52.6	540.4
2011	192.7	114.2	62.2	93.7	51.1	513.8
2012	179.3	107.1	59.3	90.1	49.7	485.6
2013	168.8	101.5	56.9	86.9	48.4	462.5
2014	162.8	98.1	55.4	84.3	47.2	447.8
2015	163.5	98.5	55.5	82.2	45.9	445.6
2016	155.6	94.1	53.6	79.5	44.7	427.5
2017	146.8	89.3	51.6	76.6	43.5	407.8
2018	143.5	87.0	49.8	73.8	42.3	396.4
2019	185.9	105.7	52.5	72.6	41.0	457.7
2020	219.8	120.4	54.4	71.1	39.8	505.5
2021	210.8	115.5	52.3	68.2	38.6	485.4
2022	202.2	110.9	50.4	65.5	37.5	466.4
2023	196.1	107.4	48.8	63.0	36.4	451.6
2024	192.6	105.1	47.7	60.6	35.3	441.3
2025	189.3	102.9	46.6	58.3	34.2	431.3
2026	181.0	98.4	44.7	55.8	33.2	413.1
2027	172.2	93.8	42.8	53.2	32.1	394.1
2028	163.5	89.6	41.0	50.7	30.7	375.5

6.2 Alberta NGL Reserves

The Alberta Energy and Utilities Board (AEUB) report ST98-2007 provides an indication of NGL reserves by component. Table 6.1.1 on Page 6-1 shows remaining established NGL reserves[94] increased to 296 10^6m^3 in 2006, up 2.3% over 2005. The AEUB report indicates cumulative net production of 958 10^6m^3 as of Dec. 31, 2006 implying that the Alberta NGL reserves are 76 % depleted (958/(958+296) *100%).

6.3 Alberta NGL Supply Forecasts

6.3.1 Assumptions

Ziff Energy employs several key assumptions in preparing Alberta NGL supply forecasts:

- gas from CBM wells provides no recoverable NGLs
- gas supply delivery is maintained for the Alberta core market
- plant and pipeline transmission fuel declines as gas production declines
- gas from Mackenzie Delta begins to flow in Nov. 2014 and is delivered to Alberta for gas processing (removal of NGLs)
- gas from the state of Alaska begins to flow in Nov. 2018 at 2.2 Bcf/d and increases to 4.4 Bcf/d by Nov. 2019 and is delivered to Alberta for additional processing (removal of NGLS)
- gas supply is allocated 20% to Cochrane, and 80% to Empress based on current actual flows
- small quantities of natural gas bypass the ATCO (0.020 Bcf/d, no decline) and TransCanada systems (0.05 Bcf/d, declines to 0.01 Bcf/d by 2028)
- the gas composition feeding the straddle plants is a volumetric weighted average of gas from Alberta, based on historical Nova (TCPL) data. Table 3 provides the natural gas composition for the border straddle plants (prior to arrival of northern gas).

Table 3
Gas Composition in Alberta, %

	Ethane	Propane	Butane	Pentanes Plus
Cochrane	6.32	1.79	0.49	0.13
Empress	4.10	1.22	0.38	0.13

Source: Straddle Plant Group response to Taylor Question 19, page 9 and Nova (TCPL) response to Ziff Question 19.2 - daily table - Gas composition at the Empress Straddle Plants

[94] the 296 10^6m^3 of AEUB NGL reserves include ethane 125, propane 72, butane 41, and pentanes plus 58 10^6m^3

Table 4 summarises the gas compositions from Mackenzie Delta, and gas compositions from Alaska, when they arrive[95].

Table 4
Gas Composition in Mackenzie Delta and Alaska, %

	Ethane	Propane	Butane	Pentanes Plus
Mackenzie Delta	3.55	1.24	0.43	0.16
Alaska (from State)	5.80	1.70	0.30	0.10
Alaska (from NOVA)	5.80	1.70	0.30	0.10

Source: Nova (TCPL) response to Ziff Question 5.1 - Gas composition of Mackenzie, and State of Alaska, Response to AEUB, page 6, Lean gas Case (the rich gas case is 7.1, 3.6, 0.70, 0.10), and Nova (TCPL) response to Ziff Question 5.1)

- gas processing efficiencies (% recovery for C2, C3, C4, and $C5^+$ at the Alberta Straddle plants) remains constant through to 2028. Table 5 summaries the gas processing efficiencies for each component at the straddle plants.

Table 5
Gas Processing Efficiencies, %

Ethane	Propane	Butane	Pentanes Plus
65.0	98.5	99.5	99.8

Source: Straddle Plant Group response to Ziff Question 8 to Drazen/Purvin &Gertz - Typical recovery rates (0.65, 0.985, 0.995, 0.998), and Ziff Energy

- Alliance gas flows are robust, and start to decline in 2015 at 2%/yr, then the decline increases to 5%/yr in 2020, and 50%/yr in 2024, with Alberta Alliance flows declining to zero[96] in 2025/2026 without Mackenzie Delta and Alaska gas supplies
- the NGL production extracted from the Alberta field gas processing plants is declining at a constant rate over the forecasted period
- NGLs available from Alberta oil refinery operations is assumed to be produced at 95% load factors and increase at 0.5%/year going forward to 2028.

[95] Ziff Energy assumes that both Mackenzie Delta and Alaska gas are delivered to Alberta. Thus this represents an upside NGL analysis as the cost to connect both northern frontier sources to the North American gas grid may be uneconomic

[96] to meet Alberta gas demand prior to gas export

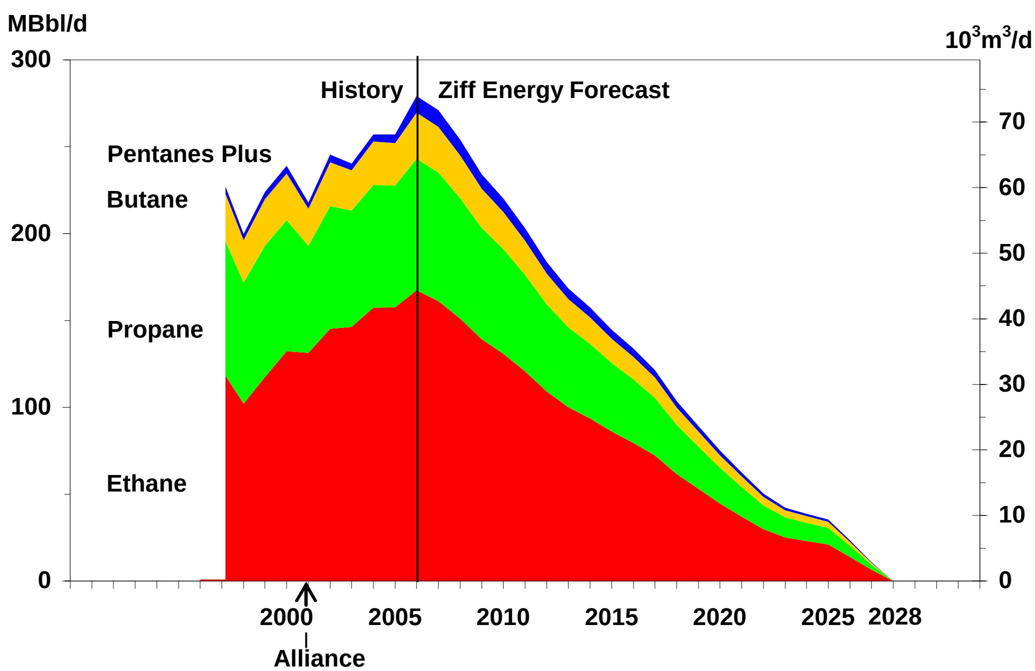
6.3.2 Alberta NGL Supply from the Border Straddle Plants

Using Ziff Energy's Alberta gas supply (solution, conventional, tight gas, and CBM) and Alberta's gas demand (residential, commercial, industrial, gas for power generation, gas for oil sands, and fuel/lease) models, Ziff Energy has developed a detailed gas supply and gas demand forecast to 2028. By subtracting core Alberta gas demand from supply available, calculation of a net gas supply available for subsequent gas processing at the Alberta border straddle plants is undertaken. Using gas compositions of ethane, propane, butane, and pentanes plus in Alberta, and extraction efficiencies for each component, a detailed forecast of the amount of each component was calculated. The results of the Ziff Energy model indicate that NGLs starts to decline each year primarily due to:

- Alberta gas supply production decline
- Alberta gas demand growth.

Figure 3 provides the NGL production from the Alberta border straddle plants by component. While some NGLs mix is actually produced, Ziff Energy assumes that the NGL is 73% propane, 25% butane, and 2% pentanes plus, and this is allocated to the NGL supply by component. This is based on a comparison of actual 2006 liquids produced to the theoretical liquids produced[97].

Figure 3
NGL Production Outlook for Alberta Border Straddle Plants by Component



Source: Ziff Energy and AEUB

[97] Ziff Energy calculates the 2006 Alberta straddle plant liquids at (all in MBbl/d) 166 C2, 76 C3, 27 C4, and 10 C5 vs the actual supply of 167 C2, 14 C3, 5 C4, 8 C5, and 85 NGLs Mix. The NGLs mix is allocated as 73% C3, 25% C4, and 2% C5

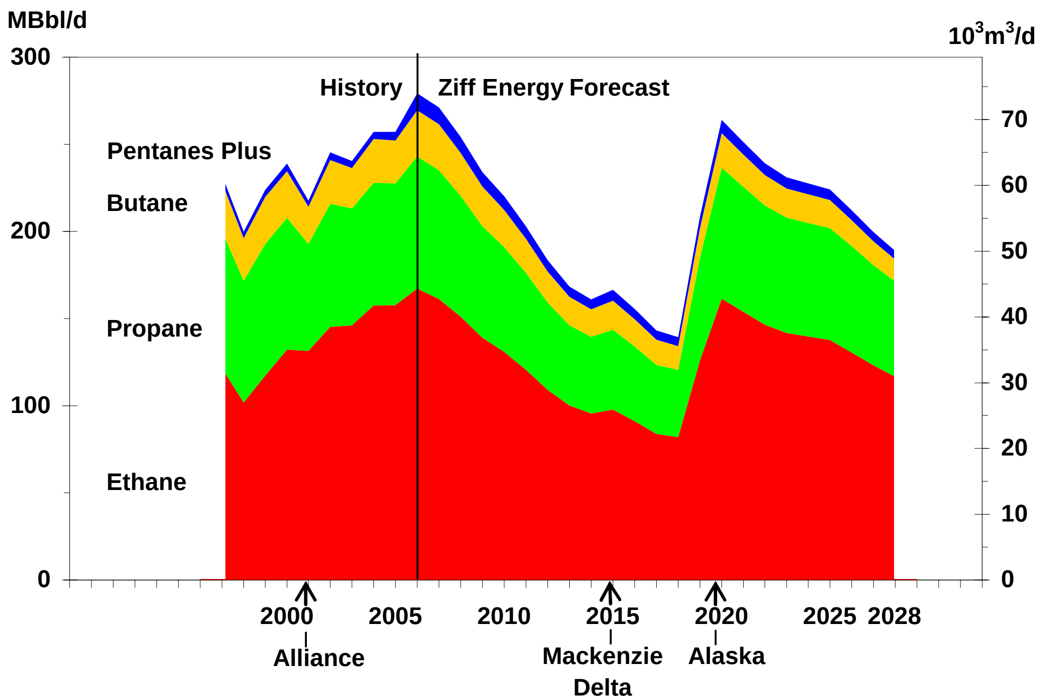
Table 6 provides a summary of the NGL production for Alberta border straddle plants by component to 2028.

Table 6
Alberta NGL Production for Alberta Border Straddle Plants by Component to 2028

Year	Ethane	Propane	Butane	Pentanes Plus	Total
	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d
1997	121.5	78.9	27.9	4.3	232.6
1998	102.0	69.7	24.5	3.6	199.8
1999	117.3	75.7	26.9	4.2	224.0
2000	132.3	75.5	26.9	4.3	238.9
2001	131.5	61.4	21.4	3.5	217.8
2002	145.3	70.5	25.2	4.3	245.4
2003	146.2	67.0	23.1	4.0	240.3
2004	157.4	70.5	25.0	4.1	257.1
2005	157.6	69.9	24.6	5.0	257.1
2006	167.2	75.8	26.5	9.6	279.2
2007	161.1	74.0	26.3	9.7	271.1
2008	151.0	69.4	24.6	9.1	254.1
2009	139.1	63.9	22.7	8.4	234.0
2010	130.9	60.2	21.4	7.9	220.3
2011	120.7	55.5	19.7	7.2	203.1
2012	109.1	50.1	17.8	6.6	183.5
2013	100.1	46.0	16.3	6.0	168.4
2014	93.6	43.0	15.3	5.6	157.5
2015	86.0	39.5	14.0	5.2	144.7
2016	79.5	36.5	13.0	4.8	133.8
2017	72.2	33.2	11.8	4.3	121.5
2018	61.6	28.3	10.0	3.7	103.6
2019	53.0	24.4	8.7	3.2	89.2
2020	44.7	20.5	7.3	2.7	75.2
2021	37.1	17.1	6.1	2.2	62.5
2022	29.8	13.7	4.9	1.8	50.2
2023	25.1	11.5	4.1	1.5	42.2
2024	23.0	10.6	3.8	1.4	38.7
2025	21.0	9.6	3.4	1.3	35.3
2026	13.9	6.4	2.3	0.8	23.3
2027	6.4	3.0	1.0	0.4	10.8
2028	0.0	0.0	0.0	0.0	0.0

Figure 4 shows the calculated Alberta NGLs by component from the Alberta border straddle plants including Mackenzie Delta and Alaska gas supply.

Figure 4
NGL Production Outlook for Alberta Border Straddle Plants with Mackenzie and Alaska – by Component



Source: Ziff Energy and AEUB

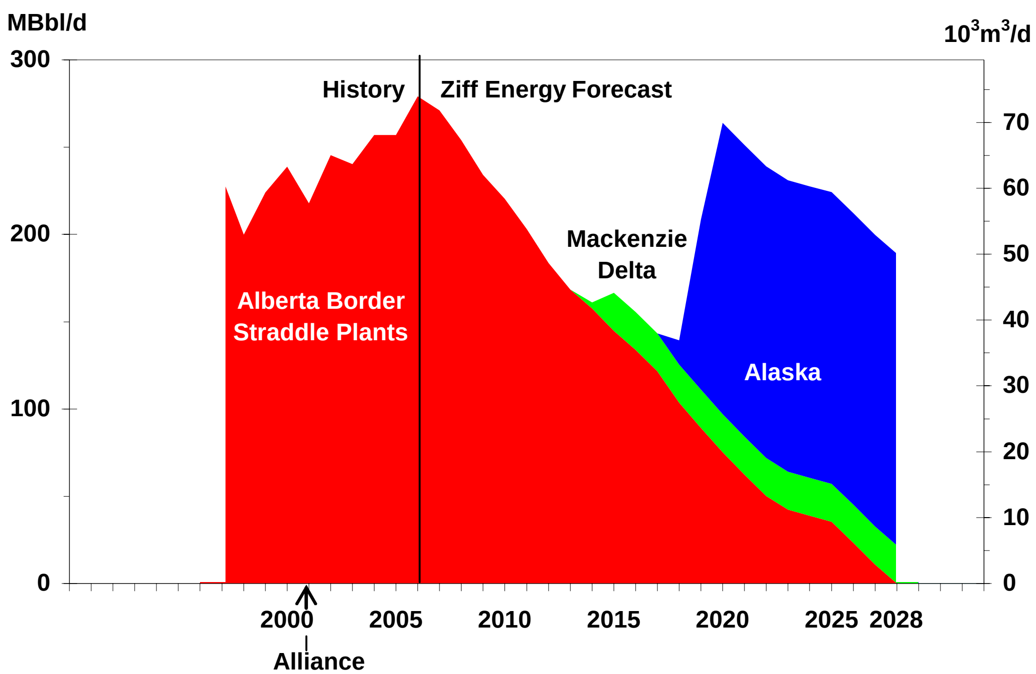
Table 7 shows the Alberta NGLs by component from the Alberta border straddle plants including Mackenzie Delta and Alaska gas supply.

Table 7
NGL Production from Alberta Border Straddle Plants, Mackenzie, and Alaska by Component to 2028

Year	Ethane	Propane	Butane	Pentanes Plus	Total
	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d
1997	121.5	78.9	27.9	4.3	232.6
1998	102.0	69.7	24.5	3.6	199.8
1999	117.3	75.7	26.9	4.2	224.0
2000	132.3	75.5	26.9	4.3	238.9
2001	131.5	61.4	21.4	3.5	217.8
2002	145.3	70.5	25.2	4.3	245.4
2003	146.2	67.0	23.1	4.0	240.3
2004	157.4	70.5	25.0	4.1	257.1
2005	157.6	69.9	24.6	5.0	257.1
2006	167.2	75.8	26.5	9.6	279.2
2007	161.1	74.0	26.3	9.7	271.1
2008	151.0	69.4	24.6	9.1	254.1
2009	139.1	63.9	22.7	8.4	234.0
2010	130.9	60.2	21.4	7.9	220.3
2011	120.7	55.5	19.7	7.2	203.1
2012	109.1	50.1	17.8	6.6	183.5
2013	100.1	46.0	16.3	6.0	168.4
2014	95.5	44.1	15.7	5.8	161.1
2015	97.7	45.9	16.6	6.3	166.5
2016	91.2	42.9	15.6	5.9	155.6
2017	83.9	39.6	14.4	5.4	143.3
2018	82.0	38.7	13.5	5.1	139.3
2019	126.0	58.9	17.1	6.5	208.5
2020	161.4	75.1	19.9	7.6	264.0
2021	153.8	71.6	18.7	7.1	251.3
2022	146.6	68.3	17.5	6.7	239.1
2023	141.8	66.1	16.7	6.4	231.1
2024	139.7	65.2	16.4	6.3	227.6
2025	137.7	64.2	16.1	6.2	224.1
2026	130.6	61.0	14.9	5.7	212.2
2027	123.1	57.5	13.7	5.3	199.6
2028	116.7	54.6	12.6	4.9	188.8

Figure 5 shows the Alberta NGLs by source (Alberta straddle border plants, Mackenzie Delta, and Alaska) to 2028. NGLs from Mackenzie Delta and Alaska are assumed to be extracted at the existing Alberta border straddle plants, although Ziff Energy has shown the NGLs separately for comparative purposes. Should either or both supplies not come on-stream or bypass the Alberta border straddle plants, Ziff Energy forecasts that gas flow and consequently NGL production will decline to zero by 2028. In this analysis, Ziff Energy has not included any new potential natural gas liquids from new straddle plants constructed to capture NGLs contained in gas flowing to the growing intra-Alberta gas markets.

Figure 5
NGL Production Outlook for Alberta Border Straddle Plants, by Gas Supply Source



Source: Ziff Energy and AEUB

Table 8 shows the Alberta NGLs by source (Alberta straddle border plants, Mackenzie Delta, and Alaska) to 2028.

Table 8
Alberta NGL Production by Source from the Alberta Straddle Border Plants, Mackenzie, and Alaska to 2028

Year	NGLs from the Border Straddle Plants	Mackenzie Delta	Alaska	Total
	MBbl/d	MBbl/d	MBbl/d	MBbl/d
1997	232.6	0.0	0.0	232.6
1998	199.8	0.0	0.0	199.8
1999	224.0	0.0	0.0	224.0
2000	238.9	0.0	0.0	238.9
2001	217.8	0.0	0.0	217.8
2002	245.4	0.0	0.0	245.4
2003	240.3	0.0	0.0	240.3
2004	257.1	0.0	0.0	257.1
2005	257.1	0.0	0.0	257.1
2006	279.2	0.0	0.0	279.2
2007	271.1	0.0	0.0	271.1
2008	254.1	0.0	0.0	254.1
2009	234.0	0.0	0.0	234.0
2010	220.3	0.0	0.0	220.3
2011	203.1	0.0	0.0	203.1
2012	183.5	0.0	0.0	183.5
2013	168.4	0.0	0.0	168.4
2014	157.5	3.5	0.0	161.1
2015	144.7	21.8	0.0	166.5
2016	133.8	21.8	0.0	155.6
2017	121.5	21.8	0.0	143.3
2018	103.6	21.8	13.9	139.3
2019	89.2	21.8	97.4	208.5
2020	75.2	21.8	167.0	264.0
2021	62.5	21.8	167.0	251.3
2022	50.2	21.8	167.0	239.1
2023	42.2	21.8	167.0	231.1
2024	38.7	21.8	167.0	227.6
2025	35.3	21.8	167.0	224.1
2026	23.3	21.8	167.0	212.2
2027	10.8	21.8	167.0	199.6
2028	0.0	21.8	167.0	188.8

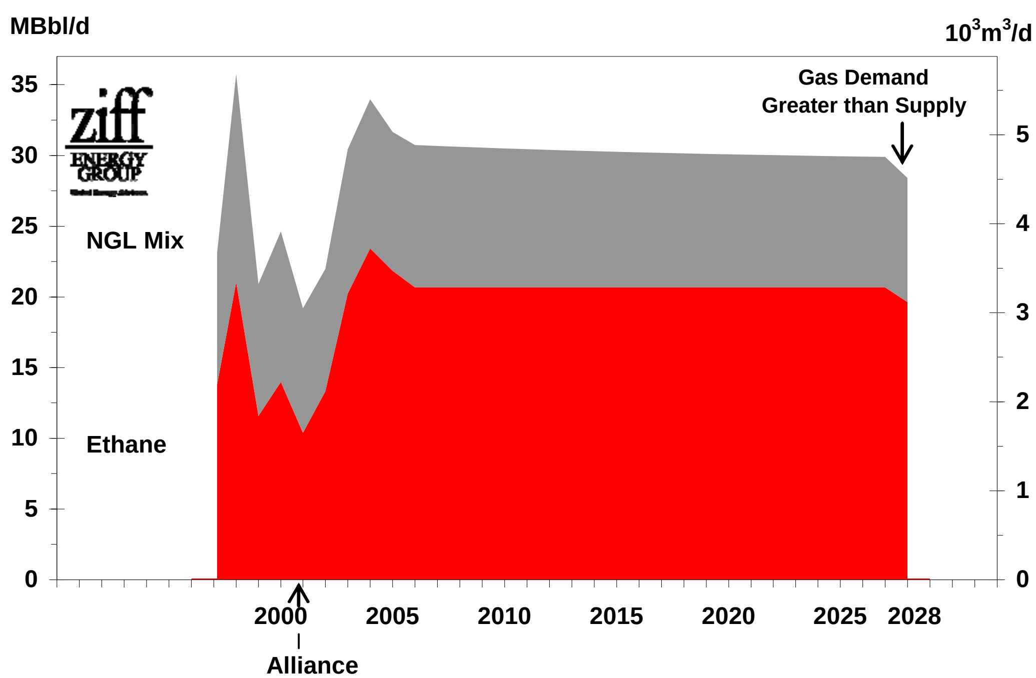
6.3.3 Alberta NGLs from the intra-Alberta Straddle Plants

While Ziff Energy believes that Alberta natural gas supply will decline, the Alberta core gas market is maintained prior to gas exports. Consequently, gas supply for the existing intra-Alberta straddle plants and hence NGL production from these plants remains relatively constant. Ziff Energy made several key assumptions:

- the gas composition of inlet gas feeding the intra-Alberta straddle plants is constant and the same as used for the Alberta straddle plants
- gas processing efficiencies (% recovery for C2, C3, C4, and $C5^+$ at the intra-Alberta straddle plants) remains constant and consistent with the values currently realised
- Ziff Energy has not assumed any plant expansions at the intra-Alberta straddle plants
- no incremental gas is processed from Mackenzie Delta and Alaska at the intra-Alberta straddle plants
- Ziff Energy has assumed there are 3 straddle plants on the ATCO pipeline system based on ATCO's initial submission[98], plus one other intra-Alberta plant (Joffre Ethane Extraction Plant).

Figure 6 provides the NGL production from the intra-Alberta Straddle plants to 2028.

Figure 6
NGL Production from the intra-Alberta Straddle Plants to 2028



Source: AEUB, Alberta Gas Plant Statistics, Ziff Energy

[98] assumed to be Edmonton, Villeneuve, and Fort Saskatchewan plants. ATCO's information responses added Fairydell Bon Accord and Paddle River plants, which are included in Ziff Energy's field gas plant forecast

Table 9 provides a summary of the Alberta NGL production by component from the intra-Alberta Straddle plants to 2028.

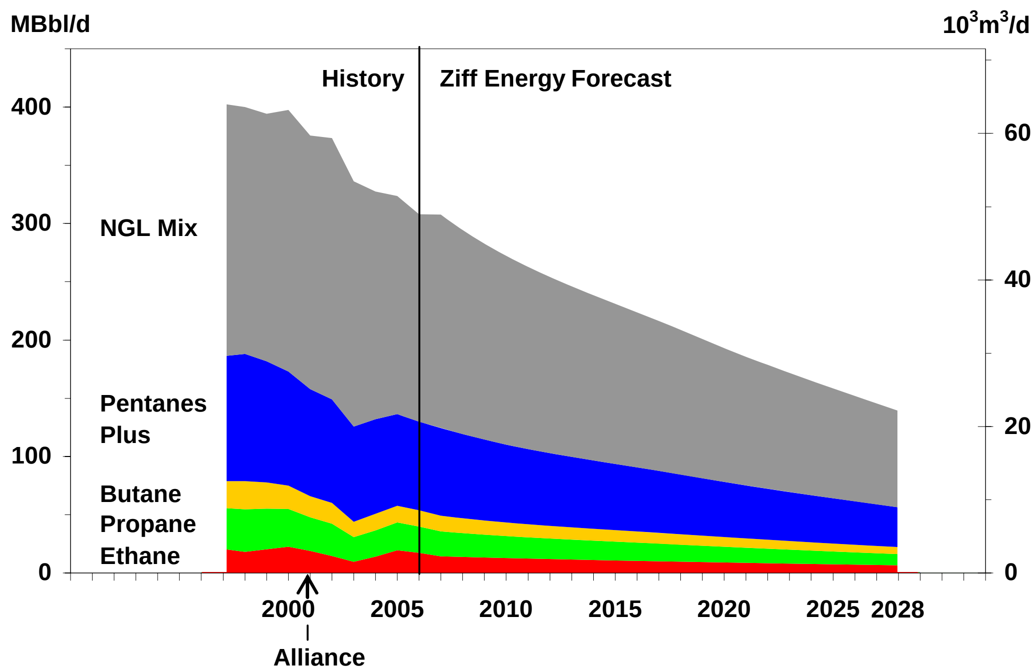
Table 9
Alberta NGL Production by Component
From the intra-Alberta Straddle Plants to 2028

Year	Ethane	NGLs Mix	Total
	MBbl/d	MBbl/d	MBbl/d
1997	12.5	8.4	20.9
1998	21.0	14.7	35.8
1999	11.6	9.3	20.9
2000	14.0	10.7	24.6
2001	10.4	8.8	19.2
2002	13.3	8.7	22.0
2003	20.2	10.2	30.4
2004	23.4	10.5	34.0
2005	21.9	9.8	31.7
2006	20.7	10.1	30.7
2007	20.7	10.0	30.7
2008	20.7	9.9	30.6
2009	20.7	9.9	30.5
2010	20.7	9.8	30.5
2011	20.7	9.8	30.4
2012	20.7	9.7	30.4
2013	20.7	9.7	30.3
2014	20.7	9.6	30.3
2015	20.7	9.6	30.3
2016	20.7	9.5	30.2
2017	20.7	9.5	30.2
2018	20.7	9.5	30.1
2019	20.7	9.4	30.1
2020	20.7	9.4	30.1
2021	20.7	9.4	30.0
2022	20.7	9.3	30.0
2023	20.7	9.3	30.0
2024	20.7	9.3	30.0
2025	20.7	9.3	29.9
2026	20.7	9.2	29.9
2027	20.7	9.2	29.9
2028	19.6	8.8	29.9

6.3.4 NGLs from the Alberta Field Gas Processing Plants in Alberta

While the Alberta straddle plants tend to extract deeper (more ethane), the 885 gas field processing plants[99] in Alberta tend to extract NGLs as a mixed supply. As natural gas supply declines, NGL production available to be extracted from the gas field processing plants will also decline. Figure 7 shows the NGL production extracted by component to 2028 from the 885 Alberta gas field processing plants. The NGL production is determined by assessing current NGL production and declining the NGL production uniformly with the declining gas production.

Figure 7
NGL Production by Component
From the Alberta Field Gas Processing Plants



Source: AEUB, Alberta Gas Plant Statistics, Ziff Energy

[99] in 2006, of the total 903 gas field processing plants in Alberta, 885 plants receive gas, and 668 plants provide NGLs

Table 10 summaries the NGL production from the Alberta field gas processing plants in Alberta to 2028 by component.

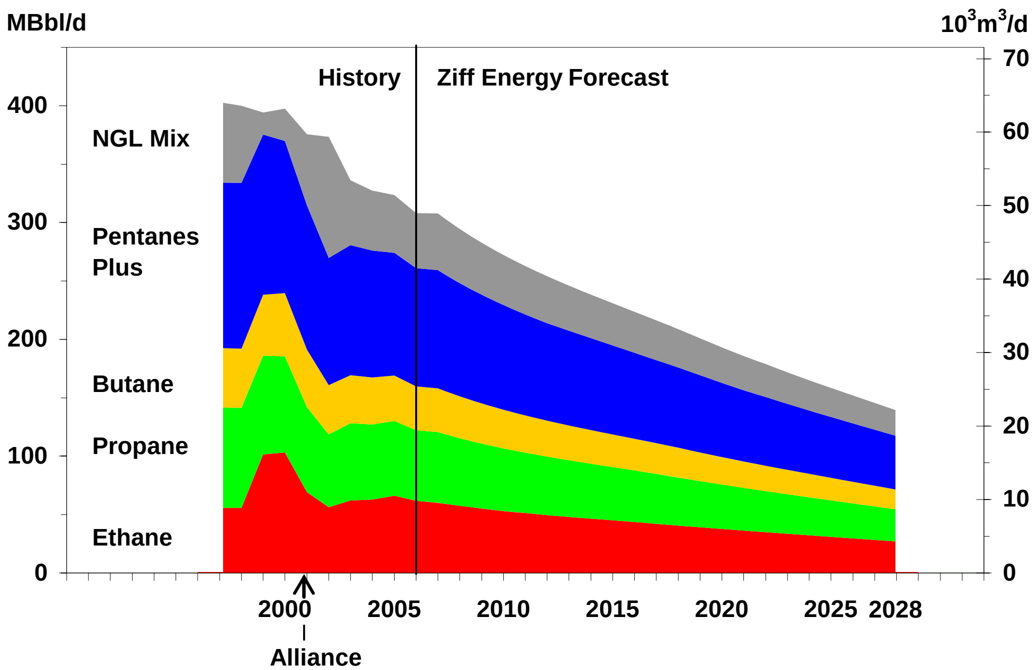
Table 10
NGL Production by Component from the Alberta Field Gas Processing Plants

Year	Ethane	Propane	Butane	Pentanes Plus	NGLs Mix	Total
	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d
1997	20.7	35.0	23.1	107.5	216.5	402.8
1998	18.1	36.4	24.2	109.3	211.8	399.9
1999	20.4	34.8	22.6	104.0	212.4	394.1
2000	22.6	32.2	20.1	98.2	224.5	397.5
2001	18.9	28.9	18.3	91.7	217.8	375.6
2002	14.6	27.5	17.9	89.1	224.3	373.4
2003	9.6	21.1	13.3	81.7	210.5	336.2
2004	14.0	22.6	14.2	81.1	195.6	327.6
2005	19.4	24.0	14.1	78.9	187.2	323.6
2006	17.4	22.5	13.9	76.2	178.2	308.1
2007	14.4	21.5	13.2	75.5	183.3	307.8
2008	13.7	20.5	12.6	72.3	175.4	294.5
2009	13.2	19.7	12.1	69.4	168.3	282.7
2010	12.7	19.0	11.7	66.8	162.1	272.2
2011	12.3	18.3	11.3	64.5	156.4	262.7
2012	11.9	17.7	10.9	62.3	151.2	254.0
2013	11.5	17.1	10.6	60.4	146.5	246.0
2014	11.1	16.6	10.2	58.5	142.0	238.6
2015	10.8	16.1	9.9	56.7	137.5	231.0
2016	10.4	15.6	9.6	54.9	133.2	223.7
2017	10.1	15.1	9.3	53.1	128.8	216.3
2018	9.7	14.5	9.0	51.2	124.3	208.7
2019	9.4	14.0	8.6	49.3	119.6	200.9
2020	9.0	13.5	8.3	47.4	114.9	193.0
2021	8.7	12.9	8.0	45.6	110.5	185.6
2022	8.3	12.5	7.7	43.9	106.4	178.8
2023	8.0	12.0	7.4	42.2	102.3	171.9
2024	7.7	11.5	7.1	40.5	98.3	165.1
2025	7.4	11.0	6.8	38.9	94.3	158.4
2026	7.1	10.6	6.5	37.3	90.6	152.1
2027	6.8	10.1	6.2	35.7	86.7	145.6
2028	6.5	9.7	6.0	34.2	82.9	139.2

6.3.4.1 NGL Mix Assessment

To allocate the NGL mix presented in Figure 7 into ethane, propane, butane, pentanes plus and some NGL mix, Ziff Energy analysed the field plants which did not have gas receipts but had NGL production, which were assumed to be fractionation plants[100]. Figure 7a illustrates the availability of ethane, propane, butane, and pentanes plus to meet the intra-Alberta NGL market.

Figure 7a
NGL Production by Component
From the Alberta Field Gas Processing Plants



Source: AEUB, Alberta Gas Plant Statistics, Ziff Energy

[100] Ziff Energy used the AEUB ST-13 report. Ziff Energy calculated the average composition of the NGL mix to be 32% ethane, 27% propane, 17% butane, 18% pentanes plus, and 7% NGL mix

Table 10a provides the NGL production from the Alberta field gas processing plants in Alberta to 2028 by component with incremental allocation of the NGL mix into ethane, propane, butane, and pentanes plus.

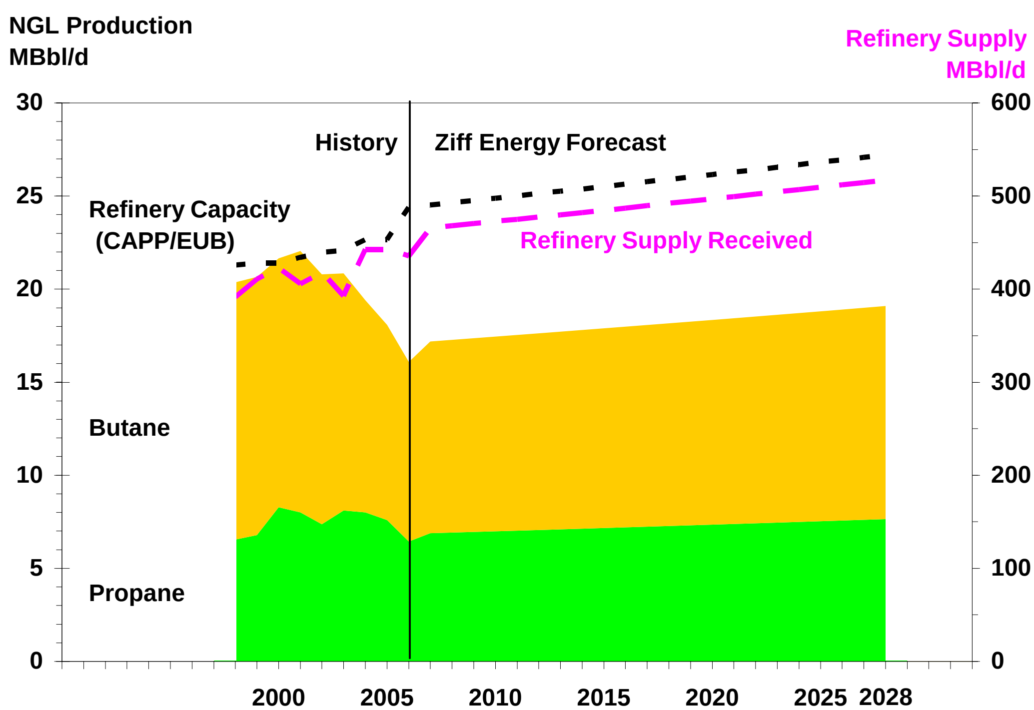
Table 10a
NGL Mix Production by Component from the Alberta Field Non-Gas Processing Plants

Year	Ethane	Propane	Butane	Pentanes Plus	NGL Mix	Total
	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d
1997	55.9	85.9	50.7	141.9	68.4	402.8
1998	55.7	85.8	50.5	142.1	65.8	399.9
1999	101.6	84.5	52.1	137.2	18.7	394.1
2000	103.1	82.2	54.4	130.0	27.8	397.5
2001	69.2	72.8	49.4	123.2	61.0	375.6
2002	56.3	62.5	42.1	108.8	103.8	373.4
2003	62.1	66.0	41.2	111.2	55.6	336.2
2004	62.9	64.3	40.1	108.6	51.7	327.6
2005	66.1	64.0	38.9	105.1	49.5	323.6
2006	61.9	60.5	37.5	101.2	47.1	308.1
2007	60.1	60.6	37.5	101.3	48.4	307.8
2008	57.5	57.9	35.9	96.9	46.3	294.5
2009	55.2	55.6	34.4	93.0	44.5	282.7
2010	53.2	53.5	33.1	89.5	42.8	272.2
2011	51.3	51.7	32.0	86.4	41.3	262.7
2012	49.6	50.0	30.9	83.6	40.0	254.0
2013	48.1	48.4	29.9	80.9	38.7	246.0
2014	46.6	46.9	29.0	78.5	37.5	238.6
2015	45.1	45.4	28.1	76.0	36.3	231.0
2016	43.7	44.0	27.2	73.6	35.2	223.7
2017	42.3	42.6	26.3	71.2	34.0	216.3
2018	40.8	41.1	25.4	68.7	32.8	208.7
2019	39.2	39.5	24.5	66.1	31.6	200.9
2020	37.7	38.0	23.5	63.5	30.4	193.0
2021	36.3	36.5	22.6	61.1	29.2	185.6
2022	34.9	35.2	21.8	58.8	28.1	178.8
2023	33.6	33.8	20.9	56.5	27.0	171.9
2024	32.2	32.5	20.1	54.3	26.0	165.1
2025	30.9	31.2	19.3	52.1	24.9	158.4
2026	29.7	29.9	18.5	50.0	23.9	152.1
2027	28.4	28.6	17.7	47.9	22.9	145.6
2028	27.2	27.4	16.9	45.8	21.9	139.2

6.3.5 NGLs from Oil Refinery and Oil Sands Operations

When crude oil is refined or bitumen is upgraded into synthetic crude, off gas containing NGLs by-products (propane and butane) are produced. Ziff Energy has assumed that any off gas (including entrained NGLs) produced at the oil sands plants is consumed on site and is not processed to recover NGLs.[101] Figure 8[102] provides an indication of the NGLs available from oil refinery operations in Alberta. Refinery Capacity is assumed to be utilised at 95% load factors and increase at 0.5%/year going forward to 2028. Butane and propane production is expected to continue at 2006 levels with respect to refinery supply.

Figure 8
Alberta NGL supply by Component
From Oil Refinery Operations to 2028



Source: StatsCan (Historical Butane, Propane, and Refinery Supply Received) and (CAPP/EUB (Historical Refinery Capacity)

[101] there is currently one off gas plant operated by Williams Energy which processes off gas from Suncor's operations, and one proposed plant. Ziff Energy has not included NGL production associated with this plant in its forecasts
[102] ST-98-2007 page 6.4 shows 5.0 MBbl/d of propane and 13.2 MBbl/d of butane for 2006 crude oil refinery recoveries. Ziff Energy has used StatsCan which shows 6.4 MBbl/d propane and 9.6 MBbl/d butane (Ziff Energy has assumed petroleum feedstock in StatsCan data is butane)

Table 11 summaries the Alberta NGL production by component from oil refinery operations to 2028.

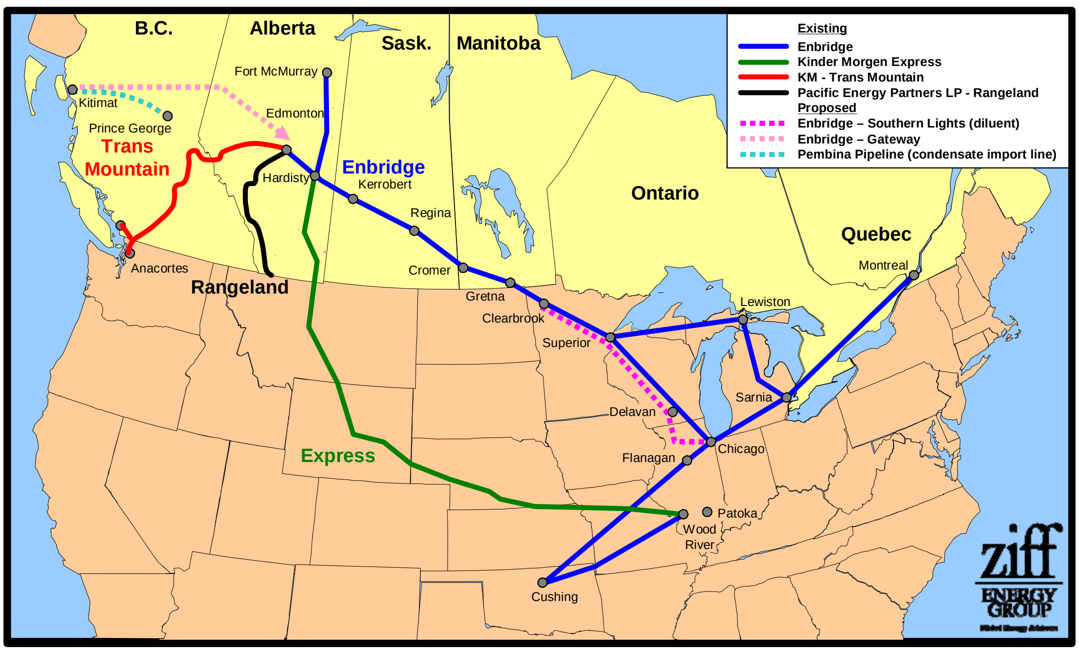
Table 11
Alberta NGL supply by Component
From Oil Refinery Operations to 2028

Year	Propane MBbl/d	Butane MBbl/d	Total MBbl/d
1998	6.6	13.8	20.4
1999	6.8	13.9	20.7
2000	8.3	13.4	21.7
2001	8.0	14.0	22.0
2002	7.4	13.4	20.8
2003	8.1	12.7	20.8
2004	8.0	11.4	19.4
2005	7.6	10.5	18.1
2006	6.4	9.6	16.1
2007	6.9	10.3	17.2
2008	6.9	10.4	17.3
2009	7.0	10.4	17.4
2010	7.0	10.5	17.5
2011	7.0	10.5	17.5
2012	7.1	10.6	17.6
2013	7.1	10.6	17.7
2014	7.1	10.7	17.8
2015	7.2	10.7	17.9
2016	7.2	10.8	18.0
2017	7.2	10.8	18.1
2018	7.3	10.9	18.2
2019	7.3	10.9	18.3
2020	7.3	11.0	18.3
2021	7.4	11.1	18.4
2022	7.4	11.1	18.5
2023	7.5	11.2	18.6
2024	7.5	11.2	18.7
2025	7.5	11.3	18.8
2026	7.6	11.3	18.9
2027	7.6	11.4	19.0
2028	7.6	11.5	19.1

6.3.6 NGLs Imported to Alberta (Diluent Imports in the Future)

To transport bitumen produced at the northern Alberta oil sands plants, a diluent such as condensate is required to thin the bitumen and allow efficient pipeline shipping. While Alberta processes natural gas and extracts pentanes plus, industry plans suggest that incremental pentanes plus will be required. Importing diluent and reusing existing diluent are the most likely mechanisms to increase diluent availability. Since this hearing is more focused on NGLs from natural gas, Ziff Energy has not made any attempt to assess the quantity of diluent imports. Figure 9 shows existing (solid lines) and proposed diluent import pipelines (dashed lines), driven by oil sands production growth.

Figure 9
Proposed Diluent/Condensate Import Pipelines

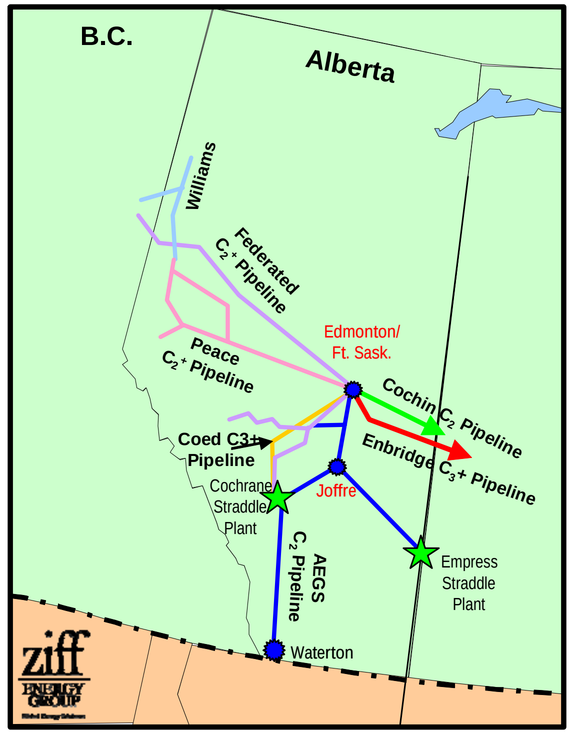


6.4 Alberta NGL Demand Forecast

6.4.1 Alberta Natural Gas Liquids Infrastructure

Figure 10 indicates the major pipelines and NGL extraction facilities within Western Canada. The pipelines primarily deliver NGLs to the large petrochemical centres at Joffre and Fort Saskatchewan.

Figure 10
Alberta Natural Gas Liquids Infrastructure



6.4.2 Use of Natural Gas Liquids

NGLs are the building blocks for the feedstocks required by the petrochemical industry and each liquid component is used to make different feedstocks. Examples of feedstocks and end products are:

- **Ethane** – ethylene, ethylene glycol, polyvinyl chloride, styrene, and low-density polyethylene. End products include film, moulding, wire and cable, flooring, plastics, detergents, synthetic lubricants, PVC pipe and cable
- **Propane** – propylene and polypropylene. End products include automotive parts, appliances, and toys. Propane is used as a car fuel, for BBQs (summer), and grain drying (fall)
- **Butane** – isobutylene and butyl alcohol. End products include Methyl Tertiary-Butyl Ether (MTBE), synthetic rubber, nylon fibres, plastics, acetic acid, household plumbing, and chewing gum. Alberta butane is typically two thirds normal butane, one third iso-butane.

6.4.3 Alberta Petrochemical Industry

Although chemical operations began in Edmonton and Fort Saskatchewan in the 1950s, a major leap occurred in the 1970s as the industry started to exploit the “Alberta Advantage” (trapped, low cost gas, and abundant NGLs to produce the feedstock for the petrochemical industry). More significant investment in expansions and new products occurred in the subsequent decades; by 2001, Alberta had the world’s largest ethane-based ethylene facility at Joffre. Alberta’s first propylene facility became operational in 2002 at Redwater. Quantities of NGLs not used in Alberta and Western Canada are transported through existing NGL pipelines to other locations such as Sarnia, Ontario.

6.4.4 NGL Marketing Hubs

Alberta (specifically Edmonton/Fort Saskatchewan) is one of the four major NGL trading hubs in North America. The other three primary NGL trading hubs are Sarnia, Ontario; Conway, Kansas; and Mont Belvieu, Texas. The Alberta market is linked with the Conway market through the interconnections between Cochin and Mapco pipelines. Notwithstanding that there is no direct link between Sarnia and Mont Belvieu; these hubs are related as they serve the same market (the U.S. Northeast). Figure 11 displays some of the major pipelines and trading hubs for North America's NGL industry.

Figure 11
North America NGL Pipelines and Trading Hubs

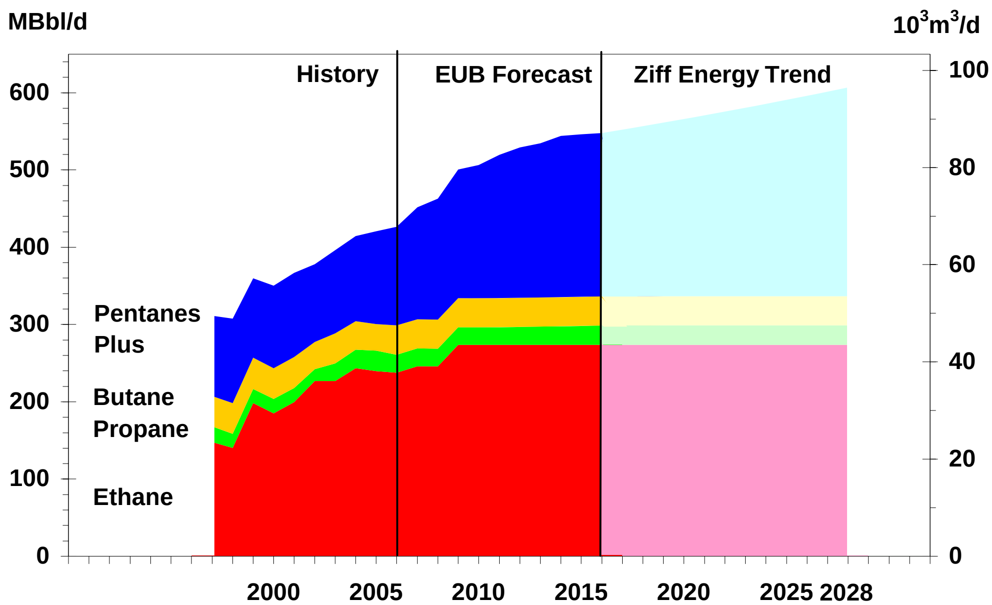
Source: Ziff Energy Northern Gas, New Assessment of the Impacts Multiclient Study

Mont Belvieu is the largest NGL consuming area in North America and has the most infrastructure. This has established Mont Belvieu as the NGL price reference point for North America (similar to the Henry Hub price for natural gas in North America). As Canadian NGL exports represent about 10% of U.S. NGL demand, the price for Canadian NGL is set by the U.S. price. The three other major trading hubs are price takers and the price differentials from Mont Belvieu generally reflect actual (Conway, Edmonton/Fort Saskatchewan) or deemed (Sarnia) pipeline tariffs. The Edmonton/Sarnia differential reflects the Cochin tariff to Sarnia.

6.5 Alberta NGL Demand

New NGL demand has grown to over 400 MBbl/d in 2006. Ziff Energy used the growing NGL demand forecast provided by the AEUB[103] to 2016. After 2016, Ziff Energy 'flattened' the NGL demand to reflect our view of declining NGL supply. While pentanes plus demand will increase with growing oilsands production and this incremental demand will require imported supply, it is not reflected in this NGL report.

Figure 12
Alberta NGL Demand to 2028



Source: EUB and Ziff Energy Analysis trend outlook

[103] Alberta Energy and Utilities Board, Alberta's Energy Reserves 2006 and Supply / Demand Outlook 2007-2016

Table 12 summaries the Alberta NGL demand by component to 2028.

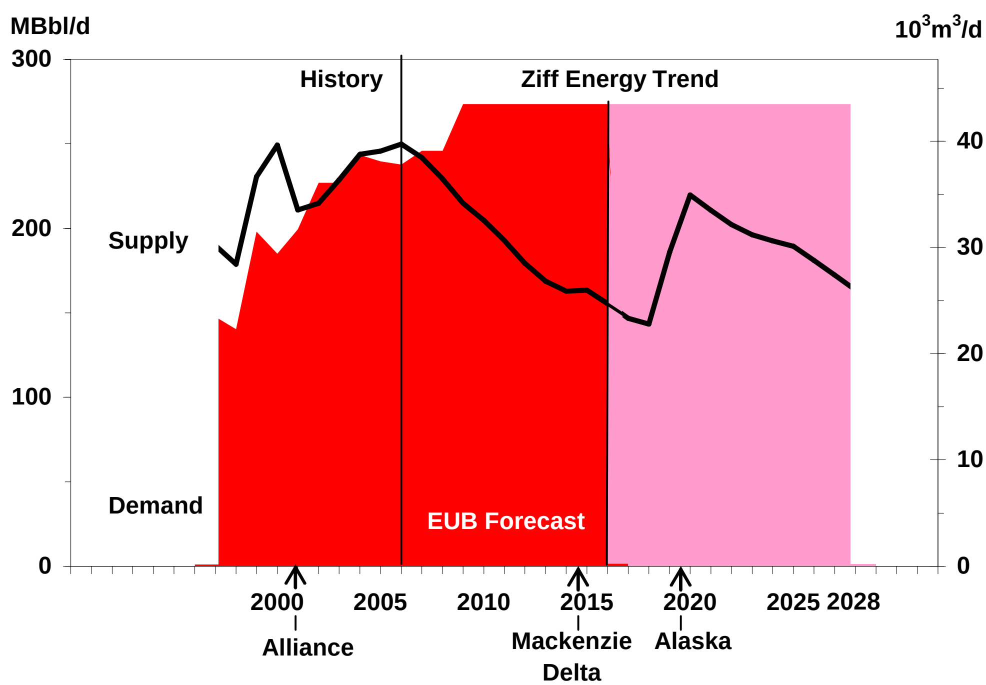
Table 12
Alberta NGL Demand to 2028

Year	Ethane	Propane	Butane	Pentanes Plus	Total
	MBbl/d	MBbl/d	MBbl/d	MBbl/d	MBbl/d
1997	147.8	20.1	39.6	103.8	311.3
1998	140.3	18.2	39.6	109.4	307.6
1999	198.1	18.2	40.9	102.5	359.8
2000	184.9	18.9	39.6	106.9	350.3
2001	199.4	18.2	40.3	108.8	366.7
2002	227.1	15.1	35.2	100.6	378.0
2003	227.1	22.6	39.0	107.6	396.3
2004	243.4	23.9	37.1	110.1	414.5
2005	239.6	26.4	34.6	120.1	420.8
2006	237.8	23.3	37.7	127.7	426.4
2007	245.9	23.3	37.7	144.7	451.6
2008	245.9	22.6	37.7	156.6	462.9
2009	273.6	22.6	37.7	166.7	500.7
2010	273.6	22.6	37.7	172.3	506.3
2011	273.6	22.6	37.7	185.5	519.5
2012	273.6	23.3	37.7	194.4	529.0
2013	273.6	23.9	37.7	199.4	534.6
2014	273.6	23.9	37.7	208.8	544.1
2015	273.6	24.5	37.7	210.1	546.0
2016	273.6	25.2	37.7	211.3	547.8
2017	273.6	25.2	37.7	215.7	552.2
2018	273.6	25.2	37.7	220.2	556.7
2019	273.6	25.2	37.7	224.8	561.3
2020	273.6	25.2	37.7	229.5	566.0
2021	273.6	25.2	37.7	234.2	570.7
2022	273.6	25.2	37.7	239.1	575.6
2023	273.6	25.2	37.7	244.1	580.6
2024	273.6	25.2	37.7	249.2	585.7
2025	273.6	25.2	37.7	254.3	590.8
2026	273.6	25.2	37.7	259.6	596.1
2027	273.6	25.2	37.7	265.0	601.5
2028	273.6	25.2	37.7	270.5	607.0

6.6 Alberta Ethane Supply vs. Demand to 2028

Figure 13 overlays the total Alberta ethane supply (black line) and the anticipated ethane demand in red to 2028. The historical ethane supply shown is based on total ethane and NGL mix produced at field plants, with NGL mix allocated to ethane and other components as described in section 6.3.4.1. A potential incremental source of ethane for Alberta would be ethane currently sold for the natural gas heating value, as not all ethane produced is extracted at the field plants or at the Alberta straddle plants. Current straddle plant efficiencies are about 65% and the EUB estimates[104] that about 35% of the ethane in the gas produced in Alberta is left in the gas. Our understanding is that extraction efficiencies could be increased to as high as 80% at processing plants with capital improvements, although our forecasts do not reflect any increases at existing plants.

Figure 13
Alberta Ethane Supply vs. Demand to 2028



Source: EUB and Ziff Energy Analysis

[104] page 5-11, Alberta's Energy Reserves 2006 and Supply/Demand Outlook 2007-2016

Table 13 summaries the Alberta ethane supply and demand to 2028.

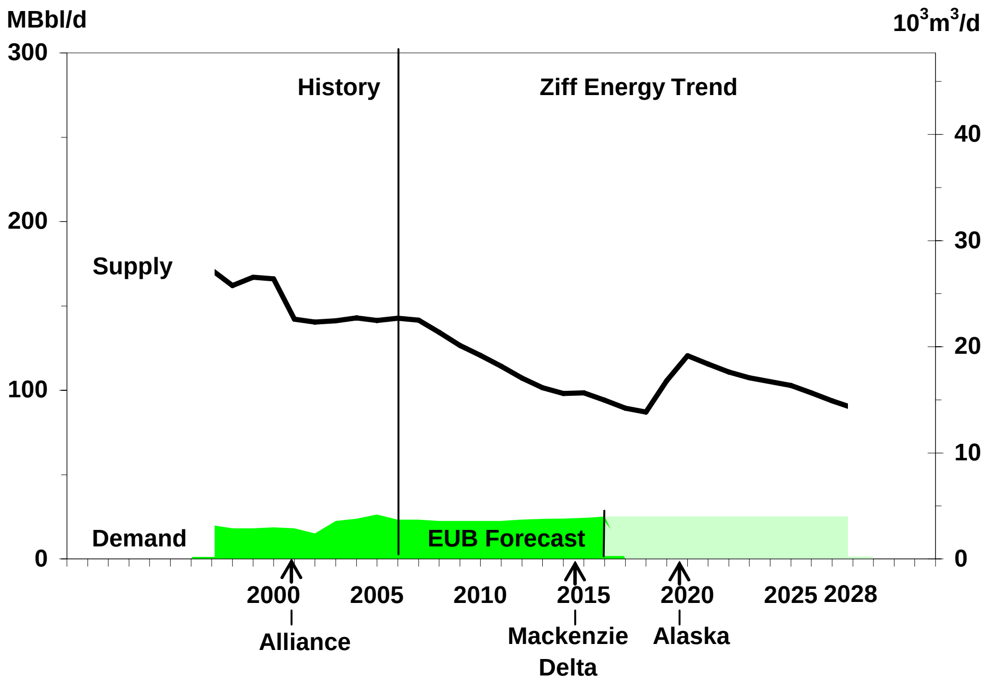
Table 13
Alberta Ethane Supply vs. Demand to 2028

Year	Ethane Supply	Ethane Demand	Supply - Demand
	MBbl/d	MBbl/d	MBbl/d
1997	189.9	147.8	42.1
1998	178.8	140.3	38.5
1999	230.5	198.1	32.4
2000	249.4	184.9	64.4
2001	211.0	199.4	11.6
2002	214.9	227.1	-12.2
2003	228.6	227.1	1.6
2004	243.7	243.4	0.3
2005	245.6	239.6	6.0
2006	249.8	237.8	12.0
2007	241.9	245.9	-4.0
2008	229.2	245.9	-16.7
2009	215.0	273.6	-58.6
2010	204.7	273.6	-68.9
2011	192.7	273.6	-80.9
2012	179.3	273.6	-94.3
2013	168.8	273.6	-104.8
2014	162.8	273.6	-110.8
2015	163.5	273.6	-110.1
2016	155.6	273.6	-118.0
2017	146.8	273.6	-126.8
2018	143.5	273.6	-130.1
2019	185.9	273.6	-87.7
2020	219.8	273.6	-53.8
2021	210.8	273.6	-62.8
2022	202.2	273.6	-71.5
2023	196.1	273.6	-77.5
2024	192.6	273.6	-81.0
2025	189.3	273.6	-84.3
2026	181.0	273.6	-92.6
2027	172.2	273.6	-101.4
2028	163.5	273.6	-110.1

6.7 Alberta Propane Supply vs. Demand to 2028

Figure 14 overlays the total Alberta propane supply and the anticipated propane demand to 2028. The propane supply shown here includes propane that is part of the NGL mix, using the methodology described in section 6.3.4.1.

Figure 14
Alberta Propane Supply vs. Demand to 2028



Source: EUB and Ziff Energy Analysis

Table 14 summaries the Alberta propane supply and demand to 2028.

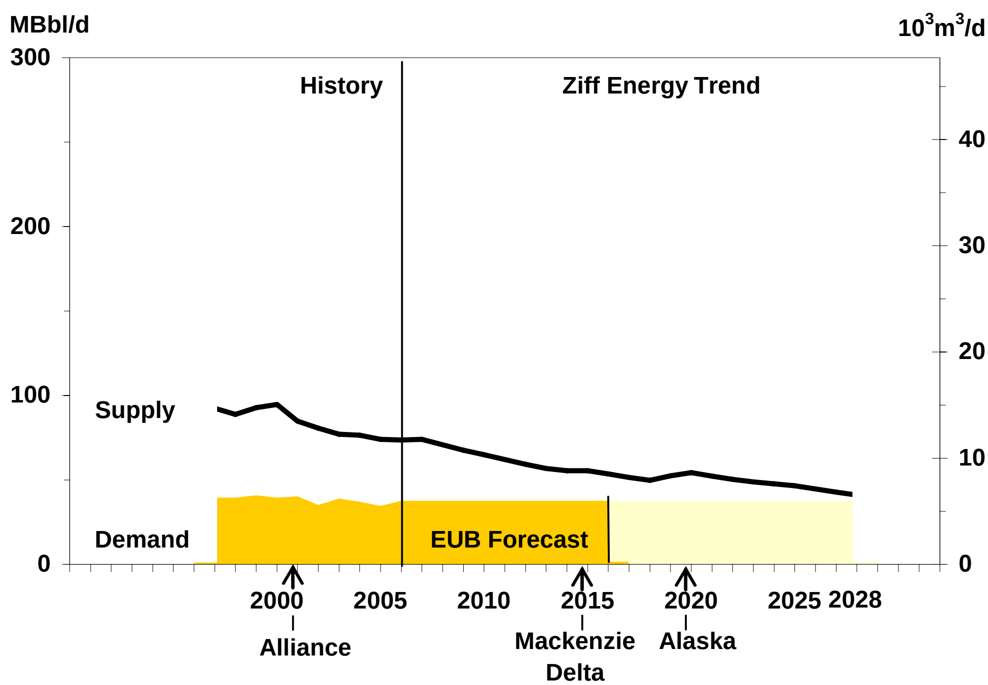
Table 14
Alberta Propane Supply vs. Demand to 2028

Year	Propane Supply	Propane Demand	Supply - Demand
	MBbl/d	MBbl/d	MBbl/d
1997	171.3	20.1	151.2
1998	162.0	18.2	143.8
1999	167.0	18.2	148.8
2000	166.0	18.9	147.1
2001	142.2	18.2	124.0
2002	140.3	15.1	125.2
2003	141.2	22.6	118.6
2004	142.8	23.9	118.9
2005	141.4	26.4	115.0
2006	142.7	23.3	119.5
2007	141.5	23.3	118.2
2008	134.3	22.6	111.6
2009	126.5	22.6	103.8
2010	120.7	22.6	98.0
2011	114.2	22.6	91.5
2012	107.1	23.3	83.9
2013	101.5	23.9	77.6
2014	98.1	23.9	74.2
2015	98.5	24.5	74.0
2016	94.1	25.2	69.0
2017	89.3	25.2	64.2
2018	87.0	25.2	61.9
2019	105.7	25.2	80.5
2020	120.4	25.2	95.3
2021	115.5	25.2	90.4
2022	110.9	25.2	85.7
2023	107.4	25.2	82.2
2024	105.1	25.2	80.0
2025	102.9	25.2	77.8
2026	98.4	25.2	73.3
2027	93.8	25.2	68.6
2028	89.6	25.2	64.4

6.8 Alberta Butane Supply vs. Demand to 2028

Figure 15 overlays the total Alberta butane supply and the anticipated butane demand to 2028. The butane supply shown here includes butane that is part of the NGLs mix, using the methodology described in section 6.3.4.1.

Figure 15
Alberta Butane Supply vs. Demand to 2028



Source: EUB and Ziff Energy Analysis

Table 15 summaries the Alberta butane supply and demand to 2028.

Table 15
Alberta Butane Supply vs. Demand to 2028

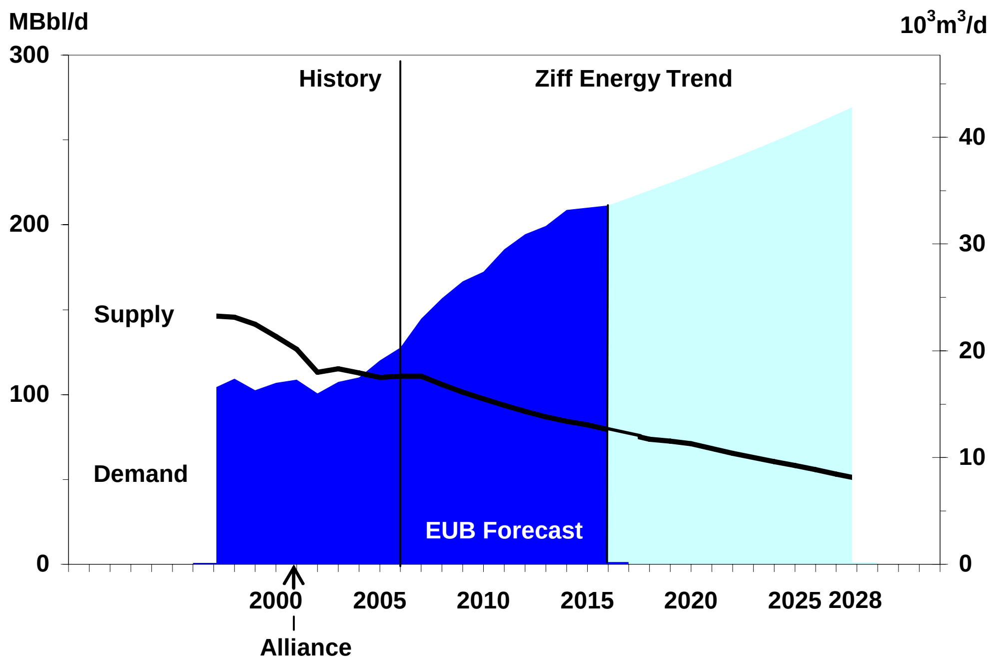
Year	Butane Supply	Butane Demand	Supply - Demand
	MBbl/d	MBbl/d	MBbl/d
1997	92.4	39.6	52.8
1998	88.9	39.6	49.2
1999	92.8	40.9	51.9
2000	94.6	39.6	55.0
2001	84.8	40.3	44.6
2002	80.7	35.2	45.5
2003	77.0	39.0	38.0
2004	76.6	37.1	39.5
2005	74.0	34.6	39.4
2006	73.7	37.7	35.9
2007	74.1	37.7	36.3
2008	70.9	37.7	33.1
2009	67.5	37.7	29.8
2010	65.0	37.7	27.2
2011	62.2	37.7	24.5
2012	59.3	37.7	21.6
2013	56.9	37.7	19.2
2014	55.4	37.7	17.7
2015	55.5	37.7	17.8
2016	53.6	37.7	15.9
2017	51.6	37.7	13.8
2018	49.8	37.7	12.1
2019	52.5	37.7	14.8
2020	54.4	37.7	16.7
2021	52.3	37.7	14.6
2022	50.4	37.7	12.6
2023	48.8	37.7	11.1
2024	47.7	37.7	10.0
2025	46.6	37.7	8.9
2026	44.7	37.7	7.0
2027	42.8	37.7	5.1
2028	41.0	37.7	3.3

6.9 Alberta Pentanes Plus Supply vs. Demand to 2028

Figure 16 overlays the total Alberta pentanes plus supply and the anticipated pentanes plus demand to 2028. The pentanes plus supply shown here includes pentanes plus that is part of the NGLs mix, using the methodology described in section 6.3.4.1.

Ziff Energy recognises that demand for pentanes plus are rising with growing oil from oil sands production; however, incremental pentanes plus would have to be imported to match the increased demand. Ziff Energy has forecast the 2016-2028 growth of pentanes plus demand to continue at 2.1%/year which is 54%[105] of the forecasted growth in Oil Sands production.

Figure 16
Alberta Pentanes Plus Supply vs. Demand to 2028



Source: EUB and Ziff Energy Analysis

[105] EUB forecast growth rate for pentanes plus was 54% of the EUB forecast growth rate to 2016 for oil sands production

Table 16 summaries the Alberta pentanes plus supply and demand to 2028.

Table 16
Alberta Pentanes Plus Supply vs. Demand to 2028

Year	Pentane Supply	Pentane Demand	Supply - Demand
	MBbl/d	MBbl/d	MBbl/d
1997	146.3	103.8	42.5
1998	145.7	109.4	36.2
1999	141.3	102.5	38.8
2000	134.3	106.9	27.4
2001	126.7	108.8	17.9
2002	113.1	100.6	12.5
2003	115.2	107.6	7.7
2004	112.7	110.1	2.6
2005	110.1	120.1	-10.0
2006	110.8	127.7	-16.9
2007	110.9	144.7	-33.7
2008	106.0	156.6	-50.7
2009	101.4	166.7	-65.3
2010	97.4	172.3	-74.9
2011	93.7	185.5	-91.9
2012	90.1	194.4	-104.3
2013	86.9	199.4	-112.5
2014	84.3	208.8	-124.5
2015	82.2	210.1	-127.8
2016	79.5	211.3	-131.9
2017	76.6	215.7	-139.1
2018	73.8	220.2	-146.4
2019	72.6	224.8	-152.2
2020	71.1	229.5	-158.4
2021	68.2	234.2	-166.0
2022	65.5	239.1	-173.6
2023	63.0	244.1	-181.1
2024	60.6	249.2	-188.6
2025	58.3	254.3	-196.1
2026	55.8	259.6	-203.8
2027	53.2	265.0	-211.8
2028	50.7	270.5	-219.8

7. REVIEW OF SUBMISSIONS BY INQUIRY PARTICIPANTS

From its review of the various submissions, Ziff Energy identified ten primary issues raised by the parties where opinions vary significantly:

1) natural gas supply forecasts
2) NGL ownership
3) perceived or real inequities of the current convention
4) need to change the conventions to attract Mackenzie Delta and Alaska gas
5) impact on the NIT market and Alberta gas prices by changing the convention
6) preferred convention for allocation of NGL extraction rights
7) impact on stakeholders if extraction conventions are changed
8) application of the same NGL extraction convention across all EUB regulated pipelines
9) criteria, public interest, and processes for evaluating sidestreaming and co-streaming projects
10) streaming of lean gas to specific markets to maximize NGL extraction, and impact on stakeholders.

Ziff Energy provides a summary of the parties' positions on these issues (where identified) and Ziff Energy's comments on the strengths and weaknesses of those positions.

7.1 Natural Gas Supply Forecasts

7.1.1 Nova Chemicals

Nova Chemicals is concerned that the gas flows and ethane content of the gas flows in NGTL's table are inconsistent with the anticipated gas flows and ethane content of the Alaskan gas. NGTL's evidence appears to suggest that ethane may be extracted upstream of the straddle plants, and that high ethane content gas will move across the proposed northern corridor to Woodenhouse for consumption in the oilsands. To capture this ethane, NGTL may require additional extraction capacity at incremental cost.

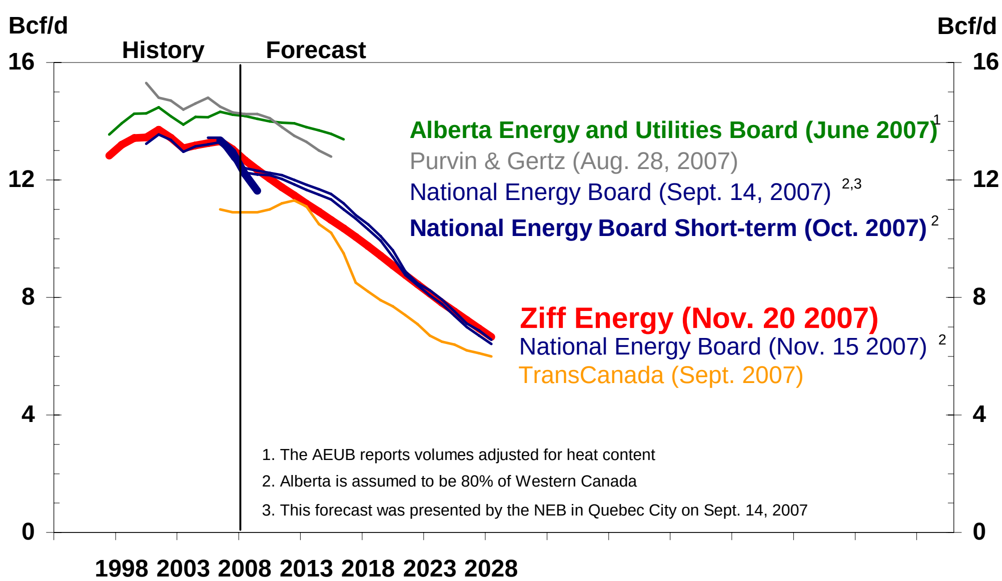
7.1.2 NGTL and Straddle Plant Group

Both these parties provided supply forecasts in their evidence which is commented on in the following section.

7.1.3 Ziff Energy Comments

Each Alberta gas supply forecast has different assumptions and methodologies. Common to all forecasts is that gas supply declines. For those forecasts that extend to 2018 and 2028 (or beyond), Alberta gas supply declines to 10.1 Bcf/d and 6.44 Bcf/d (average). The Alberta gas demand in 2028 is 6.7 Bcf/d (Ziff Energy view). All forecasts exclude Mackenzie Delta and Alaska gas supply. Figure 1 is a copy of Figure 5 from the Alberta natural gas reserves, supply, and demand section.

Figure 1
Alberta Gas Production Forecasts



Source: Ziff Energy

Alberta gas production will decline to half by 2028. Table 1 summarizes 5 gas supply forecasts that are available for review.

Table 1
Summary of Alberta Gas Supply Outlooks

				Gas Outlook (Bcf/d)			Comments
#	**Who**	**When (2007)**	**Time Period**	**2008**	**2018**	**2028**	
1	EUB	June	2016	14.2	N/A	N/A	The EUB outlook (for 2008) includes gas from bitumen wells (0.1 Bcf/d), and gas from upgrading bitumen (0.5 Bcf/d) whereas Ziff Energy nets out this supply from oil sands gas demand. The EUB includes 0.9 Bcf/d of gas shrinkage in the gas demand, whereas Ziff Energy excludes this from the gas supply (14.2 – 0.1 – 0.5 – 0.9 = 12.7 Bcf/d). The EUB determines gas supply at a standard heating value (37.5 MJ/m3)
2	NEB						
2a	Long Term	Sept. 14	2030	12.4	10.5	6.6	Presented by the NEB Chairman in a speech in Quebec City to the Industrial Gas Users Association (IGUA). The initial forecast is for Canada. Ziff Energy removes eastern Canada gas supply, and takes 80% of Western Canada as Alberta
2b	Short Term	Oct.	2009	12.2	N/A	N/A	The forecast is for Canada. Ziff Energy removes eastern Canada gas supply, and takes 80% of Western Canada as Alberta
2c	Long Term	Nov. 15	2030	12.3	10.3	6.4	The forecast is for Canada. Ziff Energy removes eastern Canada gas supply, and takes 80% of Western Canada as Alberta
3	TransCanada NGTL response Ziff-NGTL-21.2a	Sept.	2030	10.9	8.50 (plus 1.21 for Alliance, for average below)	6.1	TransCanada excludes Alberta Alliance supply (1.31 Bcf/d in 2008, 1.21 Bcf/d in 2018, and 0.0 Bcf/d in 2028) and excludes very small quantities of ATCO gas supply sourced and consumed on the ATCO pipeline system. The forecast appears to be 'gas year' starting each Nov. 1 through to Oct. 31
4	Purvin & Gertz SPG Submission	Aug. 28	2015	14.3	N/A	N/A	Numbers estimated from Purvin & Gertz gas supply graph
5	Ziff Energy	Nov. 20	2028	12.7	9.7	6.7	Excludes gas from bitumen wells as this is netted from the growing gas demand for oil sands
	AVERAGE				**10.1**	**6.4**	

7.2 NGL Ownership

7.2.1 ATCO Pipelines ("AP")

AP indicates that when a pipeline's tariff and contracts clearly address legal rights to NGLs, then there are no independent or residual rights (Response ALLNGP-AP-4.2).

7.2.2 ConocoPhillips

ConocoPhillips agrees with the Board's determination in Decision 96-7 wherein: "the Board maintains that, subject to…. the public interest, ownership of the resource should remain with the producer until the producer relinquishes that right through a commercial contract".

7.2.3 Imperial/EMC

The Board confirmed NGL ownership in the Strachan and Solex decisions: ownership remains with the producer of that resource until it is relinquished through a commercial contract. Under the current convention, producers and receipt shippers are restricted from entering into commercial contracts for their NGLs unless they become extractors in their own right or delivery shippers.

It is neither economic nor efficient for every producer to pursue field extraction at every producing field. It is likely in the public interest for producers to access the economies of scale afforded by existing straddle plants, without discrimination.

7.2.4 Keyera Energy

Keyera indicates that legal title to NGLs originate in the field and the producer has the right to extract NGLs in the field, sell NGLs to processors, marketers or shippers or inject the gas into transportation systems. Once on the system, the NGLs become intermingled in the common stream, and title to individual gas molecules are lost and the producer or shipper retain an ownership interest in the common stream in proportion to the quantity of gas injected.

7.2.5 Straddle Plant Group

SPG agrees with the Board's view that subject to the public interest, a producer has the right to extract NGL from its production upstream of NGTL, and that ownership of the resource should reside with the producer until the producer relinquishes that right through a commercial contract. SPG indicates that when a receipt shipper sells its gas instead of becoming a receipt shipper, it knowingly relinquishes all of its resource rights including rights to NGLs, and the purchaser receives the full rights including NGLs, and would have the right to extract NGLs unless the gas is sold, in which case the new purchaser now has the rights. The SPG believe that such a sale before a receipt point or at NIT was precisely what the Board envisioned with respect to relinquishment of rights through a commercial contract. SPG submitted that under the existing convention, extraction rights allocation is aligned with the ownership of the resource at the extraction point, namely the export delivery shippers.

The SPG suggests that moving extraction rights to the receipt point will create title and custody issues, and requires significant restructuring of industry contracts. They cite examples of industry contracts (GISB/NAESB) under which gas is typically sold with all components including NGLs, whereas a receipt point convention would split the common stream into parts with and without NGLs, necessitating amendments to gas sale and purchase contracts including industry standard contracts, for all gas sale transactions between producers, receipt shippers, and other parties buying/selling the gas in Alberta.

7.2.6 Western Export Group ("WEG")

WEG indicates that shippers on NGTL have the legal rights to the commingled common stream including NGLs, until those rights are sold to another shipper under a commercial contract. Legal rights to gas and entrained NGLs are normally transferred when a purchase is made at NIT.

7.2.7 Ziff Energy Comments

Ziff Energy notes that many of the parties (ConocoPhillips, Imperial/EMC, SPG, and WEG) quoted the Board Decision D96-07:

> "The Board maintains that subject to any matters of compelling public interest, the right of resource ownership should remain with the producer until the producer of that resource relinquishes that ownership through a commercial contract".

In addition, Decision 2004-06 states:

> "The Board continues to acknowledge, as it did in the Strachan decision, that joint ownership with its associated issues exists in the NGTL common stream. The Board understands that under common law and under the NGTL tariff, this means that once a producer/receipt shipper puts its gas on the NGTL system it no longer owns that particular gas. The Board agrees with ATCO that at that point the producer/shipper gives up any and all rights to that specific gas and acquires, in exchange, a share of the common stream. A producer/shipper's entitlement from that point on is limited to a right to reacquire its share of the common stream once it is severed or partitioned from the common stream. On the NGTL system, the severance or partition occurs when gas is delivered by NGTL to a customer at a delivery point. Therefore, the Board understands that all shippers together own the entire stream while the gas is contained within the NGTL facility."

Ziff Energy concurs with this description of ownership of gas between the wellhead and ultimate delivery point, and agrees with the SPG that gas sales upstream of receipt points and at NIT would be considered by the Board as commercial transactions in this context. However, Ziff Energy is not convinced that changing the convention would lead to a requirement to split the common stream in two parts with/without NGLs and necessitate major changes to standard industry contracts, as suggested by the SPG. Ziff Energy agrees with AP's comments that legal rights related to the common gas stream and entrained NGLs are also determined by pipeline tariffs,[106] and notes that

[106] for example, ATCO retains rights to any NGLs removed from the common stream during transport

under all Alberta pipeline tariffs, the pipeline maintains delivery and control of the gas on the pipeline and has a delivery commitment to return an energy equivalent quantity of gas at the delivery point[107]. Ziff Energy believes it should be possible to amend pipeline tariffs in a fashion that avoids the need to make major changes to industry purchase and sale contracts. There is likely more than one way to accomplish this, which could be determined with input from various stakeholders based on direction from the Board.

[107] see section 2.1 of report, Table 1 summarizing provisions in tariffs

7.3 Perceived or Real Inequities of the Current Convention

7.3.1 ATCO Pipelines

With respect to most of the perceived inequities identified in the NECTF report, AP believes that most of the perceived inequities are not applicable to AP, as neither receipt nor delivery shippers receive title to NGLs and all shippers receive the benefit of SPD revenues which result in lower tolls on AP's system. (response BR-AP-2(b)).

With respect to the perceived inequities 3(a) –(g) in the Board's list which pertain to the NGTL system, AP believes inequities a, b, e, and f are real, and c, d, and g are perceived.

7.3.2 ConocoPhillips

Believes the inequities in the board's list of issues are real inequities except for item (e).

7.3.3 EnCana

EnCana believes that a more proper characterization of the perceived inequities on the Board's list of issues would be "imperfection", and the key question is whether there is sufficient value in changing the convention. EnCana observes that: shippers only receive the benefit of the common stream, the current convention assumes it does not make sense to track a shipper's content, and extraction plants are close enough to export points so that export nominations are a good approximation to identify owners of extraction rights (Ziff Energy ALLNGP2-EnCana).

7.3.4 Imperial/EMC

The perceived inequities in the Board's final list of issues are real, not perceived, as Alberta producers are denied the right to fully benefit from their proportionate value of the NGLs delivered into the pipeline including their "Uplift Value". It is clear from the submissions that the current convention is plainly regarded as treating producers/receipt shippers inequitably. Straddle plant operators and export shippers have benefited from the current convention at the expense of producers and receipt shippers.

7.3.5 IGCAA

IGCAA believes that the perceived inequities in the Board's list of issues are real, and are described in the NECTF report.

7.3.6 Keyera Energy

Keyera believes the perceived inequities are real.

7.3.7 Nova Chemicals

Nova Chemical believes that perceived inequities in the Board's final list of issues are real, not perceived, and that these inequities have motivated upstream processing.

7.3.8 NGTL

The current convention is not fair as delivery shippers are not the rightful owners and beneficiaries of extraction rights, and the rightful owners (producers and receipt shippers) have to hold delivery service to obtain extraction rights, and then sell gas in a market which is far less liquid than NIT. In addition, extraction rights are allocated based on the average composition of the common stream and not on the value of the NGL components. NGTL provides two examples where one rich shipper loses $2 million/year in extraction rights, whereas a lean gas shipper gains $3 million/yr.

7.3.9 Pembina Pipelines

Pembina does not agree that the perceived inequities are in fact inequities, nor do they warrant any statutory or regulatory fix.

7.3.10 Shell

Shell agrees the existing convention unfairly prevents producers from benefiting from extraction of their entrained NGLs if they do not hold delivery service (ALLNGP-Shell 2).

7.3.11 SPG

The SPG states that the perceived inequities in the Board's list of issues are not material and there is no evidence that an alternative convention would eliminate them. With respect to perceived inequities 3 (a) to (c) and (e), they provide an example of a lean or rich shippers, where the total impact to the shipper is $0.02/GJ or less, based on an extraction premium of $0.52/GJ on extracted volumes (BR-SPG-6(a)).

7.3.12 State of Alaska

Alaska indicates that the current convention does not currently compensate shippers of rich gas. The methodology unfairly discriminates against shippers who do not own an interest in the straddle plants, small shippers, and shippers of rich gas (BR-SOA-4).

7.3.13 WEG

WEG indicates that the perceived inequities in the Board's list of issues which affect FT-R shippers with high or low level of NGLs in their gas stream may be perceived or real depending on a party's circumstances. The perceived inequities do not justify a change in convention as they result from choices made by parties regarding NGL extraction upstream of NGTL, whether to contract for FT-R (and sell gas at NIT) or take out FT-D capacity (and receive extraction rights). Alternatives have been suggested which equalize for gas value without changing the current extraction convention.

7.3.14 Ziff Energy Comments

Ziff Energy notes that the proponents of a receipt point convention include most of the producers (ConocoPhillips, Imperial/EMC, and Shell) plus Keyera, Nova Chemicals, IGCAA, the State of Alaska, and NGTL all believe that all or most of the perceived inequities identified in the Board's list of issues are real.

Parties that support maintaining the existing NGTL convention includes Pembina Pipelines, SPG, and WEG, who indicate that the perceived inequities are not/may not be real, and in any case are not material nor warrant changing the convention. These parties represent straddle plant interests (SPG), own significant export delivery capacity (WEG), and in the case of Pembina Pipelines, owns liquid pipelines moving NGLs from field plants. Ziff Energy believes that whether these inequities are real or not, depends on various perspectives which include:

1. **Rightful Ownership**:
    - Are the export delivery shippers or receipt shipper the rightful owners of NGLs entrained in the gas processed at straddle plants? While it seems generally accepted by the participants that producers own both the gas and entrained liquids when produced in the field, and then the receipt shipper owns the gas and liquids at the entrance point to the pipeline, parties views on ownership diverge after that point.

2. **Transfer of Rights via Contract**:
    - Ziff Energy agrees that when shippers sell their gas under standard contracts such as GasEDI and NAESB, and under most purchase and sale contracts that Ziff Energy is aware of, the gas and entrained components including NGLs are typically sold as part of the gas bought or sold. As a result, from a contractual perspective, whomever owns the gas at the time it is delivered to the inlet of a straddle plant would own the NGL extraction rights, unless the specific purchase and sales contracts and/or the pipeline tariffs state otherwise.

3. **Location of the Straddle Plants**:
    - Ziff Energy understands that under current pipeline tariffs in Alberta, gas delivered to the straddle plants is part of the common stream. Ziff Energy believes that NGL extraction rights ownership then could depend on whether the straddle plant was deemed to be located upstream or downstream of NIT, and if considered downstream, whether it processes gas delivered to both intra- and ex-Alberta markets, or just the latter. The current convention assumes the gas is delivered downstream of NIT and close to the borders, hence is owned by export delivery shippers. In the event NGTL's tariffs considered this gas to be delivered to the straddle plants upstream of NIT, it would be owned by receipt shippers.

7.4 Need to Change the Convention to Attract Northern and Upstream Gas to Alberta

7.4.1 ConocoPhillips

ConocoPhillips is a producer in the Alaska North Slope. It cannot project when gas will flow, and cannot guarantee that a change in convention would result in ConocoPhillips flowing its Alaska gas through NGTL and Alberta extraction system. ConocoPhillips has gas in Mackenzie Delta and expects it to flow through NGTL (SPG.CP-2).

7.4.2 Imperial/EMC

Imperial/EMC submits that equity demands a shift in convention regardless of whether this provides incentives for ex-Alberta gas. That said, making the Alberta system and NGL market place as attractive as possible to shippers of rich ex-Alberta gas should be an additional aim of the Board. Creating incentives for shippers to utilize the Alberta system and NGL marketplace is in the public interest. Making changes now is not premature as decisions on Alaska gas will be made many years before gas flows.

7.4.3 Keyera

Planning decisions associated with northern gas are being made in the near term, and delaying decisions on changing conventions may detrimentally impact the opportunity to attract liquids rich gas to the Alberta system. Alberta should be proactive in adopting systems and conventions to position Alberta to be the preferred route for northern gas, and the receipt point contracting model makes that route more attractive.

7.4.4 Nova Chemicals

Nova Chemicals observes that Imperial/ECA, ConocoPhillips, and Shell all support a change to a convention so that NGTL extraction rights would be held by receipt shippers, and further observes that affiliates of these parties are owners of and major shippers on the proposed Mackenzie Valley pipeline. Nova Chemicals notes that the State of Alaska supports a change such that receipt shippers hold NGL extraction rights, and that ConocoPhillips and Imperial/ECA have affiliates that are two of the largest three parties with Alaska gas interests in the Prudhoe Bay area. Nova Chemicals supports a change in the NGL convention in part based on the positions of these parties.

Nova Chemicals points out that Alaska gas could pursue various options such as: a pipeline that would bypass the Alberta Hub; segregated pipe capacity that bypasses the NIT market and delivers directly to extraction plants; or transportation in the commingled stream. Nova Chemicals supports the receipt point contracting convention, as it would allow shippers to sell gas at NIT and still preserves NGL extraction rights under the latter two options.

7.4.5 NGTL

NGTL disagrees with other interveners' claims that changing the convention to attract Alaska gas is premature. NGTL references the evidence of the State of Alaska which indicates that "time is of the essence". NGTL submits that changing the convention will enhance competitiveness of the Alberta system and will increase system throughput, resulting in higher netbacks and increased NIT liquidity, and also resulting in additional NGL volumes being made available for extraction and value-added upgrading.

7.4.6 Pembina Pipelines

In Pembina Pipelines' opinion, unfettered operation of Alberta's NGL market is the surest means of attracting increased Alberta or ex-Alberta supplies.

7.4.7 Shell

Shell indicates that modifications that recognize NGL extraction rights ownership at the inlet to gas transmission pipelines will send a positive message to parties who control ex-Alberta gas. Shell's proposed convention would add value to its Northern gas and this value would be reflected in its economic evaluations.

7.4.8 SPG

It is premature to make changes to the convention to attract northern gas as:

- proponents of Mackenzie gas project are already committed to NGTL
- the system that will transport northern gas through Alberta may be federally regulated, so any changes to the convention would have no impact on Alaska gas
- Alaska shippers will be motivated to hold receipt and delivery service to ensure an Alaskan pipeline project from Alaska to lower 48 qualifies for US federal loan guarantees
- in relation to the transportation cost of Alaskan gas, the extraction convention is insignificant
- transportation tariffs of potential options will not be known for many years until engineering, open seasons and regulatory approvals are complete.

Alaskan shippers will be worse off under a receipt point convention, as their extraction rights would assume they are shipping a proportion of their gas to intra-Alberta markets.

7.4.9 State of Alaska ("Alaska or the SOA")

Alaska indicates that the current NGL extraction convention clearly fails to generate fair value for producers and, in turn would not generate fair value for the State. Even if Alaska shippers hold export delivery service, they would only get the benefit of the liquids in the common stream and not the liquids in the richer Alaska gas. This may result in additional facilities being constructed to bypass these restrictions to market access. The current extraction convention could cause an Alaska pipeline through Alberta to be less economic and could lead to a project bypassing Alberta, resulting in higher tariffs (Board-Alaska 1). The State believes that time is of the essence, and that no decisions on this project are likely until this issue is resolved.

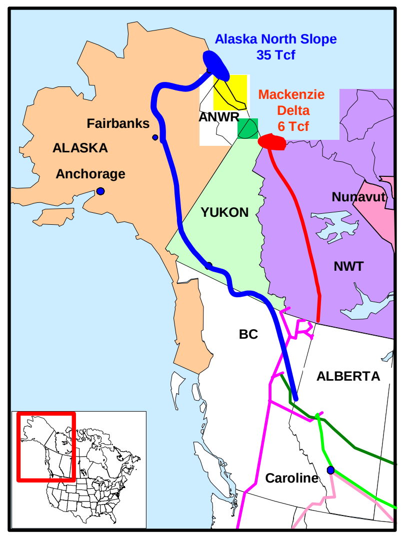
7.4.10 WEG

WEG indicates that NGTL and others have not provided any information on facility costs nor rate forecasts with or without incremental gas as a result of implementing the NEXT model, and have failed to demonstrate that the proposed change is necessary, appropriate or would provide net benefits to NGTL and its shippers.

7.4.11 Ziff Energy Comments

Figure 2 provides an illustrative view of Mackenzie Delta and Alaska. While Ziff Energy's forecasts reflect Mackenzie supply connected by Nov. 2014 and Alaska supply by Nov. 2018, these time tables are uncertain, as SPG and others such as ConocoPhillips point out. ConocoPhillips states that it cannot project when gas will flow, and cannot guarantee that a change in convention would result in a decision to flow its Alaska gas through NGTL and the Alberta extraction system.

Figure 2
Mackenzie Delta and Alaska Gas



The SOA indicates that options for Alaska gas include transporting and processing their gas in the existing Alberta pipelines / border straddle gas plants, or bypassing Alberta altogether (and incurring incremental capital for new pipeline and processing facilities). To provide an incentive for the owners of northern gas to choose Alberta for additional transportation through under utilized pipelines / border straddle plants, several parties suggest that the existing conventions be shifted to allow receipt shippers to hold extraction rights. Ziff Energy notes the SOA's position that time is of the essence to decide which convention Alberta will have for NGL extraction, the Imperial/EMC position that it is not premature to decide now as opposed to waiting, and the Keyera position that Alberta should be proactive in adopting systems and conventions to position Alberta to be the preferred route for northern gas. Ziff Energy agrees with SPG that the actual transportation tariffs of potential options will not be known for many years until engineering, open seasons, and regulatory approval are complete. However, clarity on the applicable extraction convention is a matter in respect of which SOA has requested at this time, since it could impact SOA decisions on the Alaska gas project.

Ziff Energy agrees with the SPG position that the Mackenzie gas volumes, if they flow, will likely connect through the NGTL system[108]. With respect to the SPG's assertion that an ANS gas pipeline has a high probability of being federally regulated, Ziff Energy concurs with respect to the portion of

[108] there is a remote possibility that gas from the Mackenzie Delta could connect to an Alaska pipeline, bypassing Alberta's regulated pipeline system

the pipeline from Alaska to the Alberta border. However, if the gas is then delivered from that pipeline into the NGTL system, the decision on who regulates the Alaska gas flows is not clear, and would depend on whether the gas is considered to move through the Foothills system, which is federally regulated, or the NGTL system, which is regulated by the Board.

Ziff Energy does not support the SPG claim that the Alaska shippers would be encouraged to hold both receipt and export delivery service for purposes of obtaining loan guarantees, as some producers may not require nor want the guarantee, as they may have stronger credit ratings than the US Government and therefore be able to secure more favourable financing.

SPG also asserts that Alaska shippers who take out export delivery capacity to match their receipt capacity would be better off under the current convention versus the receipt point. While Ziff Energy believes this assertion is directionally correct, it does not reflect the incremental value that would be realized under the receipt point convention as a result of Alaska gas being richer than the common stream, and the shipper would be required to hold export delivery service. In addition, given a portion of the Alaska gas molecules will be physically burnt in Alberta gas markets, it may not be equitable to allocate extraction rights to Alaska producers based on the current convention.

In reviewing the parties' positions on whether conventions need to be changed to attract northern gas, declining Alberta gas supply is important to consider. In a decade (a proxy for when Alaska may be connected), gas supply in Alberta is projected to be reduced to 10.1 Bcf/d[109] (as shown on Table 1). Concurrently, Alberta gas demand is expected to increase to 5.5 Bcf/d[110], leaving net gas supply for the Alberta border straddle plants of 4.6 Bcf/d[111]. By 2028, without northern gas, Ziff Energy believes that the Alberta straddle plants would be redundant as export flows could be nil[112].

Ziff Energy believes that gas supply from both the Mackenzie Delta and Alaska will assist in providing gas supply security to the continent. The NGL extraction potential from these northern gas supplies could significantly increase incremental throughput on NGTL and NGL production at the Alberta border straddle plants, lower pipeline tolls to all shippers, and increase gas netback value to the producers. Consequently, providing a supportive environment to attract these gas supplies is beneficial and Ziff Energy believes, in the public interest of Albertans. The SOA has indicated that no decisions on the Alaska project are likely until this issue is resolved (Board-SOA-1(e, f). Alaska indicates that NGL extraction rights should belong to the producer or shipper that owns the gas at the inlet to the NGTL system, and suggests that the NEXT model, modified to include the right to take NGLs in kind, may meet its goals. Given projects to move Alaska gas to market include alternatives to bypass Alberta or to utilize Alberta pipelines and extraction facilities, Ziff Energy believes that having a system in place that allocates extraction rights at the receipt point, and which provides rights to take in kind, would be an encouraging factor in the SOA's analysis.

---

[109] used average of 4 forecasts; for comparison, Ziff Energy evaluation is 9.7 Bcf/d

[110] Ziff Energy evaluation, and includes gas demand supplied by CBM

[111] used average supply and Ziff Energy demand, although if only Ziff Energy values, then net supply is 4.3 Bcf/d, about half of the 8.4 Bcf/d gas processed in 2007. These numbers include Mackenzie Delta gas but exclude Alaska gas

[112] so as not to digress from the Northern gas issue, Ziff Energy notes that EUB ST98-2007, page 5-28 indicates that the Alberta Gas Resources Preservation Act only allows exports from Alberta if the gas is surplus to the needs of Alberta core consumers for the next 15 years. Consequently, the Board could issue orders to reduce gas exports earlier than the time table indicated by Ziff Energy to ensure this 15 year supply is maintained. While this may be a separate issue, it is intertwined

7.5 Impact on the NIT Market and Alberta Gas Prices by Changing the Convention

7.5.1 ConocoPhillips

ConocoPhillips does not believe there will be an impact on the NIT market and price if the current extraction convention changes (BR.COP-2).

7.5.2 EnCana

In response to NGTL-EnCana 3, EnCana states "To say that there is recognition of the value of NGLs in the NIT price implies a transparency that does not exist. While there may be NGL value in the NIT price, it is not quantifiable." EnCana does not believe there will be an impact on the NIT market and price if the current extraction convention is changed.

7.5.3 Imperial/EMC

Imperial/EMC believes the NIT market functions in part because separate parties hold receipt and delivery service. Producers and receipt shippers obtain value for their natural gas without having to hold export delivery service, and the same should be true for NGLs. There is no empirical evidence that the market price at NIT includes an extraction premium.

7.5.4 IGCAA

The IGCAA indicates that its clear expectation is that the NIT market would not be affected by a receipt point contracting alternative (BR-IGCAA-2f).

7.5.5 Nova Chemicals

Nova Chemicals has not seen any evidence that NIT operation, transparency, and efficiency would be impacted if extraction rights were held by receipt shippers. It doubts that any premium for extraction rights is included in the NIT price, and believes the NIT price reflects local and North American supply and demand factors.

7.5.6 NGTL

NGTL indicates there is no definitive evidence on record in the proceeding that NIT prices reflect the value of extraction rights. NGTL provides various examples of parties' positions in this regard. NGTL suggests that implementing the NEXT model will eliminate this confusion and establish separate markets for extraction rights that will improve transparency of the NIT market.

7.5.7 Pembina Pipelines

It is Pembina Pipeline's position that NIT prices reflect the market value of gas on the NGTL system including the value associated with entrained liquids.

7.5.8 Shell

Shell does not believe that the NIT price reflects the value of extraction rights, and due to complexities of the factors affecting the price it may not be possible to determine this. Shell does not believe that a change to receipt point contracting will impact the NIT price or market (response to BR-SHELL-4).

7.5.9 SPG

SPG believes that a receipt point convention may result in two or three types of NIT transactions being required, one related to the entire stream and all components for intra-Alberta transactions, one for export sales for non-extractable components of the stream, and a third for bypassed volumes and unrecovered extractable components at the straddle plant outlet. NIT liquidity may be reduced as receipt shippers would have to makeup shrinkage volumes so would have less gas to trade at NIT. The SPG estimates the potential impact of lost NIT liquidity as a consequence of traders leaving the NIT market due to complexities of dealing with extraction rights trading, and due to reduced receipt shipper NIT trading would be several hundreds of millions of dollars.

7.5.10 Tenaska

Tenaska indicates in its submission that the NIT price recognizes the value of NGLs and extraction value is priced into every downstream transaction leaving the province. If extraction rights are transferred to receipt shippers, it would lower the price paid by export shippers, result in a lower NIT price, and could reduce NIT liquidity.

7.5.11 WEG

WEG believes that the NIT price should recognize upstream costs and opportunities and a reasonable return in the long term, otherwise it will become uneconomic for producers to continue producing. The NIT price in the short term is driven by market dynamics and willingness of buyers and sellers to transact. WEG expects there will not be a significant short term or mid term impact on the NIT market and price if current extraction conventions change because the competitive downstream and or alternative pricing dynamics will not change as a result of the convention (BR-WEG-1).

7.5.12 Ziff Energy Comments

The parties supporting a receipt point convention (producers including ConocoPhillips, Imperial/EMC, Shell, plus IGCAA, Nova Chemicals, and NGTL) generally believe that such a convention would not impact NIT liquidity nor impact the NIT price. Many of these parties suggest that either NIT does not reflect the value of extraction rights or that there is no evidence that it does. The parties that support retaining the current convention (straddle plant owners (SPG), export delivery shippers (WEG and Tenaska) and Pembina Pipelines, generally believe that the NIT price reflects the value of extraction rights and that changing to a receipt point convention will reduce NIT liquidity and price. SPG has indicated a potential impact of hundreds of millions of dollars due to lost liquidity and reduced NIT transactions because of lost shrinkage makeup sales and traders avoiding NIT due to increased complexity caused by splitting up the gas stream into gas with/without entrained liquids.

Ziff Energy has not found much empirical evidence filed in the proceeding indicating that the NIT price includes or excludes extraction values. The only analysis was provided in the rebuttal evidence of Recon Research for Imperial/EMC, who compares the NGTL toll from NIT to Empress with gas price differences between NIT and Empress in 2006 and 2007, and concludes that the two are roughly equal ($0.135/MMBtu toll vs. $0.122/MMBtu price difference). Recon concludes this shows there is no extraction premium embedded in the transportation tariff. However, Ziff Energy does not believe that such an analysis would in any case definitively identify extraction premiums, as price differences between NIT and Empress can be impacted by various factors, including supply and demand of gas at NIT and Empress, interruptible and firm transportation tolls as well as capacity availability upstream and downstream of NIT and Empress, contractual obligations to deliver gas to certain markets, and prices in downstream markets which can be accessed by Alberta gas.

Ziff Energy notes the comments of several parties that it is not possible to quantify whether or not the NIT price reflects extraction value. EnCana's comment reads: "To say that there is recognition of the value of NGLs in the NIT price implies a transparency that does not exist. While there may be NGL value in the NIT price, it is not quantifiable." Ziff Energy agrees with EnCana's comments in this regard. With respect to SPG's comment that there could be hundreds of millions of dollars impact due to a receipt point convention, Ziff Energy does not believe this to be the case. The Western Canada supply basin is currently the single largest gas basin in North America and 80% of the gas from the Western Canadian Sedimentary basin is produced in Alberta. The NIT trading point is the largest trading point in the basin and as indicated by NGTL, in 2006 there were 11.2 Bcf/d of receipts and NIT transactions ranged between 30 and 50 Bcf/d[113].

Given the size of the basin and amount of trading, Ziff Energy believes that even if a receipt point convention was implemented and caused confusion due to complexities of NGL versus gas rights, traders would not abandon the market. Liquidity may even increase, as confusion can sometimes create arbitrage opportunities which traders seek to create value for their organizations. It may be possible within a receipt point convention or other convention to require shrinkage makeup to be provided by receipt or other shippers at NIT, as is the case today, to avoid loss of liquidity. Even if there was some loss of liquidity, it is not possible to quantify the impact.

From a physical perspective, the same amount of gas will still flow in Alberta, and based on NGTL's numbers, that same gas is traded about 3 to 5 times. Many of these transactions are consummated by parties who both buy and sell gas, typically making (or losing) small amounts (pennies) on the transactions. As a result, a loss of liquidity is not a loss equal to the total value of the gas, rather would be made up of many losses/gains of the parties buying and selling gas at NIT. Consequently, it would be impossible to determine the net loss or gain resulting from reduced liquidity.

EnCana, who does not advocate changing the convention (although is open to change), does not believe there will be an impact on the NIT market and price if the current extraction convention is changed.

[113] NGTL August 28, 2007 evidence, page 9 of 30

7.6 Preferred Convention for Allocation of NGL Extraction Rights

7.6.1 ConocoPhillips

ConocoPhillips supports a receipt point contracting convention determined through a collaborative industry group (BR.COP.1).

7.6.2 EnCana

EnCana does not advocate change to the existing convention. If there is a change, it should be a two step process: first identifying an alternative that yields residual producer benefits and appears practical, and second working out details in a collaborative fashion to ensure the alternative is reasonably and efficiently implemented (Ziff Energy ALLNGP3-EnCana).

7.6.3 Imperial/EMC

Imperial/EMC supports a receipt point convention whereby components are measured at receipt points and extraction rights allocated based on these components. Producers/receipt shippers should have the option to take their NGL products in kind in return for a reasonable fee. Imperial/EMC supports the development of an open and transparent market for extraction rights for NGLs, similar to the NIT mechanism. The Board should have an oversight role in the setting of extraction fees in response to a complaint, as a last resort. The Board could assist in this role by clarifying that the straddle plants are subject to being declared common processors for extracting products on a fee for service basis, and that straddle plants must offer services where products may be taken in kind for an appropriate fee.

7.6.4 Industrial Gas Consumer's Association of Alberta (IGCAA)

IGCCA believes that an extraction convention that recognizes and gives credit at the receipt point for the various entrained components in the gas stream is one that provides appropriate economic signals and fairness to the resource owner (BR-IGCAA-1). The NGTL proposal is directionally appropriate and is a reasonable balance between economic equity and administrative simplicity.

7.6.5 Keyera Energy

Keyera supports a move to receipt point contracting, and recommends that the Shell proposal should be used as a starting point for a new convention, with exploration of a simpler equalization methodology such as that used for crude/condensate equalization.

7.6.6 Nova Chemicals

Nova Chemical suggests a competitive market based framework for NGL extraction should be developed, and this may be facilitated by adopting a receipt point convention. A receipt point convention would enhance the potential for ex-Alberta gas to use gas transportation and NGL extraction infrastructure, which would benefit straddle plant owners, NGTL toll payers, holders of extraction rights and NGL buyers. The choice between selling NGL extraction rights and tolling through straddle plants should be left to commercial considerations and the market. Nova Chemicals notes that the three receipt point models all allocate NGLs based on measured composition at NGTL receipt points, and allocate extraction rights to receipt shippers which are applied to extraction plants. Nova Chemicals supports the methodology underlying the models as it avoid complications that would result from full component tracking and balancing.

7.6.7 NGTL

NGTL submits its NEXT model is in the public interest of shippers on the NGTL system, and addresses the real inequities that exist under the current convention. The complexity is not materially different from the current convention. NGTL would use similar procedures to administer the NEXT model as are used for the current convention, and new administrative systems should not be required for straddle plants.

The NEXT model provides a more accurate and equitable proxy for the NGLs that each shipper provides to the common stream, versus Shell's model which is based on heating values above the minimum heat value of the system. NGTL indicates that its NEXT model could be implemented using existing NGTL measurement and gas accounting infrastructure, whereas Imperial/EMC's CCM model requires component tracking for implementation.

7.6.8 Pembina Pipelines

Pembina Pipelines supports the existing conventions and indicates those conventions should not be changed without demonstrating there is a clear, identifiable, and substantive problem that needs to be corrected and that a correction will result in a clear identifiable and substantive net benefit to Alberta's public interest.

7.6.9 Shell Companies ("Shell")

Shell prefers the Receipt Contracting alternative, with extraction rights based on heating values. The convention should apply to all EUB regulated pipelines, allow for orderly transition, and have clearly documented rules in EUB policy directives and/or tariffs. A default pool could be established to allow shippers to use an administrator to sell their extraction rights. Use of this model should facilitate the most economically efficient outcome for the extraction of additional NGLs from the gas stream (Response to NGTL-2).

7.6.10 State of Alaska (Alaska)

The current convention needs to be modified: the State's goal is to achieve fair value for gas and NGLs, and one way to achieve this goal is to allow shippers to take NGLs in kind. Alaska is open to other methods that could allow shippers in the system to obtain fair value; NGTL's proposal is a step in the right direction (Board-Alaska-1).

NGL extraction rights should belong to the producer or shipper that owns the gas at the inlet to the NGTL system, and the value of the components for the gas needs to be priced in a free and efficient market, using an equitable and transparent method. The SOA agrees with Imperial/EMC that the methodology should ensure that the owner of the extraction rights is free to contract to realize the value of its NGLs to the fullest extent possible. One potential modification to NEXT that Ziff Energy thinks might help achieve the SOA's goals is the ability to take NGLs in kind. (NGTL-SOA-1). The SOA believe that it is in Alberta's and the SOA's interests for the straddle plants to only charge rates on a cost of service basis (BR-SOA-3).

7.6.11 Straddle Plant Group

THE SPG supports the retention of the current convention. The convention is simple, it works, it costs very little, is a reasonable and fair solution, and provides various advantages as outlined in section 4.1 of the NECTF report. Other conventions result in additional costs without material benefits (Nova Chemicals-SPG-1(a)).

7.6.12 Taylor NGL

Taylor supports changes to the convention to the extent market access improves, and competitive principles are followed. Taylor opposes changes that create barriers to entry and inappropriate protection of incumbents. Administration procedures should fairly allocate and reconcile the gas volumes secured for NGL extraction to the actual physical gas flow to the straddle plants. Straddle plant operators should choose whether to offer take-in-kind options to extraction rights holders. Creating a more diverse group of ethane producers would be beneficial to the petrochemical industry.

7.6.13 Tenaska

Tenaska's position is that the current system works in the interest of all parties and provides a common share of NGL revenues in proportion to the common stream of gas at NIT. Tenaska indicates that any solutions to the inequities of lean versus rich gas should be addressed upstream of NIT.

7.6.14 WEG

WEG's primary submission indicates the current convention should not be altered. It is easy, cost-effective to administer, and is the basis for long-standing commercial arrangements for NGL extraction that have been developed and currently exist among parties.

7.6.15 Ziff Energy Comments

Ziff Energy notes that there are two primary conventions proposed by the parties: a) the status quo, supported by SPG, Pembina Pipelines, and export shippers (WEG and Tenaska); and b) a receipt point convention, supported by most of the producers (ConocoPhillips, Imperial/EMC, and Shell) and other remaining parties (Keyera, Nova Chemicals, IGCAA, the State of Alaska, and NGTL). EnCana indicates it does not advocate change, although it is open to change, and Taylor NGL supports change, to the extent change improves market access and competitive principles follow. Three receipt point models were proposed as follows, with Ziff Energy comments on each.

(i) The NGTL NEXT Model

The NEXT model allocates extraction rights to receipt shippers based on the value of measured components at the receipt point (component volumes times market prices for those components). These extraction rights give the owner the right to extract NGLs from a pro rata portion of the common stream at the inlet to the straddle plants.

Strengths: Once extraction rights are determined, similar operating procedures as under the current convention are used, with the main difference being that different parties than currently do so would own the extraction rights. As the extraction rights reflect measured and market prices for those components, there should be a better match of market value of the components with extraction rights.

Concerns: Extraction rights can be applied to any straddle plant on the system. While this is positive in developing a competitive market where various plants could compete for extraction rights, Ziff Energy's concern is that receipt shippers may not capture as much revenue as might be possible. For example, the Cochrane plant, which has access to richer inlet streams, should be able to pay more for extraction rights than other plants. As the owners of the Cochrane plant can negotiate with shippers representing 100% of the receipt capacity on NGTL, and will compete against straddle plants with leaner inlet streams, they only need to offer a slightly higher amount for extraction rights than the five other plants, as they can pick and choose with whom they contract. This amount could be less than what the rights are actually worth the owners of the Cochrane plant were limited to negotiating with shippers having a total volume that matched the plant capacity.

(ii) The Shell Model

Shell's model is similar to the NEXT model, except that extraction rights would be determined by using heating values at the receipt points rather than measured components. While Shell did not provide as much detail on implementation and operational procedures as NGTL, Ziff Energy believes that similar operational procedures could be employed for the Shell model, with the main difference being the amount of extraction credits allocated to each shipper. From review of the submissions of the parties, Ziff Energy understands it should not be much more complex to measure and track components at the receipt point as proposed in the NEXT model, than to measure heating values, as proposed by Shell. Shell's concern with NEXT appears to be mainly related to use of 60 day old NGL prices in the allocation, although NGTL response SCE-NGTL-8 and Shell's rebuttal evidence confirms this makes no material difference. As a result, Ziff Energy prefers the NEXT model over the Shell model, as calculated extraction rights appear to be more reflective of the actual value of shippers' NGLs in the stream.

(iii) The Imperial/EMC Model

Imperial/EMC's model proposes component tracking similar to the NEXT model, and proposes that parties have the right to take their products in kind. In addition to the "take-in-kind" option, Ziff Energy's interpretation of Imperial/EMC's evidence is that extraction rights would be based solely on allocated components. Receipt shippers with those allocated components would negotiate with the straddle plant operators with respect to custom processing/take in kind arrangements, or outright sale of those components to the straddle plant operators. In either case, the difficulty here is that the components determined at the receipt point are not the same as the component mix and total components at the inlet of the straddle plants, so an allocation mechanism would be required.

Ziff Energy understands that allocations similar to this are done at some field plants, where gas stream components are determined at the wellhead, and components extracted at the plant are allocated to the working interest partners in the wells and plant. In this case, 100% of the gas and entrained components from the wells is processed at a single plant. On NGTL, only a portion of the receipt gas is processed at straddle plants and there are six plants, so implementing Imperial/EMC's proposal would be more challenging. If for example, receipt shippers are allocated 100 units each of ethane, propane, butane, and pentanes plus, and the six straddle plants remove an aggregate of 50 units of ethane, 80 of propane, 85 of butane, and 88 of pentanes plus, how does one allocate this among numerous parties at each of the plants? It appears an allocation mechanism would need to developed and implemented at the straddle plants to accommodate this proposal.

With respect to the option to "take-in-kind", Ziff Energy believes this right could also be implemented under the first two models, with take-in-kind rights based on a proportionate share of the straddle plant NGL output (a party who has 10% of extraction rights at a straddle plant would be allocated 10% of liquids produced). Ziff Energy notes Imperial/EMC's suggestion that the Board should have an oversight role in the setting of extraction fees in response to a complaint, and that the Board should clarify that the straddle plants are subject to being declared common processors for extracting products on a fee for service basis. Given the small number of straddle plants, Ziff Energy believes that Imperial/EMC's "take-in-kind" suggestion may be a reasonable approach.

Current Model

Ziff Energy agrees with SPG and the other proponents of the current convention that it is reasonably simple, cost effective and is the basis for long standing commercial arrangements for NGL extraction that have been developed and currently exist among parties. SPG has commented that the perceived inequities in the Board's list of issues are not material and there is not any evidence that an alternative convention would eliminate them. In this regard, Ziff Energy notes SPG's analysis in BR-SPG-6(a), Table 3.1, which shows that a rich gas shipper would lose at most \$0.023/GJ, and a lean gas shipper would gain at most \$0.014/GJ, if the current convention were to be maintained, versus a receipt point convention. These calculations reflect the NGTL toll impact, where rich gas shippers pay a lower NGTL toll (when converted to \$/GJ) than do lean shippers. This difference offsets the lean gas/rich gas inequities shown in Table 3.1. In Ziff Energy's opinion, this analysis should not include the NGTL toll impact.

As pipelines are designed on a volumetric basis, volumetric tolls reflect a shippers' use of pipeline capacity. Ziff Energy sees this an incidental benefit of shipping rich gas, which should not be linked to the value of a shipper's extraction rights. If this amount is not considered, the calculation would show a maximum negative impact of $0.033/GJ for rich gas shippers and a $0.025/GJ benefit for lean gas shippers. While this difference is still small, Ziff Energy notes that individual shippers may attach additional value related to the ability to negotiate the value of their individual rights and may believe they can negotiate higher premiums than historical values. In addition, under the current convention, receipt shippers do not receive any concrete extraction value unless they hold export delivery service.

7.7 Impact on Stakeholders if Extraction Conventions are Changed, and Implementation of New Convention

7.7.1 ATCO Pipelines

ATCO Pipelines submits that a change in NGTL conventions should not be made unless clear quantifiable benefits can be shown. A receipt point contracting convention on ATCO's system would have the following impacts:

- receipt point measurement and NGL ownership would need to be recognized in ATCO's tariffs
- owners of straddle plants on the system would have to contract for extraction rights with receipt shippers, and there may be changes in their economic viability ofthose straddle plants
- AP shareholders would need to invest in capital for system upgrades and would benefit from a rate of return on the related rate base
- AP ratepayers would incur incremental costs for an NGL tracking system (SCE-AP-6a indicates AP measures heat content at least monthly and has chromatographs at 40 receipt points).

Implementing a NEXT Type model would require careful analysis of system characteristics:

- there are only straddle plants on the AP North system; gas from AP South and certain areas cannot reach straddle plants
- flow patterns are seasonal, which is not conductive to consistent gas flows to straddle plants.

7.7.2 ConocoPhillips

ConocoPhillips recognises that there may need to be a transition period for changing long term contractual arrangements in order to reflect a new convention. Contract issues could be resolved when mechanics of a receipt point contracting convention are addressed. Any long term contracts reached subsequently to the inception of this inquiry should be subject to the mechanics of the new convention. Extraction rights values would be redistributed between receipt and delivery shippers, although the price advantage to Alberta industry would not be impacted (BR.COP-2).

7.7.3 Imperial/EMC

Imperial/EMC submits that a reasonable transition period would allow for the lapse of short term contracts while renegotiation of longer term contracts will perhaps be required.

7.7.4 IGCAA

IGCAA indicates that one impact of a proposal directionally similar to NEXT would be increased pipeline rates, to recover incremental capital and operating costs. IGCAA members would benefit from attraction of long term supplies to Alberta and minimization of pipeline rates and infrastructure. A reasonable transition time of 12 – 24 months may be required to restructure contracts and allow time for NGTL and other pipeline operators to implement system changes. It is IGCAA's clear expectation that NIT would not be impacted, and IGCAA does not believe delivery markets would be impacted (BR-IGCAA-2).

IGCAA believes that an orderly transition to the new convention can and must ensure that no undue economic harm is incurred by current contracting parties, although it does not believe that the loss of an economic windfall is an example of undue economic harm (WEG-IGCAA-1 and ZIFF-IGCAA-2).

7.7.5 Nova Chemicals

Nova Chemicals submits that a transition period is required, and the ownership of NGL extraction rights must be clear and unambiguous. If the new convention is introduced before northern gas flows, it could provide an opportunity to attract newly discovered rich gas streams to NGTL and the straddle plants before then.

7.7.6 Pembina Pipelines

Pembina Pipelines quotes "pertinent points" from the NECTF report on potential effects of shifting to a receipt point contracting convention, including: reduced upstream processing, value would be shifted from ex-Alberta delivery service holders, receipt shippers would have the right to contract at extraction plants or to bypass, the potential still exists for sidestreaming, control of the downstream NGL infrastructure limits participation in the NGL market, extraction rights would be unbundled from contractual gas flows, there would be an impact on existing commercial arrangements, and the alternative would be more complex (response to Imperial/EMC-Pembina 3).

7.7.7 Shell

In its submission, Shell identified the following impacts if its proposed receipt point convention is adopted:

- receipt shippers should pay the administration costs of the proposed alternative
- producers-can negotiate with receipt shippers for the value of their NGLs or can take out receipt service
- export delivery shippers will forgo the extraction value
- intra-Alberta consumers who derive value from NGL extraction rights, would forego some value (Nova Chemicals at JEEP)
- straddle plant operators would need to administer more agreements

- pipeline operators would need to provide more data to account for extraction rights and tariff amendments may be required.

7.7.8 SPG

The SPG indicates that the incremental costs to implement a receipt point convention in Alberta would far exceed the benefits of a new convention. In its rebuttal evidence, the SPG estimated that the dollar value of benefits is zero, and while costs would include various items for which the SPG could provide estimates:

- $1.5 million/yr to recover NEXT capital costs
- straddle plant costs for IT system upgrading, and administration staff costs of $4 million in up front costs, plus $12-13 million in annual operating costs
- common stream operator costs similar to straddle plants
- reduction in gas sales revenue of $34 million/yr due to NIT falling $0.023/GJ (based on $77 million annual extraction premium and 9 TJ/d of export volumes)
- loss of NGL frac spread revenues of $27 million/yr due to bypass of 3% of straddle volumes, as some receipt shippers/CSO's would not spend the money to obtain their share of extraction rights due to administrative costs
- lost petrochemical value of $18 million/yr due to bypass of 3% of volumes
- cost to amend gas contracts to accommodate separate sale of NGLs and gas in the common stream, at some $10 million over 4 years
- a potential impact of hundreds of millions of dollars due to loss of NIT liquidity related to straddle plants no longer buying gas to make up shrinkage
- a potential impact of several hundreds of millions of dollars due to lost NIT liquidity from traders leaving the NIT market due to increased complexity of dealing with extraction rights trading
- regulatory costs of $10 million to resolve issues related to implementation of a receipt point contracting scheme
- costs of $1 million to educate industry.

SPG indicate that the total costs are $39 million one time, and $103 million/yr (plus potential of several hundred million/yr more) of ongoing costs.

7.7.9 WEG

WEG's position is that the impact of NEXT proposal on WEG companies would be lost extraction revenues, the overall cost of gas would increase to customers of WEG companies, and WEG would still pay a NIT price, although it would receive lean gas rather than the value of the commingled stream. Any new convention will upset the balance of interests of the various shippers under the current rate design, so changes should only be made after the full rate implications have been examined in a future GRA Phase II process. FT-R shippers who receive the extraction value should pay the associated costs to get the NGLs to the border extraction plants, and NIT should be theoretically moved south and east of existing straddle plants (BR-WEG2b). Any change to the extraction convention which takes extraction rights away from FT-D shippers may frustrate existing extraction contracts between FT-D shippers and straddle plants (ALLNGP1.2).

7.7.10 Ziff Energy Comments on Stakeholder Impacts from Implementing a New Convention

All of the parties acknowledge there will be costs and transition issues associated with adopting a new convention, although there are wide differences in the anticipated magnitude of costs. As almost all proponents of a new convention proposed some form of receipt point contracting, Ziff Energy's comments relate to the costs associated with moving towards that type of convention. Table 2 provides a summary of comments for the various cost items identified by the parties (all costs are as estimated by the SPG, except where noted otherwise).

Table 2
Summary of Comments

Item	One Time Cost Impact[114] ($ million)	Ongoing Cost Impact ($ million/yr)	Ziff Energy Comments
Capital Costs NGTL NEXT System		1.5 (annual revenue requirement)	Based on NGTL estimates, the rate impact is $0.0003/Mcf[115]. SPG comments that NGTL's estimate of no increase in operating costs is likely understated as NGTL has not considered title transfer issues.
Straddle Plant IT and Admin Costs	4.2	12.3	From review of NGTL's NEXT model, it appears that nomination procedures and allocations are very similar to the current convention, with the main difference being who holds the extraction rights. Ziff Energy does not understand how a receipt point model would require major changes to SPG members' IT systems. Ziff Energy accepts that there would be one time administration costs to address changes to contract and operations databases to reflect new contracting parties. However, there is insufficient evidence presented to quantify such costs. If each of the five border straddle plants had to hire two senior administrative personnel for one year at an all-in cost of $120,000/year/person, the total one-time cost would be $1,200,000.
Other Participant Costs	4.2	12.3	SPG assumes similar costs would be incurred by common stream operators (CSO's) for IT system changes and administration of extraction rights. Based on NGTL's evidence, Ziff Energy understands that NGTL would determine extraction rights based on NGTL component measurement and allocate extraction rights to individual receipt shippers at each plant rather than have this function undertaken by CSOs, so Ziff Energy does not understand how this would drive IT system changes or increased administrative procedures for common stream operators ("CSOs").
Reduced Producer Revenue		34	SPG indicates this is based on NIT price falling by $0.023/GJ, partially offset by extraction premiums paid to producers. Ziff Energy does not believe it is possible to determine whether there will be a NIT impact or the magnitude of any such an impact.
Increased Plant Bypass		27 (frac spread) 18 (lost petrochemical value)	SPG indicate there may be increased bypass of straddle plants due to smaller receipt shippers/CSOs not spending the money for the related administration of extraction rights. Ziff Energy believes that some smaller receipt shippers may not deal with their extraction rights in the short term due to the administrative burden; however, over time, larger receipt shippers may consolidate these extraction rights and reduce the impact.
Contract Change Costs	10		SPG estimates significant costs related to restructuring of standard industry contracts such as GasEDI and NAESB. Ziff Energy believes that it will be possible to amend NGTL rates in a fashion that accommodates a receipt point convention and negate the need to make changes to standard industry contracts. However, Ziff Energy recognizes that a receipt point convention will require straddle plants to negotiate new contracts with receipt shippers and negotiate termination arrangements with export shippers, which will increase short term administration costs of straddle plant owners.
NIT Liquidity		Several 100	Ziff Energy does not believe it is possible to determine whether there will be any NIT impact or the magnitude of such impact. if any.
NIT Complexity		Several 100	SPG indicates that establishing a trading market for extraction rights either separate from or as part of the NIT market will increase NIT complexity and reduce NIT liquidity. While Ziff Energy agrees with the SPG that such a market would have much less value than NIT, and there could be issues around physical settlement, Ziff Energy does not believe it would impact the NIT market. Ziff Energy suggests that if such a market proceeds, it would likely be separate from NIT and could potentially be traded on existing trading systems such as NGX, if NGX was amenable to doing so.
Regulatory Costs	10		Ziff Energy agrees with the SPG that there could be considerable costs of implementing a new convention. At a minimum, Ziff Energy expects that industry collaboration will be required to work out some of the details and to the extent agreement cannot be reached with all parties; the Board may be required to hold further regulatory hearings to finalize conventions.
Industry Education	1		SPG has estimated that education could cost in excess of $1 million. Ziff Energy believes it could be lower or higher depending on how sucheducation is undertaken. For example, education could occur as part of current pipeline/industry task groups or separate sessions open to all pipeline shippers, which could be provided by the pipeline operators and may not impact current pipeline rates.
TOTAL	**39**	**$103 plus several $100**	

[114] all estimates provided by SPG except for NGTL NEXT system costs provided by NGTL
[115] based on NGTL response to WEG-NGTL-4, rate impact = $0.01/Mcf impact per $35 million in revenue requirement

7.8 Application of the Same NGL Extraction Convention Across all EUB Regulated Pipelines

7.8.1 ATCO Pipelines

AP believes its current NGL extraction convention is appropriate, reflects the history and specific circumstances of AP's system, and provides for efficient and economic extraction on their system. AP transfers NGL rights to straddle plants and AP and its shippers are compensated by payment of the SPD toll. Parties representing stakeholder groups (CAPP, IGCAA, and UCA) have not expressed concerns regarding treatment of NGLs on AP's system.

7.8.2 Aux Sable Alliance Pipelines

NGL extraction rights on the Alliance pipeline are conferred to Aux Sable and clearly defined under Alliance's tariffs and extraction agreements that each Alliance shipper must sign.

7.8.3 Canadian Chemical Producer's Association ("CCPA")

CCPA indicates that any solution satisfactory to stakeholders should be broad enough to include the entire Alberta Energy Hub; however, if shippers on the AP or AltaGas systems do not see any inequities, then perhaps changes there will not be necessary.

7.8.4 Keyera Energy

Keyera believes receipt point contracting should work on the AP and AltaGas systems.

7.8.5 Shell

Shell believes its proposed convention should be applied across all regulated pipelines and be applied consistently to all stakeholders. It will be necessary to consider if pipelines other than NGTL have facilities to calculate the heating value of the gas streams, if tariff modifications are required, and how these systems determine the volume of gas available for processing for determining extraction rights.

7.8.6 Ziff Energy Comments

Ziff Energy notes that Shell believes the convention should be applied across all regulated pipelines and that a few other parties suggested it should be applied or should work on pipelines such as AP. On the other hand, AP believes its current convention is appropriate and provides for efficient and economic extraction on its system, and that CAPP, IGCAA, and UCA, who represent the three main stakeholders on AP's system, did not express concerns when contacted. Given that AP has not had discussions with all stakeholders on this issue in its industry task groups and that one of its shippers (Shell) would prefer a change, it is not clear to Ziff Energy whether this feedback is representative of a fair cross section of AP's stakeholders. Ziff Energy does recognize that AP's system is unique in that gas flow changes seasonally, extraction plants are only located on AP North, and those extraction plants process less than 30% of total AP South and North producer volumes on the combined system[116]. As a result, consideration of changes on the AP system should take into account whether the majority of shippers on AP's system supports such a change.

With respect to AP's comments that shippers are compensated by payment of the SPD toll, Ziff Energy's understanding is that the SPD toll does not specifically account for the value of extraction rights and primarily compensates other AP shippers for the use by the straddle plant owners of the delivery system[117]. Ziff Energy notes that the SPD credit is approximately $0.001/Mcf[118], whereas based on SPG's evidence, extraction rights on NGTL are worth about $0.023/GJ based on throughput volumes of about 9 Bcf/d[119]. Assuming a similar value exists on AP's system, shippers on AP's system may wish to pursue an extraction convention on AP's system to capture this value.

With respect to AltaGas Utilities' system, AltaGas has a small number of shippers on its system and volumes may be neither large enough (in the aggregate) nor sufficiently concentrated to allow economic NGL extraction through a straddle type facility. If a straddle facility is ever proposed, it could be dealt with at the time, taking into account principles that come out of this proceeding.

While the Alliance Pipeline system is federally regulated, Ziff Energy has included Aux Sable's comments in this section for completeness. Ziff Energy notes that Alliance shippers as part of their initial arrangements with the pipeline operator, agreed to transfer their NGL rights to Alliance's designate, which is Aux Sable, and that the terms and conditions confirming this arrangement were approved by the NEB. As Ziff Energy has not conducted a legal review, it cannot provide an opinion on whether the Board would have jurisdiction to alter these arrangements, and in any case, believe they should not be altered given they were determined by agreement between shippers and Alliance at the outset.

[116] based on SPG-AP-1a, ATCO 2006 producer receipts were 518,000 TJ/365 = 1,400 TJ/d or 1,400 MMcf/d, and from EUB ST13 extraction plant throughput on ATCO in 2006 was 400 MMcf/d
[117] BR-AP-2(d)
[118] NCC-AP-1.2(f)
[119] SPD rebuttal evidence page 24, line 8

7.9 Criteria, Public Interest and Processes for Evaluating Sidestreaming and Co-Streaming Projects

7.9.1 Imperial/EMC

Imperial/EMC supports new sidestream plants to foster competition. Each plant should be evaluated on its individual merits. Straddle plants should not be protected from co-streaming or sidestreaming and, if they are, they should be regulated. Under a receipt point convention, producers will be less likely to support sidestreaming or co-streaming as they will be able to access value for their entrained liquids. SPG claims that straddle plants operate more efficiently than would co-streaming and sidestreaming facilities. Therefore, straddle plant operators should be able to offer services at lower rates than potential co-streamers or side-streamers. Regulators should consider whether a facility will add to the resource value of the producer without compromising the ethane supply to the petrochemical industry (BR-Imperial/EMC-6).

7.9.2 Keyera Energy

The inquiry should reaffirm the producer's rights to process their raw gas and that straddle plants do not have a pre-emptive right to liquids in the common stream.

There should be no restrictions on co-streaming and sidestreaming or the ability to bypass extraction. Each case should be evaluated on its own merits.

Keyera does not support an onerous public interest test, such as is advocated by the SPG (SPG's "net benefits to province" test). An approval system which respects the ability of market forces to determine which projects are economic and efficient is preferable. Straddle plant owners should be able to position themselves to compete in light of their long entrenched position and depreciated assets.

Regarding SPG studies on co-streaming and sidestreaming projects, the utilization rates in these studies are based on comparisons of licensed capacity, which are not always an accurate reflection of actual utilization rates, when the capacities of individual functional units are taken into account.

Location of the existing straddle plants may not represent the best location to extract those liquids that are being burned or are anticipated to be burned as fuel in intra-Alberta markets. Finding ways to extract these NGLs is a desirable objective, consistent with the Alberta Government policy to increase ethane extraction.

7.9.3 Nova Chemicals

Nova Chemicals submits that establishing public interest criteria for these (co-streaming and sidestreaming) projects is outside the scope of this hearing. Projects should be reviewed individually based on the relevant public interest. Nova Chemicals does not favour administrative mechanisms, such as determining optimum capture or associated energy use.

7.9.4 Pembina Pipelines

Pembina Pipelines indicates that access to sidestreaming and co-streaming should be avoided, and that producers should undertake extraction where their molecules exist, before of after inclusion in a carrier's stream (Response to BR-Pembina-2). Pembina Pipelines references decision 2004-06; "once a producer/receipt shipper puts its gas on the NGTL system it no longer owns that particular gas", and "a producer/shipper's entitlement from that point on is limited to a right to reacquire its share of the common stream once it is severed or partitioned from the common stream".

7.9.5 Shell

Shell indicates that co-streaming should not be restricted. Shell does not support sidestreaming where it leans the common gas stream to be processed at another extraction plant. However, Shell indicates that the NGL extraction convention should not preclude sidestreaming in order to sustain a nonviable or uncompetitive extraction facility. Shell agrees that the Board must balance the producers' right to receive fair value for NGL with the broader public interest of optimum resource recovery. Shell indicates that in circumstances in which receipt shippers realize fair value for the entrained NGL, combined with efficient cost structure of the straddle facilities, their motivation to support sidestreaming projects should be reduced (BR-Shell-9).

7.9.6 SPG

SPG believes that with excess straddle plant capacity, allowing field plants to reprocess gas would reduce provincial wealth and is not in the public interest. Purvin and Gertz provides lists of gas plants which could potentially be used for co-streaming and sidestreaming and Wright Mansell provides calculations for representative scenarios showing the net social benefits of these plants to be negative. Net social benefits are calculated based on the value of incremental (or decremental) amounts of NGLs, and incremental (or decremental) capital and operating costs.

SPG maintains that the NGL extraction and NGL markets are highly competitive and costreaming and sidestreaming will not increase competition or the value of NGL extraction and upgrading, in light of leaning of the gas stream, declining supply, and increasing Alberta consumption. Producers have various extraction options including shallow or deep cut field extraction, extraction on the transmission line, or by shipping on the AP or Alliance pipeline systems.

If sidestreaming or co-streaming is allowed, it could result in double counting of extraction rights, and unfair treatment of the owners of the rights.

Sidestreaming may also reduce overall NGL recovery due to the leaning of the common stream upstream of straddle plants, such that it is no longer economic to process the common stream and the straddle plants are bypassed, resulting in lost NGL production.

7.9.7 Taylor NGL

Taylor indicates that sidestreaming may result in an unfair advantage over existing straddle plants, as those plants may have access to a richer stream and degrade composition to the straddle plants. Co-streaming is fair competition as market participants compete for the same stream (BR-Taylor 2(j)).

In its rebuttal evidence, Taylor NGL indicates that the Purvin and Gertz report on costreaming and sidestreaming ignored or did not properly assess various factors in its evaluations, such as plant design, access to pipeline gas, and liquid product transportation. Taylor suggests only the Harmattan and Jumping Pound plants have potential for economic co-streaming. Taylor indicates it would not be in Taylor's interests to construct an oversized pipeline, or provide anything better than interruptible pipeline access, which would introduce too much risk for other parties considering incremental bypass. In addition, Taylor indicates Purvin and Gertz does not provide any details on various aspects of its analysis and stated in various responses that it made simplifying assumptions or was not engaged to provide in-depth analysis. Taylor suggests that raw gas development would not decrease from co-streaming, and that the Board could attach a condition to permits requiring co-streamers to process new raw gas production.

Taylor has provided economic analysis of the Harmattan co-streaming project showing that it generates a net social benefit. The main differences compared to Wright Mansell's analysis relate to:

- forecast Cochrane flows, where Taylor used the same flow used by Interpipeline in its CERP application
- ethane recovery, where Taylor assumed Cochrane ethane recovery declines at rates above 1,400 – 1,500 MMcf/d
- variable operating cost and GHG cost estimates, where Taylor assumes reduced costs at Cochrane = incremental costs at Harmattan
- Taylor includes increased value related to extending the life of the Harmattan plant and recovering incremental reserves that would otherwise be abandoned.

7.9.8 Ziff Energy Comments

Ziff Energy notes that Imperial/EMC and Keyera support both sidestreaming and co-streaming projects to foster competition, with proposals to be evaluated on their own merits. Shell and Taylor recognize that sidestreaming may degrade the composition to straddle plants. Both indicate that co-streaming should not be restricted --- in Taylor's words, co-streaming is fair competition as market participants compete for the same stream. Pembina Pipelines and SPG conclude that co-streaming and sidestreaming are not in the public interest, and SPG indicates it would reduce provincial wealth.

With respect to comments from parties that co-streaming and sidestreaming should be allowed to increase competition, and SPG's comments that NGL extraction and NGL markets are highly competitive, Ziff Energy recognizes there are only six straddle plants on the NGTL system, with all except one plant owned by more than one party[120], and with some of those parties having interests in more than one plant. These factors may affect competition for reprocessing of gas on the NGTL system.

Keyera indicates it does not support public interest tests such as the "net provincial benefits" test advocated by the SPG; Keyera prefers a system which respects the ability of market forces to determine if projects are economic and efficient. Shell indicates that the Board must balance the producer's rights to receive fair value for NGLs with the broader public interest of optimum resource recovery. Ziff Energy understands that the Board is obligated to review projects from a public interest perspective (which can be quite broad), and so believes that net benefit studies, market support, optimum resource recovery, and other perspectives could be considered by the Board when reviewing these types of projects.

SPG provides representative economics for potential sidestreaming and co-streaming projects utilizing existing gas plants with excess capacity, concluding that net benefits are negative in all cases. Ziff Energy notes that to properly assess such economics, more detailed information would be required, which has not been supplied by SPG, as noted by Taylor. Taylor has provided an alternative evaluation for the Harmattan project, which concludes that there are positive net benefits and includes different assumptions on Cochrane flows, ethane recovery, variable operating/GHG emissions, etc. and which also includes value related to increased reserve recovery. While Taylor's analysis raises doubts regarding SPG's analysis, both analyses involve technical issues around plant design and capital/operating cost estimates which make it difficult to assess within the scope of this proceeding.

The SPG suggests that allowing co-streaming could result in double-counting of extraction rights, and unfair treatment of the owners of such rights. Ziff Energy believes that if such plants were included in a new receipt point convention, these issues would not arise as receipt shippers would be able to allocate their extraction rights to any straddle plant on the NGTL system, including a new co-stream plant.

The SPG has indicated, and Shell and Taylor recognize, that sidestreaming impacts the NGL content of the common stream at straddle plants downstream on the NGTL system. SPG indicates that this impact could make the stream uneconomic to process and result in bypass and lost NGL production. Ziff Energy agrees with these comments.

[120] except Cochrane

7.10 Streaming of Lean Gas to Specific Markets to Maximize NGL Extraction

7.10.1 AltaGas

AltaGas indicates that if gross heating values of gas dropped significantly on their system, demand could exceed pipeline capacity, and there could be issues with operation of customer appliances.

7.10.2 AP

AP indicates it cannot quantify the impact of lean gas streaming to markets on AP's system, as it does not know which interconnections would receive the gas, flow rates, pressures, or heating value of the lean gas (Ziff-AP-4.1).

7.10.3 CAPP

CAPP supports a collaborative process to deal with this issue, which may need to be broader than the TTFP, to ensure any parties who are not TTFP members who wish to participate can (CAPP-NGTL-1). Streaming of rich gas and lean gas streams should be determined on a case by case basis, with system integrity uppermost in mind. The Board should be cautious about accepting the implication that NGL issues should be an overriding consideration in designing Alberta gas transmission systems. The beneficiaries of streaming rich gas and lean gas would include parties who are not NGTL shippers, rather who are part of the NGL value chain.

7.10.4 CCPA

According to the CCPA, lean gas steaming should be a policy issue (NGTL-CCPA 2a). The Alberta public interest is better served if the added value of NGLs is realized while still providing fuel to markets. Lean gas should be used for burner tip applications. It may be necessary to look at the entire system to optimize rich gas and lean gas movements, and the beneficiaries should pay the cost (BR-CCPA-2(i)).

7.10.5 ConocoPhillips

ConocoPhillips believes that a collaborative group with wide industry representation should deal with the lean gas streaming issue, although it does not have a position concerning which group would be best suited for this undertaking.

7.10.6 EnCana

EnCana agrees that the lean gas streaming issue should be dealt with through an industry consultation process under the TTFP.

7.10.7 Imperial/EMC

Imperial/EMC agrees that the lean gas streaming issue should be dealt with through an industry consultation process under the TTFP. Each facility design should be evaluated on a case by case basis (NGTL-Imperial-3).

7.10.8 IGCAA

IGCAA believes that the Alberta public interest is served by an economic and orderly integrated gas transmission system that, where practical, streams lean gas to burner tip markets and rich gas to extraction facilities. Policy and public interest direction that comes out of the inquiry may have an impact on this issue. The costs of this should be weighed against benefits, with direction to industry groups, such as the TTFP, to work out simple cost effective approaches.

7.10.9 Nova Chemicals

Nova Chemicals proposes that, in its assessment of proposed NGTL facilities, the Board should consider the impact of such facilities on NGL recovery; and that NGTL, in its facility applications, should identify the impacts of these proposals on NGL content in associated gas streams and their impact on NGL recovery.

The Board may wish to take an active role in managing any TTFP process established to address this issue.

7.10.10 NGTL

NGTL indicates that only straddle plant owners and petrochemical companies have provided submissions on the lean/rich gas streaming issue, which indicates they would benefit from lean gas streaming. NGTL suggests that agreement on the beneficiaries of any lean gas streaming plan would be put to all stakeholders for discussion and resolution, and would be best dealt with in the TTFP.

7.10.11 Provident Energy and InterPipeline Fund (“Provident/IPF”)

Provident/IPF sees the NCC project as posing a threat to straddle plants, as the project could impact gas available to the straddle plants. It suggests that the NCC project should include an assessment of the impact of the project on the straddle plants.

7.10.12 Shell

Shell agrees that the lean gas streaming issue should be dealt with under the TTFP, with recommendations brought forward to the Board for approval.

7.10.13 SPG

While the SPG prefers a richer stream, the cost-benefit of streaming gas to specific markets is unknown (Ziff SPG5).

7.10.14 Taylor

Cost effectiveness of lean gas streaming should be based on capital required to segregate lean gas streams around Empress, versus the incremental capital to extract NGL from the common stream without segregation.

7.10.15 Ziff Energy Comments

Ziff Energy notes that many of the parties (CCPA, Shell, Imperial/EMC, EnCana, Nova Chemicals, and NGTL) support a collaborative process under the TTFP to deal with this issue, or recognize that it could be dealt with under that forum. ConocoPhillips suggests a collaborative process, although it does not indicate what forum should be used; and CAPP suggests that a collaborative process may need to be broader than the TTFP, to ensure all interested parties can participate. AltaGas indicates that its customers and pipeline capacity could be impacted by lean gas being directed to its system, and while AP indicates it cannot determine impacts, without more details on specific proposals.

Ziff Energy agrees with NGTL that in the event this was brought before the TTFP, the beneficiaries of any lean gas streaming plan would need to be identified and agreed to among the parties, and as suggested by IGCAA, that the costs should be weighed against benefits. However, Ziff Energy believes it will be challenging to gain agreement from the parties on cost allocation until specific projects, costs, related benefits, and impacts on all the parties are determined. One of the interested parties indicates there may be some obvious options "low hanging fruit" that may be less challenging to implement and gain agreement from the parties.

Ziff Energy agrees with CAPP that any forum be broad enough to allow parties who could be affected to participate. For example, AP and AltaGas have identified potential impacts, and rural gas coops could also be affected.

In BR-NGTL-3, NGTL provides estimated gas compositions from 2007 to 2020 at the eastern straddle, western straddle, and Woodenhouse C/S, assuming gas compositions at specific locations on the system remain the same as at September, 2007. Ziff Energy notes that these show declining ethane and propane at the straddle plants and increasing propane and ethane at Woodenhouse C/S prior to Alaska gas coming on-stream. Ziff Energy assumes these trends are influenced by the NCC pipeline project. After Alaska comes on-stream, compositions increase above 2007 levels at all locations except the western straddle plants. This reinforces the perspective that gas compositions change over time and are likely to be significantly impacted if northern gas arrives. Any solutions and potential benefits should consider the implications of this.

8. ALTERNATIVE MEANS TO RESOLVE ISSUES

8.1 Criteria to Assess Alternative Approaches to Resolve Issues

In the Board's July 6, 2006 Final Scoping Document, the Board identified the following assumptions related to the public interest on which the Board relied on to prepare the Final Scoping Document:

1. in providing for the economic, orderly, and efficient development of Alberta's natural resources it is in the Alberta public interest to encourage to the maximum extent practical, the extraction of NGLs within the Province of Alberta, for use, upgrading or sale within Alberta while providing the NGLs owners with fair compensation
2. clear rules and procedures with respect to NGL ownership and extraction are in the public interest
3. it is in the public interest to minimize proliferation of NGL extraction facilities where proliferation may result in decreased net NGL extraction within Alberta, increased net energy use per unit of NGL extracted within Alberta, and/or result in greater land use or environmental impact than is necessary
4. it is in the public interest to optimize the energy efficiency of NGL extraction
5. it is in the public interest to maintain a viable extraction and petrochemical industry in the Province
6. it is in the public interest to maximize efficient use of EUB regulated transmission pipeline infrastructure
7. it is in the public interest to maintain liquid and efficient markets for natural gas
8. NGL Extraction Conventions and the Alberta Ethane Policy have historically worked in the general public interest but require review at this time
9. absent a public interest reason to differentiate among EUB regulated pipelines, Producer/Receipt shipper rights with respect to NGL ownership should be equivalent.

Ziff Energy notes that these assumptions provide guidance in defining the public interest. For this reason, they have been used as criteria for evaluating alternatives identified in the proceeding.

8.2 Review of Alternative Approaches

Three main issues have arisen in this proceeding:

1. what convention should be used to account for and allocate NGL extraction rights to NGLs in the common stream of Alberta's EUB regulated pipelines?
    a) should the same convention be applied to all EUB regulated pipelines?
    b) if a new convention is adopted, how should it be implemented?
2. how should applications for side-stream and co-stream plants be handled?
3. should lean gas be streamed to end-use markets to maximize NGL extraction?

8.2.1 Review of Alternative Conventions to Account For and Allocate NGL Extraction Rights to NGLs in the Common Stream of Alberta Regulated Pipelines

The parties in the proceeding have identified two main alternatives:

1. maintaining the current convention, where export shippers continue to hold NGL extraction rights and negotiate with the straddle plants for sale of these rights ("Current Convention")
2. moving to a receipt point convention, where receipt shippers would hold the NGL extraction rights and would negotiate with straddle plants for these rights ("Receipt Point Convention").

Table 1 compares benefits, limitations, and market impacts of the two main alternatives, with respect to the criteria identified.

Table 1
Comparison of the Current Convention to a Receipt Point Convention

	Current Convention	Receipt Point Convention
1. Maximize Extraction and Upgrading of NGLs in Alberta while Providing NGL Owners Fair Compensation		
Benefits	may increase overall NGL extraction compared to a receipt point convention	more directly compensates the original owners (producers) for their NGLs
Limitations	discourages those without delivery service to put NGLs in the common stream as they are not directly compensated for NGLs	after implementation of this convention, Alberta NGL extraction may decline slightly as the common stream should become richer as producers extract less NGLs in field and leave more in the common stream. Part of this richer common stream will be burnt in intra-Alberta markets without passing through a straddle plant and thus reduce NGL extraction. This impact could be reduced by lean gas streaming and new straddle plants processing intra-Alberta demand
Market Impacts	potentially more NGLs available to petrochemical and other markets	potentially less NGLs available to petrochemical and other markets
2. Clear Rules and Procedures with Respect to NGL Ownership and Extraction		
Benefits	clear rules and procedures are already in place	a receipt point convention with clear rules should help attract Alaska gas to Alberta pipelines
Limitations		cost of implementing a new system could offset benefits, particularly in the short term
Market Impacts		
3. Minimize Proliferation of NGL Extraction Facilities		
Benefits		minimizes proliferation as producers/receipt shippers will receive extraction rights for NGLs so they are more likely to leave them in the common stream rather than building new field plants or propose sidestreaming and/or co-streaming plants
Limitations		
Market Impacts	will continue to encourage field extraction versus allowing NGLs to be extracted at straddle plants	could reduce demand for field processing services and increase NGLs available for straddle plant processing
4. Optimize Energy Efficiency of NGL Extraction		
Benefits		should increase NGL extraction efficiency as more NGLs should be left in the common stream for processing at the straddle plants versus field plants; and straddle plants have higher recovery rates than most field plants and are more energy efficient, due to their size
Limitations	lost opportunity to improve energy efficiency	partially depends on the ability/motivation of field plants to rationalize their plant capacity although, at minimum, fewer new field plants would be built. Ziff Energy believes rationalization is more likely with Empress straddle plants and field plants where proximity allows
Market Impacts		

	Current Convention	Receipt Point Convention
5. Maintain Viable Extraction and Petrochemical Industry		
Benefits	current convention may make more NGLs available to the petrochemical industry, as more NGL's will be extracted at field plants, leaving a leaner stream for straddles and a leaner stream to be consumed in intra-Alberta markets	should help attract Mackenzie Delta and Alaska gas by sending a positive message. If Alaska gas comes as forecast, it would double gas flows to extraction plants in 2019 (and therefore NGLs available to petrochemical industry) receipt point convention should result in richer inlet streams to straddle plants so helps maintain viability of these plants, although this benefit is offset by richer streams also being flowed to end-use markets and burnt without NGL extraction
Limitations		part of the richer common stream will flow to intra-Alberta markets without straddle plants, which may reduce overall NGL production available to petrochemical industry. This impact could be reduced by selectively routing lean gas to intra-Alberta markets and building new straddle plants to process intra-Alberta gas prior to consumption. Ziff Energy suggests that gas supply to the oilsands would be the obvious target for such plants
Market Impacts		
6. Maximize Efficient Use of EUB Regulated Pipelines		
Benefits		should send a positive message to Alaska gas owners that Alberta is recognizing receipt shippers rights to NGLs, so should increase the likelihood of Alaska gas flowing into Alberta pipelines
Limitations		
Market Impacts		if Alaska gas flows on to NGTL by Nov, 2018, export throughput would double and provide toll reduction benefits for all NGTL shippers
7. Maintain Liquid and Efficient Markets for Natural Gas and NGLs		
Benefits	no change	no change with respect to gas markets, however, Ziff Energy believes this may provide for a more liquid market for extraction rights
Limitations		will require implementation of a new system to trade NGL extraction rights
Market Impacts		
8. Equivalent NGL Ownership on EUB Regulated Pipelines Absent a Public Interest to Differentiate[121]		
Benefits	no change to current procedures and no incremental costs	minimizes facility proliferation as producers/receipt shippers will receive extraction rights for NGLs so they are more likely to leave NGLs in the common stream rather than build field plants
Limitations	the value of NGL rights are not recognized directly	unknown cost of implementing a receipt point convention, as only a portion of the stream can access current intra-Alberta straddle plants
Market Impacts		NGL extraction value is transferred from intra-Alberta straddle plants to receipt shippers
9. Encourage Competition in Extraction of NGLs		
Benefits		should increase competition as more and new players will be negotiating for extraction rights
Limitations	status quo would have less potential to increase competition than a receipt point convention with extraction rights trading	there are a limited number of straddle plant owners with whom to negotiate
Market Impacts		if a market system can be set up to trade extraction rights, then Ziff Energy believes that would increase liquidity and transparency of extraction rights values

[121] comments in this section relate to the Atco Pipelines and AltaGas systems

8.2.2 Consideration of Changing the Convention to Attract Alaska Gas

In determining which of the two NGTL NGL extraction conventions should be used, one of the key issues to assess is:

- will a change to a receipt point convention help attract Alaska gas, and if so, when does that change need to be made?

Ziff Energy believes that most of the parties in the proceeding would agree there would be a significant benefit to producers, shippers, Alberta border straddle plants, and the Alberta petrochemical industry if Alaska gas flows into the NGTL system. Based on Ziff Energy's forecast, if Alaska gas arrives and flows 4.4 Bcf/d into the NGTL system by Nov. 2019, Alberta gas supply will increase from 9.4 Bcf/d to 13.8 Bcf/d which based on 5.6 Bcf/d of demand, would increase gas exports (and gas available for the Alberta border straddle plants) from 3.8 Bcf/d to 8.2 Bcf/d. In such a case, transportation tolls would be significantly reduced and NGL production at the border straddle plants more than doubled, as Alaska gas has a higher heating value that the current common stream and 50% to 75% more ethane content (BR-SOA-3, Ziff-NGTL-19). This would significantly assist in prolonging the Alberta petrochemical industry service life and increase natural gas netbacks to producers through lower pipeline tolls. Ziff Energy submits that it is in the Alberta public interest for Alaska gas to utilize existing Alberta gas pipelines and Alberta border straddle plants.

Pipeline proposals to transport gas from Alaska will require approval of the State of Alaska and the State has indicated that time is of the essence and that no American decisions on the project are likely to be made until this issue is resolved. The State has indicated that:

- the current convention does not fairly compensate shippers of rich gas
- the current convention unfairly discriminates against shippers who do not own an interest in the straddle plants
- the State is not able to provide specific analysis of the necessary changes to the NGL extraction conventions that would cause Alaska gas shippers to desire using Alberta pipelines
- the NGTL Next model is a step in the right direction
- allowing shippers of Alaskan gas to take NGL's in kind is one reasonable way to achieve the State's goal.

Despite the State's indication that "time is of the essence", Ziff Energy recognizes that once a proposal is accepted, the proponents of the project including the Alaska producers, and owners/shippers of the as yet to be constructed Alaska pipeline, will have significant leverage with respect to negotiating Alberta pipeline tolls and NGL extraction arrangements. Consequently, whatever NGL extraction conventions are determined as a result of this proceeding, another proceeding may be required to satisfy these parties and the current NGTL shippers. Serious negotiations would not likely occur until the Alaska gas project is better defined and parties are close to a 'go/no go' decision phase, which may not occur for a number of years.

Ziff Energy notes that those producers in this proceeding who have direct interests or who are related to companies with direct interests in Alaska gas reserves (ConocoPhillips and Imperial/EMC), companies who may have interests in a new Alaska pipeline (TCPL), Alberta petrochemical plants (Nova Chemicals), industrial consumers (IGCAA), and Shell all support a receipt point convention. In addition, both the State of Alaska and Imperial/EMC support a convention that includes take-in-kind options. This suggests to Ziff Energy that a receipt point convention with a take in kind option would send positive signals to the State of Alaska and potential Alaska pipeline owners and shippers, versus maintaining the existing convention.

However, as noted previously, timing of the Alaska gas project is uncertain, so the importance of sending this message needs to be weighed against the other costs, benefits, and public interest criteria.

8.2.3 Other Reasons to Change to a Receipt Point Convention

From review of Table 1, Ziff Energy believes both positive and negative impacts would result from changing to a receipt point convention:

Positive Impacts

1) it should lead to reduced proliferation of facilities by reducing new field processing plants and proposals for co-streaming and side-streaming plants, as producers would be more inclined to let their NGLs flow into the common stream as they will receive extraction rights for those NGLs
2) it would provide improved compensation to the original owners of the gas, who are the initial producers and owners of the NGLs
3) it should increase the energy efficiency of NGL extraction, assuming straddle plants can more efficiently extract NGLs than field plants due to economies of scale, and help maintain viability of the Alberta border straddle plants, as those plants should receive a richer gas stream
4) it should increase competition for NGL extraction, as there will be new parties negotiating arrangements with the Alberta border straddle plant operators, with the added potential to establish a market for trading of NGL extraction rights.

Negative Impacts

1) there will be costs to implement the new convention, including NGTL costs for equipment and IS systems, potential costs for the Alberta border straddle plant system operators, and costs related to negotiation of new extraction contracts between the Alberta border straddle plant operators and receipt shippers
2) there is potential for NGL recovery to be slightly reduced, as producers are more likely to forgo field extraction and leave NGLs in the common stream, resulting in a richer common stream, of which part is burnt in intra-Alberta markets. This impact

can be reduced by lean gas streaming to intra-Alberta markets and building straddle plants to process gas destined for intra-Alberta markets (such as oil sands operations).

It is not possible to quantify the relative tradeoffs of the above positive and negative impacts. However, in Ziff Energy's opinion, point 2 under Positive Impacts warrants further discussion, which is provided below:

Parties supporting a receipt point convention have suggested that producers, as rightful owners of the resources, should have the ability to directly negotiate for the value of their natural gas liquids. Ziff Energy offers the following example in support. If the Alberta gas pipeline/extraction/petrochemical industry was to start today (from scratch) with a new pipeline, straddle plant extraction system, and new petrochemical plants, then producers, as owners of the resource, would likely be able to negotiate directly for the value of their NGLs extracted at straddle plants, over and above the energy value of the natural gas. Similarly, owners of Alaska gas should, because of the value they can bring to the Alberta system, have significant negotiating power to establish terms and conditions for shipping and extraction of NGLs from their gas.

Ziff Energy suggests that this is a reasonable argument in support of a convention that recognizes the rights of producers to the NGLs in the common stream. From a practical perspective, parties favouring moving NGL rights back to the producers have proposed a receipt point convention, which recognizes these rights at the receipt point. While Ziff Energy recognizes that transfer of rights to the receipt shipper (rather than the producer/ delivery point shipper) is not perfect, from a practical perspective it is probably as close as industry in Alberta can get to transferring NGL rights back to the producer.

With respect to parties who suggest that NGL rights are sold as part of the common stream under most industry contracts, Ziff Energy suggests that if one accepts that the border straddle plants were built for the benefit of the whole NGTL system, and were located close to the borders for practical reasons to maximize NGL extraction, this should not affect the producer's rights to the NGLs. For example, if the straddle plants were deemed to be located upstream of NIT, from a contractual perspective, receipt gas would be processed at straddle plants rather than an export shipper's gas.

If the Board accepts these arguments, then the Board may wish to implement a receipt point convention to provide fairness to receipt shippers.

8.2.4 If a Receipt Point Model is Adopted, What Form Should it Take?

Ziff Energy believes the NGTL NEXT model should be used as a basis for this convention, with the additional option for parties to take their NGLs in kind at extraction plants. The NEXT model was most widely accepted by the parties supporting a receipt point convention. Operating procedures to nominate gas flows at the extraction plants would be nearly identical as those employed under the current convention, with the main difference being that Alberta border straddle plant operators would be dealing with receipt shippers rather than export shippers with respect to extraction rights. Ziff Energy prefers the NEXT model over the other two models proposed (Shell and

Imperial/EMC[122]), as the NEXT model uses allocation methods similar to those currently in place and calculates extraction rights that are more reflective of the actual value of shippers' NGLs in the gas delivered to NGTL[123].

If the take-in-kind option were to be adopted as part of the convention, NGLs could be allocated on the basis of a *pro rata* share of total liquids extracted at the plants, determined on the basis of extraction rights allocated to each receipt shipper compared with the total extraction rights allocated to all receipt shippers contracting for extraction at that plant.

8.2.5 Timing for Implementation and Transition to a New Convention, if a New Convention is Adopted

Some of the proponents of a receipt point model indicate that implementation should be over a two to three year time frame to minimize transition issues and allow time for restructuring of contracts. SPG indicated that just over half the volumes contracted by straddle plants were subject to contracts of one year or less, and roughly 75% were under contracts with terms of four years or less[124]. NGTL indicates that they would need 12 to 18 months to implement the NEXT model. To accommodate a transition which balances a desire to implement the model within a reasonable timeframe, yet minimizes issues associated with renegotiating contracts, Ziff Energy believes that transition could occur for 50% of the gas volumes within 18 to 24 months of a decision, and the remaining volumes within three years. Assuming an EUB decision for this proceeding is issued by the second quarter of 2008, initial implementation for the first 50% of volumes could become effective in the first half of 2010. As suggested by NGTL, the TTFP could be used to refine the model and operating procedures.

8.2.6 If a New Convention is Adopted on NGTL, Should it be Applied to all EUB Regulated Pipelines?

Ziff Energy believes that while the NGTL (TCPL) NEXT model could be applied to all EUB regulated pipelines, it may not be practical or be supported by shippers on the AP and AltaGas systems. On AltaGas system, AltaGas producer gas volumes are likely neither sufficient nor sufficiently concentrated to allow incremental economic NGL extraction through another intra-Alberta straddle facility. If a straddle facility is proposed, it could be dealt with at the time of application taking into account the principles that come from this proceeding.

AP's system is unique in that gas flow changes seasonally, extraction plants are only located on AP North, and those facilities process less than 30% of total AP South and North producer volumes on the system.[125] Consideration of changes on the AP system should take into account whether the majority of shippers on AP's system support such a change. Given that AP has not addressed this

[122] the Imperial/EMC proposal did not include sufficient detail on allocation procedures to assess potential implementation issues and costs

[123] compared to Shell's model, which bases extraction rights on heating value, whereas NGTL uses measured components and market prices of those components

[124] Wright Mansell report titled "Issues Regarding the Distribution of Benefits from NGL extraction in Alberta", page 6

[125] based on SPG-AP-1a, Atco 2006 producer receipts were 518,000 TJ/365 = 1,400 TJ/d or 1,400 MMcf/d, and from EUB ST13 extraction plant throughput on Atco in 2006 was 400 MMcf/d

issue with individual shippers, Ziff Energy is not clear whether or not those shippers would support it. Attraction of future northern gas supplies is not an issue associated with the AP system.

Ziff Energy recommends that AP be directed to address this in an open forum with its shippers and advise the Board by a specific date as to recommendations on how the issue should be treated on the AP system.

8.2.7 How Could Transition Costs and Other Costs Associated with Changing the Convention be Handled

Ziff Energy believes that the beneficiaries of the change should bear the implementation costs. In this case, the receipt shippers would be the beneficiaries. From the evidence, NGTL identified $10 million in capital costs to implement the NEXT system. While the SPG identified various costs associated with a revised convention including costs to upgrade IT systems, Ziff Energy does not understand why all such costs would be required to be incurred given that nomination procedures would remain almost the same as at present. However, Ziff Energy notes that the straddle plant operators would incur costs to negotiate extraction contracts with receipt shippers and, potentially to terminate contracts with export shippers. The EUB may wish to implement some type of transition cost applicable to receipt shippers that could be credited to the Alberta border straddle plant operators to cover these types of costs. Ziff Energy notes it would be difficult to determine the reasonability of such costs without a detailed cost review, which the Board may wish to avoid.

Export shippers may be concerned that, given the loss of extraction rights revenues, they should be compensated. Such compensation would depend on the Board's view as to whether the change in convention was made because producers/receipt shippers are the rightful owners of NGL extraction rights versus the export shippers or whether the change was made primarily for reasons related to the public interest. If the latter, it would probably be reasonable to have some form of transition fee applied to receipt rates and credited to export delivery rates over a defined period.

8.2.8 Sidestream Plants

Conceptually, sidestreaming plants, should they proceed, would process and remove NGLs from the common stream of a regulated gas pipeline, reinjecting a leaner gas stream into the common stream upstream of the existing straddle plants. This reduces NGL content in the common stream feeding the existing straddle plants, increases their operating costs per unit of NGL extracted, and reduces NGL recovery at the straddle plants. Considerations in this regard are:

- while sidestreaming should not decrease Alberta NGL recovery in the short term, it could impact recovery rates in the future, if sidestreaming plants render downstream straddle plants uneconomic and results in some common stream flows not being processed
- an additional sidestreaming plant may or may not require a new NGL extraction facility[126], and would extract NGL from the common gas stream. If the sidestreaming

[126] a sidestreaming plant may involve an existing field gas plant that has unused processing capacity. Thus by taking additional gas from an EUB regulated pipeline, the additional gas may not require a plant expansion, rather the additional gas would merely use surplus processing capacity that already exists

concept were approved by the Board, it could create additional opportunities for other plant operators to install new sidestream plants upstream of the initial sidestreaming plant, rendering the first side-stream plant redundant. This could result in proliferation of unnecessary NGL extraction facilities and greater land use which in Ziff Energy's opinion is not in the public interest

- while there is potential for new sidestreaming plants to have higher NGL recovery rates than existing straddle plants, the incremental recoveries would not likely compensate for the other downside risks
- as Alberta gas supply continues to decline and Alberta gas demand continues to grow, less gas will be available for the existing Alberta border straddle plants. It is Ziff Energy's opinion that this will render some of the straddle plants redundant, thus consolidation or rationalization will be required in the future
- the financial health of the existing NGL extraction plants and petrochemical supply (particularly ethane) would be impacted by side-streaming, as sidestreaming reduces NGL content of inlet streams to the straddle plants. Given these plants are already facing a dwindling gas supply outlook, this may not be in the public interest
- sidestreaming projects which use existing field plants with excess capacity may provide opportunities to prolong the life of the field plant and thereby increase potential reserve recovery from the area served by the plant. However, Ziff Energy believes that the related benefits would not offset the negative impacts described above.

While side-streaming represents an innovative solution to improve declining Alberta field plant load factors, for the above reasons Ziff Energy is not supportive of these sidestreaming solutions.

8.2.9 Co-stream Plants

Co-stream plants are effectively straddle plants that share and process the same inlet streams and return processed gas downstream of the existing straddle plants. This is basically what occurs at Empress, where four plants share the total inlet stream and deliver residue gas into the same pipelines downstream. As a result, new co-stream plants would reduce inlet flows to the existing straddle plants although they would not reduce the NGL content of the inlet gas streams feeding the existing straddle plants. The proposed Taylor Harmattan project is for co-streaming, proposed to access the NGTL common stream upstream of the Cochrane straddle plant, process the gas through the existing Harmattan field plant, and re-inject the residue gas downstream of Cochrane.

In evaluating policies for assessment of co-streaming projects, Ziff Energy believes some context would be helpful. Alberta gas supply is expected to decline and gas demand increase substantially mainly due to oil sands gas requirements. By 2019, supply available to the Alberta straddle plants is projected to be 2.7 Bcf/d, close to one third of current levels, and by 2028, without northern gas, Alberta border straddle plant throughput is projected to be nil. Northern gas would change the supply picture significantly, more than doubling border straddle plant supply around 2019 and would represent effectively the entire border straddle plant supply in 2028. As a result, Ziff Energy expects consolidation and rationalization of the border straddle plants which are currently operating below capacity, especially the Empress plants. Co-stream plants, which would compete for the same streams and reduce gas available to the existing straddle plants, would likely exacerbate this situation. Based on the evidence and the proposed co-stream plants to date (Harmattan), co-stream plants which compete for flows to the Cochrane plant are more likely, due to richer gas flows at Cochrane versus Empress and the fact that there are adjacent field plants with excess capacity. With respect to the impact of these projects, Ziff Energy provides the following comments:

- in the short term total extraction of NGLs should be similar with or without the co-stream plants. In some cases, a co-stream plant may be able increase recovery percentages of the various components. For the most part, the current straddle plants (and likely co-stream proposals) would recover almost all propane plus in the gas streams. Consequently increased recovery (if any occurs) would primarily be ethane, for which Ziff Energy forecasts shortages into the future, as gas supply declines to the extraction plants
- should one co-stream plant be approved, then other co-stream plants are more likely to follow. Additional co-stream plants decrease the overall extraction efficiency of the existing straddle plants, as the existing straddle plants would now have reduced gas flows available to them. This could cause earlier shut down of some of the plants than would otherwise occur, and result in bypass of some NGTL volumes with a corresponding reduction in NGL recovery
- Ziff Energy believes that proposals involving greenfield projects are not likely in the public interest, as net benefits of proposals using existing plants appear to be debatable[127], and new greenfield projects would have higher capital costs and raise proliferation issues
- similarly to sidestreaming plants, co-streaming projects which use existing gas plants with excess capacity may provide opportunities to prolong the life of the plant and thereby increase potential reserve recovery from the area served by the plant.

With respect to competition issues, Ziff Energy recognizes there are only six straddle plants on the NGTL system, all except one of which being owned by more than one party[128], with some of those parties having interests in more than one plant. These factors may affect competition for reprocessing of gas on the NGTL system. Ziff Energy believes that allowing co-stream plants would increase competition in provision of these services. If such plants were allowed and a receipt point convention adopted, then such plants should be included with the existing straddle plants, in any allocation of extraction credits. This should prevent double counting of extraction rights with respect to these projects.

Given the potential impacts, Ziff Energy believes this issue becomes one of balancing the benefits of increased competition versus the impacts on the existing straddle plants and potential loss of NGL recovery due to accelerated shutdown of those plants (albeit with potential offsets for increased ethane recovery and increased gas reserve recovery).

[127] for example, SPG's analysis show net benefits of Harmattan project are negative, and Taylor show them to be positive

[128] except Cochrane

Given it is not possible to provide a general assessment of such benefits/costs on a generic basis, Ziff Energy believes a reasonable approach is to evaluate the merits of each project on an individual basis as they are brought before the EUB. If the Board decides to take this approach, Ziff Energy recommends that the Board require parties proposing such projects to provide evidence that would assist the Board in determining whether the project is in the public interest.

This could include items such as:

1. impact on Alberta natural gas and NGL reserve recovery and production
2. impact on Alberta straddle plants and the petrochemical industry
3. impact on NGL markets
4. analysis of net provincial benefits
5. minimization of plant proliferation
6. optimization of the energy efficiency of NGL extraction.

8.2.10 Lean Gas Streaming to End Use Markets to Increase NGL Recovery

Ziff Energy notes that most of the parties in the proceeding supported some form of a collaborative process to deal with the lean gas issue. CCPA, Shell, Imperial/EMC, EnCana, Nova Chemicals, and NGTL all either support a TTFP process or recognize that this matter could be addressed within under that forum. Ziff Energy agrees that a collaborative process is needed here which, as suggested by CAPP, needs to be sufficiently broad to ensure parties that could be affected have the opportunity to participate. At minimum it should include shippers on NGTL, LDCs, straddle plants, gas co-ops, industrial, and other end use customers, and potentially the ADOE and Board representatives. Ziff Energy is not a member of any pipeline/customer committees. Consequently Ziff Energy is uncertain whether the TTFP could be effectively expanded for this purpose, or if a separate forum should be created.

Ziff Energy agrees with NGTL that, in the event the streaming of lean gas supply issue was brought before the TTFP or another forum, the beneficiaries of any such plan should be identified and agreed to among the parties. It is important, as suggested by IGCAA, that the costs of such lean gas streaming be weighed against the benefits. However, Ziff Energy believes it will be challenging to attain consensus of the parties on cost allocation until specific projects, costs, related benefits, and impacts on the affected parties are determined. One of the interested parties indicates there may be some obvious options (“low hanging fruit”) that may be less challenging to implement and thus gain agreement of all parties.

Ziff Energy recommends that the Board direct that such a process be carried out, with specific timelines and deliverables, which could include:

1) proposed lean gas streaming plans and projects, including volumes of gas to be streamed and projected impacts on NGL recovery in the province
2) projected impacts on LDCs, end-use customers, and downstream pipelines
3) related capital and operating costs
4) rate impacts and proposed allocation of costs among shippers.

9. APPENDICES

9.1 Appendix 1 – EUB RFP

REQUEST FOR PROPOSAL

Review of Alberta NGL Extraction Conventions

1 Requirements

The Alberta Energy and Utilities Board (EUB) intends to conduct an Inquiry into matters related to natural gas liquids (NGL) extraction on EUB regulated pipeline transmission systems and other EUB regulated facilities (the Inquiry). The Inquiry will examine issues related to NGL extraction from the perspective of maximizing the economic, orderly and efficient development of Alberta's natural resources in the public interest. The issues that the Inquiry will examine include, without limitation:

- existing extraction conventions
- potential dilution of the common stream energy content by lean gas associated with CBM
- growing intra-Alberta consumption demand
- potential for northern gas; and
- Alberta regulated Straddle facilities on NEB regulated pipelines.

The EUB views that an independent assessment of the issues to be placed before the Inquiry is needed and requires the services of an independent consultant to prepare this assessment. This assessment will include options that the Inquiry panel may consider for resolving those issues. The Board recognizes that this is a significant undertaking and that a substantial level of effort will be required on the part of the consultant through to the completion of the Inquiry. It is anticipated that the EUB will require the services of the independent consultant from *mid June, 2007 to November 30, 2007*.

2 Expertise and Resources

The successful consultant must have access to staff resources with the necessary expertise to perform the services required. The consultant must be familiar with the Alberta natural gas, extraction, NGL, pipeline and petrochemical industries. In addition, the consultant must be familiar with the northern potential for natural gas. In particular, the consultant will be expected to be presently familiar with industry and regulatory background materials including gas and NGL reserve, supply and demand forecasts, the history and development of the NGL extraction and petrochemical industries in Alberta, EUB *Information Letter IL 90-09: Government of Alberta Ethane Policy Implementation Procedures*, the report of the NGL Extraction Convention Task Force (NECTF report), and relevant Board decisions.

3 Statement of Work

The specific responsibilities and key deliverables of the independent consultant will include:

3.1 Consultants Report

Preparation of a report (The Report) which includes the following items:

3.1.1 Background Materials and Forecasts

The Report shall include the following background materials and forecasts:

- Copies or descriptions, if documentation is not available of existing NGL extraction conventions, related tariff provisions and practices on each of the NGTL, ATCO Pipelines and AltaGas pipeline systems. A copy or summary of proposed NGL extraction conventions and practices with respect to the proposed Aux Sable Canada Ltd. North Sable Extraction Plant - Fort Saskatchewan.
- Copies and analysis of decisions or approaches used by other relevant jurisdictions with respect to NGL recovery from main gas transmission pipeline systems.
- The Consultant will review the reserve, supply and demand forecasts and trend analysis of natural gas and NGLs provided by Inquiry Participants for the purpose of ensuring that the Board has before it a coherent, comprehensive and consistent view of 1 year, 10 year and 20 year forecasts and trend analysis with respect to:
  a) NGL supply (by component) entrained in EUB regulated pipelines and facilities; and
  b) the demand requirements for NGLs within Alberta.

  Where such forecasts have been presented, the Report should comment on the forecasts and identify any omissions or inappropriate assumptions. Examples of omissions would include the failure to considered factors such as the impact of CBM, expanding intra-Alberta markets, off-gas from bitumen upgraders, northern gas and other relevant factors.

  If required, the consultant will supplement such forecasts to address the identified concerns and gaps in order to ensure the Board has a coherent and consistent view of the 1 year, 10 year and 20 year reserve, supply and demand forecasts and trend analysis.

3.1.2 Review and Analysis of Submissions by Inquiry Participants

- The Consultant will conduct a review of direct evidence filed by Inquiry Participants for purposes of submitting information requests (IRs) for clarification, greater understanding and to address gaps in the information supplied in the submissions.
- The Consultant will conduct an analysis of the direct evidence, information responses and rebuttal evidence of each Inquiry Participant (Evidence) and where the several Participant’s Evidence is in significant conflict, the Report shall contain the

Consultant's comments on the conflict highlighting the strengths and weaknesses of the positions of the respective parties.

Receipt of initial submissions by parties to the Inquiry is expected to occur in late July and IRs of those submissions are expected to occur in early August.

3.1.3 Propose Alternative Means to Resolve Issues

The Report will identify and assess one or more possible alternative approaches (or modifications to Inquiry Participant proposals) to address the matters before the Inquiry if the Consultant considers such alternative approach(s) preferable in the overall Alberta public interest to any of the approaches suggested by Inquiry Participants, along with an assessment of the benefits, limitations and market impacts of the alternatives.
The Report is to be submitted to the Inquiry by *September 24*.

3.2 Information Responses

- Consultant will respond in writing to IRs from parties on the Report.

3.3 Attendance at Inquiry

Project Leader and principal parties involved in the Report representing the independent consultant will be required to:

- Appear at the Inquiry for cross-examination on Report by Inquiry participants over a minimum two day period.

4 Terms and Conditions

a) **Work Terms:** All work is to be carried out at the offices of the independent consultant. Once awarded the contract for this work, the consultant will be expected to work independently of EUB staff involved in the Inquiry and maintain an arms-length relationship with the EUB until the conclusion of the Inquiry and the issuance of a decision.

b) **Payment Terms:** Unless otherwise specified in the Service Contract (Schedule B), payment for services will be per contractors proposed fee schedule for the duration of the contract.

c) **Legal Status:** The EUB requires all consultants to be employees or subcontractors of an incorporated or limited company.

d) **Contract**: The candidate selected as the consultant will enter into a EUB Service Contract, substantially in the form attached. The EUB recognizes that certain provisions of the Service Contract may not be appropriate with respect to the services to be performed by the consultant. The form of Service Contract is attached for your information and does not need to be completed as part of your submission.

e) **Insurance Requirements:** Please note that the EUB requires consulting companies to have commercial general liability insurance (no less than $2,000,000) and in some cases, errors and omissions insurance ($1,000,000), as per Schedule C of the Service Contract. The EUB also requires that the consulting company show proof of coverage for the successful candidate by the

Workers' Compensation Board of Alberta, as per Schedule D of the Service Contract. If the service to be provided be listed as an exempt industry by the WCB, a special clearance letter from the WCB must be provided to the EUB. The EUB shall not be held liable or responsible for death, bodily or personal injury as per Clause 17 in the Terms and Conditions of the Service Contract. Proof of both types of insurance will be required prior to execution of the Service Contract.

f) **Legal Counsel:** The consultant will be entitled to retain reasonably priced legal counsel of its choice which will be paid for by the EUB.

5 Submission Requirements

Companies intending to provide submissions are required to:

a) Describe the approach to preparing the documented review as well as the responses to the submitted information requests.

b) Provide a description of the experience and qualifications of the Project Lead as well as other members of the proposed consulting team.

c) Provide a description of the existing reports, data bases, forecasts or other resources all ready available to the consultant in performing the services.

d) Provide references regarding successful completion of projects of a similar nature, complexity, scale and scope.

e) Provide a fee schedule for all members of the project team, including legal council that will assist the consultant during the actual Inquiry, along with a cost estimate that indicates time and costs related to preparing the report as well as preparing information responses and attendance at the Inquiry. All assumptions made in preparation of the bid are to be included in the submission.

f) Confirm that the proposed time schedules for each of the activities as described can be accommodated by the team members.

g) Ensure availability of the Project Leader for an interview during the 5-10 business days following the closing date of this request.

h) Deliver submission of proposals to the EUB **before 4:00 PM (Alberta Time), June 11, 2007.** Submissions may be delivered by e-mail address to Heather.Gnenz@eub.ca. The entire submission must be contained in one (1) electronic file in PDF OCR format. The submission must consist of a written proposal addressing items a through e above.

Note: Late submissions may not be considered.

6 Selection Process

a) The EUB may choose to conduct further discussions with one or more of the proposed consultants. Companies will only be contacted if an interview is required or if a proposal has been selected. The EUB retains the right to not award a contract if no suitable consultant is available or if in the view of the EUB circumstances of the Inquiry change.

b) The process of selecting a consultant is not a formal competitive bid. Information related to this request is non-binding on either party and is subject to change prior to contract signing.

c) Awards for contracts for services estimated to have a value greater than $75,000 are subject to the vendor selection conditions stated in the Agreement on Internal Trade (AIT). The AIT specifies that a public notification process (e.g. Alberta Purchasing Connection) be used to post the requirement and that the selection criteria and weightings be disclosed. Accordingly, the selection criteria and weightings are as follows:

Experience of Project Leader	40%
Suitability of consulting team	35% (range and level of relevant experience)
Referenced project competence	15%
Cost	10%

7 Questions

All questions pertaining to this document should be addressed to Heather Gnenz at 403-297-3539 or Kim Eastlick at 403-297-4325.

This page intentionally left blank.

9.2 Appendix 2 – Summary of Participant's Letters of Intervention

Interested Party	Classification	Comments on Issues	Comments on Process, Timing	Business Interests, Other Comments
Alberta Energy, Mineral Development and Strategic Resources	Government	Agrees with issues identified by EUB, although question whether it may be more efficient to allow industry to work co-operatively to identify solutions outside the inquiry process		
Alberta Envirofuels Inc.	NGL Pipeline or Marketer	None		largest consumer of butane in Alberta
Alberta Ethane Gathering System, L.P.	NGL Pipeline or Marketer	None		transports spec ethane from extraction plants to major petrochemical complexes in Joffre and Fort Saskatchewan
Alliance Pipeline	Gas Pipeline Company	inquiry should give clear recognition of ongoing facilities and tariff regulation of the NEB for a federally regulated pipeline, including disposition of NGL's therein		shippers have agreed to grant NGL extraction rights to Aux Sable Liquid Products LP (discussed in Alliance certificate hearing and NEB GH-3-97). Aux Sable plans to build new 40,000 BBL/d ethane extraction plant in Fort Saskatchewan
AltaGas Ltd.	Extraction Plant Owner	treat AltaGas Ltd. and AltaGas Utilities as separate entities as straddle plant owner and regulated pipeline owner		owns straddle plants at border and in central Alberta
AltaGas Utilities Inc.	Alberta Gas Utility	treat AltaGas Ltd. and AltaGas Utilities as separate entities as straddle plant owner and regulated pipeline owner		not involved in past NGT EUB proceedings nor industry task forces on NGL issues. Gas is produced and consumed on AUI's distribution system and small amounts of NGL's are removed for quality control
Atco Midstream	Extraction plant owner	issues may be too broad, increase time/expense and distract attention from principal issues, causing uncertainty on future investments. Narrow scope to contentious issues		owns/operates 5 NGL extraction plants with 1632 mmcfd inlet gas
Atco Pipelines	Gas Pipeline Company	Needs more time to address issues		differs from NGTL system as Atco pipelines mainly designed to deliver gas to utility distribution systems. Needs to talk to stakeholders to determine participation in hearing
Aux Sable Canada Ltd.	Extraction Plant Owner	See comments re issue 11 at right		Existing NEB tariffs on Alliance Pipeline giving Aux Sable rights to NGL's are not subject to review and change by the EUB. Proposing to build new 40,000 Bbl/d straddle plant adjacent to Alliance Pipeline in Fort Saskatchewan to produce ethane for Alberta petrochemical industry.
B.C. Ministry of Energy, Mines and Petroleum Resources	Government			Gas from BC is exported into Alberta
BP Canada Energy Company	Extraction Plant Owner, NGL Pipeline or Marketer, Producer	1. Group issues into 3 main categories: a) expiry of existing ethane policy b) determination of whether changes to NGL practices/conventions are in public interest c) maximizing economic, orderly and efficient development of NGL extraction 2. include detailed info on costs, economic implications, market liquidity impact, existing NGTL contractual rights impacts for any proposed modifications to current rules 3. consider all products from condensate to ethane 4. focus on applied for and exisiting facilities and policies, premature to consider northern gas 5. data on current and proposed straddle plants is commercially sensitive and may be unavailable 6. consider implications of sour gas and CO2 content on extraction plants and NGL facilities 7. consider implications of converting existing field extraction plants into facilities that can access gas from main transmission system 8. consider impacts of potential changes to exisiting facilities (contractual, physical, financial, operational)	Board should hold a pre hearing conference with participants prior to enquiry to discuss role, need of Board expert and scope of expert's report; process, objectives, schedule, and role of Board in updated ethane policy	has interests as an oil and gas producer; field plant and straddle plant owner/operator; purchaser, shipper and marketer of natural gas and NGL's, and pipeline owner/operator.

Interested Party	Classification	Comments on Issues	Comments on Process, Timing	Business Interests, Other Comments
Canadian Chemical Producer's Association	Petrochemical or Industrial	Enquiry should provide a long term view of the valuation of liquids in natural gas entering, transiting and being consumed in the province		Need to put in place long term valuation conventions to optomize opportunitites for market based transactions for value added extraction, upgrading and manufacturing opportunities
CAPP	Producer	Remove issue 2 from the enquiry. All issues fall under: 1) NGL extraction contracting conventions 2) facilities implications of pathing lean and rich gas streams	hold a pre-inquiry conference to address concerns, process, expected outcomes, information required and role of expert. Expert should only provide advice to Board through public process at same time as intervenors, and be subject to cross examination. Need at least 2 months to develop submission	
Cargill	Industrial			
Conoco Phillips	Producer	Limit scope to two issues: 1. NGL extraction contracting convention 2. industry impacts of potential streaming of lean & rich gas Exclude review of Alberta Ethane Policy, as commercial arrangements have addressed these issues	need more time to develop positions once issues finalized	one of largest producers in WCSB, large holder of NGTL FT-R and FT-D service, produces NGL's
Coral	Energy Marketer	need upfront process to review assumptions and reduce number of issues		shipper on NGTL and Atco Pipelines
Devon Canada Corporation	Producer			significant producer in WCSB with volumes on NGTL, Alliance and Atco systems, extracts NGL's in field and has commercial interests in border extraction facilities
Direct Energy	Producer	exclude review of IL 90-09 from review	need at least two months to prepare evidence use NECTF report as grounding for discussions	Alberta producer and firm shipper on NGTL
Dow Chemical	Petrochemical or Industrial	None		owns and operates processing unit LHC-1 at Fort Saskatchewan using ethane to manufacture ethylene
Enbridge	NGL Pipeline, Gas Pipelines			has interests in Alliance and Vector Pipelines, owns Enbridge Gas Distribution and pursuing pipeline opportunities related to northern gas, which could be impacted by NGL conventions
EnCana	Producer, Extraction Plant Owner	Issues too general-parties requiring change to existing conventions should be required to describe changes required and reasons for same		
Export Users Group	Export Shipper	add a new issue or broaden issues 4 and 7 so they consider the impacts on ex-Alberta gas markets and competitiveness of Alberta gas versus other supply alternatives		EUG is made up of Avista Energy, Cascade Natural Gas Corporation, Puget Sound Energy, Inc. and Northwest Natural Gas Company.
FB Energy Canada Corp.	Energy Marketer	include consideration of NGL extraction related competitive issues with respect to intra Alberta pipeline companies		engaged in purchase and sale of natural gas purchased, processed and transported in Alberta
Gaz Metro	Export Shipper	None		delivery shipper on NGTL, one of largest shippers on TCPL, buys 100 BCF of gas from Alberta producers
Government of Northwest Territories	Government	None	submission dates should be moved back to Aug 7/07 and all subsequent dates moved back 2 weeks	treatment of gas in Alberta affects northern gas which may flow into Alberta
Granite Gas Products Inc.	Petrochemical or Industrial	None		Assumptions 3(j) and 3(k) in preliminary scoping document are vague
Husky Energy	Producer	None		large exploration and production company operating in WCSB

Interested Party	Classification	Comments on Issues	Comments on Process, Timing	Business Interests, Other Comments
Husky Energy	Producer	None		large exploration and production company operating in WCSB
Imperil Oil and ExxonMobil Canada Energy	Producer	EUB should hold a pre-Inquiry conference to clarify process, need at least 2 months for submissions -key focus should be the extraction convention, including ownership and rights to extraction, and gas composition as it realtes to producer's ability to obtain market value of NGL's in their gas streams - Issue 2 re updating Alberta Ethane Policy should not be in Inquiry Scope, issue 4 should consider producer's rights to extract their share of liquids from gas streams		producers need to be ensured the opportunity to obtain market value for NGL's in gas streams. Issue is complex, needs to be market based and supported by sound economics
Industrial Gas Consumers Association of Alberta	Industrial		process should allow parties to file Argument or summary comments following November Inquiry	-represents member companies who consume and upgrade over 1 Bcf/d of gas, and some members upgrade and add value to natural gas liquids.
Inter Pipeline Fund	NGL Pipeline, Marketer	Item 3 on perceived inequities with the Present NGL Extraction Conventions should be a subset of 7 Item 4 sidestreaming should be broadened to clarify that the public interest on this issue should reflect potential opportunties for plants to access gas from Alliance, Atco, NGTL anf Foothills, and new mainline straddle plant capacity -add new issue - consideration of opportunities for enrichment of NGTL and Foothills pipelines by changing tariffs, specifications or other means	allow more time for submissions	major petroleum transportation, liquid storage and natural gas liquids extraction business has interests in Cochrane, Empress II and Empress V extraction plants
Keyera Energy Partnership	Extraction Plant Owner	add new issues: identify priorities regarding NGL extraction the degree to which policy changes arising from the Inquiry apply to exsiting facilities, existing contractual rights, and impact on existing NGL extraction business	allow one more week for submissions and adjust other dates accordingly	operates natural gas gathering and processing, and NGL extraction and storage facilities: extracts 26,000 Bbl/d of NGL's, processes 46,000 Bbl/d of NGL's at 3 fractionation facilities, markets 50,000 Bbl/d of NGL's assumptions need to guided by fairness, transparency and balancing interests, and assumption that it is in the public interest to maintian liquid and efficient gas markets should also include NGL's
Kinder Morgan Cochin ULC	NGL Pipeline, Marketer			owns 112,000 Bbl/d Cochin liquids pipeline from Edmonton to Windsor
Nexen Inc.	Producer	Inquiry should consider two main issues: 1. NGL Extraction Contracting Convention (put issues 1, 3, 6, 7, 8, 9, 10 and 11 under this) 2. Potential Dilution of the Common Stream Energy Content (put issues 4, 5,and 6 under this) Issue 2 on the Alberta Ethane Policy expiry should be dealt with by the Alberta Government, not the Inquiry	expert report should be provided at same time as other submissions use NGL Extraction Convention Task Force Report as reference for the NGL Extraction Convention Issue	natural gas producer including CBM and shipper on on all major Alberta pipelines and downstream pipelines
Nova Chemicals	Petrochemical or Industrial	generally agrees with issues, focus on broad issues, key objective should be facilitate cost competitiveness and efficient growth of natural gas, NGL production and end use markets.	extend date for submissions	large industrial consumer of natural gas, buys ethane and holds transportation on NGTL and Atco large investments rely on reliable, cost competitive ethane supply
NGTL	Pipeline Company	Scope is too broad, start with NGL Extraction Convention Issue	allow more time between steps of schedule, hold procedural conference to clarify expectations of submissions and to finalize issues and schedule	subisdiary of TCPL, operates NGTL Alberta system which gathers gas for delivery and use within Alberta and for delivery to ex Alberta markets

Interested Party	Classification	Comments on Issues	Comments on Process, Timing	Business Interests, Other Comments
Pacific Gas and Electric	Export Shipper			major ex-Alberta shipper on NGTL, holds extraction rights on the western path
Pembina Pipeline Corporation	NGL Pipeline or Marketer	issues should include examination of the Incremental Ethane Extraction Policy proposed by Alberta Government and its potential impact on Alberta ethane extraction	extend deadlines for submission, include second round of information requests	transports 100,000 Bbl/d of NGLS's from various facilities
Provident Energy Ltd.	Straddle Plant Owner, Producer	Issues can be distilled down to NGL contracting conventions, gas compositions in pipelines, potential economic and tolling issues	Aux Sable North Sable Extraction Project and NGTL North Central Corridor Project should be examined after or in conjuntion with establishment of a future NGL extraction policy.	owner/operator of NGL extraction facilities, holder of NGTL receipt capacity and natural gas exporter
Quicksilver Resources Canada Inc.	Producer	some assumptions in the scoping document are in conflict and lack of detail make it difficult to comment on	inquiry decision in late 2008 or 2009 seems more realistic hold pre-Inquiry meeting to develop schedule and discuss other matters	leading CBM producer
Shell Canada Energy	Producer, Extraction Plant Owner	Inquiry needs to be broad enough to consider interests of all associated industries in Alberta	allow at least two months to develop submissions hold pre-Inquiry conference to develop well defined issues and clarify Board's anticipated outcome make consultant report available to inquiry participants and allow time for comment	Shell produces natural gas, natural gas liquids, crude oil and bitumen, has ownership in NGL extraction facilties and has an affiliate Shell Chemicals Canada Ltd. which produces chemicals using components produced from NGL extraction
Spectra Energy Empress L.P.	Extraction Plant Owner		hold a preliminary meeting to allow constructive input into the issues and schedule	owns majority of 2.4 Bcf/d NGL extraction plant at Empress
State of Alaska, Department of Natural Resources	Government			state is soliciting proposals to transport 4 Bcf/d of Alaska gas to market which could involve high pressure dense phase flow to transport gas with enriched NGL's, and wants to ensure the project receives fair value for the NGL's in the gas
Straddle Plant Group	Extraction Plant Owner		hold a preliminary meeting to allow constructive input into the issues, scope, schedule and role of the independent consultant and nature of the consultant report	represents owners/operators of Alberta straddle plants (AtlaGas Ltd., Inter Pipeline Fund, Spectra Energy Empress L.P., Atco Midstream, Provident Energy)
Talisman Energy	Producer	exclude issue # 2 on updating of the ethane policy	allow more time for initial submission	producer, midstream operator, shipper and marketer of natural gas and NGL's
Taylor NGL Limited Partnership	Extraction Plant Owner			owns/operates NGL extraction facilities
Tenaska Marketing Canada	Energy Marketer			large natural gas exporter and export shipper on NGTL
Terasen Gas Inc.	Export Shipper			ex Alberta shipper holding extraction rights on the western path

9.3 Appendix 3 – NGTL Annual Plan Excerpts

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 2006 design 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. A map of the Alberta System is provided in Appendix 7. The 976 Receipt Points and 173 Delivery Points on the system (year end 2005) 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 Agreement 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 84 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 2007/08 Gas Year.

Interruptible transportation capability may exist from time to time on certain parts of the Alberta System. However, Customers should not rely on interruptible transportation to meet their firm transportation requirements.

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. NGTL will not construct facilities for STFT or FT-DW service.

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. 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 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

for firm transportation to be authorized for commencement of service before the end of the design period.

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, NGTL makes assumptions on the volumes associated with new requests for service based upon historical data, contract utilization and supply potential.

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 NGTL 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 June 2006 design 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. NGTL performed computer simulations of the pipeline system to identify the facilities that would be required for NGTL to meet its firm and peak transportation expectations for the 2007/08 Gas Year.

This page intentionally left blank.

9.4 Appendix 4 – NGTL Tariff Excerpts

General Terms and Conditions

1.40 "Export Delivery Point" shall mean any of the following points where gas is delivered to a Customer for removal from Alberta under a Schedule of Service:

Alberta-British Columbia Border
Alberta-Montana Border
Boundary Lake Border
Cold Lake Border
Demmitt #2 Interconnect
Empress Border
Gordondale Border
McNeill Border
Unity Border

1.41 "Extraction Delivery Point" shall mean the point in Alberta where gas may be delivered to the Extraction Plant by Company for Customer under a Schedule of Service.

1.42 "Extraction Plant" shall mean a facility connected to the Facilities where Gas liquids are extracted.

1.43 "Extraction Receipt Point" shall mean the point in Alberta where gas may be received from the Extraction Plant by Company for Customer under a Schedule of Service.

1.44 "Facilities" shall mean Company's pipelines and other facilities or any part or parts thereof for the receiving, gathering, treating, transporting, storing, distributing, exchanging, handling or delivering of gas.

1.45 "Financial Assurance" shall have the meaning attributed to it in paragraph 10.1.

1.46 "Flow" shall mean, with respect to a Receipt Point, the rate in $10^3m^3/d$ or GJ/d, as the case may be, that gas is being delivered into Company's Facilities through such Receipt Point at any point in time and means with respect to a Delivery Point, the rate in $10^3m^3/d$

(ii) declare any and all amounts payable now or in the future by Customer to Company for any and all Service to be immediately due and payable as liquidated damages and not as a penalty.

5.7.3 In the event that it is finally determined that Customer's monthly bill was incorrect and that an overpayment has been made, Company shall make reimbursement of such overpayment. Company shall pay interest on the overpayment to Customer, commencing from the date such overpayment was made and continuing until the date reimbursement is actually made, at a rate per annum equal to the Prime Rate plus one (1) percent.

6.0 POSSESSION AND CONTROL

6.1 Control

Gas received by Company shall be deemed to be in the custody and under the control of Company from the time it is received into the Facilities until it is delivered out of the Facilities.

6.2 Warranty

Customer warrants and represents it has the right to tender all gas delivered to Company.

7.0 GAS PRESSURES

7.1 The Gas Pressure At Receipt Points

The pressure of gas tendered by Customer to Company at any Receipt Point shall be the pressure, up to the Maximum Receipt Pressure, that Company requires such gas to be tendered, from time to time, at that Receipt Point.

7.2 Pressure Protection

Customer shall provide or cause to be provided suitable pressure relief devices, or pressure limiting devices, to protect the Facilities as may be necessary to ensure that the pressure of gas delivered by Customer to Company at any Receipt Point will not exceed one hundred ten (110%) percent of the Maximum Receipt Pressure.

7.3 The Gas Pressure At Delivery Points

The pressure of gas delivered by Company at any Delivery Point shall be the pressure available from the Facilities at that Delivery Point, provided that such pressure shall not exceed the Maximum Delivery Pressure.

8.0 GAS USED, GAS LOST AND MEASUREMENT VARIANCE

8.1 Company's Gas Requirements

Company may, at its option, either:

(a) take from all Customers at Receipt Points a quantity of gas equal to the aggregate quantity of any or all Gas Used, Gas Lost and Measurement Variance for any period; or

(b) arrange with a Customer or Customers or any other Persons at Receipt Points to take and pay for a quantity of gas equal to the aggregate quantity of any or all Gas Used, Gas Lost and Measurement Variance for any period.

8.2 Allocation of Gas Taken

If Company in any period exercises its option to take a quantity of gas as provided for in subparagraph 8.1 (a), each Customer's share of the quantity of such gas taken in such period will be a quantity equal to the product of the quantity of such gas taken in such period and a fraction, the numerator of which shall be the aggregate quantity of gas received by Company from Customer in such period at all of Customer's Receipt Points and the denominator of which shall be the aggregate quantity of gas received by Company from all Customers in such period at all Receipt Points.

8.3 Gas Received from Storage Facilities

Notwithstanding anything contained in this article 8.0, any gas received into the Facilities from a gas storage facility that was previously delivered into the gas storage facility through the Facilities shall not be included in any calculation, and shall not be taken into account in any allocation, of Company's gas requirements.

9.0 DELIVERY OBLIGATION

9.1 Company's Delivery Obligation

Subject to paragraph 9.2:

(a) Company's delivery obligation for any period where Company has exercised its option as provided for in subparagraph 8.1 (a), shall be to deliver to all Customers at all Delivery Points the quantity of gas Company determines was received from all Customers in such period at all Receipt Points, less all Customers share as determined under paragraph 8.2; and

(b) Company's delivery obligation, for any period where Company has exercised its option to purchase gas as provided for in subparagraph 8.1 (b), shall be to deliver to all Customers at all Delivery Points the quantity of all gas received from all Customers, other than gas taken from such Customers and paid for pursuant to subparagraph 8.1 (b), in such period at all Receipt Points.

Rate Schedule FT-X

RATE SCHEDULE FT-X

FIRM TRANSPORTATION - EXTRACTION

1.0 DEFINITIONS

1.1 The capitalized terms used in this Rate Schedule have the meanings attributed to them in the General Terms and Conditions of the Tariff unless otherwise defined in this Rate Schedule.

2.0 SERVICE DESCRIPTION AND AVAILABILITY

2.1 Subject to the stated terms and conditions, service under Rate Schedule FT-X shall mean:

(i) the delivery of gas by Company for Customer at Extraction Delivery Points; and

(ii) the receipt of gas by Company for Customer at Extraction Receipt Points.

Subparagraphs (i) and (ii) are collectively referred to as the "Service" which includes the transportation of gas Company determines necessary to provide services under the Tariff.

2.2 The Service is available to a Customer that has executed a Service Agreement and Schedule of Service under Rate Schedule FT-X and a valid Service Agreement under Rate Schedule FCS is executed by any Customer at the Extraction Delivery Point. A standard form Service Agreement for Service under this Rate Schedule FT-X is attached.

2.3 Company shall not be required to construct or install Facilities for any Service under Rate Schedule FT-X. If Company determines that new Facilities are required that are directly attributable to Customer's request for Service, Company shall not be required to provide such requested Service unless a valid Service Agreement under Rate Schedule FCS exists in respect of such new Facilities.

3.0 CHARGE FOR SERVICE

3.1 Company shall not charge Customer for Service under this Rate Schedule FT-X.

4.0 ALLOCATION OF GAS RECEIVED AND DELIVERED

4.1 Notwithstanding any other provision of this Rate Schedule, any Service Agreement or the General Terms and Conditions of the Tariff, and without regard to how gas may have been nominated, the aggregate volume of gas delivered by Company for Customer at Extraction Delivery Points or received by Company for Customer at Extraction Receipt Points shall be allocated only to Service to Customer under Rate Schedule FT-X.

5.0 TERM OF SERVICE

5.1 Term of a Schedule of Service

The term of any Schedule of Service for Service under Rate Schedule FT-X shall be the term requested by Customer provided that the term is a minimum of one (1) year and terminates on the last day of the Gas Year.

5.2 Term of Service Agreement

Customer's Service Agreement shall terminate on the latest Service Termination Date of Customer's Schedules of Service for Service under Rate Schedule FT-X.

6.0 TRANSFER OF SERVICE

6.1 A Customer entitled to receive Service under Rate Schedule FT-X shall not be entitled to transfer Service under Rate Schedule FT-X to any Receipt Point or Delivery Point.

7.0 TERM SWAPS

7.1 A Customer entitled to receive Service under Rate Schedule FT-X shall not be entitled to swap the Service Termination Date of any Schedules of Service under Rate Schedule FT-X with the Service Termination Date under any Schedule of Service.

8.0 TITLE TRANSFERS

8.1 A Customer entitled to receive Service under Rate Schedule FT-X may transfer all or a portion of Customer's Inventory to another Customer or may accept a transfer of all or a portion of Customer's Inventory from another Customer provided such Customer is entitled to receive service under any Rate Schedule that permits title transfers and such title transfer is in accordance with the Terms and Conditions of Service Respecting Title Transfers in Appendix "C" of the Tariff.

9.0 RENEWAL OF SERVICE

9.1 Renewal Notification

Customer shall be entitled to renew Service under Rate Schedule FT-X, if Customer gives notice to Company of such renewal at least one (1) year prior to the Service Termination Date. If Customer does not provide such notice, the Service shall expire on the Service Termination Date.

9.2 Irrevocable Notice

Customer's notice to renew pursuant to paragraph 9.1 shall be irrevocable one (1) year prior to the Service Termination Date.

Any renewal of Service is subject to the Financial Assurances provisions in Article 10 of the General Terms and Conditions.

9.3 Renewal Term

Customer's notice shall specify a renewal term of not less than one (1) year consisting of increments of whole years.

10.0 APPLICATION FOR SERVICE

10.1 Applications for Service under this Rate Schedule FT-X shall be in such form as Company may prescribe from time to time.

11.0 GENERAL TERMS AND CONDITIONS

11.1 The General Terms and Conditions of the Tariff and the provisions of any Service Agreement for Service under Rate Schedule FT-X are applicable to Rate Schedule FT-X to the extent that such terms and conditions and provisions are not inconsistent with this Rate Schedule.

Service Agreement FT-X

SERVICE AGREEMENT

RATE SCHEDULE FT-X

BETWEEN:

NOVA Gas Transmission Ltd., a body corporate having an office in Calgary, Alberta ("Company")

- and -

•, a body corporate having an office in •, • ("Customer")

IN CONSIDERATION of the premises and the covenants and agreements in this Service Agreement, the parties covenant and agree as follows:

1. Customer acknowledges receipt of a current copy of the Tariff.

2. The capitalized terms used in this Service Agreement have the meanings attributed to them in the General Terms and Conditions of the Tariff, unless otherwise defined in this Service Agreement.

3. Customer requests and Company agrees to provide Service pursuant to Rate Schedule FT-X in accordance with the attached Schedules of Service. The Service will commence on the Billing Commencement Date and will terminate, subject to the provisions of this Service Agreement, on the Service Termination Date.

4. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to this Rate Schedule FT-X including, without limiting the generality of the foregoing, an assurance that necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities upstream of any Receipt Point or downstream of any Delivery Point in respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating volumes of gas received or delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided.

If Customer fails to provide such assurances and information forthwith following request by Company, from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested.

5. Customer acknowledges that the Facilities have been designed based on certain assumptions and forecasts described each year in Company's Annual Plan, and that interruption and curtailment of Service may occur if the aggregate gas volume actually received or the aggregate gas volume actually delivered at the Facilities is different than forecast.

6. Every notice, request, demand, statement, bid or bill (for the purpose of this paragraph, collectively referred to as "Notice") provided for in Rate Schedule FT-X, this Service Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person's address as follows:

Customer:

- •
- •
- •

Attention: •

Fax: •

Company:

- •
- •
- •

Attention: Customer Account Representative

Fax: •

Notice may be given by fax or other telecommunication and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice shall be deemed to be given four (4) business days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event of disruption of regular mail, every payment not made electronically shall be personally delivered, and any other Notice shall be given by one of the other stated means.

Any Notice for the matters listed in the Notice Schedule for Electronic Commerce in Appendix "F" of the Tariff shall be given via EBB. Company shall not accept or provide any such Notice for those matters listed in Appendix "F" via any other alternative means, unless the EBB is inoperative or Customer is unable to establish connection with the EBB, in which case Notice shall be given by any other alternative means set out herein. Any Notice given by the EBB shall be deemed to be given one (1) hour after transmission.

Any Notice may also be given by telephone followed immediately by EBB, fax, personal delivery, courier or prepaid mail, and any Notice so given shall be deemed to have been given as of the date and time of the telephone notice.

7. The terms and conditions of Rate Schedule FT-X, the General Terms and Conditions and Schedule of Service under Rate Schedule FT-X are by this reference incorporated into and made a part of this Service Agreement.

IN WITNESS WHEREOF the parties have executed this Service Agreement by their proper signing officers duly authorized in that behalf all as of the • day of •, •.

•	NOVA Gas Transmission Ltd.
Per: ______________________	Per : ______________________
Per: ______________________	Per : ______________________

SCHEDULE OF SERVICE
RATE SCHEDULE FT-X

CUSTOMER: •

Schedule of Service Number	Extraction Receipt and Delivery Point Number and Name	Extraction Receipt and Delivery Point Legal Description	Maximum Delivery Pressure kPa	Service Termination Date	Additional Conditions
•	• •	•	•	•	•

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ____________________	Per : ____________________
Per: ____________________	Per : ____________________

Rate Schedule FCS

RATE SCHEDULE FCS

FACILITIES CONNECTION SERVICE

1.0 DEFINITIONS

1.1. The capitalized terms used in this Rate Schedule have the meanings attributed to them in the General Terms and Conditions of the Tariff unless otherwise defined in this Rate Schedule.

2.0 SERVICE DESCRIPTION AND AVAILABILITY

2.1 Subject to the stated terms and conditions, service under Rate Schedule FCS shall mean the measurement of gas delivered by Company to Customer's facilities at an Alberta Delivery Point, Extraction Delivery Point, or Storage Delivery Point and the provision of any other Facilities that Company determines necessary (the "Service").

2.2 The Service is available to any Customer that has executed a Service Agreement and Schedule of Service under this Rate Schedule FCS. A standard form Service Agreement for Service under this Rate Schedule FCS is attached.

3.0 CHARGE FOR SERVICE

3.1 Aggregate of Customer's FCS Charges

The aggregate of Customer's charges, if any, for Service under Rate Schedule FCS shall be equal to the sum of the charges for each of Customer's Schedules of Service under Rate Schedule FCS determined in accordance with Attachment 1 (the "FCS Charge").

3.2 Aggregate of Customer's Surcharges

The aggregate of Customer's Surcharges shall be equal to the sum of all Surcharges set forth in the Table of Rates, Tolls and Charges applicable to each of Customer's Schedules of Service under Rate Schedule FCS.

3.3 Aggregate Charge for Service

Customer shall pay the sum of the amounts calculated in accordance with paragraphs 3.1 and 3.2 for Service under all Schedules of Service under Rate Schedule FCS.

4.0 TERM OF SERVICE

4.1 Term of a Schedule of Service

If in the provision of Service, Company determines that:

(i) no Extension Facilities (as defined in Attachment 1) are required to provide the Service requested, the term of the Schedule of Service for Service under Rate Schedule FCS shall be the term requested by Customer provided that the term is a minimum of one (1) year; or

(ii) Extension Facilities are required to provide the Service requested, the term of the Schedule of Service for Service under Rate Schedule FCS shall be the term requested by Customer provided that the term is a minimum of three (3) years.

4.2 Term of Service Agreement

Customer's Service Agreement shall terminate on the latest Service Termination Date of Customer's Schedules of Service for Service under Rate Schedule FCS.

5.0 SERVICE RELEASE

5.1 If Customer desires to release all of its Service under any Schedule of Service under Rate Schedule FCS, Customer shall notify Company of its request to release such Service describing the location and nature of the reduction in Service requested. Company shall not have any obligation to find any Person to assume such Service. If after notice is given to Company a Person is found who agrees to assume such Service, Company may allow Customer to release such Service to the extent that such Service is provided for in a Service Agreement and Schedule of Service under Rate Schedule FCS executed by Company and such Person.

6.0 PAYMENT ON RETIREMENT OF FACILITIES

6.1 In the event that there remains on Company's books of account any net book value in respect of Facilities, other than Extension Facilities (as defined in Attachment 1), used in providing Service under any Schedule of Service under this Rate Schedule FCS either:

(i) at the Service Termination Date described in the Schedule of Service in respect of a particular Service; or

(ii) at the expiry of a period of six (6) months where the Facilities which would be used to provide such Service have not been used; and

Company determines in its sole discretion to retire such Facilities, Customer shall pay to Company within a time determined by Company, an amount equal to the net book value of such Facilities adjusted for all costs and expenses associated with such retirement.

7.0 RENEWAL OF SERVICE

7.1 Company may in its sole discretion allow Customer to renew Service under Rate Schedule FCS on terms and conditions mutually satisfactory to Company and Customer.

8.0 GENERAL TERMS AND CONDITIONS

8.1 The General Terms and Conditions of the Tariff and the provisions of any Service Agreement for Service under Rate Schedule FCS are applicable to Rate Schedule FCS to the extent that such terms and conditions and provisions are not inconsistent with this Rate Schedule.

Service Agreement FCS

SERVICE AGREEMENT

RATE SCHEDULE FCS

BETWEEN:

NOVA Gas Transmission Ltd., a body corporate having an office in Calgary, Alberta ("Company")

- and -

•, a body corporate having an office in •, • ("Customer")

IN CONSIDERATION of the premises and the covenants and agreements herein contained, the parties covenant and agree as follows:

1. Customer acknowledges receipt of a current copy of the Tariff.

2. The capitalized terms used in this Service Agreement have the same meanings attributed to them in the General Terms and Conditions of the Tariff, unless otherwise defined in this Service Agreement.

3. Customer requests and Company agrees to provide Service pursuant to Rate Schedule FCS in accordance with the attached Schedules of Service. The Service will commence on the Billing Commencement Date and will terminate, subject to the provisions of this Service Agreement, on the Service Termination Date.

4. Customer agrees to pay to Company for all Service rendered under this Service Agreement, an amount equal to the aggregate charges for Service described in Rate Schedule FCS.

5. Customer shall:

(a) provide such assurances and information as Company may reasonably require respecting any Service to be provided pursuant to this Rate Schedule FCS including, without limiting the generality of the foregoing, an assurance that all necessary arrangements have been made among Customer, producers of gas for Customer, purchasers of gas from Customer and any other Person relating to such Service, including all gas purchase, gas sale, operating, processing and common stream arrangements; and

(b) at Company's request provide Company with an assurance that Customer has provided the Person operating facilities upstream of any Receipt Point or downstream of any Delivery Point in respect of which Customer has the right to receive service with all authorizations necessary to enable such Person to provide Company with all data and information reasonably requested by Company for the purpose of allocating volumes of gas received or delivered by Company among Company's Customers and to bind Customer in respect of all such data and information provided.

If Customer fails to provide such assurances and information forthwith following request by Company from time to time, Company may at its option, to be exercised by notice to Customer, suspend the Service to which such assurances and information relate until such time as Customer provides the assurances and information requested, provided however that any such suspension of Service shall not relieve Customer from any obligation to pay any rate, toll, charge or other amount payable to Company.

6. Every notice, request, demand, statement, bid or bill (for the purposes of this paragraph, collectively referred to as “Notice”) provided for in Rate Schedule FCS, this Service Agreement and the General Terms and Conditions, or any other Notice which either Company or Customer may desire to give to the other, shall be in writing and each of them and every payment provided for shall be directed to the Person to whom given, made or delivered at such Person's address as follows:

Customer:

- •
- •
- •

Attention: •

Fax: •

Company:

- •
- •
- •

Attention: Customer Account Representative

Fax: •

Notice may be given by fax or other telecommunication and any such Notice shall be deemed to be given four (4) hours after transmission. Notice may also be given by personal delivery or by courier and any such Notice shall be deemed to be given at the time of delivery. Any Notice may also be given by prepaid mail and any such Notice shall be deemed to be given four (4) business days after mailing, Saturdays, Sundays and statutory holidays excepted. In the event of disruption of regular mail, every payment not made electronically shall be personally delivered, and any other Notice shall be given by one of the other stated means.

Any Notice for the matters listed in the Notice Schedule for Electronic Commerce in Appendix "F" of the Tariff shall be given via EBB. Company shall not accept or provide any such Notice for those matters listed in Appendix "F" via any other alternative means, unless the EBB is inoperative or Customer is unable to establish connection with the EBB, in which case Notice shall be given by any other alternative means set out herein. Any Notice given by the EBB shall be deemed to be given one (1) hour after transmission.

Any Notice may also be given by telephone followed immediately by EBB, fax, personal delivery, courier or prepaid mail, and any Notice so given shall be deemed to have been given as of the date and time of the telephone notice.

7. The terms and conditions of Rate Schedule FCS, the General Terms and Conditions and Schedule of Service under Rate Schedule FCS are by this reference incorporated into and made a part of this Service Agreement.

IN WITNESS WHEREOF the parties hereto have executed this Service Agreement by their proper signing officers duly authorized in that behalf all as of the • day of •, •.

•	NOVA Gas Transmission Ltd.
Per: ______________	Per : ______________
Per: ______________	Per : ______________

SCHEDULE OF SERVICE
RATE SCHEDULE FCS

CUSTOMER: •

FCS CHARGE: See Attachment 1 hereto

Schedule of Service Number	Delivery Point Number and Name	Legal Description	Maximum Delivery Pressure kPa	Maximum Daily Delivery Volume $10^3m^3/d$	Service Termination Date	Additional Conditions
•	• •	•	•	•	•	•

THIS SCHEDULE FORMS PART OF THE SERVICE AGREEMENT DATED • AND SHALL BE DEEMED TO BE ATTACHED THERETO.

•	NOVA Gas Transmission Ltd.
Per: ____________	Per : ____________
Per: ____________	Per : ____________

ATTACHMENT 1

Attached to and Forming Part of Schedule of Service No. •

1.0 DEFINITIONS

1.1 The capitalized terms used in this Attachment 1 have the meanings attributed to them in the General Terms and Conditions of the Tariff unless otherwise defined in this Attachment 1.

2.0 INTRODUCTION

2.1 For Service provided annually during the period commencing January 1 and ending December 31 (the "Year"), Company will determine the FCS Charge, if any, payable by Customer to Company for Service under Rate Schedule FCS.

3.0 Calculation of FCS Charge

3.1 Following the completion of each Year, Company will calculate the FCS Charge using the following six steps:

(i) determine the annual cost of service of the Facilities required to provide Service under the Schedule of Service ("ACS") as described in paragraph 3.2;

(ii) determine the minimum annual volume of gas Company is to measure ("MAV") at the Delivery Point set out in the Schedule of Service as described in paragraph 3.3;

(iii) determine the MAV component of the FCS Charge as described in paragraph 3.4;

(iv) if such Delivery Point, other than a Storage Delivery Point, is associated with a Facility which extends Company's Facilities ("Extension Facility"), determine in accordance with paragraph 3.5 a minimum annual volume of gas Company is to measure ("EAV") at such Delivery Point and as set out in the Schedule of Service under Additional Conditions;

(v) determine the EAV component of the FCS Charge as described in paragraph 3.6; and

(vi) calculate the FCS Charge as described in paragraph 3.7.

3.2 Determination of ACS

The ACS is equal to the sum of the components in paragraphs (i) through (v):

(i) Operating and Maintenance ("O&M")

O&M expense is an estimate of O&M costs of the Facilities used to provide Service under the Schedule of Service under Rate Schedule FCS for the Year, and may vary from Year to Year.

(ii) Municipal Taxes

Municipal tax expense is the actual municipal taxes paid for the Facilities used to provide Service under the Schedule of Service under Rate Schedule FCS for the Year, and may vary from Year to Year.

(iii) Depreciation

Depreciation expense is calculated on a straight-line basis using Company's system average depreciation rates, which may vary from time to time.

(iv) Income Taxes

Income tax expense is calculated on a flow-through basis. The income tax rate used is computed by applying the current combined federal and provincial income tax rates.

(v) Return on Rate Base

Return on rate base is calculated by applying Company's current rate of return to the average of the opening and closing balances in the rate base account related to the Facilities used to provide Service under the Schedule of Service under Rate Schedule FCS for the Year. The rate of return may vary from time to time as determined by Company.

The opening balance in the rate base is equal to the capital cost of the Facilities used to provide Service under the Schedule of Service under Rate Schedule FCS for the Year, less accumulated depreciation, as reflected in the rate base account on the last day of the preceding Year, plus a working capital adjustment.

3.3 Determination of MAV

The MAV will be calculated each Year for each type of Delivery Point as follows:

(i) Delivery Points other than Storage Delivery Points:

If Service under Rate Schedule FCS is at a Delivery Point other than a Storage Delivery Point, the MAV will be calculated as follows:

$$\text{MAV} = \frac{\text{ACS}}{2 \times \text{B}}$$

Where:

"B" = the FT-A Rate.

(ii) Storage Delivery Points:

If Service under Rate Schedule FCS is at a Storage Delivery Point, the MAV will be calculated as follows:

$$\text{MAV} = \frac{\text{ACS}}{\text{UC}}$$

Where:

"UC" = the firm service unit cost, as determined by Company as the sum of the firm transportation receipt revenue requirement and firm transportation delivery revenue requirement divided by the sum of the FT-R and FT-D billing determinants.

3.4 Determination of the MAV Component of the FCS Charge

The MAV component of the FCS Charge will be calculated each Year for each Schedule of Service as follows:

$$\text{MAV Charge} = \left(\frac{\text{MAV} - \text{C}}{\text{MAV}}\right) \times \text{ACS}$$

Where:

"MAV Charge" = the MAV component of the FCS Charge; and

"C" = the actual volume of gas delivered by Company for Customer, as determined by Company, at the Delivery Point as set out in the Schedule of Service for the Year.

If C is greater than or equal to MAV, the MAV component of the FCS Charge is zero.

3.5 Determination of EAV

If the Delivery Point as set out in the Schedule of Service, other than a Storage Delivery Point, is associated with an Extension Facility, Company and Customer shall determine Customer's portion of the EAV for such Extension Facility, provided that the aggregate of EAV for all Delivery Points associated with such Extension Facility ("Associated Delivery Points") is no less than:

(a) 1,028,350.0 10^3m^3 (36.5 Bcf) per year for a minimum term of three (3) years; or

(b) 3,085,050.0 10^3m^3 (109.5 Bcf) over a maximum term of five (5) years, provided that at least one of the year's EAV is no less than 1,028,350.0 10^3m^3 (36.5 Bcf).

3.6 Determination of the EAV Component of the FCS Charge

The EAV component of the FCS Charge for a Delivery Point, other than a Storage Delivery Point,will be calculated each Year for each Schedule of Service as follows:

$$\text{EAV Charge} = (D - E) \times S \times R$$

Where:

"EAV Charge" = the EAV component of the FCS Charge;

"D" = the aggregate EAV for the Delivery Point and all the Associated Delivery Points as set out in the Schedule of Service for the Year;

"E" = the aggregate of the actual volume of gas delivered by Company, as measured by Company, at such Delivery Point and Associated Delivery Points for the Year;

"S" = the Customer's share of the EAV Charge, determined as follows:

$$\left(\frac{EAV - V}{F}\right)$$

Where:

"V" = the actual volume of gas delivered by Company, as measured by Company, at the Delivery Point and each of the Associated Delivery Points for the Year;

"F" = the aggregate shortfall of such Delivery Point and the Associated Delivery Points, determined by Company as the aggregate of EAV minus V at each Associated Delivery Point for the Year.

If V is greater than or equal to EAV for an Associated Delivery Point, EAV minus V at such Delivery Point or Associated Delivery Point is set to zero; and

"R" = the Average Firm Service Receipt Price as set out in the Table of Rates, Tolls and Charges converted to a daily rate.

If E is greater than or equal to D or if V is greater than EAV for the Delivery Point for such Year, the EAV component of the FCS Charge is zero.

3.7 Calculation of the FCS Charge

The FCS Charge will be calculated each Year for each Schedule of Service as:

i) the sum of the amounts calculated in accordance with paragraphs 3.4 and 3.6 , for Service under Rate Schedule FCS at a Delivery Point other than a Storage Delivery Point; or

ii) the amount calculated in accordance with paragraphs 3.4, for Service under Rate Schedule FCS at a Storage Delivery Point.

9.5 Appendix 5 – ATCO Pipelines Tariff Excerpts

ATCO Pipelines

TRANSPORTATION SERVICE REGULATIONS
EFFECTIVE DATE: April 1, 2006
BY Order U2005-221

2.5 **Title or Interest in the Gas**

The Agreement is solely for the receipt, transportation, and delivery of Gas and Customer shall not acquire any title or interest in the Gas Pipeline System of ATCO Pipelines and ATCO Pipelines shall not acquire any title or interest in the Gas being transported under the Agreement.

Gas received by ATCO Pipelines from Customer shall be under the exclusive control of ATCO Pipelines from the time such Gas is received until it is delivered.

ATCO Pipelines does not dedicate the Gas Pipeline System or any segment thereof to Customer, and accordingly the routing and facilities used in the movement of Gas for Customer shall be at ATCO Pipelines' discretion and may change from time to time.

ATCO Pipelines may in the course of receiving and delivering Gas in the Gas Pipeline System commingle such Gas with or exchange for Gas owned by or transported for others, or remove certain hydrocarbon components present in the Gas. As commingling, exchanging, or the removal of certain hydrocarbon components may alter the Gross Heating Value or constituent parts of the Gas received by ATCO Pipelines at the Point of Receipt, ATCO Pipelines shall not be required to deliver Gas with the same Gross Heating Value or containing the same constituent parts as Gas received and ATCO Pipelines shall make whatever compensating adjustments to volume and Gross Heating Value as may be warranted. In the event, and to the extent, that any hydrocarbon components in the Gas received at the Point of Receipt are absent from the Gas delivered as the result of commingling, exchanging or removal of such hydrocarbon components in the course of transporting the Gas, title to such hydrocarbon components shall, notwithstanding anything to the contrary otherwise contained in the Agreement, be deemed conclusively to have passed to ATCO Pipelines.

This page intentionally left blank.

9.6 Appendix 6 – AltaGas Utilities Inc. Tariff Excerpts

Current Transportation Service Regulations

(cc) **"10^3m^3"** means one thousand (1,000) cubic metres of Gas;

(dd) **"Transportation Service"** means the service of transporting Gas through AltaGas Utilities Inc.'s pipelines or other facilities;

(ee) **"Unaccounted For Gas"** means Customer's share of AltaGas Utilities Inc.'s line loss, unaccounted for Gas, and compressor fuel (excluding Gas lost referred to in Clause 5.8(1) at those rates specified in the Rate Schedule);

(ff) **"Year"** means a period commencing on the Billing Commencement Date or anniversary of same and ending on the next succeeding anniversary of the Billing Commencement Date.

1.3 Interpretation

(1) In the interpretation of the Service Agreement, words in the singular shall be read and construed in the plural or words in the plural shall be read and construed in the singular where the context so requires.

(2) The headings used throughout the Service Agreement are inserted for reference purposes only, and are not to be considered or taken into account in construing the terms or provisions of any Article, Clause or Schedule nor to be deemed in any way to qualify, modify or explain the effect of any such provisions or terms.

(3) The definitions of all units of measurement and their prefixes used throughout the Service Agreement shall be in accordance with the International System of Units.

Article 2 - General Provisions

2.1 Transportation Only

The Service Agreement is solely for the transportation of Gas and Customer shall not acquire any title or interest in the Gas Pipeline System of AltaGas Utilities Inc. and AltaGas Utilities Inc. shall not acquire any title or interest in the Gas being transported under the Service Agreement.

2.2 Gas Under AltaGas Utilities Inc. Control

Gas delivered to AltaGas Utilities Inc. by Customer for transportation shall be under the exclusive control of AltaGas Utilities Inc. from the time such Gas is accepted for transportation at the Point of Receipt until delivered at the Point of Delivery.

AltaGas Utilities Inc.
Transportation Service Regulations

2.3 AltaGas Utilities Inc. Determines Routing

AltaGas Utilities Inc. does not dedicate the Gas Pipeline System or any segment thereof to transport Gas for Customer, and accordingly the routing and facilities used in the transportation of Gas for Customer shall be at AltaGas Utilities Inc.'s discretion and may change from time to time.

2.4 Gas May be Commingled

(1) AltaGas Utilities Inc. may in the course of transporting Gas in the Gas Pipeline System commingle with or exchange for Gas owned by or transported for others, or remove certain hydrocarbon components present in the Gas.

(2) As commingling, exchanging, or the removal of certain hydrocarbon components may alter the Gross Heating Value or constituent parts of the Gas between the Point of Receipt and the Point of Delivery, AltaGas Utilities Inc. shall not be required to deliver at the Point of Delivery Gas with the same Gross Heating Value or containing the same constituent parts as Gas delivered at the Point of Receipt and AltaGas Utilities Inc. shall make whatever compensating adjustments to volume and Gross Heating Value as may be warranted.

(3) In the event, and to the extent, that any hydrocarbon components in the Gas delivered at the Point of Receipt are absent from the Gas delivered at the Point of Delivery as the result of commingling, exchanging or removal of such hydrocarbon components in the course of transporting the Gas, title to such hydrocarbon components shall, notwithstanding anything to the contrary otherwise contained in the Service Agreement, be deemed conclusively to have passed to AltaGas Utilities Inc. at the Point of Receipt.

2.5 Customer Confirms Right to Deliver

Customer covenants with AltaGas Utilities Inc. that Customer shall have the right to transport all Gas delivered under the Service Agreement to AltaGas Utilities Inc. at the Point of Receipt.

2.6 Commitment to Maintain Systems

The parties hereto mutually undertake to operate and maintain their respective pipeline systems and equipment safely and in such a manner as not to interfere with the system or equipment owned by the other party and in particular each party undertakes and agrees to consult with the other before commencing construction or operation of any new equipment or facilities which such party reasonably expects might interfere with or affect the operation of the other party's pipeline system or equipment and to make modifications to the design or construction of any such equipment or facilities as practically may be requested of it to minimize any interference with such party's pipeline system or equipment.

In the event Customer's facilities interfere with AltaGas Utilities Inc.'s ability to provide accurate measurement at the Point of Receipt or the Point of Delivery, AltaGas Utilities Inc. may immediately and without prior notice cease to receive further deliveries of Gas at the Point of Receipt pending the remedying by Customer of the cause of such interference to the satisfaction of AltaGas Utilities Inc.

4.12 Use of NOVA Measurements

AltaGas Utilities Inc. and Customer hereby agree that notwithstanding anything contained elsewhere in the Service Agreement, at a Point of Delivery or at a Point of Receipt which is a NOVA/AltaGas Utilities Inc. system interconnection, where NOVA's, not AltaGas Utilities Inc.'s, measuring equipment is used or relied on by AltaGas Utilities Inc. for measuring Gas transported under the Service Agreement, NOVA's measurement and testing of Gas procedures shall apply.

4.13 Forecast Volumes

Customer agrees to provide to AltaGas Utilities Inc., for planning purposes, such forecasts of future Monthly volumes to be transported under the Service Agreement as AltaGas Utilities Inc. may request from time to time.

Article 5 - Gas Delivery

5.1 Matching Receipts and Delivery

Subject to the other provisions of this Article, AltaGas Utilities Inc. agrees to receive from Customer at the Point of Receipt the quantity of Gas which Customer tenders for transportation up to the Contract Demand plus Customer's share of AltaGas Utilities Inc.'s Unaccounted For Gas and compressor fuel, and AltaGas Utilities Inc. agrees to tender for delivery to Customer and Customer shall receive at the Point of Delivery, a volume of Gas containing the equivalent number of joules as are contained in the volume of Gas tendered by Customer at the Point of Receipt less Customer's share of AltaGas Utilities Inc.'s Unaccounted For Gas; provided however that AltaGas Utilities Inc. shall not be required in any hour to accept at the Point of Receipt nor deliver at the Point of Delivery a quantity of Gas in excess of five (5) percent of the Contract Demand, unless otherwise specified on the applicable Rate Schedule.

5.2 Responsibility for Balancing

(1) Customer shall at all times have the obligation to balance, on a daily and monthly basis, the quantity of Gas which Customer tenders for transportation at the Point of Receipt, less Unaccounted For Gas, with the quantity of Gas delivered by AltaGas Utilities Inc. to Customer at the Point of Delivery.

Proposed Transportation Service Regulations

ARTICLE 2 – General Provisions

2.1. Transportation Only

The Transportation Contract is solely for Transportation Service and Producer shall not acquire any title or interest in the Gas Pipeline System of AUI and AUI shall not acquire any title or interest in the Gas being transported under the Transportation Contract.

2.2. Request for Service

When Producer requests Transportation Service from AUI, AUI must inform the Producer of the conditions to be satisfied before a Transportation Contract can be accepted and service commenced. Producer must provide any information AUI reasonably requires to assess the request. AUI retains the right to refuse a Producer's request for Transportation Service.

2.3. Need for a Contract

Every Producer must sign a Transportation Contract to receive Transportation Service.

2.4. Land Use

Producer must ensure that, with respect to property owned or controlled by the Producer, AUI is provided at no cost with any land use rights required to provide and maintain the service.

2.5. Right of Entry

(1) AUI has the right to enter the installation or complex of the Producer at any reasonable time:

(a) to install, maintain, or remove its facilities,

(b) to read, inspect, repair, or remove its metering devices, or

(c) to do anything else incidental to providing or discontinuing the Transportation Service.

(2) If any of AUI's equipment is situated within the Producer's installation or complex, the Producer must ensure that AUI can obtain access to the equipment when necessary.

2.6. Gas Under AUI Control

Gas delivered to AUI by Producer for Transportation Service shall be under the exclusive control of AUI from the time such Gas is accepted for Transportation Service at the Point of Receipt until delivered at the Point of Delivery.

2.7. AUI Determines Routing

AUI does not dedicate the Gas Pipeline System or any segment thereof for Transportation Service for Producer, and accordingly the routing and facilities used for Transportation Service for Producer shall be at AUI's discretion and may change from time to time.

2.8. Gas May be Commingled

(1) AUI may in the course of transporting Gas in the Gas Pipeline System commingle with or exchange for Gas owned by or transported for others, or remove certain hydrocarbon components present in the Gas.

(2) As commingling, exchanging, or the removal of certain hydrocarbon components may alter the Gross Heating Value or constituent parts of the Gas between the Point of Receipt and the Point of Delivery, AUI shall not be required to deliver at the Point of Delivery Gas with the same Gross Heating Value or containing the same constituent parts as Gas delivered at the Point of Receipt and AUI shall make whatever compensating adjustments to volume and Gross Heating Value as may be warranted.

(3) In the event, and to the extent, that any hydrocarbon components in the Gas delivered at the Point of Receipt are absent from the Gas delivered at the Point of Delivery as the result of commingling, exchanging or removal

of such hydrocarbon components in the course of transporting the Gas, title to such hydrocarbon components shall, notwithstanding anything to the contrary otherwise contained in the Transportation Contract, be deemed conclusively to have passed to AUI at the Point of Receipt.

2.9. Producer Confirms Right to Transport

Producer covenants with AUI that Producer shall have the right to transport all Gas delivered under the Transportation Contract to AUI at the Point of Receipt.

2.10. Commitment to Maintain Systems

The parties hereto mutually undertake to operate and maintain their respective pipeline systems and equipment safely and in such a manner as not to interfere with the system or equipment owned by the other party and in particular each party undertakes and agrees to consult with the other before commencing construction or operation of any new equipment or facilities which such party reasonably expects might interfere with or affect the operation of the other party's pipeline system or equipment and to make modifications to the design or construction of any such equipment or facilities as practically may be requested of it to minimize any interference with such party's pipeline system or equipment.

2.11. Specific Facilities

A Producer may be required to pay a contribution for any incremental facilities ("Specific Facilities") required to provide the service.

4.13. Forecast Volumes

Producer agrees to provide to AUI, for planning purposes, such forecasts of future Monthly volumes to be transported under the Transportation Contract as AUI may request from time to time.

ARTICLE 5 – Gas Delivery

5.1. Matching Receipts and Deliveries

Subject to the other provisions of this Article, AUI agrees to receive from Producer at the Point of Receipt the quantity of Gas which Producer tenders for transportation up to the Contract Demand; provided however that AUI shall not be required in any hour to accept at the Point of Receipt a quantity of Gas greater than 1/20th of the Contract Demand, unless otherwise specified on the applicable Rate Schedule. AUI agrees to tender for transportation to Customer and Customer shall receive at the Point of Delivery, a volume of Gas containing the equivalent number of joules as are contained in the volume of Gas tendered by Customer at the Point of Receipt less Customer's share of AUI's Unaccounted-For-Gas and compressor fuel.

5.2. Overriding Rights and Obligations

Notwithstanding anything contained elsewhere in this Article, AUI reserves the right to restrict the flow of Gas at the Point of Receipt or the Point of Delivery to achieve a balance, to correct any imbalance or in the event Producer repeatedly exceeds the Contract Demand without AUI's authorization.

5.3. Inability to exchange

(1) Notwithstanding anything contained elsewhere in the Transportation Contract, if a Point of Delivery is an interconnection with a pipeline system of a third party ("Other System") Producer recognizes that AUI's ability to deliver Gas may be dependent upon an exchange with

This page intentionally left blank.

9.7 Appendix 7 – Alliance Pipeline Tariff Excerpts

General Terms and Conditions

Alliance Pipeline Limited Partnership Page 25

GENERAL TERMS AND CONDITIONS

ARTICLE 17: NOTICES OF CHANGES IN OPERATING CONDITIONS

17.1 Transporter and Shipper shall notify each other from time to time as necessary of expected changes in the rates of delivery or receipt of Gas, or in the pressures or other operating conditions, and the reason for such expected changes, to the end that the other party may be prepared to meet them when they occur.

ARTICLE 18: POSSESSION AND CONTROL OF GAS

18.1 Transporter shall be deemed to be in possession of, in control of and responsible for all Gas received by it until the Gas is delivered by it at the Delivery Point.

Firm Transportation Service Agreement

ARTICLE 5
OPTION TO EXTRACT AND PURCHASE LIQUIDS

5.1 Shipper's receipts and deliveries, less the Fuel Requirement, will be balanced on volume and heating value bases at the Delivery Point in accordance with the Tariff.

5.2 Shipper hereby grants to Transporter acting solely in its capacity as agent for the party identified in Schedule C hereto (the "**Optionee**"), the option, exercisable at any time or times, and for any periods during the term of this Transportation Service Agreement, to extract from the commingled Natural Gas transported by Transporter and purchase all natural gas liquids or liquefiable hydrocarbons received by Transporter from Shipper that the Optionee elects to remove or process and hereby relinquishes to Transporter, acting solely in its capacity as agent for the Optionee, all proceeds, profits and losses derived from or allocable to the removal, processing or sale of such natural gas liquids or liquefiable hydrocarbons.

5.3 At any time that the Optionee exercises its option, then in consideration for the sale by Shipper of the extracted natural gas liquids or liquefiable hydrocarbons, Transporter solely in its capacity as agent for the Optionee, shall arrange for the delivery to Shipper by the U.S. Transporter at delivery points on the U.S. Pipeline of quantities of Natural Gas that have a heating value equal to the heating value of the quantities of such extracted natural gas liquids or liquefiable hydrocarbons acquired by the Optionee.

5.4 Shipper will, at the time of execution and delivery of this Transportation Service Agreement, or at any time thereafter as required by Transporter, execute, and, if required by Transporter, cause any of its Affiliates or any other Person who has been allocated transportation service on the U.S. Pipeline for volumes of Natural Gas corresponding to the Contracted Capacity to execute, agreements or instruments specifically providing for the option created in Section 5.2 or the acknowledgement of such option in the forms required by Transporter, provided that such agreements or instruments will not:

(a) affect, vary or alter the amounts payable by Shipper for transportation service under this Transportation Service Agreement; or

(b) affect, vary or alter the entitlement of Shipper to have deliveries made to it by Transporter at the Delivery Point balanced with its deliveries to Transporter on volume and heating value bases, after allowance for the Fuel Requirement; or

(c) affect, vary or alter the entitlement of Shipper or its Affiliates or any other Person who has been allocated transportation service on the U.S. Pipeline to have deliveries made to it by the U.S. Transporter at delivery points on the U.S. Pipeline balanced with its deliveries to the U.S. Transporter on a heating value basis, after allowance for the U.S. Fuel Requirement.

Interruptible Transportation Service Agreement

has all requisite legal power and authority to execute this Interruptible Transportation Service Agreement and carry out the terms, conditions and provisions hereof; (b) this Interruptible Transportation Service Agreement constitutes the valid, legal and binding obligation of Tranporter, enforceable in accordance with the terms hereof; (c) there are no actions, suits or proceedings pending or, to Transporter's knowledge, threatened against or affecting Transporter before any court or Authority that might materially adversely affect the ability of Transporter to meet and carry out its obligations under this Interruptible Transportation Service Agreement; and (d) the execution and delivery by Transporter of this Interruptible Transportation Service Agreement has been duly authorized by all requisite partnership action.

2.2 Representations and Warranties of Shipper: Shipper represents and warrants that: (a) it is duly organized and validly existing under the laws of __________________ and has all requisite legal power and authority to execute this Interruptible Transportation Service Agreement and carry out the terms, conditions and provisions hereof; (b) this Interruptible Transportation Service Agreement constitutes the valid, legal and binding obligation of Shipper, enforceable in accordance with the terms hereof; (c) there are no actions, suits or proceedings pending or, to Shipper's knowledge, threatened against or affecting Shipper before any court or Authority that might materially adversely affect the ability of Shipper to meet and carry out its obligations under this Interruptible Transportation Service Agreement; and (d) the execution and delivery by Shipper of this Interruptible Transportation Service Agreement has been duly authorized by all requisite corporate action.

ARTICLE 3
PAYMENT OF CHARGES

3.1 Shipper agrees to pay each month in accordance with the Toll Schedule Interruptible Transportation Service and the General Terms and Conditions the charges fixed by Transporter from time to time in respect of each month that this Interruptible Transportation Service Agreement and any renewal thereof is in effect.

ARTICLE 4
GAS TO BE TRANSPORTED

4.1 Subject to the provisions of this Interruptible Transportation Service Agreement and the Tariff, Transporter shall provide Transportation for Shipper, for a volume of Natural Gas not exceeding the Maximum Daily Contract Quantity set out in Schedule B, from the Receipt Points identified in Shipper's Nominations to the Delivery Point.

ARTICLE 5
OPTION TO EXTRACT AND PURCHASE LIQUIDS

5.1 Shipper's receipts and deliveries, less Fuel Requirement, will be balanced on volume and heating value bases at the Delivery Point in accordance with the Tariff.

5.2 Shipper hereby grants to Transporter acting solely in its capacity as agent for the party identified in Schedule C (the "**Optionees**"), the option, exercisable at any time or times, and for any periods during the term of this Interruptible Transportation Service Agreement and any renewal thereof, to extract from the commingled Natural Gas transported by Transporter and purchase all natural gas liquids or liquefiable hydrocarbons received by Transporter from Shipper that Optionee elect to remove or process and hereby relinquishes to Transporter, acting solely in its capacity as agent for the Optionee, all proceeds, profits and losses derived from or allocable to the removal, processing or sale of natural gas liquids or liquefiable hydrocarbons.

5.3 At any time that the Optionee exercises its option, then in consideration for the sale by Shipper of the extracted natural gas liquids or liquefiable hydrocarbons, Transporter solely in its capacity as agent for the Optionees, shall arrange for the delivery to Shipper by U.S. Transporter at delivery points on the U.S. Pipeline of quantities of Natural Gas that have a heating value equal to the heating value of the quantities of such extracted natural gas liquids or liquefiable hydrocarbons acquired by the Optionees.

5.4 Shipper will, at the time of execution and delivery of this Interruptible Transportation Service Agreement, or at any time thereafter as required by Transporter, execute, and, if required by Transporter, cause the execution of on any of its Affiliates or any other Person who has been allocated corresponding transportation service by the U.S. Pipeline for volumes of Natural Gas, to execute agreements or instruments specifically providing for the option created in Section 5.2 or the acknowledgement of such option in the forms required by Transporter, provided that such agreements or instruments will not:

(a) affect, vary or alter the amounts payable by Shipper for interruptible transportation service under this Interruptible Transportation Service Agreement; or

(b) affect, vary or alter the entitlement of Shipper to have deliveries made to it by Transporter at the Delivery Point balanced with its deliveries to Transporter on a heating value basis, after allowance for Fuel Requirement; or

(c) affect, vary or alter the entitlement of Shipper or its Affiliates or any other Person who has been allocated corresponding transportation service on the U.S. Pipeline to have deliveries made to it by U.S. Transporter at delivery points on the U.S. Pipeline balanced with its deliveries to U.S. Transporter on a heating value basis, after allowance for U.S. Fuel Requirement.

ARTICLE 6
TERM OF CONTRACT

6.1 This Interruptible Transportation Service Agreement shall be effective from the _____ day of ______________ (the "**Effective Date**") and shall continue until the ________ day of ______________ (the "**Primary Term**"), or on the final day of any extension effected pursuant to Section 6.2.

6.2 Shipper shall have the right to extend the term of this Interruptible Transportation Service Agreement beyond the Primary Term for further periods of a minimum of one (1) year each by providing written notice to that effect not less than ____ days prior to the expiry of

9.8 Appendix 8 – Aux Sable Canada Fact Sheet[129]

Fort Saskatchewan Extraction Plant Project

FACT SHEET

Project Information
April 2007

The purpose of this Fact Sheet is to provide an initial overview to neighbors and interested parties about a proposed project to construct and operate an ethane extraction plant in the City of Fort Saskatchewan. A more comprehensive information package is being prepared and will be available for distribution in May

Background

On March 21, 2007 a press release (attached) was issued announcing that NOVA Chemicals and Aux Sable Canada LP ("ASC") had signed a letter of intent to develop an ethane extraction plant in the municipality of Fort Saskatchewan. The proposed extraction plant would be constructed on land owned by ASC adjacent to the site of ASC's Heartland Off-Gas plant in the NE corner of the city limits and will be owned and operated by ASC. NOVA Chemicals will purchase the ethane produced at the extraction plant, with supply originating from the Alliance Pipeline. A map showing the location of the proposed extraction plant appears on page 5.

The Project

The extraction plant will be sited adjacent to the Alliance pipeline and will have an inlet processing capacity of 33.7×10^6 m^3 (1.2 billion cubic feet) per day of sweet natural gas from the Alliance Pipeline. Approximately $6350 m^3$/day (40,000 barrels/day) of ethane will be recovered and delivered to NOVA Chemicals' Joffre site ethylene plants. The Alliance Pipeline gas in excess of the processing capacity of the extraction plant will bypass the plant.

Alliance Pipeline Ltd. currently transports approximately 1.6 BCF/day of gas from Alberta and Northern British Columbia to delivery points near Chicago, Illinois. Since December 2000, the ethane contained in the pipeline gas stream has been extracted at a deepcut natural gas processing facility near Chicago, Illinois. The proposed Fort Saskatchewan extraction facility will provide an alternative ethane market.

In the Fall of 2006, the Alberta Government announced a policy to encourage the extraction of ethane in the province to ensure a secure supply of cost-competitive ethane feedstock to the Alberta petrochemical industry, expand opportunities for value-added upgrading and support investments in supply infrastructure This policy is an important aspect for the development of the proposed ethane extraction project and an application will be made once the details are outlined.

Alberta is Canada's largest petrochemical producing area, with annual shipments including chemicals of over $9 billion, exports of more than $5 billion and direct employment for more than 6,500 Albertans. More information about the Alberta petrochemical industry can be obtained on the Alberta government website at www.energy.gov.ab.ca.

[129] Source: http://www.auxsable.com/ca/projects/northsable/2007-04-26-northsable-fact-sheet.pdf

Fort Saskatchewan Extraction Plant Project
FACT SHEET

Project Information
April 2007

Project Schedule

Under the current project schedule, the extraction plant is expected to be operational in mid-2010. The plant design and front-end engineering process and the environmental reviews are currently underway.

In addition to the dissemination of written materials containing information about the project, the public consultation process will involve consultations with interested parties, including various levels of government and industry and community stakeholders to ensure ASC has a full understanding of any possible concerns and has an opportunity to address these concerns on a timely basis.

ASC is also developing a comprehensive human resources plan to address the staffing requirements for the development, construction, and operation of the plant.

The project schedule beyond the engineering and design phase will depend on the receipt of all required regulatory approvals.

Economic Benefits

The development of the extraction plant will provide an additional opportunity for the value-added upgrading of the natural gas resource within the province and will be an important step toward meeting a growing demand for the ethane required to sustain the Alberta petrochemical industry. Economic benefits will also be realized from the construction and operation of the extraction plant. Up to 25 permanent jobs will be created for the ongoing operation of the extraction plant. Taxes will benefit the City of Fort Saskatchewan and the provincial and federal governments.

Plant Description

The extraction plant will process gas that has undergone initial processing at a field plant to meet Alliance Pipeline gas specifications and as such will be a "straddle plant" under the EUB facility classification system. It will be a conventional cryogenic extraction plant utilizing existing extraction technologies to recover a purified ethane product from a high pressure, dense phase natural gas stream. Alliance Pipeline gas will enter and exit the plant at high pressure. While the gas is in the plant, it will be chilled to very cold temperatures to remove NGLs in the form of ethane and a propane plus heavier hydrocarbon ("propane plus") mixture. The propane plus mixture will be re-injected into the Alliance Pipeline System. A process overview appears on page 4.

Fort Saskatchewan Extraction Plant Project
FACT SHEET

Project Information
April 2007

Safety and Environment

ASC is committed to the safe, environmentally sound and efficient construction and operation of the extraction plant. This plant will be a zero-flare facility during normal operation. Flaring will be limited to maintenance situations and infrequent plant shutdowns. The plant will produce a relatively small amount of air emissions from the operation of two natural gas-fired heaters. Electrical motors will be used throughout the operation. The plant will process sweet natural gas which will result in little potential for hydrocarbon odors.

The project team will undertake a number of environmental studies early in the project design phase including soil and groundwater baseline assessments, noise modeling assessments, air dispersion modeling of emissions and flare stack modeling.

The ethane extracted from the gas will be transported away from the plant by pipeline. No on-site hydrocarbon storage tanks or vessels are required. Environmental monitoring programs will be an integral part of operations.

No surface or groundwater impacts are expected from operations. No fresh water for the plant processes will be required. A small wastewater stream will be captured in an on-site holding tank and transported by truck to an approved facility for appropriate disposal. Surface water will be collected in a surface water retention pond. The plant design will include spill containment systems that will reduce the potential for impact on soil and groundwater.

The plant will be designed and constructed with appropriate mitigation measures to ensure that all regulations are met. A comprehensive Emergency Response Plan (ERP) will be prepared for the extraction plant. The project team will work with County and Municipal officials and surrounding industry stakeholders to prepare the ERP, ensure its compatibility with the regional ERP and regularly test its effectiveness.

During construction, traffic impacts will be minimized by adhering to set construction routes and meeting other requirements identified by the City of Fort Saskatchewan and the County of Strathcona and through the stakeholder consultation program.

Contact Information

For additional information or to provide your views or input please contact:

Robyn McMorris
Aux Sable Canada Ltd.
403.508.5882
robyn.mcmorris@auxsable.com

Figure 1 – Process Overview

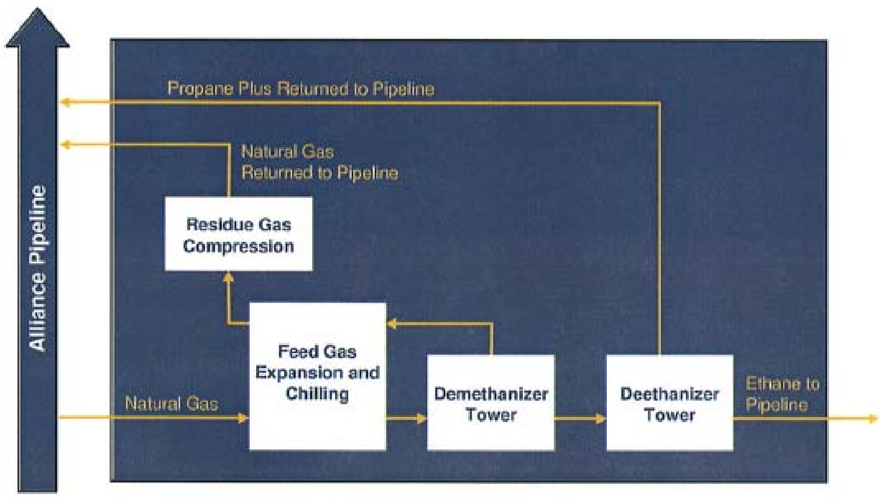
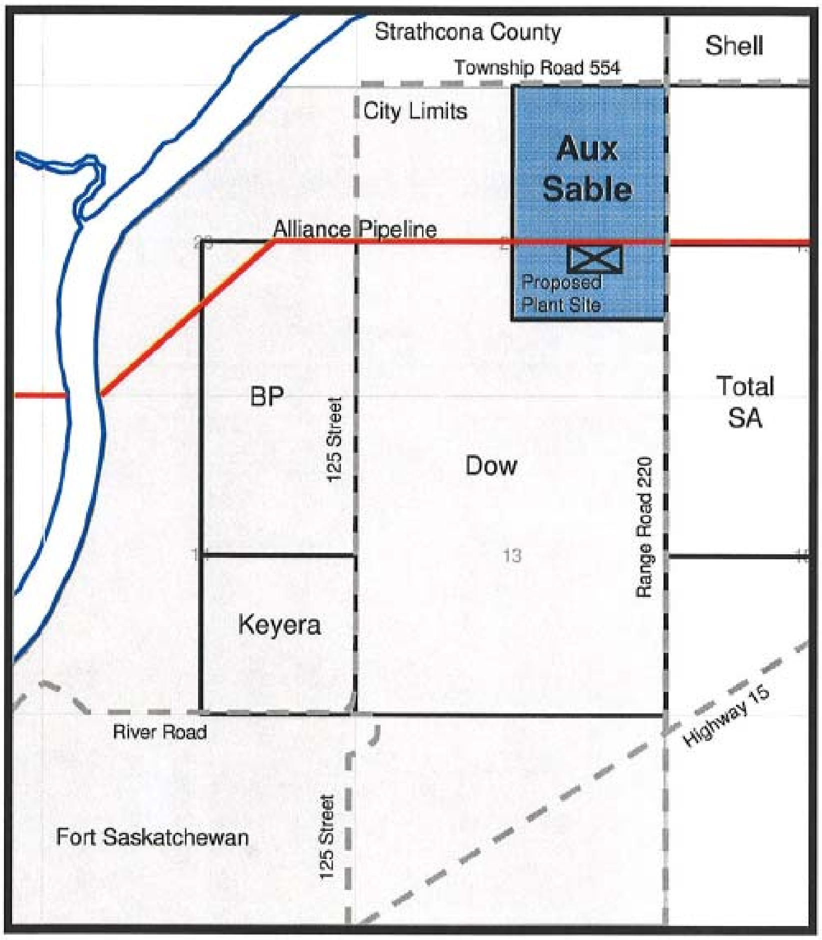
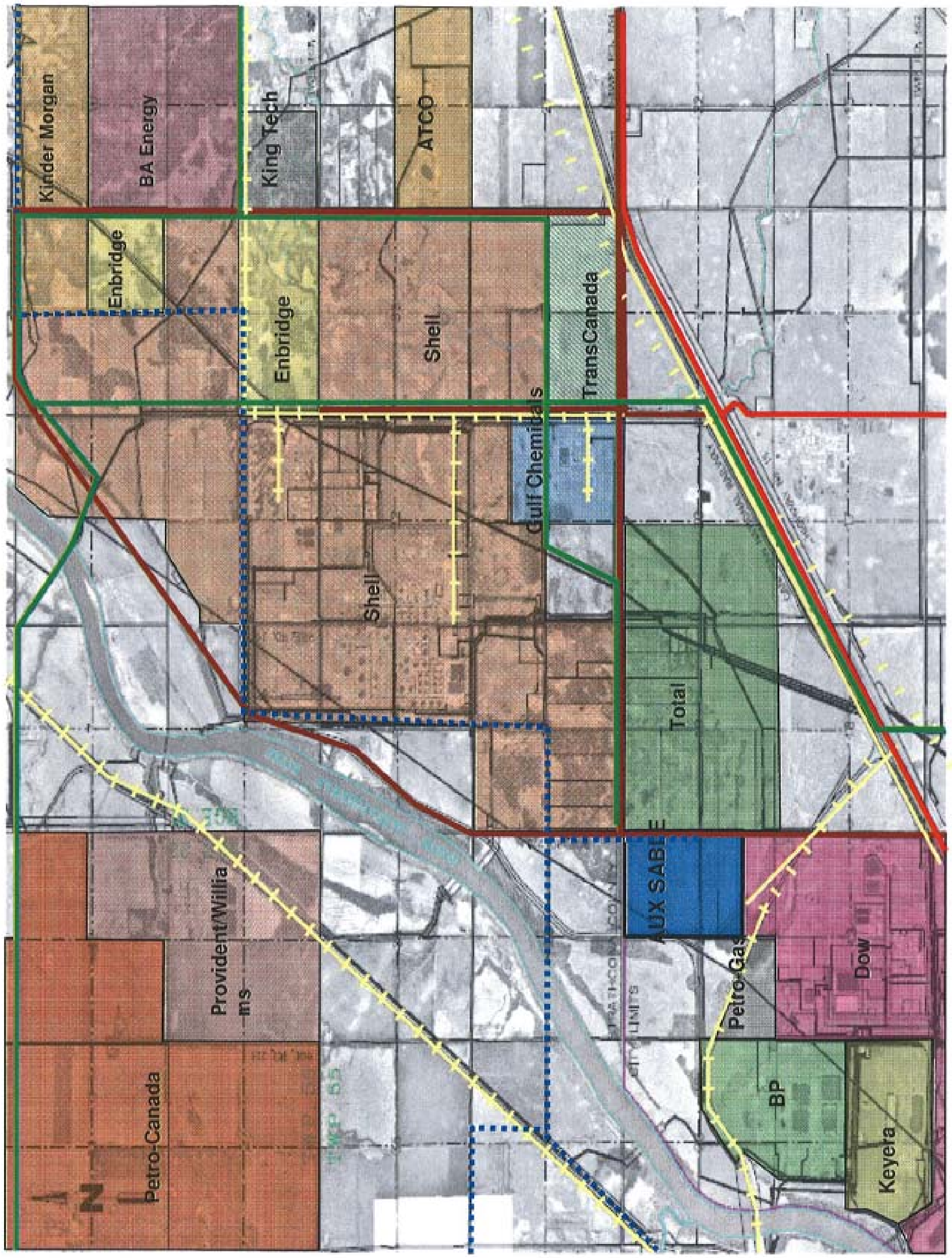


Figure 2 – Extraction Plant Location SE24-55-22 W4M




Kinder Morgan
BA Energy
King Tech
ATCO
Enbridge
Enbridge
Shell
TransCanada
Gulf Chemicals
Shell
Total
AUX SABLE
Petro-Gas
Dow
BP
Keyera
Provident/Willia
ms
Petro-Canada
N

9.9 Appendix 9 – Foothills Pipe Lines Tariff Excerpts

Service Agreement FT

ARTICLE 5

Title and Custody

5.1 Although Company does not acquire title of the gas transported under this Service Agreement, Firm Transportation Service gas received by Company from Shipper hereunder shall be deemed to be in the custody and under the control of Company from the time such gas is accepted for transportation at the Receipt Points until it is delivered to Shipper at the Delivery Points.

ARTICLE 6

Address of Parties

6.1 Any notice or any request, demand, statement, bid or bill (for the purpose of this subsection, collectively referred to as "Notice") provided for by the Rate Schedules, the Service Agreements and the General Terms and Conditions, or any other Notice which either Shipper or Company may wish to give to the other, shall be in writing and shall be directed as follows:

Shipper: •

•

•

Attention: •

Fax: •

E-mail: •

Company: Foothills Pipe Lines Ltd.

450 First Street S.W.

Calgary, AB

T2P 5H1

Attention: Manager, Western Markets and Interconnects

Fax: •

E-mail •

Service Agreement STFT

ARTICLE 5

Title and Custody

5.1 Although Company does not acquire title of the gas transported under this Service Agreement, Short Term Firm Transportation Service gas received by Company from Shipper hereunder shall be deemed to be in the custody and under the control of Company from the time such gas is accepted for transportation at the Receipt Point until it is delivered to Shipper at the Delivery Point.

ARTICLE 6

Address of Parties

6.1 Any notice or any request, demand, statement, bid or bill (for the purpose of this subsection, collectively referred to as "Notice") provided for by the Rate Schedules, the Service Agreements and the General Terms and Conditions, or any other Notice which either Shipper or Company may wish to give to the other, shall be in writing and shall be directed as follows:

Shipper:	•
	•
	•
Attention:	•
Fax:	•
E-mail:	•
Company:	Foothills Pipe Lines Ltd.
	450 First Street S.W.
	Calgary, AB
	T2P 5H1
Attention:	Manager, Western Markets and Interconnects
Fax:	•
E-mail	•

Service Agreement SGS

ARTICLE 5

Title and Custody

5.1 Although Company does not acquire title of the gas transported under this Service Agreement, Small General Service gas received by Company from Shipper hereunder shall be deemed to be in the custody and under the control of Company from the time such gas is accepted for transportation at the Receipt Points until it is delivered to Shipper at the Delivery Points.

ARTICLE 6

Address of Parties

6.1 Any notice or any request, demand, statement, bid or bill (for the purpose of this subsection, collectively referred to as "Notice") provided for by the Rate Schedules, the Service Agreements and the General Terms and Conditions, or any other Notice which either Shipper or Company may wish to give to the other, shall be in writing and shall be directed as follows:

Shipper:	•
	•
	•
Attention:	•
Fax:	•
E-mail:	•
Company:	Foothills Pipe Lines Ltd.
	450 First Street S.W.
	Calgary, AB
	T2P 5H1
Attention:	Manager, Western Markets and Interconnects
Fax:	•
E-mail	•

Service Agreement IT

ARTICLE 5

Title and Custody

5.1 Although Company does not acquire title to the gas transported under this Service Agreement, Interruptible Transportation Service, gas received by Company from Shipper hereunder shall be deemed to be in the custody and under the control of Company from the time such gas is accepted for transportation at the Receipt Points until it is delivered to Shipper at the Delivery Points.

ARTICLE 6

Address of Parties

6.1 Any notice or any request, demand, statement, bid or bill (for the purpose of this subsection, collectively referred to as "Notice") provided for by the Rate Schedules, the Service Agreements and the General Terms and Conditions, or any other Notice which either Shipper or Company may wish to give to the other, shall be in writing and shall be directed as follows:

Shipper:	•
	•
	•
Attention:	•
Fax:	•
E-mail:	•
Company:	Foothills Pipe Lines Ltd.
	450 First Street S.W.
	Calgary, AB
	T2P 5H1
Attention:	Manager, Western Markets and Interconnects
Fax:	•
E-mail	•

Rate Schedule FT

7.2 Receipt and Delivery Obligations

7.2.1 At each Delivery Point, Company and Shipper shall establish the Maximum Daily Delivery Quantity ("MDDQ") and shall specify the portion of such MDDQ to be received at each Receipt Point. The aforementioned MDDQ and portions thereof shall be specified in Appendix A to the Service Agreement, Firm Transportation Service.

7.2.2 At each Delivery Point, identified in Appendix A to the Service Agreement, Firm Transportation Service, Company is obligated to deliver to Shipper a daily quantity of gas which has an aggregate energy content of all gas received from Shipper at each Receipt Point destined for such Delivery Point, less Shipper's share for each Zone of the energy content of Company Use Gas used in the transportation of such gas on such day.

Shipper's share shall be calculated pursuant to section 8 of the General Terms and Conditions of this Gas Transportation Tariff.

7.2.3 Notwithstanding subsection 7.2.2 herein, Shipper shall not be allocated a share of Company Use Gas in respect of Backhaul service.

7.2.4 Company will provide Backhaul service under this Rate Schedule FT, Firm Transportation Service to Shipper on Zones 8 and 9 only in circumstances where such service is requested by Shipper and, in Company's judgement, there is sufficient quantity of gas being received into Company's system to enable such service to be provided.

7.3 Daily Gas Nominations

7.3.1 Shipper shall advise Company, in writing, of the total daily quantity of gas nominated by it for each Delivery Point. Such total daily quantity of gas shall not, subject to Article 1.2 of Shipper's Service Agreement, Firm Transportation Service, exceed the MDDQ for each such Delivery Point.

Rate Schedule STFT

7. CHARACTER OF SERVICE

7.1 Short Term Firm Transportation Service

Gas transported by Company for Shipper under this Rate Schedule STFT, Short Term Firm Transportation Service shall not be subject to curtailment or interruption except as provided in the General Terms and Conditions of this Gas Transportation Tariff.

7.2 Delivery Obligation

At the Delivery Point, identified in Appendix A to the Service Agreement, Short Term Firm Transportation Service, Company is obligated to deliver to Shipper a daily quantity of gas which has an aggregate energy content of all gas received from Shipper at the Receipt Point, less Shipper's share for Zone 8 or Zone 9 as applicable of the energy content of Company Use Gas used in the transportation of such gas on such day.

Shipper's share shall be calculated pursuant to section 8 of the General Terms and Conditions of this Gas Transportation Tariff.

7.3 Daily Gas Nominations

7.3.1 Shipper shall advise Company, in writing, of the total daily quantity of gas nominated by it for the Delivery Point. Such total daily quantity of gas shall not, subject to Article 1.2 of Shipper's Service Agreement, Short Term Firm Transportation Service, exceed the Maximum Daily Delivery Quantity ("MDDQ") for each such Delivery Point.

7.3.2 Shipper may provide its nomination through written confirmations received by Company from a downstream carrier. Company shall rely on such confirmations received from downstream carrier to determine Shipper's nomination quantities at Delivery Points. For certainty, this would include Shipper's written confirmation received by Company from Northern Border or Gas Transmission Northwest.

Rate Schedule SGS

6.2 Receipt and Delivery Obligations

6.2.1 At each Delivery Point, Company and Shipper shall establish the Maximum Daily Delivery Quantity and shall specify the portion of such Maximum Daily Delivery Quantity to be received at each Receipt Point. The aforementioned Maximum Daily Delivery Quantity and portions thereof shall be specified in Appendix A to the Service Agreement, Small General Service.

6.2.2 At each Delivery Point, identified in Appendix A to the Service Agreement, Small General Service, Company is obligated to deliver to Shipper a daily quantity of gas which has an aggregate energy content of all gas received from Shipper at each Receipt Point destined for such Delivery Point, less Shipper's share of the energy content of Company Use Gas used in the transportation of such gas on such day.

6.2.3 For the purpose of calculating Shipper's share of Company Use Gas pursuant to subsection 8.3 of the General Terms and Conditions of this Gas Transportation Tariff, all of Shipper's quantities received into Zone 9 shall be deemed to have been transported 1/2 of the total distance in Zone 9 (130 km).

6.3 Daily Gas Nominations

6.3.1 Shipper shall advise Company of the total daily quantity of gas nominated by it for each Delivery Point. Such total daily quantity of gas shall not, subject to Article 1.2 of Shipper's Service Agreement, Small General Service, exceed the Maximum Daily Delivery Quantity for each such Delivery Point.

6.3.2 Out of such total daily quantity of gas nominated for each Delivery Point, Shipper shall advise Company of the daily quantity of gas nominated by it for transportation from each Receipt Point.

Rate Schedule IT

Saskatchewan/U.S. border
near Monchy,
Saskatchewan.

4. CHARACTER OF SERVICE

4.1 Interruptible Transportation Service

Gas transported by Company for Shipper under this Rate Schedule IT, Interruptible Transportation Service shall be subject to curtailment or interruption, at any time, and from time to time, when Company estimates in its sole judgment, that service hereunder would in any way interfere with or restrict Company's ability to provide service pursuant to Rate Schedule SGS, Small General Service, Rate Schedule FT, Firm Transportation Service, Rate Schedule STFT, Short Term Firm Transportation Service or to other Shippers pursuant to Rate Schedule IT, Interruptible Transportation Service. Company shall not be obligated to construct additional facilities for the purpose of providing the interruptible service hereunder.

4.2 Receipt and Delivery Obligations

4.2.1 At each Delivery Point identified in Appendix A to the Service Agreement, Interruptible Transportation Service shipper may nominate a daily quantity of gas for interruptible service, subject to the provisions of subsection 4.3.

4.2.2 At each Delivery Point identified in Appendix A to the Service Agreement, Interruptible Transportation Service, Company is obligated to deliver to Shipper a daily quantity of gas which has an aggregate energy content of all gas received from Shipper and accepted by Company at each Receipt Point destined for such Delivery Point, less Shipper's share of the energy content of Company Use Gas used in the transportation of such gas on such day.

Shipper's share shall be calculated pursuant to section 8 of the General Terms and Conditions of this Gas Transportation Tariff.

4.2.3 Notwithstanding subsection 4.2.2 herein, for any service provided hereunder where the Delivery Point is upstream of the Receipt Point, Shipper shall not be allocated a share of Company Use Gas in respect of such Backhaul service.

4.3 Daily Gas Nominations

4.3.1 Shipper shall advise Company, from time to time as required by Company, of the daily quantity of gas to be transported under Rate Schedule IT, Interruptible Transportation Service pursuant to subsection 4.1, for each Delivery Point to be transported on an interruptible basis from the Receipt Point.

Shipper shall deliver such quantities at the Receipt Point at hourly rates of flow as nearly constant as possible and shall take delivery at the Delivery Point at hourly rates of flow as nearly constant as possible.

4.3.2 Departures from scheduled daily deliveries shall be kept to a minimum permitted by operating conditions.

4.3.3 If on any day Shipper fails to deliver to the Receipt Point, or accept at the Delivery Point, the gas nominated pursuant to subsection 4.3.1 herein, Company shall be entitled to curtail further receipts of gas from Shipper until the quantity delivered at the Receipt Point balances with the quantity delivered at the Delivery Point.

Without limiting Company's rights as set forth above, Company will use reasonable efforts to implement other operational procedures including:

(a) The notification of Shipper with an imbalance of other Shippers with positive or negative inventory in order that, by exchange, inventories may be brought to zero balance; and

This page intentionally left blank.

9.10 Appendix 10 – Westcoast Energy Inc. Tariff Excerpts

Article 16

ARTICLE 16
POSSESSION AND CONTROL OF GAS AND ENTITLEMENTS TO SULPHUR, LIQUID PRODUCTS, FORT NELSON LIQUIDS AND NATURAL GAS LIQUIDS

16.01 Possession and Control of Gas. Subject to Section 16.02, Westcoast shall be deemed to be in possession and control of, and responsible for, all gas received by it at a Receipt Point, until such gas is delivered by Westcoast to or for the account of a Shipper at a Delivery Point, and shall have the right at all times to commingle such gas with other gas in the Pipeline System.

16.02 Shipper Entitlements. Subject to Sections 16.03 and 16.05 and as between a Shipper and Westcoast, the Shipper shall be entitled to:

(a) the quantities of sulphur and Liquid Products recovered by Westcoast from the Shipper's gas in the Processing Plants;

b) the quantities of Fort Nelson Liquids recovered by Westcoast from the Shipper's gas in the Fort Nelson RGT System except for those Fort Nelson Liquids consumed by Westcoast in Pipeline System operations;

(c) direct Westcoast by means of a nomination given in accordance with Article 4 to deliver to the Straddle Plant Operator at the Straddle Plant Delivery Point, the volumes of residue gas physically processed for the Shipper at the McMahon Processing Plant and the volumes of residue gas physically delivered for the account of the Shipper to Compressor Station No. 1 through the Alberta Mainline and the Boundary Lake Pipeline, other than gas delivered into the Alberta Mainline at the Receipt Points designated as Parkland, West Doe Creek and the ABC/Gordondale Interconnection;

(d) those Natural Gas Liquids entrained in the Shipper's Contracted Residue Gas which is delivered by Westcoast for the account of the Shipper to the Straddle Plant Operator at the Straddle Plant Delivery Point; and

(e) the quantities of Natural Gas Liquids which are extracted and recovered from a Shipper's Uncontracted Residue Gas delivered by Westcoast to the Straddle Plant Operator pursuant to Section 16.04.

16.03 Displacement Deliveries. Notwithstanding any other provision of a Service Agreement and these General Terms and Conditions, a Shipper shall not be entitled to give a nomination for or to have residue gas delivered for its account by displacement to the Straddle Plant Operator at the Straddle Plant Delivery Point except for residue gas which is physically delivered through the Alberta Mainline and the Boundary Lake Pipeline to Compressor Station No. 1, other than gas delivered into the Alberta Mainline at the Receipt Points designated as Parkland, West Doe Creek and the ABC/Gordondale Interconnection.

16.04 Natural Gas Liquids Recovery by Westcoast. Westcoast may from time to time deliver Uncontracted Residue Gas to the Straddle Plant Operator for the purpose of extracting Natural Gas Liquids whenever Westcoast, in its sole discretion, determines that such extraction is required to ensure that the residue gas delivered by Westcoast to or for the account of a Shipper at a Delivery Point in Zone 3 or Zone 4 complies with the specifications prescribed in Article 12. Except for the recovery of Liquid Products in the McMahon Processing Plant and the recovery of Natural Gas Liquids from Uncontracted Residue Gas to the extent permitted by this Section, Westcoast shall not extract or recover, or cause any other person to extract or recover, Natural Gas Liquids from residue gas which is processed at the McMahon Processing Plant or from residue gas which is delivered to Compressor Station No. 1 through the Alberta Mainline or the Boundary Lake Pipeline.

16.05 Curtailment of Deliveries, Straddle Plant. Notwithstanding any other provision of a Service Agreement and these General Terms and Conditions, if Westcoast determines that the flowing temperature of the residue gas in the Pipeline System at the outlet of the Taurus compressor unit located at Compressor Station No. 1 is or is likely to be in excess of 49°C on any day, Westcoast may:

(a) refuse to authorize the delivery of Contracted Residue Gas to the Straddle Plant Operator at the Straddle Plant Delivery Point and the delivery of Contracted Residue Gas and other residue gas into the Pipeline System by the Straddle Plant Operator at the Straddle Plant Receipt Point; and

(b) curtail or interrupt deliveries of Contracted Residue Gas previously authorized by Westcoast for delivery to the Straddle Plant Operator at the Straddle Plant Delivery Point and deliveries of Contracted Residue Gas and other residue gas previously authorized by Westcoast for delivery into the Pipeline System by the Straddle Plant Operator at the Straddle Plant Receipt Point,

to the extent that Westcoast, in its sole discretion, determines is necessary to ensure that the flowing temperature of the residue gas at the outlet of the Taurus compressor unit does not exceed that temperature. Where Westcoast curtails or interrupts deliveries of Contracted Residue Gas at the Straddle Plant Delivery Point and deliveries of Contracted Residue Gas and other residue gas into the Pipeline System at the Straddle Plant Receipt Point in accordance with this Section, such curtailment or interruption shall be made in the priority and sequence prescribed in Section 3.04. Notwithstanding the provisions of Article 8, a Shipper shall not be entitled to any Contract Demand Credits if Westcoast refuses to authorize, or curtails or interrupts deliveries of Contracted Residue Gas and other residue gas in accordance with this Section.

16.06 Daily Delivery of Fort Nelson Liquids. Westcoast shall deliver on each day and, subject to section 16.08, each Shipper shall take on any such day, a quantity of Fort Nelson Liquids equal to each such Shipper's daily entitlement as determined by Westcoast for that day.

16.07 Excess Deliveries of Fort Nelson Liquids. If a Shipper takes a quantity of Fort Nelson Liquids which exceeds the total of its daily entitlement and that quantity of Fort Nelson Liquids that Westcoast has authorized the Shipper to remove from storage pursuant to Section 16.08, Westcoast may reduce the Shipper's daily entitlement for the following day or days, by the amount of such excess.

Westcoast Energy Inc.

GENERAL TERMS AND CONDITIONS - SERVICE

16.08 Deliveries of Fort Nelson Liquids to and from Storage. At a Shipper's request, Westcoast will deliver into storage all or any portion of the Shipper's daily entitlement of Fort Nelson Liquids provided such delivery will not cause the Shipper to exceed its storage entitlement as determined by Westcoast from time to time. Westcoast will, subject to operating conditions and limitations, authorize the removal from storage of Fort Nelson Liquids held for a Shipper's account in the quantities requested by the Shipper from time to time.

16.09 Failure to Take Fort Nelson Liquids. If at any time a Shipper fails to take any portion of its daily entitlement to Fort Nelson Liquids that is in excess of the Shipper's storage entitlement for any reason whatsoever, Westcoast may dispose of that quantity of such Fort Nelson Liquids which the Shipper has failed to take, in which event Westcoast will remit to the Shipper the proceeds of sale received by Westcoast less all costs and expenses (including, without limitation, transportation costs) reasonably incurred by Westcoast with respect to the disposition of that quantity. Where the costs of disposition exceed the proceeds of sale, the Shipper will pay the difference to Westcoast.

16.10 Possession and Control of Fort Nelson Liquids. Westcoast shall be deemed to be in possession and control of and responsible for all Fort Nelson Liquids recovered for a Shipper's account until such liquids are delivered by Westcoast to or for the account of the Shipper from the facility at which such liquids are recovered. Westcoast shall have the right at all times to commingle the Fort Nelson Liquids in its possession and control.

This page intentionally left blank.

9.11 Appendix 11 – BC Energy Plan Excerpt[130]

The BC Energy Plan
A Vision for Clean Energy Leadership

OIL AND GAS POLICIES

British Columbia has the opportunity for technological advancements and commercialization, particularly in environmental management, flaring, carbon sequestration and hydrogeology. The service sector has noted that it can play an important role in developing and commercializing new technologies, however, access to funds is an issue. Royalty credits is one option that is currently not available to the service sector and under this objective, the Ministry will assess the possibility of providing a company with transferability of royalty credits as a funding mechanism.

Establish a technology transfer incentive program.

The province will establish a technology transfer incentive program similar to the Saskatchewan Petroleum Research Incentive model but focusing on different technologies. This program, possibly funded by royalty credits, will encourage the research, development and use of innovative technologies to increase recoveries from existing reserves and encourage responsible development of new oil and gas reserves. The program should be designed to fully recover program costs, over time, through increased royalties generated by expanded development and production of BC's petroleum resources. An additional objective is to transfer the technology developed so there is a greater awareness and use of new technology in BC, particularly technology that leads to the reduction of environmental impacts of oil and gas production.

The BC Scientific Research and Experimental Development Program provides financial support to corporations for research and development that leads to new or improved products and processes. The Ministry, in consultation with the Ministry of Small Business and Revenue, will explore the expansion of the program to cover an individual's project costs directly related to commercially applicable research, development or demonstration for new or improved technologies conducted in British Columbia that facilitate expanded oil and gas production through credits or refunds. Work will also proceed in collaboration with PTAC.

Explore and establish other research and development programs for the oil and gas industry.

The Province will develop a program targeting specific areas where BC has demonstrated strengths.

The Province will work with the Fort St. John Centre of Excellence and other partners to establish an oil and gas technology incubator, encouraging entrepreneurs to develop and commercialize new and innovative technologies and processes. Workshops, information provision and expansion of existing events (e.g., tradeshows and oil and gas conferences) will be held to assist innovators.

The Province will develop a program to encourage oil and gas innovation and research in British Columbia's post-secondary institutions.

The Province will promote investment in research and development opportunities with the PTAC and the new MOU between BC and Alberta on Energy Research, Technology Development and Innovation.

50. Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.

[130] Source: http://www.energyplan.gov.bc.ca/PDF/BC_Energy_Plan_Oil_and_Gas.pdf

The BC Energy Plan
A Vision for Clean Energy Leadership

OIL AND GAS POLICIES

The goal is to develop a strategy promoting gas processing facilities in British Columbia. With a number of proposals for new pipelines carrying crude to the coast, landing condensate, and liquefied natural gas regassification terminals, there may be an opportunity to create an integrated petroleum refining and petrochemical industry, providing jobs and investment on the north coast.

Conduct an analysis into the potential for processing facilities to be located in British Columbia.

The Ministry will identify and analyze constraints, in the form of scale or nature of oil and gas processing facilities, that limit development and enhanced stewardship of BC's oil and gas resource.

Determine the viability of establishing a new petroleum refinery and petrochemical industry in British Columbia.

British Columbia is a small crude oil producer in Canada. With approximately 17 million barrels of crude oil production per year (2.8 billion litres), BC provides 1.8 per cent of total Canadian crude oil production. About half of BC's crude oil production is processed at the two refineries—Chevron in North Burnaby and Husky in Prince George, and the rest is processed in Alberta. Small quantities are exported to the US.

There are numerous proposals for condensate and crude oil pipelines, and importing liquefied natural gas for regasification. The Province will establish an industry/government working group to develop business cases and promote opportunities for new refining and petrochemical investment in BC. The working group will report to the Minister within six months with recommendations on the viability of a new petroleum refinery and petrochemical industry and measures, if any, to encourage investment.

51. Provide information about local oil and gas activities to local governments, education and health service providers to inform and support the development of necessary social infrastructure.

Provide local communities and service providers with regular reports of trends and industry activities so that they can more effectively plan for growth in required services and infrastructure.

Work with local communities, ministries and industry to address housing demands.

Ministry of Energy, Mines and Petroleum Resources, in partnership with the Ministry of Forest and Range's Housing Policy Branch, will actively work with and assist communities wishing to implement recommendations of the 2006 Housing Report.

52. Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.

9.12 Appendix 12 – TransGas Posted Heating Values for August, 2007 (MJ/m³)[131]

Meter	Physical Meter	Meter Name	PHV (MJ/m³)	Meter	Physical Meter	Meter Name	PHV (MJ/m³)
			20070801	159	6309	BRONSON LAKE-EOG-CT1	36.62
100	1613	SENATE-PROVIDENT-CT	36.5	160	6309	BRONSON LAKE-EOG-CT2	36.62
101	1614	MERRYFLAT-PRAIRIE SCHOONER-CT	36.25	161	6311	BEACONHILL-NUVISTA #3-CT	36.28
103	2511	HATTON-APACHE #2-CT	36.41	162	6313	BRONSON-HUSKY-CT1	37.17
104	2514	HATTON-CNRL#2-CT1	36.56	163	7100	POUNDMAKER-BAYTEX-CT	35.41
105	2515	RICHMD-CTY MED HAT-CT	36.5	164	8740	STEELMAN-BPCANADA-CT	39.89
107	2518	FOX VALLEY-ENERPLUS-CT	36.32	165	4654	BUFFALO COULEE-NEXEN-CT	37.95
109	2522	HATTON-PETRO CAN-CT	36.46	168	2514	HATTON-CNRL#2-CT2	36.56
110	2538	CRANE LAKE-PETRO-CT	36.02	178	5059	CACTUS LK-PENNWEST 3-CT	37.43
111	2539	BIGSTICK-PETROCAN-CT	36.45	179		HATTON-COMP-DISCHARGE	36.54
119	4504	W BAYHURST-SPUR-CT		201	6225	FROG LAKE-TGL-RECEIPT	37.63
120	4507	GREENAN-HUSKY-CT	35.2	221	5062	LASHBURN-MURPHY-CT	34.3
127		DODSLAND-ALTAGAS#2-CT	38.08	225	4672	MANTARIO-CONOCO CDA-CT	40.14
129	5036	TANGLEFLAGS-HUSKY-CT1	37.47	226	4313	BUFFALO COULEE-GANZE CT	37.36
130	5037	TANGLEFLAGS-HUSKY2-CT	36.69	231	4736	MAJOR-PENN WEST-CT	37.29
135	5070	CACTUS LAKE #4-CNRL-CT	36.6	233	6313	BRONSON NORTH-TGL-REC	37.17
136	5071	LANDROSE-CNRL-CT	35.96	236		ESTHER-TGL RECEIPT	38.59
140	6210	GREENSTREET-KEYERA-CT	36.54	237	6225	FROG LAKE-TGL RECEIPT	37.63
141	6211	FORT PITT-CNRL-CT	36.5	243	6239	MARWAYNE-TGL RECEIPT	36.89
143	6217	MACKLIN-NUVISTA #2-CT1	36.92	246	4620	HOOSIER-PENN WEST-CT	39.23
144	6221	FORT PITT #2-TGL - CT	36.38	248	7700	LYONS CR#2-CANETIC-CT1	36.07
145	6222	NORTHMINSTER-CNRL#1-CT	36.26	249	7700	LYONS CR#2-CANETIC-CT2	36.07
146	6223	SALVADOR-PENNWEST-CT	36.87	250	5036	TANGLEFLAGS-HUSKY-CT2	37.47
147	6224	PARADISE HILL-BAYTEX-CT	35.72	251	1624	CACTUS LAKE EAST-PENGROWTH CT1	37.42
148	6229	NORTHMINSTER-GEOCAN-CT	36.32	253		COLEVILLE-ALTAGAS #1-CT	38.08
151	6237	NORTHMINSTER-HUSKY-CT	36.31	255	4676	SMILEY-PENN WEST #1-CT	37.06
154	6300	BEACONHILL-BONAVISTA #1-CT	36.59	256	1627	COLEVILLE-TRUE ENERGY-CT	36.36
155	6305	BRONSON LAKE-NUVISTA #1-CT	36.07	257	4757	SALT LAKE-NUVISTA CT	36.31
156	6306	BRONSON LK-BONAVISTA#1S-CT1	36.11	260	3030	E CANTUAR-HUSKY-CT	37.15
158	6308	MAKWA LAKE-NUVISTA-CT	36.1	264	4734	BATTLE CR-MILAGRO-CT	36.39

[131] Source:Transgas website   http://www.transgas.com/infopostings/phv/PHVDisplay.asp

Meter	Physical Meter	Meter Name	PHV (MJ/m^3)	Meter	Physical Meter	Meter Name	PHV (MJ/m^3)
265	7700	LYONS CR#2-CANETIC-CT3	36.07	324	4775	MIRY CREEK-FET ENERGY-CT1	35.49
266	1624	CACTUS LAKE EAST-PENGROWTH CT2	37.42	325	4776	CRAMERSBURG-FET ENERGY-CT	35.55
267	1623	TURTLEFORD#2-EOG-CT	36.42	327	1650	SPRING CREEK-HUSKY-CT	35.66
268	1623	TURTLEFORD#2-EOG-CT2	36.42	329	4786	UNITY-PEARL E and P-CT	36.28
269	4654	BUFFALO COUL-NEXEN-CT#2	37.95	331	8603	BATTLE CR-CANETIC-CT	35.93
273	6306	BRONSON LK-BONAVISTA#1S- CT2	36.11	332	8604	LONE ROCK-CNRL-CT	35.59
274	1622	EDAM-NEW VENTURE-CT	33.65	333	6275	UNITY-VITAL ENERGY-CT2	36.35
277	1622	EDAM-FLAGSHIP-CT	33.65	334	8606	EDAM - HUSKY - CT	35.05
278	2513	BURSTALL-EOG CT1	36.58	335	1654	KYLE-HUSKY-CT	34.77
280	1637	BALDWINTON-PROVIDENT-CT	36.98	336	1655	KYLE-FET ENERGY-CT	34.97
281	2513	BURSTALL-EOG-CT2	36.58	338	8608	CYPRESS LK-PROVIDENT-CT	36.39
282	4652	SMILEY-PENN WEST #2-CT1	38.46	339	1657	CACTUS LK#2-NEXEN-CT	37.59
283	4652	SMILEY-PENN WEST #2-CT2	38.46	340	6263	LACADENA-FET ENERGY-CT2	
286	1501	RICHMOUND-FET ENERGY CT1	36.15	341	6264	WHITE BEAR-FET ENERGY-CT2	35.32
289	6209	HILLMOND-REMINGTON-CT1	36.85	347	8617	BATTLE CR-ENCANA-CT	36.35
290	6209	HILLMOND-REMINGTON-CT2	36.85	348	6273	CRANE LK-ACTION ENERGY-CT2	36.31
295	4734	BATTLE CREEK-MILAGRO-CT3	36.39	349	1502	RICHMOUND-CITY OF MED HAT-CT1	36.34
299	6217	MACKLIN-NUVISTA#2 - CT2	36.92	350	6286	REFLEX LK-NUVISTA-CT	35.01
300		MID-CNT SOUTH-NPS24-MIP-REC-LOG	36.65	351	6287	BEACON HILL-ENTERRA-CT	36.08
302	6258	GLEN EWEN-BP CANADA-CT	43.9	329	4786	UNITY-PEARL E and P-CT	36.28
303	4668	LOVERNA-PENN WEST CT	38.63	331	8603	BATTLE CR-CANETIC-CT	35.93
305	6263	LACADENA-FET ENERGY-CT1		332	8604	LONE ROCK-CNRL-CT	35.59
308	8772	SHACKLETON-PARAMOUNT-CT	35.44	333	6275	UNITY-VITAL ENERGY-CT2	36.35
310	6264	WHITE BEAR-FET ENERGY-CT1	35.32	334	8606	EDAM - HUSKY - CT	35.05
313	6273	CRANE LK-ACTION ENERGY-CT1	36.31	335	1654	KYLE-HUSKY-CT	34.77
314	6274	N CADILLAC-ENCANA-CT	34.6	336	1655	KYLE-FET ENERGY-CT	34.97
315	6275	UNITY-VITAL ENERGY-CT1	36.35	338	8608	CYPRESS LK-PROVIDENT-CT	36.39
316	6276	PAYNTON-HUSKY-CT	35.16	339	1657	CACTUS LK#2-NEXEN-CT	37.59
319	6283	CABRI-APACHE-CT	35.27	340	6263	LACADENA-FET ENERGY-CT2	
321	4773	PORTREEVE-FET ENERGY-CT	35.9	341	6264	WHITE BEAR-FET ENERGY-CT2	35.32
323	4774	LANCER-FET ENERGY-CT	35.79	347	8617	BATTLE CR-ENCANA-CT	36.35

Meter	Physical Meter	Meter Name	PHV (MJ/m^3)	Meter	Physical Meter	Meter Name	PHV (MJ/m^3)
348	6273	CRANE LK-ACTION ENERGY-CT2	36.31	388	1669	WHITE BEAR-HUSKY-CT	35.4
349	1502	RICHMOUND-CITY OF MED HAT-CT1	36.34	391	6328	MANTARIO-TRUE OIL-CT1	37.78
350	6286	REFLEX LK-NUVISTA-CT	35.01	392	6328	MANTARIO-TRUE OIL-CT2	37.78
351	6287	BEACON HILL-ENTERRA-CT	36.08	1501		RICHMOUND - FET ENERGY	36.15
352	8618	PIERCELAND-NUVISTA-CT	37.19	1502		RICHMOUND-CITY OF MED HAT	36.34
353	6240	JOHN LK-CNRL-CT1	36.22	1603		MID-CNT SOUTH-NPS24-MIP-REC	36.53
354	6240	JOHN LK-CNRL-CT2	36.22	1613		SENATE-PROVIDENT	36.5
355	6288	MEOTA - CNRL - CT	27.55	1614		MERRYFLAT-PRAIRIE SCHOONER	36.25
358	7700	LYONS CR#2-CANETIC-CT4	36.07	1622		EDAM-FLAGSHIP	33.65
359	4534	COLE-PENN WEST-CT	37.82	1623		TURTLEFORD#2-EOG	36.42
360	6291	SUPERB-DOSCK ENERGY-CT	37.37	1624		CACTUS LAKE EAST-PENGROWTH	37.42
362	6293	STRANRAER-TRUE ENERGY-CT	38.98	1625		WYMARK-HUSKY	34.5
363	4736	MAJOR-SPUR-CT	37.29	1627		COLEVILLE-TRUE ENERGY	36.36
366	6294	KINDERSLEY-LOS ALTARES-CT	35.85	1629		MAIDSTONE-CNRL	35.73
367	2703	HATTON-CNRL #3-CT	36.62	1630		MARENGO-ALTAGAS	37.48
368	4769	BEVERLEY-PENN WEST-CT	37.96	1631		PLOVER LK-NEXEN	37.42
369	5045	CACTUS LAKE-PENGROWTH #1-CT	37.36	1632		LOON LAKE-EOG	36.38
370	6218	ST WALBURG-ISH-CT	36.85	1633		MAIDSTONE-PARAMOUNT	34.79
371	7702	LYONS CREEK-CANETIC-CT	36.13	1635		WYMARK-GALLEON	34.19
372	6299	SENATE-ENCANA-CT	36.45	1637		BALDWINTON-PROVIDENT	36.98
373	6321	SENATE-CNRL-CT	36.5	1640		HATTON-EOG	36.44
374	4759	PLOVER LK-PENGROWTH-CT	37.08	1641		HATTON-NEXEN	36.68
375	4775	MIRY CREEK-FET ENERGY-CT2	35.49	1643		BALDWINTON-PARAMOUNT	35.92
376	1666	ABBEY-GRIZZLY-CT	35.52	1644		MERVIN-HUSKY	35.19
378	6324	VIEWFIELD-CRESCENT PT-CT	43.5	1650		SPRING CREEK-HUSKY	35.66
379	6325	SENLAC-NUVISTA-CT	36.34	1654		KYLE-HUSKY	34.77
380	6322	EDAM-CNRL-CT	33.08	1655		KYLE-FET ENERGY	34.97
382	6337	OXBOW-CRESCENT POINT-CT	43.91	1657		CACTUS LK #2-NEXEN	37.59
384	1667	TYNER-FET-CT	34.93	1666		ABBEY-GRIZZLY	35.52
385	6332	LACADENA-FET-CT	35.24	1667		TYNER-FET	34.93
386	6333	SNIPE LK-FET-CT	35.23	1669		WHITE BEAR-HUSKY	35.4

Meter	Physical Meter	Meter Name	PHV (MJ/m^3)	Meter	Physical Meter	Meter Name	PHV (MJ/m^3)
1675		W BAYHURST 7-22-24-26 - SPUR	35.46	2522		HATTON-PETRO CAN	36.46
1800		SENG @ UNITY-TGL	38.85	2523		HATTON-APACHE	36.36
1801		AMOC @ UNITY-TGL	38.04	2525		HATTON-CNRL	36.6
1806		CGLL @ UNITY-TGL	38	2526		BIGSTICK-EOG	36.47
1828		TGAS@UNITY-TGL	38.82	2528		HATTON-ARC #3	36.46
1833		SETC@ UNITY-TGL		2529		CRANE LAKE-CITY MED HAT	36.03
1835		NCAN @ UNITY-TGL	39.52	2530		CRANE LAKE- ARC #1	36.25
1839		CONO @ UNITY-TGL		2532		HATTON-CITY MED HAT	36.57
1892		NEX2@UNITY	39.52	2534		MCLAREN LAKE-APACHE #1	36.43
1894		TMC@UNITY-TGL		2536		FREEFIGHT-CITY MED HAT	36.17
1895		SPOW @ UNITY-TGL	38.38	2537		LIEBENTHAL#1-EOG	36.23
1900		SENG @ COLD LAKE-TGL	37.73	2538		CRANE LAKE-PETROCAN	36.02
1905		TGAS@COLDLAKE	37.83	2539		BIGSTICK-PETROCAN	36.45
1906		CGLL@COLDLAKE-TGL	37.78	2540		HORSHAM-ARC	36.51
1951		AMOC @ COLD LAKE-TGL	37.82	2541		HATTON-COMP-SUCTION	36.53
1994		TMC @ COLDLAKE-TGL	37.82	2542		HATTON-HIGHWAY 21 - EOG	36.46
2501		HATTON-CNRL #1 NORTH	36.63	2545		CRANE LAKE-ARC #2	36.28
2502		HATTON-CNRL #1 SOUTH	36.56	2546		HATTON-CITY MED HAT #2	36.42
2503		HATTON-EAST NEXEN	36.47	2547		LIEBENTHAL #3-EOG	36.3
2504		MAPLE CREEK-CNRL	36.45	2702		HATTON-CNRL #1	36.56
2508		HATTON-CNRL #4	36.36	2703		HATTON-CNRL #3	36.62
2510		FOX VALLEY-EOG	36.27	2704		HATTON-ARC #1	36.54
2511		HATTON-APACHE #2	36.41	2997		SUCCESS-COMPRESSION-INJECTION	36.61
2512		HATTON-ARC #2	36.46	2998		SUCCESS-COMPRESSION-PRODUCTION	36.61
2513		BURSTALL-EOG	36.58	2999		CANTUAR-FLD PRODUCTION	36.59
2514		HATTON-CNRL #2	36.56	3000		CANTUAR-FLD INJECTION	36.57
2515		RICHMOUND-CITY MED HAT	36.5	3014		VERLO-AVENIR	37.42
2516		HATTON-CNRL #6	36.55	3016		W GULL LAKE-HUSKY	37.88
2518		FOX VALLEY-ENERPLUS	36.32	3030		E. CANTUAR-HUSKY	37.15
2519		FOX VALLEY-CITY MED HAT	36.32	4313		BUFFALO COULEE-GANZE	37.36
2520		LIEBENTHAL-EOG #2	36.27	4405		BROCK-RACING	36.18

Meter	Physical Meter	Meter Name	PHV (MJ/m^3)	Meter	Physical Meter	Meter Name	PHV (MJ/m^3)
4506		WHITESIDE-HUSKY	36.21	4763		COLEVILLE-ISH	37.5
4507		GREENAN -HUSKY	35.2	4767		GULL LAKE-FET ENERGY	38.74
4508		TOTNES-FET ENERGY	35.88	4769		BEVERLEY-PENN WEST	37.96
4516		DODSLAND-TRUE ENERGY	39.06	4773		PORTREEVE-FET ENERGY	35.9
4532		DODSLAND-PENN WEST #1	40.01	4774		LANCER-FET ENERGY	35.79
4533		COLEVILLE-ALTAGAS#1	39	4775		MIRY CREEK-FET ENERGY	35.49
4534		COLE-PENNWEST	37.82	4776		CRAMERSBURG-FET ENERGY	35.55
4535		DODSLAND-HUSKY	38.9	4781		ONION LK-PEARL E and P	36.38
4537		S BAYHURST-TCPL#1-REC	36.46	4786		UNITY-PEARL E and P	36.28
4539		DODSLAND-GANZE-REECE	39.51	5034		UNITY-SPUR	36.18
4600		PRAIRIEDALE-ISH	40.01	5036		TANGLEFLAGS-HUSKY	37.47
4603		COLEVILLE-IMPERIAL OIL (R)	39	5037		TANGLEFLAGS-HUSKY #2	36.69
4620		HOOSIER-PENN WEST	39.23	5043		YONKERS-NUVISTA	36.56
4649		COURT-PENN WEST	37.47	5045		CACTUS LAKE-PENGROWTH #1	37.36
4650		COSINE-PENGROWTH	37.54	5047		CACTUS LAKE #2-PENNWEST	37.11
4652		SMILEY-PENN WEST #2	38.46	5048		YONKERS-CNRL	36.7
4654		BUFFALO COULEE-NEXEN	37.95	5052		SENLAC-TALISMAN	36.78
4656		GLIDDEN VERENDRYE-ISH	37.61	5057		CACTUS LAKE-PENGROWTH #2	37.13
4661		LOVERNA-ALTAGAS	38.5	5059		CACTUS LAKE#3-PENNWEST	37.43
4666		SMILEY- ISH	38.95	5062		LASHBURN-MURPHY	34.3
4668		LOVERNA-PENN WEST	38.63	5064		SENLAC #2-TALISMAN	36.79
4672		MANTARIO-CONOCO CDA	40.14	5065		SENLAC-CNRL	36.99
4676		SMILEY-PENN WEST #1	37.06	5066		EDAM-ISH	35.28
4710		HOOSIER-NUVISTA ENERGY	38.64	5067		SILVERDALE-EMPIRE	36.61
4720		DODSLAND-PENN WEST #2	39.69	5069		CACTUS LK-PENN WEST	37.16
4727		DODSLAND-ALTAGAS #2	39	5070		CACTUS LAKE#4 CNRL	36.6
4734		BATTLE CREEK-MILAGRO	36.39	5071		LANDROSE-CNRL	35.96
4736		MAJOR-SPUR	37.29	5073		NEILBURG-CNRL	36.51
4757		SALT LAKE-NUVISTA	36.31	5076		HILLMOND-BAYTEX	36.17
4759		PLOVER LAKE-PENGROWTH	37.08	5077		LASHBURN-MURPHY #2	35.53
4762		LLOYDMINSTER-ALTAGAS	35.82	6009		BH PROD 03-30-61-24	36.73

Meter	Physical Meter	Meter Name	PHV (MJ/m^3)	Meter	Physical Meter	Meter Name	PHV (MJ/m^3)
6101		BH PROD 11-07-61-24	36.74	6229		NORTHMINSTER-GEOCAN	36.32
6103		BH PROD 10-08-61-24	36.75	6232		BIG GULLY- PEARL E and P	35.62
6107		BH PROD 10-10-61-24	36.74	6234		PIERCE LK-NUVISTA	35.77
6109		BH PROD 11-15-61-24	36.75	6237		NORTHMINSTER-HUSKY	36.31
6111		BH PROD 07-16-61-24	36.76	6238		MUDIE LAKE-NUVISTA	35.99
6113		BH PROD 10-17-61-24	36.8	6239		MARWAYNE-HUSKY	36.89
6119		BH PROD 10-13-61-25	36.71	6240		JOHN LAKE-CNRL	36.22
6121		BH PROD 15-05-61-24	36.75	6250		PARADISE HILL-CNRL	36.05
6125		BH PROD 10-09-61-24	36.71	6252		NORTHMINSTER-BAYTEX	36.16
6127		BH PROD 01-18-61-24	36.78	6253		LILYDALE-VITAL	36.14
6129		BH-PROD 05-08-61-24	36.74	6258		GLEN EWEN-BP CANADA	43.9
6130		BH-PROD 04-09-61-24	36.71	6261		LACADENA-HUSKY	35.28
6131		BH-PROD 04-15-61-24	36.75	6262		SHACKLETON-HUSKY	35.6
6132		BH-PROD 04-16-61-24	36.74	6263		LACADENA-FET ENERGY	
6134		BH PROD 08-24-61-25	36.74	6264		WHITE BEAR-FET ENERGY	35.32
6135		BHPROD 11- 19-61-24	36.74	6265		CABRI-FET ENERGY	35.46
6205		FORT PITT-NUVISTA	36.13	6267		FLAT VALLEY-NUVISTA	35.77
6206		PARADISE HILL-HUSKY	36.39	6272		THUNDERCHILD-PEARL E and P	36.21
6207		FORT PITT-ALTAGAS	36.49	6273		CRANE LK-ACTION ENERGY	36.31
6209		HILLMOND-REMINGTON	36.85	6274		N CADILLAC-ENCANA	34.6
6210		GREEN STREET-KEYSPAN	36.54	6275		UNITY-VITAL ENERGY	36.35
6211		FORT PITT-CNRL	36.5	6276		PAYNTON-HUSKY	35.16
6215		LASHBURN-RIFE	35.15	6283		CABRI-APACHE	35.27
6217		MACKLIN-NUVISTA #2	36.92	6286		REFLEX LK-NUVISTA	35.01
6218		ST. WALBURG-ISH	36.85	6287		BEACON HILL-ENTERRA	36.08
6221		FORT PITT #2 - TGL	36.38	6288		MEOTA - CNRL	27.55
6222		NORTHMINSTER-CNRL #1	36.26	6291		SUPERB-DOSCK ENERGY	37.37
6223		SALVADOR-PENNWEST	36.87	6292		UNITY-ARTEMIS EXPLORATION	35.94
6224		PARADISE HILL-BAYTEX	35.72	6293		STRANRAER-TRUE ENERGY	38.98
6225		FROG LAKE-ALTAGAS	37.63	6294		KINDERSLEY-LOS ALTARES	35.85
6227		LANDROSE -REMINGTON	36	6299		SENATE-ENCANA	36.45

Meter	Physical Meter	Meter Name	PHV (MJ/m^3)	Meter	Physical Meter	Meter Name	PHV (MJ/m^3)
6300		BEACONHILL-BONAVISTA #1	36.59	8606		EDAM - HUSKY	35.05
6302		BEACONHILL-BONAVISTA	36	8608		CYPRESS LK-PROVIDENT	36.39
6303		BEACONHILL-NUVISTA	36.28	8610		FORT PITT-PEARL E and P	36.07
6304		BRONSON LAKE-NUVISTA #2	36.02	8612		SHAUNAVON-ALTAGAS	38.59
6305		BRONSON LAKE-NUVISTA #1	36.07	8617		BATTLE CR-ENCANA	36.35
6306		BRONSON LAKE-BONAVISTA	36.11	8618		PIERCELAND-NUVISTA	37.19
6308		MAKWA LAKE-NUVISTA	36.1	8740		STEELMAN-BP CANADA	39.89
6309		BRONSON LAKE-EOG	36.62	8762		KISBEY-GRIMES	41.22
6311		BEACONHILL-NUVISTA #3	36.28	8772		SHACKLETON-PARAMOUNT	35.44
6312		BRONSON LK - CRESCENT	36.36	8776		GOLDEN PRAIRIE-APACHE	36.43
6313		BRONSON LK-HUSKY	37.17	9483		DEVONIA LK-MIP-REC	37.2
6315		LOON LAKE-ENTERRA	36.31	9669		DEVONIA LAKE-TGL-REC	37.9
6320		ESTEY-FET ENERGY	35.81	9801		BRONSON-MIP/NOVA-REC	37.02
6321		SENATE-CNRL	36.5	9802		BRONSON N-MIP/REN/REC	37.17
6322		EDAM-CNRL	33.08	9803		COLD LAKE-MIP/NOVA-REC	37.78
6324		VIEWFIELD-CRESCENT PT	43.5	9804		ESTHER-MIP/NOVA/REC	38.59
6325		SENLAC-NUVISTA	36.34	9805		FROG LAKE-MIP/REC	37.63
6328		MANTARIO-TRUE OIL	37.78	9806		UNITY-MIP/NOVA/REC	38.46
6329		W BAYHURST-ENTERRA	35.41	9809		LOOMIS-MIPL(C)L-REC	
6331		SEAGRAM LK-PEARL E and P	35.08	9817	6239	MARWAYNE-MIP#2-HUSKY	36.89
6332		LACADENA - FET	35.24	9818		MARWAYNE-MIP#1-HUSKY	36.89
6333		SNIPE LK - FET	35.23	9900		EMPRESS-TCPL CD	37.41
6337		OXBOW-CRESCENT POINT	43.91				
7100		POUNDMAKER-BAYTEX	35.41	9902		SHAUNAVON-N NATURAL	36.96
7700		LYONS CREEK #2-CANETIC	36.07	9907		UNITY-NOVA	38.46
7702		LYONS CREEK-CANETIC	36.13	9909		COLD LK-NOVA	37.78
8024		BELLE PLAINE-TCPL	37.29	9916		BEACON HILL-PIERCELAND BAYHURST	37.09
8036		NOTTINGHAM-NAL	42.97	9917		BEACON HILL-MANVILLE BAYHURST	36.74
8602		LEADER-ENCANA	36.19	9918			
8603		BATTLE CR-CANETIC	35.93				
8604		LONE ROCK-CNRL	35.59			**Average**	**36.72**

This page intentionally left blank.

9.13 Appendix 13 - TransGas Tariff Excerpts

TransGas Limited

General Terms and Conditions

The terms used herein shall have the meanings as ascribed to in the corresponding terms set out in the Definitions section of this Tariff.

ARTICLE 1 - DELIVERY PRESSURES

1.1 Point of Receipt

Customer agrees to deliver the Gas, or cause the Gas to be delivered into the Gas Transmission System at the Point of Receipt at such pressures as TransGas requires from time to time at the Point of Receipt not to exceed the maximum pressure limit as set out on the respective Schedule of Service. TransGas reserves the right to change the said maximum pressure limit upon six (6) Months written notice to Customer.

1.2 Point of Delivery

TransGas agrees to deliver the Gas to Customer at the Point of Delivery out of the Gas Transmission System at pressures as follows:

(a) Intra-Saskatchewan demand and non-demand Delivery Transportation Service Customers: at gauge pressures within the pressure limits as set out on the respective Schedule of Service;

(b) Export Delivery Transportation Service Customers: at pressures as required by the Customer, subject to the maximum pressure limit as set out on the respective Schedule of Service.

ARTICLE 2 - QUANTITY OF GAS

2.1 General Obligations

Subject to the other provisions of the Tariff, TransGas agrees to receive from Customer each Day at each Point of Receipt the quantity of Gas which Customer tenders for transportation on such Day, up to the Contract Demand, and TransGas agrees to tender for delivery to Customer and Customer shall take on such Day at the Point of Delivery, an amount of Gas containing the equivalent amount of Energy as are contained in the amount of Gas tendered by Customer at the Point of Receipt, less Customer's share of Fuel Gas and Line Loss, where applicable, up to the Contract Demand.

This page intentionally left blank.

9.14 Appendix 14 – Nova Scotia Energy Strategy Report Excerpt[132]

NOVA SCOTIA CANADA   Government of Nova Scotia

Nova Scotia Energy Strategy: Seizing the Opportunity

Petroleum Directorate
December 12, 2001 12:31

The provincial government has released its new energy strategy, which will enable Nova Scotians to gain maximum benefits from energy industry development. The strategy includes putting a portion of future offshore petroleum royalties into a Nova Scotia Offshore Heritage Trust fund. It also introduces limited competition for some electric power customers, as well as setting new standards to help reduce air pollution. To implement the strategy, the government will create a new Department of Energy.

"We are determined to seize the opportunity presented by a growing offshore energy sector," said Premier John Hamm. "We see many benefits flowing to the people of our province in the years ahead. We want to use our non-renewable resources to make permanent changes in our economic and financial future."

"This strategy comes as a result of extensive consultations over the past nine months," said Natural Resources Minister Ernest Fage. "The actions being taken are the result of recommendations from many people, including Nova Scotians, energy interest groups and experts."

"We are looking for a broad range of benefits from offshore developments," said Gordon Balser, minister responsible for the Petroleum Directorate. "A vibrant energy sector needs to invest in research and development and training. It must support Nova Scotia-based businesses that can grow into world-class competitors."

The minister also noted that before this can happen, new discoveries must be made. To this end, one of the strategy's prime objectives is to encourage all aspects of exploration.

The energy strategy covers a broad range of issues and energy sectors in a 52-page report and in a second volume of detailed energy-sector background papers.

In electric power generation, competition will be gradually introduced. This will enable the province to develop new sources of renewable energy and create opportunities to export power. Municipal utilities will gain access to the transmission system so they can buy power from any generator. There will be open competition for new power generation. Renewable energy standards will be set. New clean-coal technology development will be encouraged and conservation efforts supported.

Air pollution standards are being tightened to reduce the emissions that cause acid rain, smog and other potential health hazards. In particular the province will work with Nova Scotia Power Inc. and other industrial companies to reduce sulphur dioxide emissions by 25 per cent by the middle of the decade and by a cumulative 50 per cent by the end of the decade.

---

[132] Source: http://www.gov.ns.ca/news/details.asp?id=20011212008

In order to enhance the opportunity for both the fishing and the energy industry to prosper, the energy strategy takes steps to improve consultation with the fishing industry on offshore exploration and development. Coastal communities will be consulted before any future exploration licences are offered for bid within sight of a shoreline of Cape Breton or mainland Nova Scotia (within 18 km offshore).

The energy strategy sees major future benefits from the use of a new fuel source -- natural gas. Barriers to local gas distribution are being removed, allowing the new system to operate on a firm commercial basis.

"The former system of setting targets for pipelines to be built without consideration for markets and economics has clearly failed," said Mr. Balser. "The new policies are designed to ensure that natural gas will be available as markets and new sources of natural gas develop."

The strategy recognizes that coal will continue to play a major role in electrical generation in the province for many years to come. It encourages the development of local coal resources where it is economically and environmentally feasible. Opportunities for surface mining as part of land reclamation are expected to be identified in Cape Breton. Other mine developments may also be possible with advances in clean-coal technology.

Research and development are strongly supported by the strategy. The province will encourage increased energy research and development in the public and private sectors and will examine possible incentives.

The province intends to secure additional industry support for research and development, training and expanded opportunities for economic development in Nova Scotia. It will accomplish these ends through Offshore Strategic Energy Agreements. Agreements with new project developers are designed to ensure that future project developments help the province achieve the strategy objectives.

The province plans to use a portion of offshore oil and gas royalties for long-term, provincewide economic and financial benefit. When the higher net-revenue royalties begin, a portion will be placed into a Nova Scotia Offshore Heritage Trust. The trust will ensure the benefits of today continue on for future generations. Income from the trust will be used for initiatives that improve the province's long-term economic future.

The current offshore regulatory system is a joint responsibility of the federal and provincial governments. Efforts will be made to make the system more efficient and effective. The federal government has agreed to work with the province and industry to discuss key issues to avoid duplication and overlap.

FOR BROADCAST USE:

The provincial government has released a new energy strategy that will enable Nova Scotians to gain maximum benefits from energy industry development.

The strategy includes putting a portion of future offshore petroleum royalties into a Nova Scotia Offshore Heritage Trust fund.

It also introduces limited competition for some electric power customers, as well as setting new standards to help reduce air pollution.

To implement the strategy, the government will create a new Department of Energy.

Premier John Hamm says the government is determined to seize the opportunity presented by a growing offshore energy sector and to use the non-renewable resources to make permanent changes in Nova Scotia's financial future.

-30-

Contact: Bruce Cameron
Petroleum Directorate
902-424-2288
Cell: 902-499-8849
E-mail: cameronb@gov.ns.ca

kjd 12 December 2001 12:28 P.M.

Page 9 from Nova Scotia's Energy Strategy[133]

Petrochemical Opportunities in Nova Scotia

One reason for seeking access to natural gas liquids in Nova Scotia is to develop a petrochemical industry. Natural gas-based petrochemical manufacturing can be classified into two general categories: those that use methane as the basic feedstock, and those that use natural gas liquids such as ethane, propane, or butanes.

Products such as methanol, nitrogen fertilizers, acrylic fibers, explosives, gasoline additives, and wood resins/adhesives can be manufactured from methane. Plastics (e.g. polyethylene, polypropylene, and polyvinylchloride), aromatics, polyurethanes, acetic acid, and anti-freeze are produced from natural gas liquids.

The government has undertaken several studies to identify opportunities for developing a petrochemical industry. The criteria used in the assessment were raw material availability, presence of key petrochemical infrastructure components in Nova Scotia, investment required, feedstock requirements, supply and demand balance, technology access and turnover, plant complexity, investment requirements, infrastructure, and socio-economic and environmental factors. These studies indicated that the production of methanol, nitrogen fertilizers and ethylene derivatives offered the most potential in Nova Scotia.

Existing Arrangements for Access to Gas and Liquids in Nova Scotia

Natural Gas Liquids

The Government of Nova Scotia has an agreement signed by each of the members of the Sable consortium (Sable producers) that makes natural gas liquids available for use in the province by a petrochemical industry. The June 1999 Petrochemical Supply Agreement commits the Sable producers:

- to fractionate natural gas liquids in the Point Tupper area of Nova Scotia;
- to not dispose of such liquids under any contract longer than two years without acquiring Nova Scotia's permission to do so, or making an equivalent quantity of liquids available in Nova Scotia;
- to remove, or allow third parties to remove, ethane from the natural gas stream; and
- to not guarantee a specific ethane content in any natural gas sold as part of the SOEI project.

Market-based prices and normal operational standards will apply to the liquids covered by the agreement. It is anticipated that future offshore project developers will sign similar agreements. These agreements provide simple, effective, and enforceable mechanisms to achieve the province's objectives of access to natural gas liquids for petrochemical manufacture in Nova Scotia.

If agreement cannot be reached with future producers, the province has the right under the Petroleum Resources Removal Permit Act to require an extensive permitting process for the sale and transport of NGLs outside Nova Scotia. These permits would be limited to a two year time period, effectively achieving the same purpose as the MOU. Producers who sign the MOU are exempt from the provisions of the Act, because the MOU provides for the same degree of certainty with a simpler process.

Nova Scotia's Energy Strategy 9

[133] Source :http://www.gov.ns.ca/energy/AbsPage.aspx?id=1247&siteid=1&lang=1

9.15 Appendix 15 – EIA Report on Natural Gas Processing

Natural Gas Processing: The Crucial Link between Natural Gas Production and Its Transportation to Market

This special report examines the processing plant segment of the natural gas industry, providing a discussion and an analysis of how the gas processing segment has changed following the restructuring of the natural gas industry in the 1990s and the trends that have developed during that time. It focuses upon the natural gas industry and its capability to take wellhead quality production, separate it into its constituent parts, and deliver pipeline-quality natural gas (methane) into the nation's natural gas transportation network. Questions or comments on the contents of this article may be directed to James Tobin at James.Tobin@eia.doe.gov or (202) 586-4835, Phil Shambaugh at Phil.Shambaugh@eia.doe.gov or 202-586-4833, or Erin Mastrangelo at Erin.Mastrangelo@eia.doe.gov or (202)-586-6201.

The natural gas product fed into the mainline gas transportation system in the United States must meet specific quality measures in order for the pipeline grid to operate properly. Consequently, natural gas produced at the wellhead, which in most cases contains contaminants[1] and natural gas liquids,[2] must be processed, i.e., cleaned, before it can be safely delivered to the high-pressure, long-distance pipelines that transport the product to the consuming public. Natural gas that is not within certain specific gravities, pressures, Btu content range, or water content levels will cause operational problems, pipeline deterioration, or can even cause pipeline rupture (see Box, "Pipeline-Quality Natural Gas").[3]

Although the processing/treatment segment of the natural gas industry rarely receives much public attention, its overall importance to the natural gas industry became readily apparent in the aftermath of Hurricanes Katrina and Rita in September 2005. Heavy damage to a number of natural gas processing plants along the U.S. Gulf Coast, as well as to offshore production platforms and gathering lines, caused pipelines that feed into these facilities to suspend natural gas flows while the plants attempted to recover.[4] While several processing plants in southern Mississippi and Alabama were out of commission for only a brief period following Katrina, 16 processing plants in Louisiana and Texas with a total capacity of 9.71 billion cubic feet per day (Bcf/d) and a pre-hurricane flow volume of 5.45 Bcf/d were still offline 1 month following the two storms.[5] Consequently, a significant portion of the usual daily output that flowed into the interstate pipeline network from the tailgates of these plants was disrupted, in some cases indefinitely.

Pipeline-Quality Natural Gas

The natural gas received and transported by the major intrastate and interstate mainline transmission systems must meet the quality standards specified by pipeline companies in the "General Terms and Conditions (GTC)" section of their tariffs. These quality standards vary from pipeline to pipeline and are usually a function of a pipeline system's design, its downstream interconnecting pipelines, and its customer base. In general, these standards specify that the natural gas:

- Be within a specific Btu content range (1,035 Btu per cubic feet, +/- 50 Btu)
- Be delivered at a specified hydrocarbon dew point temperature level (below which any vaporized gas liquid in the mix will tend to condense at pipeline pressure)
- Contain no more than trace amounts of elements such as hydrogen sulfide, carbon dioxide, nitrogen, water vapor, and oxygen
- Be free of particulate solids and liquid water that could be detrimental to the pipeline or its ancillary operating equipment.

Gas processing equipment, whether in the field or at processing/treatment plants, assures that these tariff requirements can be met. While in most cases processing facilities extract contaminants and heavy hydrocarbons from the gas stream, in some cases they instead blend some heavy hydrocarbons into the gas stream in order to bring it within acceptable Btu levels. For instance, in some areas coalbed methane production falls below the pipeline's Btu standard, in which case a blend of higher btu-content natural gas or a propane-air mixture is injected to enrich its heat content (Btu) prior for delivery to the pipeline. In other instances, such as at LNG import facilities where the heat content of the regasified gas may be too high for pipeline receipt, vaporized nitrogen may be injected into the natural gas stream to lower its Btu content.

In recent years, as natural gas pricing has transitioned from a volume basis (per thousand cubic feet) to a heat-content basis (per million Btu), producers have tended, for economic reasons, to increase the Btu content of the gas delivered into the pipeline grid while decreasing the amount of natural gas liquids extracted from the natural gas stream. Consequently, interstate pipeline companies have had to monitor and enforce their hydrocarbon dew point temperature level restrictions more frequently to avoid any potential liquid formation within the pipes that may occur as a result of producers maximizing Btu content.

---

[1] Includes non-hydocarbon gases such as water vapor, carbon dioxide, hydrogen sulfide, nitrogen, oxygen, and helium.

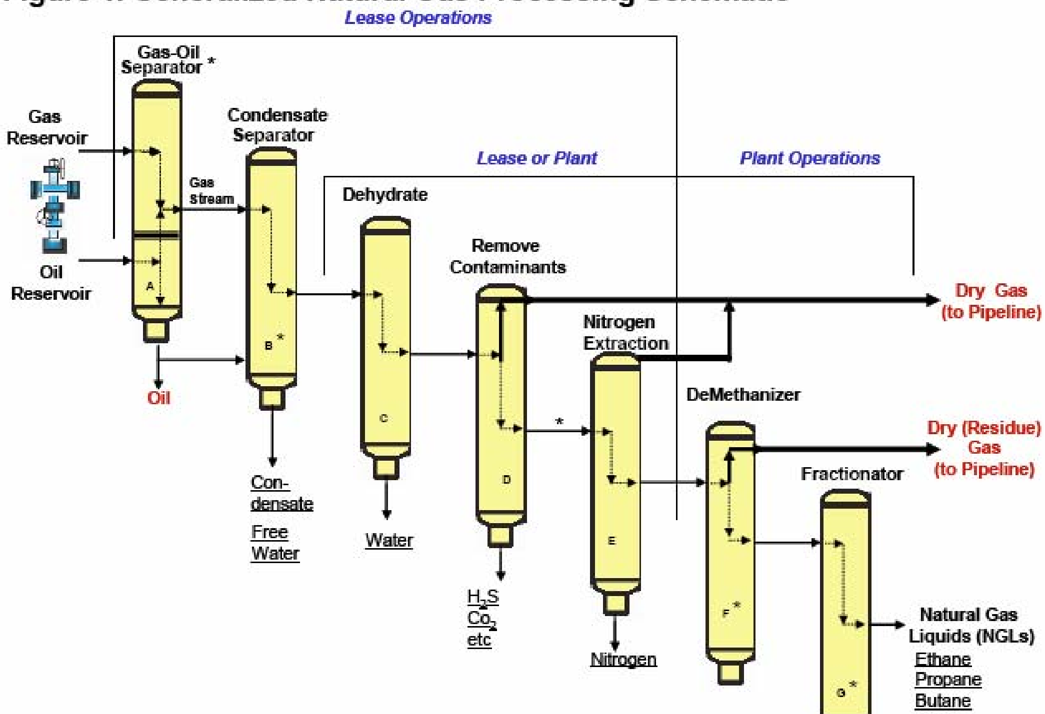
[2] Ethane, propane, and butane are the primary heavy hydrocarbons (liquids) extracted at a natural gas processing plant, but other petroleum gases, such as isobutane, pentanes, and normal gasoline, also may be processed.

[3] For a detailed examination of the subject see Joseph Wardzinski, et al., "Interstate Natural Gas – Quality Specifications & Interchangeability," Center for Energy Economics (CEE), The Institute for Energy, Law, & Enterprise, University of Houston Law Center (Houston, Texas, December 2004). http://www.beg.utexas.edu/energyecon/lng/

[4] Some of these feeder pipelines also had to suspend operations because they themselves suffered damage, the production platforms that they serviced were damaged, or the connecting pipelines were damaged.

[5] Department of Energy, "DOE's Hurricane Response Chronology" provided by Secretary Samuel Bodman at Senate Energy and Natural Resources Committee Hearing, October 27, 2005.

Figure 1. Generalized Natural Gas Processing Schematic



* Optional Step, depending upon the source and type of gas stream.
•Source: Energy Information Administration, Office of Oil and Gas, Natural Gas Division.

In 2004, approximately 24.2 trillion cubic feet (Tcf) of raw natural gas was produced at the wellhead.[6] A small portion of that, 0.1 Tcf, was vented or flared, while a larger portion, 3.7 Tcf, was re-injected into reservoirs (mostly in Alaska) to maintain pressure. The remaining 20.4 Tcf of "wet"[7] natural gas was converted into the 18.9 Tcf of dry natural gas that was put into the pipeline system. This conversion of wet natural gas into dry pipeline-quality natural gas, and the portion of the natural gas industry that performs that conversion, is the subject of this report.

Background

Natural gas processing begins at the wellhead (Figure 1). The composition of the raw natural gas extracted from producing wells depends on the type, depth, and location of the underground deposit and the geology of the area. Oil and natural gas are often found together in the same reservoir. The natural gas produced from oil wells is generally classified as "associated-dissolved," meaning that the natural gas is associated with or dissolved in crude oil. Natural gas production absent any association with crude oil is classified as "non-associated." In 2004, 75 percent of U.S. wellhead production of natural gas was non-associated.

Most natural gas production contains, to varying degrees, small (two to eight carbons) hydrocarbon molecules in addition to methane. Although they exist in a gaseous state at underground pressures, these molecules will become liquid (condense) at normal atmospheric pressure. Collectively, they are called condensates or natural gas liquids (NGLs). The natural gas extracted from coal reservoirs and mines (coalbed methane) is the primary exception, being essentially a mix of mostly methane and carbon dioxide (about 10 percent).[8]

[6]Energy Information Administration, *Natural Gas Annual 2004* (December 2005), Table 1. http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_annual/nga.html

[7]Wet gas is defined as the volume of natural gas remaining after removal of condensate and uneconomic nonhydrocarbon gases at lease/field separation facilities and less any gas used for repressurization.

[8]The Energy Information Administration estimates that about 9 percent of 2004 U.S. dry natural gas production, or about 1.7 Tcf, came from coalbed methane sources, which do not contain any natural gas liquids. *U.S. Crude Oil and Natural Gas, and Natural Gas Liquids Reserves: 2004 Annual Report*, http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/

Natural gas production from the deepwater Gulf of Mexico and conventional natural gas sources of the Rocky Mountain area is generally rich in NGLs and typically must be processed to meet pipeline-quality specifications. Deepwater natural gas production can contain in excess of 4 gallons of NGLs per thousand cubic feet (Mcf) of natural gas compared with 1 to 1.5 gallons of NGLs per Mcf of natural gas produced from the continental shelf areas of the Gulf of Mexico. Natural gas produced along the Texas Gulf Coast typically contains 2 to 3 gallons of NGLs per Mcf.[9]

The processing of wellhead natural gas into pipeline-quality dry natural gas can be quite complex and usually involves several processes to remove: (1) oil; (2) water; (3) elements such as sulfur, helium, and carbon dioxide; and (4) natural gas liquids (see Box, "Stages in the Production of Pipeline-Quality Natural Gas and NGLs"). In addition to those four processes, it is often necessary to install scrubbers and heaters at or near the wellhead. The scrubbers serve primarily to remove sand and other large-particle impurities. The heaters ensure that the temperature of the natural gas does not drop too low and form a hydrate with the water vapor content of the gas stream. These natural gas hydrates are crystalline ice-like solids or semi-solids that can impede the passage of natural gas through valves and pipes.

The wells on a lease or in a field are connected to downstream facilities via a process called gathering, wherein small-diameter pipes connect the wells to initial processing/treating facilities. Beyond the fact that a producing area can occupy many square miles and involve a hundred or more wells, each with its own production characteristics, there may be a need for intermediate compression, heating, and scrubbing facilities, as well as treatment plants to remove carbon dioxide and sulfur compounds, prior to the processing plant (see Box "Other Key Byproducts of Natural Gas Processing"). All of these factors make gathering system design a complex engineering problem.

In those few cases where pipeline-quality natural gas is actually produced at the wellhead or field facility, the natural gas is moved directly to receipt points on the pipeline grid. In other instances, especially in the production of non-associated natural gas, field or lease facilities referred to as "skid-mount plants" are installed nearby to dehydrate and decontaminate raw natural gas into acceptable pipeline-quality gas for direct delivery to the pipeline grid. These compact "skids" are often specifically customized to process the type of natural gas produced in the area and are a relatively inexpensive alternative to transporting the natural gas to distant large-scale plants for processing.

Natural gas pipeline compressor stations,[10] especially those located in production areas, may also serve as field level processing facilities. They often include additional facilities for dewatering natural gas and for removal of many hydrocarbon liquids. Some pipeline compressor stations located along the coast of the Gulf of Mexico, for instance, are set up to process offshore production to a degree permitting delivery of a portion of its natural gas throughput directly into the pipeline grid. The remaining portion is forwarded to a natural gas processing plant for further processing and extraction of heavy liquids.

Non-pipeline-quality production is piped to natural gas processing plants for liquids extraction and eventual delivery of pipeline-quality natural gas at the plant tailgate. A natural gas processing plant typically receives gas from a gathering system and sends out processed gas via an output (tailgate) lateral that is interconnected to one or more major intra- and inter-state pipeline networks. Liquids removed at the processing plant usually will be taken away by pipeline to petrochemical plants, refineries, and other gas liquids customers. Some of the heavier liquids are often temporarily stored in tanks on site and then trucked to customers.

Various types of processing plants have been utilized since the mid-1850s to extract liquids, such as natural gasoline, from produced crude oil. However, for many years, natural gas was not a sought after fuel. Prior to the early 20th century, most of it was flared or simply vented into the atmosphere, primarily because the available pipeline technology permitted only very short-distance transmission.[11]

It was not until the early 1920s, when reliable pipe welding techniques were developed, that a need for natural gas processing arose. Yet, while a rudimentary network of relatively long-distance natural gas pipelines was in place by 1932, and some natural gas processing plants were installed upstream in major production areas,[12] the depression of the 1930s and the duration of World War II slowed the growth of natural gas demand and the need for more processing plants.[13]

After World War II, particularly during the 1950s, the development of plastics and other new products that required natural gas and petroleum as a production component

[9] Enterprise Products Partners LP, Annual SEC 10K filing, 2004, p. 18.

[10] All compressor stations contain some type of separation facilities which are designed to filter out, before compression, any water and/or hydrocarbons that may form in the gas stream during transport.

[11] William L. Leffler, "The Technology and Economic Behavior of the U.S. Propane Industry" (Tulsa , Oklahoma, 1973, The Petroleum Publishing Company), Chapter 1.

[12] Most of these pipelines extended from the Texas Panhandle and Louisiana to the Midwestern United States. Gas processing plants for these systems were located primarily in the Houghton Basin of northern Texas/Oklahoma/Kansas and the Katy area of eastern Texas.

[13] Arlon R. Tusing & Bob Tippee, "The Natural Gas Industry: Evolution, Structure, and Economics" (Tulsa, Oklahoma, 1995, Pennwell Publishing Company).

Stages in the Production of Pipeline-Quality Natural Gas and NGLs

The number of steps and the type of techniques used in the process of creating pipeline-quality natural gas most often depends upon the source and makeup of the wellhead production stream. In some cases, several of the steps shown in Figure 1 may be integrated into one unit or operation, performed in a different order or at alternative locations (lease/plant), or not required at all. Among the several stages (as lettered in Figure 1) of gas processing/treatment are:

A) **Gas-Oil Separators**: In many instances pressure relief at the wellhead will cause a natural separation of gas from oil (using a conventional closed tank, where gravity separates the gas hydrocarbons from the heavier oil). In some cases, however, a multi-stage gas-oil separation process is needed to separate the gas stream from the crude oil. These gas-oil separators are commonly closed cylindrical shells, horizontally mounted with inlets at one end, an outlet at the top for removal of gas, and an outlet at the bottom for removal of oil. Separation is accomplished by alternately heating and cooling (by compression) the flow stream through multiple steps. Some water and condensate, if present, will also be extracted as the process proceeds.

B) **Condensate Separator:** Condensates are most often removed from the gas stream at the wellhead through the use of mechanical separators. In most instances, the gas flow into the separator comes directly from the wellhead, since the gas-oil separation process is not needed. The gas stream enters the processing plant at high pressure (600 pounds per square inch gauge (psig) or greater) through an inlet slug catcher where free water is removed from the gas, after which it is directed to a condensate separator. Extracted condensate is routed to on-site storage tanks.

C) **Dehydration:** A dehydration process is needed to eliminate water which may cause the formation of hydrates. Hydrates form when a gas or liquid containing free water experiences specific temperature/pressure conditions. Dehydration is the removal of this water from the produced natural gas and is accomplished by several methods. Among these is the use of ethylene glycol (glycol injection) systems as an absorption* mechanism to remove water and other solids from the gas stream. Alternatively, adsorption* dehydration may be used, utilizing dry-bed dehydrators towers, which contain desiccants such as silica gel and activated alumina, to perform the extraction.

D) **Contaminant Removal**: Removal of contaminates includes the elimination of hydrogen sulfide, carbon dioxide, water vapor, helium, and oxygen. The most commonly used technique is to first direct the flow though a tower containing an amine solution. Amines absorb sulfur compounds from natural gas and can be reused repeatedly. After desulphurization, the gas flow is directed to the next section, which contains a series of filter tubes. As the velocity of the stream reduces in the unit, primary separation of remaining contaminants occurs due to gravity. Separation of smaller particles occurs as gas flows through the tubes, where they combine into larger particles which flow to the lower section of the unit. Further, as the gas stream continues through the series of tubes, a centrifugal force is generated which further removes any remaining water and small solid particulate matter.

E) **Nitrogen Extraction:** Once the hydrogen sulfide and carbon dioxide are processed to acceptable levels, the stream is routed to a Nitrogen Rejection Unit (NRU), where it is further dehydrated using molecular sieve beds. In the NRU, the gas stream is routed through a series of passes through a column and a brazed aluminum plate fin heat exchanger. Using thermodynamics, the nitrogen is cryogenically separated and vented. Another type of NRU unit separates methane and heavier hydrocarbons from nitrogen using an absorbent* solvent. The absorbed methane and heavier hydrocarbons are flashed off from the solvent by reducing the pressure on the processing stream in multiple gas decompression steps. The liquid from the flash regeneration step is returned to the top of the methane absorber as lean solvent. Helium, if any, can be extracted from the gas stream through membrane diffusion in a Pressure Swing Adsorption (PSA) unit.

F) **Methane Separation**: The process of demethanizing the gas stream can occur as a separate operation in the gas plant or as part of the NRU operation. Cryogenic processing and absorption methods are some of the ways to separate methane from NGLs. The cryogenic method is better at extraction of the lighter liquids, such as ethane, than is the alternative absorption method. Essentially, cryogenic processing consists of lowering the temperature of the gas stream to around -120 degrees Fahrenheit. While there are several ways to perform this function the turbo expander process is most effective, using external refrigerants to chill the gas stream. The quick drop in temperature that the expander is capable of producing condenses the hydrocarbons in the gas stream, but maintains methane in its gaseous form.The absorption* method, on the other hand, uses a "lean" absorbing oil to separate the methane from the NGLs. While the gas stream is passed through an absorption tower, the absorption oil soaks up a large amount of the NGLs. The "enriched" absorption oil, now containing NGLs, exits the tower at the bottom. The enriched oil is fed into distillers where the blend is heated to above the boiling point of the NGLs, while the oil remains fluid. The oil is recycled while the NGLs are cooled and directed to a fractionator tower. Another absorption method that is often used is the refrigerated oil absorption method where the lean oil is chilled rather than heated, a feature that enhances recovery rates somewhat.

G) **Fractionation**: Fractionation, the process of separating the various NGLs present in the remaining gas stream, uses the varying boiling points of the individual hydrocarbons in the stream, by now virtually all NGLs, to achieve the task. The process occurs in stages as the gas stream rises through several towers where heating units raise the temperature of the stream, causing the various liquids to separate and exit into specific holding tanks.

* Adsorption is the binding of molecules or particles to the surface of a material, while absorption is the filling of the pores in a solid. The binding to the surface is usually weak with adsorption, and therefore, usually easily reversible.

Sources: Compiled from information available at the following Internet web sites: American Gas Association (http://www.naturalgas.org/naturalgas/naturalgas.asp), Environmental Protection Agency (http://www.epa.gov/ttn/chief/ap42/ch05/final/c05s03.pdf), Cooper Cameron Inc. (http://www.coopercameron.com/cgi-bin/petreco/products/products.cfm?pageid=gastreatment), AdvancedExtractionTechnologies, Inc. (http://www.aet.com/gtip1.htm#refriglean), SPM-3000 Gas Oil Separation Processing (GOSP) (http://www.simtronics.com/ catalog/spm/spm3000.htm), and Membrane Technology and Research, Inc. (http://www.mtrinc.com/Pages/NaturalGas/ng.html#).

Other Key Byproducts of Natural Gas Processing

While natural gas liquids, such as propane and butane, are the byproducts most often related to the natural gas recovery process, several other products are also extracted from natural gas at field or gas treatment facilities.

Helium (He)

The world's supply of helium comes exclusively from natural gas production. The single largest source of helium is the United States, which produces about 80 percent of the annual world production of 3.0 billion cubic feet (Bcf). In 2003, U.S. production of helium was 2.4 Bcf, about two-thirds of which came from the Hugoton Basin in north Texas, Oklahoma, and Kansas (Figure 2). The rest mostly comes from the LaBarge field located in the Green River Basin in western Wyoming, with small amounts also produced in Utah and Colorado. According to the National Research Council, the consumption of helium in the United States doubled between 1985 and 1996, although its use has leveled off in recent years. It is used in such applications as magnetic resonance imaging, semiconductor processing, and in the pressurizing and purging of rocket engines by the National Aeronautics and Space Administration.

Twenty-two natural gas treatment plants in the United States currently produce helium as a major byproduct of natural gas processing. Twenty of these plants, located in the Hugoton-Panhandle Basin, produce marketable helium which is sold in the open market when profitable, while transporting the remaining unrefined helium to the Federal Helium Reserve (FHR). The FHR was created in the 1950s in the Bush salt dome, underlying the Cliffside field, located near Amarillo, Texas. Sales of unrefined helium in the United States for the most part, come from the FHR.

Carbon Dioxide (CO_2)

While most carbon dioxide is produced as a byproduct of processes other than natural gas treatment, a significant amount is also produced during natural gas processing in the Permian Basin of western Texas and eastern New Mexico. A limited amount is also produced in western Wyoming. In 2004 about 6.2 Bcf of carbon dioxide was produced in seven plants in the United States.

The carbon dioxide produced at these natural gas treatment plants is used primarily for re-injection in support of tertiary enhanced oil recovery efforts in the local production area. The smaller, uneconomic, amounts of carbon dioxide that are normally removed during the natural gas processing and treatment in the United States are vented to the atmosphere.

Hydrogen Sulfide (H_2S)

Almost all the elemental sulfur today is sulfur recovered from the desulfurization of oil products and natural gas. Hydrogen sulfide is extracted from a natural gas stream, or condensate, that is referred to as "sour." It is passed through a chemical solution that removes hydrogen sulfide and carbon dioxide, which are then fed to plants where the hydrogen sulfide is converted to elemental sulfur. The small quantities of non-sulfur components are incinerated and vented into the atmosphere. "Sour" condensate from plant inlet separators is fed to a condensate stabilizer where hydrogen sulfide and lighter hydrocarbons are removed, compressed, and then cycled to sulfur plants.

coincided with improvements in pipeline welding and pipeline manufacturing techniques. The increased demand for natural gas as an industrial feedstock and industrial fuel supported the growth of major natural gas transportation systems, which in turn improved the marketability and availability of natural gas for residential and commercial use.

Consequently, as the natural gas pipeline network itself became more efficient and regulated, the need for more and better natural gas processing increased both the number and operational efficiencies of natural gas processing plants.

National Overview

More than 500 natural gas processing plants currently operate in the United States (Table 1). Most are located in proximity to the major gas/oil producing areas of the Southwest and the Rocky Mountain States (Figure 2).[14] Not surprisingly, more than half of the current natural gas processing plant capacity in the United States is located convenient to the Federal offshore, Texas, and Louisiana. Four of the largest capacity natural gas processing/treatment plants are found in Louisiana while the greatest number of individual natural gas plants are located in Texas.

Although Texas and Louisiana still account for the larger portion of U.S. natural gas plant processing capability, other States have moved up in the rankings somewhat during the past 10 years as new trends in natural gas production and processing have come into play. For instance:

[14] The largest gas producing areas and States in 2004 were Texas onshore, the Federal offshore (waters off Texas, Louisiana, Alabama, and Mississippi), Oklahoma, New Mexico, Wyoming, Louisiana onshore, Colorado, and Kansas.

Table 1. Natural Gas Processing Plant Capacity in the Lower 48 States, 1995 and 2004

	Natural Gas Processing Capacity (Million cubic feet per day)				Number of Natural Gas Processing/Treatment Plants				Percentage Change 1995 to 2004	
State	In 2004	Percent of Total U.S.	In 1995	Percent of Total U.S.	In 2004	Percent of Total U.S.	In 1995	Percent of Total U.S.	In Capacity	In Number
Louisiana	16,512	27.3	15,569	28.0	61	11.5	87	12.0	6.1	-29.9
Texas	15,825	26.1	18,259	32.9	166	31.3	278	38.2	-13.3	-40.3
Wyoming	6,920	11.4	4,730	8.5	45	8.5	53	7.3	46.3	-15.1
Kansas	3,533	5.8	3,424	6.2	10	1.9	11	1.5	3.2	-9.1
New Mexico	3,427	5.7	3,697	6.7	25	4.7	34	4.7	-7.3	-26.5
Oklahoma	3,438	5.7	4,220	7.6	59	11.1	100	13.8	-18.5	-41.0
Illinois	2,202	3.6	2	--	2	0.4	1	0.1	--	100.0
Colorado	2,093	3.5	1,490	2.7	43	8.1	40	5.5	40.5	7.5
Mississippi	1,572	2.6	40	0.1	6	1.1	5	0.7	--	20.0
Alabama	1,310	2.2	468	0.8	15	2.8	12	1.7	179.9	25.0
California	1,037	1.7	925	1.7	24	4.5	31	4.3	12.1	-22.6
Utah	970	1.6	779	1.4	16	3.0	13	1.8	24.5	23.1
Michigan	483	0.8	524	0.9	16	3.0	19	2.6	-7.8	-15.8
West Virginia	460	0.8	421	0.8	8	1.5	7	1.0	9.3	14.3
North Dakota	222	0.4	241	0.4	8	1.5	9	1.2	-7.9	-11.1
Kentucky	154	0.3	178	0.3	3	0.6	5	0.7	-13.5	-40.0
Montana	133	0.2	115	0.2	3	0.6	8	1.1	15.7	-62.5
Florida	90	0.1	361	0.6	1	0.2	2	0.3	-75.1	-50.0
Arkansas	67	--	70	0.1	7	1.3	6	0.8	-4.3	16.7
Pennsylvania	62	0.1	20	--	9	1.7	2	0.3	210.0	350.0
Ohio	23	--	23	--	3	0.6	3	0.4	--	0.0
Nebraska	0	--	10	--	0	0.0	1	0.1	NA	NA
Total Lower 48 States	60,533	100.0	55,566	100.0	530	100.0	727	100.0	8.9	-27.1

Note: -- = less than .05 or greater than 999.99 percent. Although more than 8 billion cubic feet per day of gas processing capacity exists in the State of Alaska, almost all of the natural gas that is extracted does not enter any transmission system. Rather, it is re-injected into reservoirs.

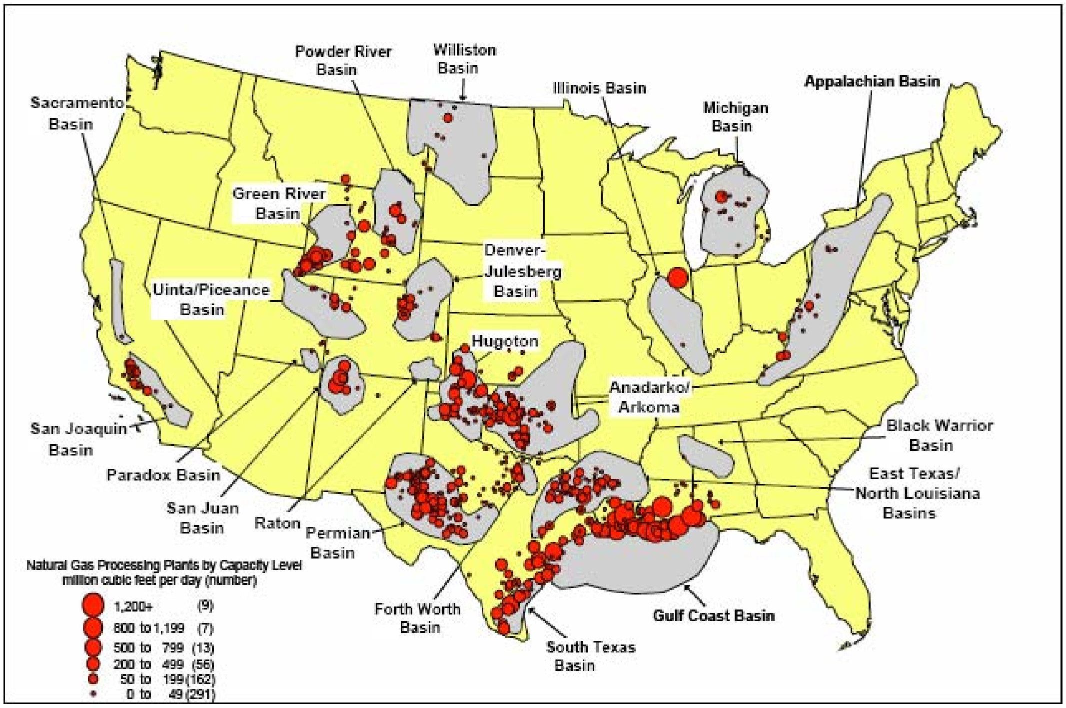
Source: Energy Information Administration, Gas Transportation Information System, Natural Gas Processing Plant Database (Compiled from data available from the Form EIA-64A, Form EIA-816, PentaSul Inc's *LPG Almanac*, and Internet sources.)

- **The Aux Sable natural gas plant, one of the largest natural gas processing plants in the Lower 48 States with an initial design capacity of 2.2 Bcf/d, was built in 2000 in Illinois, a State that has little or no natural gas production of its own.** Located at the receiving end of the Alliance Pipeline, which was built specifically to transport "wet" natural gas from British Columbia and Alberta, Canada, to Aux Sable, the plant currently processes about 1.5 Bcf daily, separating methane from natural gas liquids. The plant's northern Illinois location was selected to take economic advantage of extracting natural gas liquids in the Chicago (hub) area with its easy access to several hydrocarbon products pipelines, while delivering "dry" natural gas to the interstate pipeline system via the Chicago Hub. Four interstate, and two intrastate, pipelines receive natural gas at the Aux Sable plant tailgate.

- **Since 1995, average daily natural gas plant processing capacity in the United States increased by 49 percent as new and larger capacity plants were installed and a number of existing ones were expanded.** Over the past 10 years, average plant capacity increased from 76 million cubic feet per day (MMcf/d) to 114 MMcf/d and decreased in only 4 of the 22 States with natural gas processing plant capacity (Table 1). In Texas, although the number of plants and overall processing capacity decreased, the average capacity per plant increased from 66 MMcf/d to 95 MMcf/d as newer plants were added and old, less efficient plants were idled. In Alabama, Mississippi, and the eastern portion of South Louisiana, new larger plants and plant expansions built to serve new offshore production increased the average plant capacity significantly in those areas.

- **Expanding natural gas production in Wyoming in recent years led to the installation of seven new gas processing plants and the expansion of several more.** Since 1995, Wyoming's natural gas plant processing capacity increased by almost 46 percent, adding more than 2.2 Bcf/d (Table 1). Much of the activity has been focused in the southwestern area of Wyoming's Green River Basin where one of the nation's largest gas plants, the Williams Company's 1.1 Bcf/d Opal facility, is located. Increased natural gas development behind the plant and a significant expansion of pipeline capacity at

Figure 2. Concentrations of Natural Gas Processing Plants, 2004



Note: Eight Alaska plants not displayed, but count is reflected in the legend.
Source: Energy Information Administration, Gas Transportation Information System, Natural Gas Processing Plant Database.

the plant tailgate (Kern River Transmission and Northwest Pipeline systems) necessitated two significant plant expansions at Opal since 2000, the last being a 350-MMcf/d increase in early 2004.

- **Successful exploration and development in the Piceance Basin in western Colorado and increased natural gas production in the San Juan Basin in southern Colorado have contributed to the installation of 13 new or replacement plants in the State and the expansion of several existing facilities.** In part, these increases have supported the installation of new pipeline systems in the region such as the TransColorado Gas Transmission system built in 1999, which can transport up to 650 MMcf/d of Piceance and San Juan basin production to interstate pipeline connections with western markets.

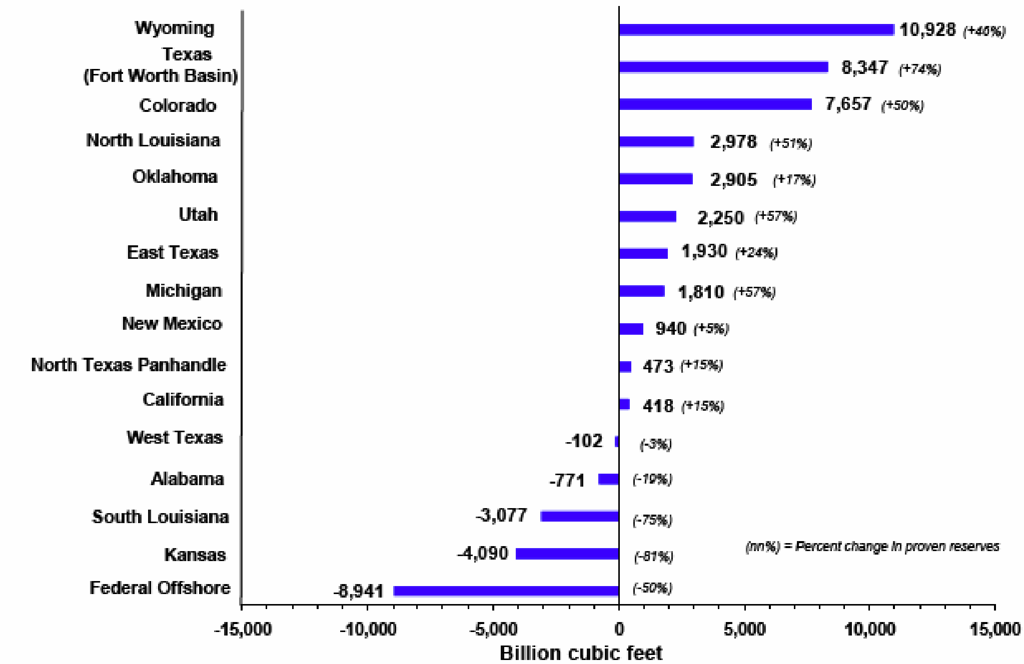
Over the next several years, additional new natural gas processing plants and capacity can be expected to be installed in Wyoming and Colorado as exploration and development efforts in those States continue, especially if the prices of natural gas and natural gas liquids remain high. Increased exploration and development has increased the level of proved natural gas reserves in these two States by more than 45 percent, or 18.6 trillion cubic feet, since 1995 (Figure 3).

Moreover, it can be expected that new plant capacity will be needed in other areas currently undergoing increased exploration and development, such as the Fort Worth Basin in northeast Texas (gas shale), the Texas panhandle, and the east Texas area. Since 1995, growth in the level of proved natural gas reserves in these areas has been significant.

Shift in Installation Patterns

While a number of market factors can influence the location and level of gas processing capacity in the United States, shifts in exploration and development activity and subsequent changes in natural gas production levels have had the greatest impact during the past 10 years. The level of overall natural gas plant processing capacity in an area follows the development of new oil and gas fields (rise in supply) and the decline of older fields (fall in supply).

Figure 3. Major Changes in Proved Natural Gas Reserves, 1995 to 2004
(Wet after lease separation)



Source: Energy Information Administration, *U.S. Crude Oil and Natural Gas, and Natural Gas Liquids Reserves, 1995 and 2004 Annual Reports*: Table 9.

As natural gas production (Table 2) and annual added proved reserves (Figure 3) decreased significantly in southern Louisiana and the Gulf of Mexico (GOM) between 1995 and 2004,[15] several natural gas processing plants in the region were idled, especially in the western portion of the region where older production fields are predominate. However, in the deepwater and eastern portion of the Gulf several substantial new natural gas deposits were developed and began producing during the period. Subsequently, new natural gas production facilities and new gathering pipelines were built to deliver this natural gas onshore. To accommodate these new natural gas flows, eight natural gas plants located in southern Louisiana were expanded. These expansions helped increase Louisiana's overall natural gas plant capability by 6 percent between 1995 and 2004, despite declining overall natural gas production both onshore and off.

Increased deepwater natural gas development also affected the number and capacity of natural gas processing facilities in Alabama and Mississippi. In Alabama, two of the seven new processing plants installed after 1995 were principally dedicated to processing offshore production delivered via the Dauphin Island Gathering System and Transco's Mobile Bay lateral. Both were large 600-MMcf/d facilities located along Mobile Bay.[16] In Mississippi, a new 500-MMcf/d plant was developed in the mid-1990s at Pascagoula, primarily to serve onshore production. The plant's capacity was doubled in 2000 in order to accept natural gas from the offshore via the new Destin Pipeline. Growth in natural gas processing demand owing to new offshore production brought Mississippi and Alabama, from a ranking (by overall capacity) of 18th and 11th, respectively, in 1995, to 9th and 10th in 2004.

The Rocky Mountain States have seen expanding development of coalbed methane resources as well as steadily increasing exploration/development efforts and

[15] In 1995, proved gas reserve additions from new fields and new reservoir discoveries in old fields in southern Louisiana and the Gulf of Mexico amounted to 3,174 Bcf (wet basis) with gas production at 5,827 Bcf, while the corresponding figures in 2004 were 991 Bcf and 4,866 Bcf, respectively. Energy Information Administration, *U.S. Crude Oil, Natural Gas and Natural Gas Liquids Reserves*, 1995 and 2004 Annual Reports, Table 9.

[16] In 2004, a co-owner of one of the facilities removed one processing train (300 MMcf/d) from the plant and moved it to Louisiana.

Table 2. Major Lower 48 Natural Gas Producing States and Federal Offshore
(Volumes in Trillion Cubic Feet)

State	Wet Gas Production		Percentage Change	Processed Volume		Percent Processed	
	1995	2004	1995-2004	1995	2004	1995	2004
Texas	5.11	5.66	10.8	0.39	0.35	7.6	6.2
Federal Offshore	4.67	4.01	-14.0	0.04	0.09	0.9	2.3
Oklahoma	1.66	1.66	-0.2	0.10	0.10	6.0	5.8
New Mexico	1.48	1.62	9.7	0.08	0.09	5.4	5.7
Wyoming	0.84	1.59	89.4	0.03	0.07	3.6	4.5
Louisiana	1.50	1.36	-9.5	0.10	0.04	6.7	2.8
Colorado	0.54	1.09	101.1	0.03	0.04	5.6	3.3
Kansas	0.71	0.40	-43.1	0.08	0.02	11.3	5.9
Total	17.51	17.39	-0.7	0.85	0.80	4.9	4.6

Source: Energy Information Administration, *U.S. Crude Oil and Natural Gas, and Natural Gas Liquids Reserves: 1995 and 2004 Annual Reports.*

growing production from tight-sands and conventional natural gas sources. As a result, significant increases in natural gas plant processing capacity in Wyoming, Colorado, and Utah have occurred. While Montana has much less overall natural gas processing capacity than the other Rocky Mountain States, it too experienced an increase in processing capacity (Table 1) as natural gas production in the State rose by 16 percent and proved reserves grew by 27 percent during the past decade.

As mentioned earlier, the number of plants and the level of natural gas processing capacity in Texas decreased by 40 and 13 percent, respectively, between 1995 and 2004. While natural gas production within Texas increased overall during that time period, several areas such as the Permian Basin in the western part of the State experienced decreases. A number of natural gas plants in that area were idled while new processing plants were built in developing areas such as the Fort Worth Basin area in northeast Texas.

In most of the country, the increases and decreases in installed natural gas processing capacity have closely tracked the changes in proved natural gas reserves since 1995. Moreover, where significant new proved reserves have been added, the expectation is that eventually new natural gas production will follow, and new natural gas processing plants will need to be installed accordingly (Figure 3).

Impact of Restructuring

As the FERC-mandated restructuring of the natural gas industry[17] took effect during the 1990s, changes also occurred in the economics of natural gas processing plant ownership. Before restructuring, many natural gas processing plants were owned and operated by natural gas and oil producers as part of their overall energy production and marketing business. With restructuring, many of these producers sold their natural gas processing facilities in order to focus on exploration and development activities.

Before restructuring, more than 310 individual companies owned and/or operated natural gas processing plants. By 1995 there were 270 companies, and by 2004 the number had dropped to 209. Yet, the amount of new processing capacity rose by 8.9 percent during the same 9-year period (Table 1). As competition increased and the economics of production and processing changed under restructuring, consolidation of plant ownership significantly increased. In 2004, for instance, the top 10 natural gas plant owner/operators had access to or owned about 74 percent (44.5 Bcf/d) of the total natural gas plant capacity in the United States. This compares with about half that much in 1995, although the percentage of plants owned/operated remained at about 36 percent.

Between 1995 and 2004, the type of companies owning/operating processing plants shifted from primarily oil/gas producers to what are now referred to as "midstream" companies or operating divisions. These entities focus their efforts on the natural gas gathering, natural gas processing, and natural gas storage operations segments of the industry. In 1995 production companies such as Shell Western E&P, Texaco Production, Exxon Co USA, and Warren Petroleum controlled the largest share of natural gas plant processing capacity. In 2004, however, midstream operating companies such as Duke Energy Field Services (54 plants, 7.5 Bcf/d capacity), Enterprise Products Operating LP (26, 6.3 Bcf/d), Targa Resources[18] (21, 3.4 Bcf/d), and BP PLC (13, 5.6 Bcf/d), predominate.[19]

Natural Gas Processing Cost Recovery

The primary role of a natural gas processing plant in today's marketplace is to produce pipeline-quality natural gas. The production of natural gas liquids and other products from the natural gas stream is secondary. The quantity and quality of the byproducts actually produced during a particular time period is, in many instances, a function of their current market prices. If the market value of a byproduct falls below the current production cost, a natural gas plant owner/operator may suspend its production temporarily. In some instances, a plant operator may increase the Btu content of its plant residue (plant tailgate) gas stream, as long as it remains within pipeline tolerances, in order to absorb some of the byproducts. In other cases the raw liquid stream (minus methane) is stored on-site temporarily or sold off.

[17] FERC Order 636, issued in 1993, primarily dealt with revising how interstate pipeline companies did business. Order 636 required interstate pipeline companies to change from buying and selling the natural gas they transported to selling the transportation service only.

[18] In late 2005, Targa Resources, Inc., acquired the gas processing plant interests of Dynegy Midstream Services LP in Louisiana, Texas, and New Mexico. In combination with its existing gas plant assets, the acquisition moved Targa Resources significantly higher in the rankings of midstream companies.

[19] In those cases where a gas plant is not fully owned by the party, a percentage of the total capacity of the plant equal to the ownership percentage was included in the Bcf/d capacity item.

As noted earlier, before restructuring of the natural gas industry in the 1990s, most natural gas processing was performed by an affiliate of the production company. The processor was reimbursed through what is commonly referred to as a keepwhole contract.[20] Under such a contract the NGLs recovered at the facility are retained by the processor as payment, while the other party's delivery is "kept whole" by returning an amount of residue (plant tailgate) natural gas (equal on a Btu basis to the natural gas received at the plant inlet) at the tailgate of the plant.

In today's more competitive restructured marketplace, where supply/demand fluctuations are more commonplace, natural gas prices are more variable, and price levels are relatively high compared with other forms of energy, including NGLs, "keepwhole" arrangements tend to create income uncertainty for processors. Such arrangements are profitable when the value of the NGLs is greater as a separated liquid than as a portion of the residue natural gas stream; they are less profitable when the value of the NGLs is lower as a liquid than as a portion of the residue natural gas stream.

As a result, participants in the natural gas processing industry have been replacing keepwhole contracts with alternative arrangements as the contracts come up for renewal. Several unique types of natural gas processing arrangements are being offered in their place. Among them are: percent-of-liquids contracts, percent-of-index contracts, margin-band contracts, fee-based contracts, and hybrid contracts. In broad terms, they function as follows:

- ***Percent-of-liquids or percent-of-proceeds.*** With this type of contract the processor takes ownership of a percentage of the NGL mix extracted from a producer's natural gas stream. The producer either retains title to, or receives the value associated with, the remaining percentage of the NGL mix. The producer reimburses the processor for the costs involved in the liquids extraction operation.
- ***Percent-of-index contracts.*** Under this type of contract the processor generally purchases its natural gas at either a percentage discount to a specified index price, a specified index price less a fixed amount, or a percentage discount to a specified index price less an additional fixed amount. The processor then resells the natural gas at the index price or at a different percentage discount to the index price.
- ***Margin-band contracts.*** Under this type of arrangement the processor takes ownership of NGLs extracted from the natural gas stream delivered by the producer, while the producer is paid a return based on the energy value of the NGL mix that was extracted from the natural gas stream less the fuel consumed in the extraction process. Both parties accept specified floor and ceiling return levels which are intended to provide an acceptable return to each party when natural gas processing economics tend to become negative or the economic gains become excessive.
- ***Fee-based contracts.*** In these contracts a set fee is negotiated based on the anticipated volume of natural gas to be processed. The producer either retains title to, or receives the value associated with, any NGLs extracted and is responsible for all energy costs of processing.
- ***Hybrid contracts.*** Such arrangements usually provide processing services to a producer under a monthly percent-of-liquids arrangement initially, with the producer having the option of switching to either a fee-based arrangement or in certain cases to a keepwhole basis. The intent is to give both producer and processor the incentive to maintain operations during periods of natural gas price swings, especially during those periods when the price of natural gas is high relative to the economic value of NGLs.

Contracts for natural gas processing have terms ranging from month-to-month to the life of the producing lease. Intermediate terms of 1 to 10 years are also common.

Outlook and Potential

Since 1995, natural gas plant processing capacity has increased by almost 9 percent (Table 1), with most of this growth following new production field development. Based upon trends that have developed over the past several years, especially in the finding of newly proved reserves (Figure 3), or lack thereof, two areas of the country in particular could experience sizable shifts in natural gas processing plant resources, with increases expected in the Rocky Mountain area and decreases expected along the Gulf Coast.

Continuing a trend begun in the late 1990s, ongoing expansion of natural gas exploration and development in Colorado, Utah, and Wyoming could add to natural gas plant processing requirements over the next several years.[21] Each of these States experienced a 25 percent or greater increase in installed natural gas processing plant capacity over the past decade. It is generally anticipated that the Unita Basin of eastern Utah and the Piceance Basin of western Colorado will become more actively developed over the next decade, with several new large-scale capacity natural gas pipelines scheduled to be installed to transport the produced natural gas

[20] Much of the background material used in this section is based on information and discussions of gas processing contracts found in the 2004 SEC 10K filings of Enterprise Products Partners LP and MarkWest Energy Partners LP.

[21] On November 30, 2005, EnCana Ltd announced that it has begun construction of a new 650 MMcf/d natural gas processing plant in northwestern Colorado to accommodate increasing natural gas production in the Piceance Basin. The plant is scheduled to be in service in early 2007. Platts Inc., *Gas Daily*, December 1, 2005, p. 4.

to western and midwestern markets.[22] These new pipelines will also need new processing plants to be installed to treat this natural gas prior to receipt.

New natural gas processing capacity will perhaps be needed in Texas as well. Despite a net decrease in natural gas plant capacity in the State of about 13 percent between 1995 and 2004 (Table 1), several new plants were added and others are planned as a result of increased development in the Barnett Shale Formation of the Fort Worth Basin in northeast Texas. The gas shales located in this area, which encompasses several counties north and west of Dallas, Texas, were once considered uneconomical to develop, but the advent of new technologies has greatly improved its potential and, thus, its attraction to natural gas producers.

In southern Louisiana and the Gulf of Mexico, on the other hand, decreasing natural gas production and a significant drop in the volume of new proved natural gas reserves found in the region during the past decade likely will slow growth of natural gas processing capacity along the Gulf Coast over the next several years. However, since the Gulf of Mexico and southern Louisiana will remain the largest natural gas producing area in the country for years to come, most existing natural gas processing plants in the region should remain active, although perhaps processing at lower daily flow rates.

The potential remains, nevertheless, for the discovery of some major natural gas finds in the deepwater regions of the Gulf, which could lead to expansion of some existing plants or even installation of an occasional new one. However, in the short term, this seems unlikely. No new offshore-to-onshore pipelines are scheduled for development through 2008, except for those related to LNG imports through the Gulf States.[23] The lack of proposals for pipeline development would tend to indicate that existing plant capacity serving the Gulf of Mexico is adequate for the foreseeable future.

Although gross natural gas production in the United States has remained relatively level since 2000,[24] rising natural gas wellhead prices can be expected to lead to increases in natural gas exploration and development efforts. Some increases in production could occur in the older production fields, but much of the additional natural gas production will probably come from newly developed reserves found in the areas mentioned above. Consequently, as new sources of production are developed, new processing facilities, or greater use of now-underutilized plant capacity, will follow suit, while some older facilities, particularly those taking gas from depleting areas, will be closed or relocated.

[22] Energy Information Administration, Gas Transportation Information System, Natural Gas Pipeline Projects Database, as of December 2005.

[23] Imported LNG supplies often have higher Btu content than domestic natural gas supplies and may need to be processed to meet U.S pipeline quality specifications. The introduction of additional LNG volumes into the Gulf area may increase processing plant utilization beyond what is required for domestic natural gas production. However, this need is uncertain and depends on the construction of new facilities and the quality of the future LNG imports.

[24] See Energy Information Administration, *Natural Gas Annual 2004*, (Washington, D.C. December 2005), Table 1. http://www.eia.doe.gov/oil_gas/natural_gas/data_publications/natural_gas_annual/nga.html

This page intentionally left blank.

9.16 Appendix 16 – White Paper on Liquid Hydrocarbon Drop Out

White Paper on Liquid Hydrocarbon Drop Out in Natural Gas Infrastructure

NGC+ Liquid Hydrocarbon Drop Out Task Group
February 28, 2005

Gas Quality White Paper
Control of Hydrocarbon Liquid Drop Out

Section 1 - Introduction

1.0 Objective

1.1 The objective of this report is to provide background on the issue of **gas quality, specifically hydrocarbon liquid drop out,** and recommend how it can be managed in a way that balances the concerns of all stakeholders in the value chain[1]. These concerns are summarized below:

1.1.1 **Producers** want the ability to supply natural gas to meet increasing demand. They seek to maximize their natural gas revenue stream by electing the level to process their gas based on market conditions while satisfying pipeline tariff, safety and environmental requirements.

1.1.2 **Gas Processors** want to know the long term specification requirements for the quality of gas to be delivered into transmission pipelines in order to set operating conditions, evaluate potential investments in reconfiguring their plants to optimize the production of thermal content and meet the pipeline quality specifications and, in many instances, renegotiate the contracts that they have with the gas producers.

1.1.3 **Pipelines** want to provide transportation flexibility to meet demand but are concerned about operational safety and reliability, system integrity and environmental issues. They are also concerned about whether components of gas they accept for delivery may make the gas in their pipeline unacceptable to distribution systems and end users.

1.1.4 **Local distribution companies** want to meet customer demand but are concerned about operational safety and reliability, system integrity, and environmental issues as well as the impacts on end use equipment. They have little or no existing capacity to remove or extract hydrocarbons from their systems.

1.1.5 **Direct connect customers (e.g., power plants and industrial users directly connected to transmission pipeline)** want uniformity of gas quality because of safety and environmental concerns, and potential negative impacts on equipment, end products, and operational reliability. They have little or no existing capacity to remove or extract hydrocarbons from their systems.

1.1.6 **End Users (e.g., customers receiving gas from the LDC)** expect uniformity of gas quality for appliances, industrial applications, including use as a feedstock or building block in chemical manufacturing.

[1] There is a separate effort directed at higher heating values, including the role of liquefied natural gas. This effort is referred to as "interchangeability" and is being managed by the Natural Gas Council Interchangeability Task Group.

Gas Quality White Paper
Control of Hydrocarbon Liquid Drop Out

1.2 Overview of the Report

This report will examine the occurrence of hydrocarbon liquids in natural gas, the role of gas processing, and historical measures used to control hydrocarbon liquid drop out. There are seven sections, including this Introduction. They are:

1.2.1 Section 2 - Liquid Hydrocarbons in Natural Gas

This section describes the sources of natural gas and shows that all gas as produced is not the same. It describes the role of treatment and processing to provide a more uniform, fungible commodity. It also describes the challenges to controlling hydrocarbon liquid drop out when faced with the influences of pressure reductions and ambient temperature.

1.2.2 Section 3 – Hydrocarbon Liquid Drop Out Control Measures

This section describes measures used historically to control hydrocarbon liquid drop out, including heating value (Btu/volume), and composite concentrations of heavier weight hydrocarbons (such as the mole fraction of heavier weight hydrocarbons measured as the "pentane plus" fraction, referred to as C5+ or the "hexane plus", referred to as C6+)[2]. This section also provides a description of blending, a tool to provide shippers and pipeline operators some flexibility in controlling hydrocarbon liquid drop out.

1.2.3 Section 4 - Overview of Hydrocarbon Dew Point (HDP)

This section defines hydrocarbon dew point and describes how it can be used as a means to understand the behavior of hydrocarbons in a natural gas stream. The section provides a basic description of the thermodynamic principles governing the behavior of compounds found within natural gas. It describes the behavior of hydrocarbons as gas is processed, and as pressure and temperature change downstream in the value chain.

1.2.4 Section 5 - Historical Levels of Hydrocarbons and Hydrocarbon Dew Point

This section provides a summary of historical data on natural gas streams from a variety of sources, including detailed analyses of hydrocarbon constituents in gas as produced and processed. The section also provides historical levels of hydrocarbon dew points.

1.2.5 Section 6 - Determination of Hydrocarbon Dew Point – Measurement and Estimation

This section provides an overview of the direct determination of hydrocarbon dew point. A chilled mirror is used to measure hydrocarbon dew point directly. Alternatively, a combination of sampling, analysis and calculation using a simplified equation of state from chemical thermodynamics is used to estimate the hydrocarbon dew point. The section provides an overview of the value of each in predicting hydrocarbon liquid drop out.

1.2.6 Section 7 – Recommendations

This section provides a set of recommendations developed by the Natural Gas Council HDP Task Group to manage hydrocarbon liquid drop out.

---

[2] The abbreviation C6 for example refers to hexanes. The addition of "+" is a term of art used in analytical chemistry that refers to a grouping of compounds (or fraction). For example, C6+ represents C6, as well as C7, C8 and higher molecular weight hydrocarbons. C9+ refers to C9 plus C10, C11 and so forth.

1.2.7 Appendices

A. Parameters to be Considered in Establishing a Cricondentherm Hydrocarbon Dew Point and C6+ Gallons Per Million (GPM) Cubic Feet Based Limits
B. Process for Establishing a Cricondentherm Hydrocarbon Dew Point (CHDP) Limit

1.3 Background and Summary of the Issues

1.3.1 Historically, the commercial value of the liquefiable hydrocarbons extracted from North American natural gas, referred to as natural gas liquids (NGLs), has been greater than the commercial value of the thermal content that would be added if the NGLs remained part of gas stream. The infrastructure to extract these NGLs, referred to as the processing industry, has been built up over time. Some facilities were built to remove NGLs for operational concerns, but the economic uplift derived from extracting NGLs has resulted in an entire industry dedicated to production and sales of NGL products.

1.3.2 At times, the value of natural gas has increased dramatically as compared to the value of the NGLs. Rising natural gas prices relative to NGL prices decrease the economic incentive to extract NGLs. In this environment suppliers and processors may elect to reduce extraction levels or bypass processing.

1.3.3. This economic environment creates two issues for transmission, distribution and utilization of domestic natural gas. First the decreased level of processing causes the presence of larger amounts of liquefiable hydrocarbons in the gas stream resulting in a greater potential for hydrocarbon liquids to drop out of the gas phase while in transit to end use equipment. This increases the potential for problems in pipeline and LDC operations with compression, measurement, pressure regulation, over-pressure protection devices and potential interference with odorization. Second, problems can also occur in end-use applications such as flame extinguishing or over-firing in home appliances or physical damage to gas turbines used to generate electricity.

1.3.4. In addition, those LDC's that operate LNG peak shaving liquefaction plants are concerned about the impact of increasing hydrocarbon dew point has on the overall thermodynamic process. Feedstock received with an excessive hydrocarbon dew point can result in adverse plant operations including heat exchanger fouling and excess liquids collection at points in the process beyond what the plant is designed to handle. This subject is also directly linked to the Interchangeability issue and will be discussed in detail in the Interchangeability White Paper.

1.4 Natural Gas – From Wellhead to Burner Tip

1.4.1 This report begins with a brief description of how natural gas makes its way from the wellhead to the burner tip. Natural gas is produced from one of three sources: associated gas, recovered in conjunction with oil production, non-associated gas (gas from a field not producing oil), and as a gaseous stream from coal seams (normally referred to as coal bed methane). All natural gas is not of the same quality when produced. Each of the sources exhibits distinct characteristics and even gas produced from a particular source may vary with the most abundant component being methane. Produced gas will also contain varying quantities of non-methane hydrocarbons and other constituents that contribute little or no heating value. Depending upon the concentrations present, the gas may require treatment to reduce constituents such as water, carbon dioxide, nitrogen, oxygen, total sulfur and hydrogen sulfide. Natural gas that is rich in non-methane hydrocarbon constituents may also be further processed to extract natural gas liquids.

1.4.2 The next step in the path to the burner tip is the custody transfer to a Shipper who contracts for the transportation of the gas through open access pipelines (Transporters) that transport gas to a delivery point at which it is delivered to a distribution company or directly to an end user. Tariffs filed with FERC define the contract and commercial conditions for transporting gas from a specified receipt point to a specified delivery point. Transactions involving transportation of natural gas on pipelines are measured in units of energy called "dekatherms" (MMBtus[3]). Meters measure gas volumes and the heating value is determined by compositional analysis using results of gas chromatography. In general, gas volumes are measured continuously using one of several types of meters. Larger volume onshore receipt points generally use online continuous gas chromatographs (typically daily volumes of about 5 to 50 MMSCF[4], or higher). Manual spot or composite samples are more typical at smaller volume receipt points as well as most offshore transmission receipt points.

1.4.3 Pipeline operators (transporters) have found the need to establish tariff specifications at receipt points for certain constituents affecting gas quality, including water, carbon dioxide, oxygen, total sulfur, hydrogen sulfide, among others, to ensure safe and reliable operations. These constituents, in sufficient quantities, can create a corrosive environment adversely affecting safety and operations in the pipeline system and eventually can create combustion problems in downstream end use equipment. The tariff limits are typically expressed as maximum limits. Gas nominated for transportation must be provided within these limits. Depending upon regulatory issues, operating conditions, and other criteria, pipeline operators may waive tariff limits for a particular shipper on a short-term basis. Natural gas as it is transported in the manner described above is viewed as being fungible; that is, gas transported by one shipper may be interchanged with gas from another shipper without impacting the pipeline's ability to transport gas of acceptable quality to its downstream customers.

1.4.4 As stated earlier, when the commercial value of natural gas liquids is at a discount relative to their value as a thermal contribution in the natural gas, producers may elect to reduce extraction or bypass gas processing if not otherwise obligated. Most pipelines have been designed throughout the years with a variety of means to capture small incidental volumes of liquids so as to protect downstream facilities. Some pipeline companies have installed various two-phase (i.e., gas and liquid) lines to accommodate the presumption of liquid formation. Generally, these facilities are located upstream of compressor stations and measurement stations. Some pipelines have configured their producing area pipelines to handle both liquids and gas. These special lines are located in proximity to and upstream of liquids handling infrastructure such as a condensate removal facilities or a processing plant. With the exception of the specially designed two-phase systems, most pipeline systems anticipated liquid free operation and in many instances found no need to install liquid

[3] million Btus
[4] million standard cubic feet

handling equipment. The chemistry and thermodynamics of processed natural gas support operations in this manner. This is because processed gas is sufficiently lean (low liquefiable content) as to be able to provide absorptive capacity in the event that small volumes of liquefiable hydrocarbons are introduced into the pipeline system. However, if the gas temperature becomes sufficiently low at any point in the pipeline system or in the end user system, hydrocarbons can condense to form liquids from the natural gas mixture. Similarly, water vapor in the natural gas stream can condense to free water if the temperature of the gas gets low enough.

1.4.5 The water dew point is the temperature at which water vapor will condense to liquid water. The water content in a pipeline is already covered by tariff provisions and is mentioned here for illustrative purposes. Similarly, the hydrocarbon dew point (HDP) is the temperature at which hydrocarbons will begin to condense (refer to Section 4 – Overview of HDP); hence the expression "hydrocarbon liquid drop out".

1.4.6 The simplest means of controlling small incidental liquid accumulation is through installation of drips; a vessel attached to the pipeline that removes liquids through physical impingement or gravity collection in the pipeline system. The captured liquids accumulate and are periodically pumped or siphoned off and then either recovered as a fuel co-product (if regulation allows) or disposed of as a RCRA[5], TSCA[6] or State-listed hazardous waste. Disposal of these liquids as a hazardous waste may cause a dramatic increase in pipeline operating costs. The trend in recent years has been to remove drips from pipeline systems as they may be subject to corrosion. The Office of Pipeline Safety in some cases has required or encouraged operators to remove drips from their systems since the late-1990s.

1.4.7 Some pipeline operators have installed filtration or separation equipment, or both, on the suction side of compressor stations to collect solids (e.g. rust, weld slag and sand) and small volumes of water and compressor oils carried over from upstream stations. In addition, some LDCs and end users have installed similar equipment to collect small quantities of liquids dropping out as a result of temperature reductions associated with pressure reductions at city gate stations.

1.4.8 LDCs take custody of gas at the transmission pipeline delivery point. Direct connect customers take delivery from a delivery point on the mainline or often a lateral connected to the mainline. The gas must be measured at the point of the custody transfer from the pipeline to the LDC or customer. A metering station will occasionally include knockout vessels to remove any fugitive solids or liquids that may be in the gas prior to flowing through the measurement device. The pressure is normally reduced to the operating pressure of the LDC pipeline system either upstream or downstream of the meter. As the gas pressure is reduced, the temperature also will be reduced (the Joule Thomson effect). If the gas is not processed to specified levels, it is possible that a pressure reduction is enough to chill the gas to below the corresponding hydrocarbon dew point, thereby causing liquids to fall out. Likewise, if the processing is not done to specified levels, existing preheaters, separators or knockout vessels may be overwhelmed as to their capability to handle more than small quantities of hydrocarbon drop out. Heaters will be discussed further in sections

[5] - Resource Conservation and Conservation Recovery Act
[6] - Toxic Substances Control Act

2.4.6, 2.4.8 and 3.3. At high velocities, liquids become entrained, forming a mist. The mist may coalesce on the walls of the downstream pipeline and begin to collect in low spots of the pipeline system. Eventually, liquids can be swept along by the gas flow until reaching an exit point on the system -- a customer meter and burner. Liquids reaching a burner are a serious safety concern. They can degrade performance, spew out through the burner ports and either cause a large uncontrolled flame or extinguish the flame altogether and form a puddle in the hot appliance, with the potential to explosively reignite.

1.4.9 Hydrocarbon liquids in sensing lines to the equipment used for controlling pressure can cause erratic pressure variations in the delivered pipeline pressure. Such variations can impact nearby regulating stations upsetting large portions of a gas distribution system. This results in potential adverse impacts on system reliability or safety including overpressure protection devices.

1.4.10 Additional reliability and safety concerns for LDCs and end users due to natural gas liquids include the impact to polyethylene (PE) plastic piping, plastic piping components and current handling / pipe joining methodologies. According to APGA, approximately fifty percent of the typical LDCs distribution system is now comprised of plastic pipe and approximately ninety percent of new pipe installed is now plastic (2003 OPS Annual Report). Hydrocarbon gas constituents that are normally present within historical acceptable levels will have a minimal effect on the long-term strength of the plastic. However, it has been shown that aliphatic gaseous fuels of higher molecular weights ("heavy hydrocarbons") tend to be absorbed to a small extent by PE. This absorption somewhat reduces the long-term strength of PE pipe materials. Further, if the (NGLs) are routinely present, these liquids can cause a greater reduction in long-term strength up to 40% [7]. In addition, it has been reported that during the heat fusion joining of PE piping that has been in service conveying fuel gases that consist of, or include heavier hydrocarbons, the PE surfaces being heated in preparation for fusion on occasion will exhibit a "bubbly" appearance. The bubbling is a result of the rapid expansion (by heat) and passage of absorbed heavier hydrocarbon gases through the molten material, which could compromise the fusion joint if not properly recognized [8,9,10].

1.4.11 Hydrocarbon liquids present in a pipeline may not only cause operational and safety problems but also result in significant measurement error and unaccounted volume/energy losses. If liquids enter the gas sampling points, the sample will not be representative of the flowing gas stream, which results in inaccurate energy data, equipment failure, and costly equipment repair. Some pipeline operators and LDCs have had to install

[7] "Polyethylene Plastic Piping Distribution System Components of Liquefied Petroleum Gases", PPI Technical Report TR-22.

[8] Sudheer M. Pimputkar, Barbara Belew, Michael L. Mamoun, Joseph A. Stets, "Strength of Fusion Joints Made From Polyethylene Pipe Exposed to Heavy Hydrocarbons", Fifteenth International Plastics Pipe Symposium, October 1997.

[9] S.M. Pimputkar, J.A. Stets, and M.L. Mamoun, "Examination of Field Failures", Sixteenth International Plastics Pipe Symposium, November 1999.

[10] Gas Research Institute Topical Report GRI-96/0194, "Service Effects of Hydrocarbons on Fusion and Mechanical Performance of Polyethylene Gas Distribution Piping, May 1997.

more elaborate filtering systems on the inlet to these instruments at a significant cost that will ultimately be borne by end-use customers. Standards for accurate natural gas measurement are predicated on various principles, including, for example, the absence of liquids. Introduction of hydrocarbon liquids may cause significant degradation of measurement accuracy, thereby leading to incorrect accounting and potentially distorted imbalances between suppliers and those entities receiving the natural gas.

1.4.12 When natural gas is processed to a specified level, the presumption of fungibility is sound and the original design basis of the pipeline infrastructure for managing incidental free liquids is appropriate. However, as processors elect to reduce extraction levels or not to process gas, such as times when natural gas liquids are at a discount to their value in the gas, the increase in liquefiable content may create a dilemma for transporters and end-users. The presumption of fungibility may no longer be appropriate. It is important to recognize that in pipeline systems designed to transport single-phase gas, facilities may not exist to prevent, or accumulate and remove liquids fallout. Any portion of the gas condensed into liquid may not only cause operational or safety problems, but may also result in loss of that portion of the energy quantity (dekatherms) in the process of transportation. The shipper will take receipt of the dekatherms contracted for with the pipeline. Energy lost during transportation because of liquid drop out must be made up by the pipeline in the short term. Where the liquids accumulate in the pipeline or associated equipment, the pipeline operator experiences shortages that must be made up to meet the natural gas demand. This results in increased lost and unaccounted for (UAF) gas. Ultimately, all shippers on the system must contribute their pro-rata share of the UAF.

Section 2 - Liquid Hydrocarbons in Natural Gas

2.1 Sources of Natural Gas Production

2.1.1 Natural gas produced from geological formations comes in a wide array of compositions. The varieties of gas compositions can be broadly categorized into three distinct groups:

- Associated Gas,
- Non-Associated Gas
- Coal Bed Methane.

2.1.2 These produced gases can contain both hydrocarbon based gases (those which contain hydrogen and carbon) and non-hydrocarbon gases. Hydrocarbon gases are Methane (C_1), Ethane (C_2), Propane (C_3), Butanes (C_4), Pentanes (C_5), Hexanes (C_6), Heptanes (C_7), Octanes (C_8), and Nonanes plus (C_9+). The non-hydrocarbon gas portion of the produced gas can contain Nitrogen (N_2), Carbon Dioxide (CO_2), Helium (He), Hydrogen Sulfide (H_2S), water vapor (H_2O), Oxygen (O_2), other sulfur compounds and trace gases. CO_2 and H_2S are commonly referred to as "acid gases" since they form corrosive compounds in the presence of water. N_2, He and CO_2 are referred to as diluents since none of these burn, and thus they have no heating value.

2.1.3 Associated gas is produced as a by-product of oil production and the oil recovery process. After the production fluids are brought to the surface, they are separated at a tank battery at or near the production lease into a hydrocarbon liquid stream (Crude Oil or Condensate), a produced water stream (brine or salty water) and a gaseous stream. The gaseous stream is traditionally very rich (Rich Gas) in natural gas liquids (NGLs). NGLs are defined as Ethane, Propane, Butanes, and Pentanes and "Heaviers" (higher molecular weight hydrocarbons) (C_5+). The C_5+ product is commonly referred to as Natural Gasoline. Rich gas will have a high heating value and a high HDP. When referring to NGLs in the gas stream, the term GPM (gallons per thousand cubic feet) is used as a measure of hydrocarbon richness. The terms "rich gas" and "lean gas" are commonly used in the gas processing industry. They are not precise indicators but only indicate the relative NGL content.

2.1.4 Non-Associated gas (sometimes called "gas well gas") is produced from geological formations that typically do not contain much, if any, hydrocarbon liquids. This gas generally is lower in NGL content than Associated Gas. Non-Associated Gas can contain all, or none, of the other non-hydrocarbon gases identified above.

2.1.5 Coal Bed Methane is found within geological formations of coal deposits. Because coal is a solid, very high carbon content mineral, there are usually no liquid hydrocarbons contained in the produced gas. The coal bed must first be de-watered to allow the trapped gas to flow through the formation to produce the gas. Consequently, Coal Bed Methane usually has a lower heating value, and elevated levels of CO_2, O_2 and water that must be treated to an acceptable level, given its potential to be corrosive.

2.1.6 Gas quality can have significant effects on the operation of gas storage facilities. Three common types of gas storage facilities are mined salt caverns (either in a salt bed or a salt dome), aquifer, and depleted hydrocarbon reservoirs (geological rock formations). There are two significant ways for high HDP gas to create problems for storage operators. First, if the HDP specification is relaxed at any time, higher HDP gas could be injected into storage. A second cause of high HDP gas being in a storage facility could occur when low HDP pipeline gas is injected into a reservoir whereby it may become enriched if it comes in contact with hydrocarbon liquids existing in the reservoir prior to injection. The absorption is greatest during the first few years after a reservoir has been converted to storage and generally diminishes over time. In either case, when the gas is withdrawn from storage as a higher HDP gas, some of the liquefiable hydrocarbons can drop out through cooling of the withdrawn gas due to pressure reductions or contact with cold winter-time ground temperatures. In the first case, the injection of adequately processed gas would eliminate the problems associated with the withdrawal of high-HDP gas previously injected. In the second case, clean-up or "processing" of the withdrawn storage gas would need to be done at the compressor station used to inject and withdraw the gas from the storage reservoir.

2.1.7 Supply sources connected to interstate/intrastate pipeline systems are usually aggregated to a central delivery point (CDP) in the field through a gathering system. The CDP is the logical point where most gas processing occurs because of the aggregated volumes of gas. CDPs provide producers with economies of scale by centralizing facilities. It is not uncommon for larger CDPs to have connections to multiple interstate pipeline systems. Not all gas enters pipelines through CDPs. Pipelines sometimes have interconnects to one or several wells. The economics of conditioning gas from these sources can be problematic depending on the production potential of the well(s).

2.2 Role of Gas Processing

2.2.1 Gas processing is an important step in the journey natural gas makes from the wellhead to the burner tip. The gas processing function is commonly referred to as part of the Midstream Industry, a term used to describe the activities between Upstream – Exploration and Production, and Downstream – Gas Transportation and Marketing. Midstream companies are active in gathering gas from production facilities; aggregate the volumes; and treat and process the gas, before it enters the pipeline transmission system and downstream markets. Offshore, the produced gas enters the pipeline transportation system at the production platform and is transported to an onshore processing plant before being transported further to the downstream markets.

2.2.2 Produced gas can be partially treated at the wellhead to remove solids and liquids through simple, rudimentary physical separation equipment. This treatment is generally done to protect the gathering pipeline facilities used to transport the gas.

2.2.3 Gas processing entails two separate and distinct functions prior to the produced natural gas being deemed marketable. The gas will first be "treated" to remove major "contaminants" such as CO_2, H_2S and water vapor from the hydrocarbon gases if necessary and then, if there are sufficient levels of NGLs, the NGLs will be removed from the hydrocarbon stream.

2.2.4 Gas treating can be done on a stand-alone basis or in an integrated facility in conjunction with recovery of NGLs. Treating and integrated processing plants can be located at the terminus of gathering and aggregating systems. Alternatively, integrated plants can be found on a transmission pipeline near production areas. These plants are referred to as "straddle plants".

2.2.5 If H_2S, CO_2 and O_2 are present in the production gas, the first step is to treat the gas to reduce these gases to acceptable levels. Pipeline tariff specifications establish the acceptable level of contaminants for the pipeline and therefore the processor knows the degree of removal required to make an acceptable natural gas product. Processing plants often reduce the concentration of contaminants below pipeline standards in order to meet NGL product specifications. Water vapor is often reduced to extremely low levels as part of the low temperature extraction process. These gases are removed because they are potentially corrosive to the pipelines delivering the gas to the plant, to the processing equipment inside the plant and downstream transmission and distribution facilities.

2.2.6 Once the gas is cleaned of potentially corrosive gases, it can be processed to remove NGLs or it may be suitable for delivery into pipelines without further processing, as is the case of some non-associated gas and coal bed methane. In most offshore pipelines, natural gas condensate is injected with the gas produced on the offshore platform so that the combined gas and liquids are transported to shore in a single pipeline. This injected condensate, plus additional liquids that drop out as the gas is transported to shore, is removed by specially designed condensate removal equipment prior to gas processing or further pipeline transportation.

2.2.7 If the gas contains levels of nitrogen in excess of tariff limits or contains commercial quantities of helium, the next step in gas processing is to reduce the concentrations of these gases. To achieve this, cryogenic plant equipment is required. This is a very costly process, both in operating expense and capital investment. Recovery of helium and rejection (removal) of nitrogen are not commonly used processes and will not be discussed in any greater detail.

2.2.8 There are three common processes to recover NGLs: Refrigeration, Lean Oil Absorption and Cryogenic. Additional processes such as quick-cycle hydrocarbon adsorption are occasionally used and are becoming more common especially in situations with poor processing economics. Today, a processor will select the process to build after evaluating the richness of the gas, the appropriate technology for NGL recovery, market values of the natural gas and NGLs, the costs to get the NGLs to market, capital costs, fuel, and other operating costs. However, as discussed below, the infrastructure that exists today has been constructed over time. Older plants tend to be either refrigeration or lean oil while newer plants tend to be cryogenic. The quick-cycle hydrocarbon adsorption process was commercialized in the late 1940's. It targets recovery of the C5+ to meet hydrocarbon dew point specifications. It can be the simplest technology since no compression is required. A fixed bed of silica gel or other adsorption material is used to remove the liquids from the gas.

2.2.9 Refrigeration plants have the least capital cost but also recover the least NGLs. This process can extract a large percentage of propane and most of the C4+ gases and uses the least amount of fuel, compared to the other processes. The NGLs extracted from this type of plant are lower in vapor pressure and lends itself to trucking if pipelines are not available to move the NGLs to a fractionation plant. In the early days of gas processing, cruder forms of these plants and ambient lean oil plants were referred to as Gasoline Plants.

2.2.10 Lean Oil Absorption plants were the type of processing plant built in the 1960s. These plants were the next evolution from the refrigeration plants and can extract 90%+ of the C3+ in the gas stream and about 30% of the ethane by bubbling the gas through a chilled absorption oil operating at approximately –30°F. The fuel consumption of this type of plant is higher than that of the refrigeration plant. The ethane and propane were recovered to feed the ethylene plants at the infancy of the plastics and petrochemicals industries. Many of these plants are still operating and they straddle the large transcontinental gas pipelines built to transport the rapidly growing gas supplies found in the Gulf of Mexico and the eastern half of Texas during the 60's and 70's to markets in the northern and eastern parts of the U.S.

2.2.11 Cryogenic plants became prevalent in the 1970s as technology enabled higher ethane recoveries and demand for feedstocks increased to feed the growing plastics and petrochemical industries. These first generation cryogenic plants could extract up to 70% of the ethane from the gas, leaving a gas that was 90+% methane with the remainder being ethane and inert gases. To reach these higher extraction levels more expensive metallurgy, compression, and other capital investment are required. Since the early 1990s, modifications to the cryogenic process have allowed ethane recoveries to reach close to a 99% extraction level; still, due to the increased pressure reduction involved in the process, there is a higher operating expense due to the added fuel needed to run the compressors.

2.2.12 There are 556 facilities located in the United States that are engaged in processing of natural gas using the technologies described above, comprising approximately 68.4 billion cubic feet (BCF) per day of processing capacity (or approximately 25 trillion cubic feet (TCF) on an annual basis)[11]. There are 263 cryogenic facilities, 72 lean oil, 167 refrigeration and 44 using a quick-cycle or other technology. Approximately 50 percent of the available capacity is operated using cryogenic technology; with 20 percent being lean oil; 20 percent refrigeration and 10 percent other technology. Cryogenic facilities, generally being of a newer vintage are also larger with 100 of the 263 facilities being greater than 100 MMcfd, and 37 having capacities greater than 250 MMcfd. The refrigeration facilities are generally smaller with only 41 of the 167 facilities having capacities of greater than 100 MMcfd; there is one very large facility in Alaska that represents 60 percent of all of refrigeration capacity. The lean oil plants are also generally smaller with only 25 of the 72 being larger than 100 MMcfd.

2.2.12 Gas processing plants at times operated in reduced recovery modes to reduce the NGLs removed from the gas stream. However, the plants were designed to achieve high recoveries of all the NGLs and the "turndown" to lower recoveries has been difficult to attain. Typically, gas plants are not designed to recover only the C5+, or only the butanes, because they are designed to operate in a mode that recovers at least some percentage of all the components. In addition, it is not generally possible to operate the plants to achieve a specific HDP without blending of unprocessed gas.

2.3 Economics of Processing

2.3.1 The basics of NGL processing economics are to evaluate the amount of NGLs available to extract (which is determined by gas composition and the type of plant available to process the gas stream), determine the revenue generated from the sale of those NGLs and deduct the costs of processing. Processing costs include (1) the cost of the gas equivalent used or consumed in the conversion of production gas into NGLs (Shrinkage), (2) the fuel the plant consumes to operate the extraction process, (3) the payment or "processing fee" charged by the plant owner for this service, and (4) the operating costs for the plant. The shrinkage has value as a liquid product, but it also has value as natural gas if it had been left in the gas stream. Shrinkage and plant fuel are calculated both as a volume reduction and as a thermal reduction. Volume reduction occurs because the NGLs removed from the gas stream entering the processing plant and the plant fuel are not in the residue sales stream leaving the plant and therefore the residue gas is less than 100% of the inlet gas stream. Once the gas is processed, there is a gas value and a NGL value to the shrinkage part of the gas. The margin is the difference between the revenues received from selling the residue gas and NGLs, and the cost of the produced gas. If the NGL value less processing costs is greater than the equivalent gas value, then the margin is positive and it makes economic sense to extract the NGLs from the gas. On the other hand, if the NGL value as a liquid is less than the equivalent gas value, then the margin is negative and it does not make

[11] Oil and Gas Journal, Annual Survey of Gas Processing, 2004.

economic sense to extract the NGLs from the gas, except when the gas requires processing to meet pipeline specification and user need.

2.3.2 In the early years of the gas industry, producers sold their gas production to gas pipeline companies, normally through long term, fixed price contracts. Gas was generally considered a byproduct of oil exploration and production and a producer would take whatever value they could get for the gas instead of venting or flaring it. The production gas was processed in "Gasoline Plants" which simply compressed the gas, cooled it with either air or water to condense any heavy hydrocarbon gases, (i.e. Natural Gasoline) and then delivered the gas to a pipeline company. This Natural Gasoline was more valuable to the producer since it could be blended into and sold as a more valuable motor gasoline and removal of Natural Gasoline improved the operations of the pipelines. Once the majority of the heavy hydrocarbons were removed from this gas, pipelines took custody of the gas and transported it through their pipelines to markets elsewhere. As pipeline pressures increased, at times, more condensable hydrocarbons were removed at compressor stations and pipeline drips along the route of the pipeline. As pipelines moved gas to regions further from the producing region and the industry became more sophisticated in engineering and materials, gasoline plants began to chill the gas through simple pressure reduction/expansion, by passing the gas through light oil (absorption) or with refrigerants such as ammonia or propane. This evolution continued through the years and was influenced by the price of natural gas, NGLs, crude oil and by many government actions.

2.4 Influence of Ambient Temperatures and Pressure Reductions

2.4.1 Ambient ground and atmospheric temperatures and pressure reductions during transport or at a custody transfer point reduce flowing gas temperatures that in turn can result in hydrocarbon liquid drop out. Ambient temperatures become a concern when they are below *the flowing gas temperature and* the hydrocarbon dew point of a gas stream. Pressure regulation from a high-pressure to a lower pressure results in rapid cooling of the gas stream, a characteristic referred to as the Joule-Thomson effect.

2.4.2 Ambient ground temperature at pipe depth is one of the influential factors in flowing gas temperature. In general, the temperature of the gas exiting a compressor station ranges from 100 to 120 °F. Once the gas leaves the compressor and travels underground, the temperature of the gas falls rapidly due to the difference between the ambient ground temperature and the flowing gas temperature. The potential for hydrocarbon drop out increases as the ground temperature becomes sufficiently cold as to approach or be below the hydrocarbon dew point. This concern exists in cooler climates where the pipeline may be above the frost line, the depth to which frost penetrates the ground and ground temperatures can reach 32 °F. Pipelines located above the frost line may have flowing temperatures less than 32 °F. Transmission pipelines located in the northern part of the country may have been installed at depths below the frost line where the flowing gas temperature is not likely to fall below freezing.

2.4.3 Ambient air temperature is another factor that affects the flowing gas temperature. When the pipeline moves above ground such as at a meter station, compressor station, or aerial crossings, the gas will be heated or cooled based on the ambient air temperature. The concern is whether there will be sufficient heat loss to cause the flowing gas temperature to go below the hydrocarbon dew point. Some larger gate stations or gas processing facilities utilize piping insulation where ambient temperature impacts present a specific concern. However, in most cases, piping is not insulated due to pipeline integrity program visual inspection requirements for monitoring atmospheric corrosion. In addition as a practical matter, historically, small diameter piping and appurtenances associated with LDC gas distribution operations are not typically insulated throughout the country due to minimal benefit insulation would provide relatively small surface areas.

2.4.4 Water crossings also can affect the flowing gas temperature. Pipelines built today are often bored beneath rivers at depths below the mud line. At this depth the temperature of the river has no effect on the flowing gas temperature. However, most pipelines lay on or slightly under the riverbed. Under these conditions the water temperature can affect the flowing gas temperature. As long as the riverbed is not frozen solid, the underwater flowing gas temperature should not fall below 32 °F. It is important to note that many water crossings involve piping offsets that create "low points" which could result in liquid collection from hydrocarbon liquid dropout. If not designed to handle liquid collection, this could result in excessive pressure drops and flow restrictions and ultimately, may result in unscheduled shutdown and supply interruption.

2.4.5 Pressure reductions such as those that can occur at a meter or regulation station can cause the flowing gas temperature to drop. The rule of thumb is that for every 100 pounds of pressure drop the gas temperature will drop by 7 °F (applicable up to 1000 psig). Thus, if the pipeline is delivering gas at a pressure of 800 psig to an end user who requires a pressure of 200 psig, the gas temperature will drop approximately 42 °F ((800-200)/100 *7) as the pressure is reduced. The example below shows the resultant flowing gas temperature for a delivery to a northern Indiana meter station in January.

Gas temp. based on historic ground temp.		*38 °F*
Temp. drop due to minimal above ground pipe	*less*	*2 °F*
Regulation from 800 psig to 200 psig	*less*	*42 °F*
Resultant gas temp. (without heating)		*-6 °F*

2.4.6 The resultant low temperature demonstrates how pressure regulation can have significant influence on the flowing gas temperature. In some cases, heaters are used to raise the flowing gas temperature prior to regulation. These heaters are gas fired heat exchangers that heat the gas before it enters the regulator, thereby reducing the potential that hydrocarbon liquids and hydrates will form. The potential increase in temperature of the flowing gas depends on the type of heater employed. In the example above, if the operator or LDC used a heater that only raised the flowing gas temperature by 20 °F, the resultant flowing gas temperature would be 14 °F.

2.4.7 It is common in the LDC distribution systems to regulate to operating pressures of 60 psig or less. In the example above, this generates an additional temperature drop of almost 10° F causing a resultant temperature of -16° F in the above example. With the added heat of 20° F, the new temperature will be 4° F. Even if a heater is part of the conditioning at a gate station, often further regulation is done immediately downstream into lower pressure systems. Operating at these low temperatures may result in hydrocarbon

liquefiable condensation, solids blockage or service freeze-up of residential, commercial customers caused not only from potential hydrocarbon fallout but also from water vapor freezing to become a solid methane hydrate.
The formation of hydrates in the small orifices or tubing of regulator control equipment can cause disruption of supply to an LDC and in some cases stop operation of over-pressure protection equipment.

2.4.8 Gas heating prior to pressure reduction has been utilized throughout the industry at strategic locations for decades. The reasoning behind installation of supplemental gas heating equipment varies with industry segments. In general, all segments of the industry recognize that when possible, heating gas prior to a significant pressure reduction provides protection from hydrate formation as well as hydrocarbon liquid dropout. Historically, heaters were strategically installed by some LDC's to help control frost heave of mains and service lines due to subsurface ice formation and freezing of surrounding soils from temperature reductions associated with pressure reduction. In addition, heaters are installed to mitigate external ice ball formation on external piping and equipment surfaces that could interfere with proper operation of control equipment.

2.4.9 While gas heaters do indeed provide immediate protection from the abovementioned problems, gas heating alone should not be considered a system wide hydrocarbon dew point control. Gas heating addresses a specific process condition *at the point of installation* and they may not provide needed protection downstream or upstream. In addition, if heaters need to become more prevalent to reduce hydrocarbon liquid drop out, new as well as retrofit installations will be problematic due to community influences, air permitting, space availability and noise.

Section 3 - Hydrocarbon Liquid Drop Out Control Measures

3.1 Introduction

3.1.1 The 1971 AGA Gas Measurement Committee Report 4a, "Report on Natural Gas Contract Measurement and Quality Clauses" prepared by the Task Group on Gas Contracts established much of the standard Gas Quality language that was originally used in tariffs. It focused on the gas quality requirements that the seller had to meet when delivering gas to the pipeline, including specifications for liquids and solids and limits on non-combustibles or diluents. Many tariffs still contain the phrase originated in this document: "The gas shall be commercially free from dust, gum, gum forming constituents, and liquids at the pressure and temperature at which the gas is delivered." It also made recommendations for levels of water, H2S, total sulfur, CO_2, oxygen and heavy hydrocarbon content (using C5+ GPM (gallons per thousand standard cubic feet) as the reference) because these constituents in concentrations above recognized limits might be detrimental to pipeline integrity. Pipelines addressed the hydrocarbon content of the gas in a variety of ways, but at no time has there ever been a common set of specifications for components such as there has been for CO_2, H_2S and water. Much of this is due to the way the gas industry developed. It is also important to note that while most pipeline tariffs prescribe specifications for CO_2, H_2S and water, the exact specifications vary among pipelines.

3.1.2 Many, if not all pipelines have minimum specifications for heating value. This resulted from gas historically being produced from fields high in N_2 or CO_2 and long ago from manufactured gas plants N2 and CO_2 are inert and do not have any thermal value, thus they dilute the natural gas and, when in sufficient concentrations, can cause an end user's appliance to experience flame instability. Approximately a third of all interstate pipelines specify a maximum heating value, but there is no differentiation as to whether this is a condition at the receipt point or delivery point. The use of a maximum heating value is an inadequate predictor of hydrocarbon liquid drop out because a gas can have a relatively low heating value and a high C6+ content that can exhibit an elevated HDP and result in hydrocarbon liquid drop out. Conversely, a gas with an elevated ethane level will have a high heating value but a low HDP if the C6+ content is low.

3.1.3 Some pipelines selected another parameter for controlling liquids fallout by establishing a C5+ GPM, C5+ mole percent or C6+ GPM specification. A C6+ GPM specification may in some instances be used as an indicator of the potential for hydrocarbon liquid drop out but as will be discussed in Section 6, there are problems in applying this measure broadly. The C6+ composition varies among gas streams and has the largest effect on the hydrocarbon dew point. It also provides a good indication of liquid volume levels that may condense from the gas if the gas temperature falls below the HDP. By itself, however, the use of a C6+ GPM specification alone does not ensure that the flowing gas will not enter into a two-phase region and cause liquids to drop out. Nonetheless, correlating C6+ GPM levels to HDP can be used as a screening tool or as the basis for establishing a control limit.

3.1.4 More recently, some pipeline operators have elected to establish hydrocarbon dew point limits. As of June 2004, eleven interstate pipeline operators had established currently approved tariff hydrocarbon dew point limits. Three other operators have proposed hydrocarbon dew point limits. An HDP limit can be used to provide a wide range of gas compositions to end-users without compromising the safety, operational reliability, system integrity or environmental compliance within the natural gas infrastructure. The use of an appropriate hydrocarbon dew point specification will provide the information necessary to operate transmission and distribution systems and processing plants.

3.2 Blending

3.2.1 Blending is the mixing of gas streams that yields a volume-weighted average of the concentrations of each constituent. Pipelines and their customers have benefited from blending for years to make the combined quality of its gas stream from the individual gas streams meet gas quality related requirements. Blending has specifically been used in some instances for controlling Btu content and to meet other gas quality requirements. As the industry moves to implement new quality specifications relating to hydrocarbons, blending can play a role in managing hydrocarbon levels and provide the potential to accommodate receipts of gas with varying levels of hydrocarbons. While the overall goal remains to prevent pipeline condensate from forming, blending provides pipelines a mechanism to achieve that goal while still maintaining the flexibility to accept gas streams with varying hydrocarbon levels. In any case, the ability to utilize gas blending to manage HDP is dependent on a number of factors including pipeline configuration, receipt and delivery location, gas supply composition, gas markets and shippers' nominations, supply disruption, geographic location, and flowing gas temperature.

3.2.2 Each pipeline operator using blending will define the methodology and process for blending and monitoring the resulting hydrocarbon levels based upon their specific operations. The HDP of the mixed or commingled stream will depend on the volumes and compositions of the two blended streams. In other words a small amount of low HDP gas will not reduce the HDP temperature of a large volume of high HDP gas significantly. Conversely, even small amounts of high HDP gas when mixed into a low HDP gas can significantly raise the HDP of the mixture. When two different gas streams are mixed/blended, each compositional component of the commingled stream changes the equilibrium of the new mixture creating a completely separate and unique gas quality.

3.2.3 There are two distinctively different types of blending: physical and contractual.

3.2.4 **Physical blending** is when two or more gas streams are mixed together prior to being introduced into or within the pipeline. The combined stream changes in physical composition as discussed above. The blended gas streams may not however, thoroughly mix when combined. It may take some distance and possibly compression or some other mixing event, before they truly become a homogenous blend.

3.2.5 **Contractual blending** is when a producer of rich gas contracts with a lean gas producer or a processing plant upstream of the rich gas producer to reduce its HDP by blending where the resulting HDP is lowered to meet a specific HDP limit through agreement with the pipeline operator. These two volumes may enter at different parts of the pipeline and may not directly blend in the pipe. As such this type of blending does not work on all pipelines. But in theory, the two gas streams do actually blend prior to delivery by the pipeline if they both ultimately flow in the same segment of pipeline. In this type of blending, the overall blended stream of each pipeline segment or area must still meet the pipeline's required limit prior to being delivered. Even though the two combined streams may meet the HDP limit set by the pipeline, the pipeline may not approve this type blending if a section of the pipeline has a HDP limit that cannot be met by one of the contracting parties.

3.3 Heaters

3.3.1 Problematic hydrocarbon condensation often occurs at points of pressure regulation (or immediately downstream). In some cases, water bath heaters can be used to increase the flowing gas temperature prior to pressure regulation. In a water bath heater, as the name indicates, water surrounds and provides heat to a tube bundle (heat exchanger) containing the flowing natural gas, Since these units burn natural gas, they require air permitting. In addition, since pressure regulation often occurs post custody transfer from the pipeline to the LDC or other end user, gas heaters may not be practical or even feasible due to space limitations in urban environments. For example, a measurement and regulating (M&R) station heater could be as large as 8 feet in diameter and 20 feet in length which is simply not practical to install in a small subsurface modern pressure reduction station. As previously mentioned, gas heaters provide specific process temperature control only at the point of installation. As a result, some LDC's or end users partially depend on pipeline heat of compression to mitigate temperature decreases associated with local pressure reduction.

3.4 Offshore Gas and Liquids Handling

3.4.1 Handling gas and liquids in the offshore environment is different than onshore gathering because of the way gas and condensate is handled. In the offshore environment most gas pipelines allow for the produced fluids to be separated at the offshore platform, then the condensate is re-injected into the pipeline after the gas is metered so that only one pipeline is necessary to transport both condensate and gas from offshore. Also, since the gas is additionally cooled as it flows in the underwater pipeline systems, additional liquids, commonly called retrograde condensate, are generated by the time the gas arrives at the onshore separation and processing facilities. These liquids must be removed before the gas can be processed for NGL recovery or further transported to market.

3.4.2 When natural gas and condensate are present together in a pipeline, or pressure vessel, they are likely to be intimately mixed and reach a point of "equilibrium" or a saturation point. The gas stream is at its hydrocarbon dew point at the temperature and pressure of the pipeline or pressure vessel. So any time this offshore sourced gas is delivered to a pipeline without processing or without further hydrocarbon content reduction utilizing a JT plant[12], it is most likely to be at its dew point and any cooling of the gas from the ground or water temperature or a pressure reduction (like a pressure regulator) can condense liquids.

Section 4 - Overview of Hydrocarbon Dew Point

4.1 Introduction

4.1.1 The hydrocarbon dew point (HDP) defines whether the natural gas stream in a pipeline at a given pressure and temperature consists of a single gas phase or two phases, gas and liquid. The HDP is defined as the series of matching pressure and temperature points at which hydrocarbons condense into liquid from a natural gas mixture. The hydrocarbon dew point **pressure** is the pressure at which hydrocarbons will begin to condense from a gas mixture at a given temperature. The hydrocarbon dew point **temperature** is the temperature at which hydrocarbons will begin to condense from a gas mixture at a given pressure, and it is usually more important for pipeline operations where the pressure is determined independently.

4.1.2 When condensate forms from a gas mixture, the distribution of hydrocarbons changes so that the liquid phase becomes enriched in the heavier components while the gas phase becomes depleted of these heavier components. As the gas is cooled

[12] A J-T valve has the least capital cost but also recovers the least amount of NGLs. This simple process is used mainly to control HDP temperatures and primarily recovers the C_5 components only. The J-T process (or Joule-Thomson) involves cooling a gas stream by reducing its pressure (adiabatic expansion) through a control valve. Produced liquids are recovered in a cold separator and the gas stream off the top of the separator is used to cool the inlet stream to the J-T valve. This process may require considerable compression to achieve the desired pressure drop across the J-T valve thus resulting in high operating costs.

below its original dew point temperature, the entire dew point curve shifts cooler for the remaining gas phase that is now depleted in heavier components. The chilled gas temperature becomes the new HDP of the gas stream.

4.2 Hydrocarbon Dew Point Curve

4.2.1 The HDP for natural gas with a given composition is typically displayed on a phase diagram, an example of which is shown in Figure 4-1. The HDP curve is plotted as a function of gas pressure (P) and temperature (T). The left-hand side of the curve (in blue) is the bubble point line and divides the single-phase liquid region from the two-phase gas-liquid region. The right-hand side of the curve (in black) is the dew point line and divides the two-phase gas-liquid region and the single-phase gas region. The bubble point and dew point lines intersect at the critical point, where the distinction between gas and liquid properties disappears. Note that two dew point temperatures are possible at a given pressure (P_3) and two dew point pressures are possible at a given temperature (T_3). This phase envelope phenomenon provides for behavior known as retrograde condensation. The retrograde phenomenon occurs when liquids form at a given temperature when the pressure is lowered (see red arrow). The word "retrograde" means moving backward and this phenomenon was given the name because it is contradictory to the phase behavior of pure components, which condense with increasing pressure and or decreasing temperature. The maximum pressure at which phase change occurs (P_{max}) is called the **cricondenbar**, and the maximum temperature (T_{max}) at which phase change l occurs form is called the **cricondentherm**.

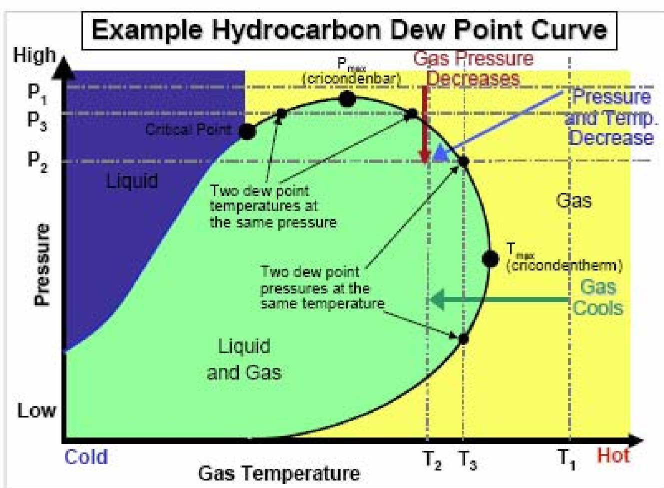


Figure 4-1 - Hydrocarbon Dew Point Curve for a Typical Natural Gas Mixture

4.2.2 The HDP is a function of the composition of the gas mixture and is strongly influenced by the concentration of the heavier hydrocarbons, especially C_6+. The presence of heavier hydrocarbons will increase the HDP and failure to include them in a HDP calculation will under–predict the HDP. For most pipeline conditions, the HDP temperature at a given pressure increases as the concentration of heavier hydrocarbons increases. Thus, the **potential** to form liquids at certain pipeline conditions exists for gases rich in C6+. Processing of the gas stream primarily removes or extracts heavy hydrocarbons and thus reduces the HDP of a given mixture. The level of hydrocarbon removal directly impacts the HDP. Figure 4-2 shows examples of the HDP curve for unprocessed and processed gas mixtures. The unprocessed HDP curve is in red and has a higher cricondentherm temperature while the processed HDP curve is in blue. The difference between the two curves shows the impact of processing on the HDP.

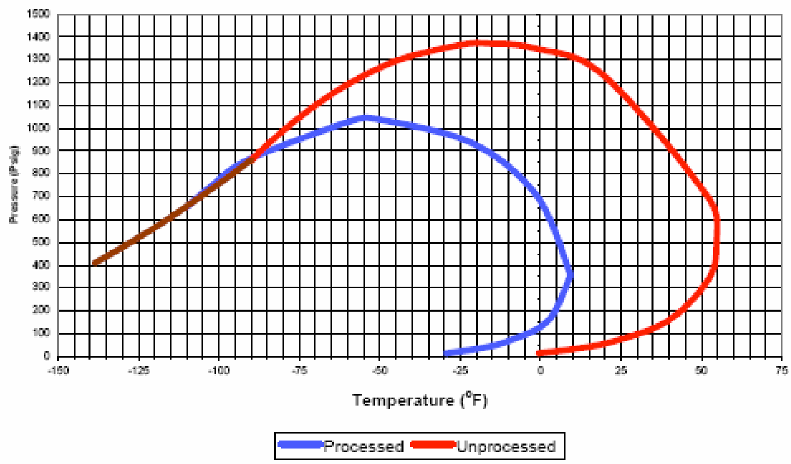


Figure 4-2 – Contrast of Unprocessed and Processed Natural Gas

The significance of the HDP curve for gas transmission and distribution operations lies in the potential transition from the single-phase gas region to the two-phase gas-liquid region. For example, the arrows in Figure 4-1 (Figure numbers to be corrected) show changes in pipeline pressure and temperature in which the end-point lies inside the gas-liquid phase. In this situation, condensate formation inside the pipeline will occur. It is important to recognize, however, that the volume of condensate **cannot** be determined simply by plotting points on the HDP curve. The volume of condensate can be determined by analyzing the gas phase compositions upstream and downstream of a potential condensation location (e.g., regulator, pipeline) and determining the GPM (gallons of liquids per thousand standard cubic feet of gas) for the liquefiable components in each stream.

Gas Quality White Paper
Control of Hydrocarbon Liquid Drop Out

Section 5 - Historical Levels of Hydrocarbons and Hydrocarbon Dew Point

5.1 Introduction

5.1.1 There is not an abundance of historical data on hydrocarbon levels or hydrocarbon dew points. However, approximate ranges for cricondentherm hydrocarbon dew points can be estimated by referencing the types of processing in the gas industry from the 1940s to the present.

5.1.2 Prior to the advent of gas processing, hydrocarbon dew points in pipelines and market areas would approach ambient temperatures (between 30 and 60 °F). Pipelines collected liquids and developed their own methods to force these liquids from the gas prior to its delivery to customers. As uses for gas progressed beyond crude lighting and cooking appliances, processing developed and operators were able to discontinue these practices and remove equipment. The first gas processing plants were really compression plants similar to air conditioning units and operated prior to the advent of refrigeration plants. They compressed the casing head gas and cooled the gas using air or water heat exchangers to condense the heavy NGLs. This resulted in recovery of approximately 25% of the C6+ and reduced the cricondentherm to about 10 °F at the plant outlet.

5.1.3 Propane as a refrigerant became available post 1940 when demand for butane for use in motor gasoline increased and rural heating was converted from butane to propane in the 1940s-1950s. Refrigeration dropped the cricondentherm from 80 °F at the plant outlet to slightly above 0 °F and recovered 50% or so of the propane and 80% or more of the $C4^{+}$. The gas processed was very rich casing head gas on the order of 1200 -1400 Btu per cubic foot (HHV), (4 - 7 GPM), as this gas was a by-product of oil production.

5.1.4 As ethane became a valued commodity in the early 1960s, the new onshore oil and gas fields discovered in that era had lean oil plants built in the same geographic regions. These lean oil plants had somewhat higher NGL recovery than the older refrigeration plants (70+% of the propane, 90% of the C4+). Cricondentherm of the processed gas was -30 °F or lower.

5.1.5 When oil prices increased dramatically after the 1972 oil embargo, there was a strong economic incentive to recover all the NGLs. During this same time period, cryogenic processing technology developed where it became more economical. Cryogenic plants generally recover from 60% to 99% of the ethane (depending on the technology employed) and essentially all of the C3+ producing cricondentherm temperatures of -100 °F or lower. Due to the increase in value of the NGLs, cryogenic technology was retrofitted at many of the larger, older onshore refrigeration plant sites in the late 1970s to replace the lower recovery refrigeration plants. The lean oil plants built in the 1960s continued to operate until field declines in the 1980s and 1990s, coupled with increased operating expenses, justified the shutdown of some of these older plants. The remaining production formerly processed in these plants was consolidated with other production field gases and processed in the newer plants linked together to create regional processing centers (i.e. the Duke Energy Field Services Oklahoma Super System, the Williams Energy Opal, Wyoming complex, etc.) that afforded the operator a way of efficiently utilizing available capacity.

Other major changes occurring in the 1990s were the spin-off of producer plant assets to new business entities such as Dynegy, Enterprise Products, GPM, Tejas, UPR Fuels and many of the "Field Service Companies" such as Duke, El Paso and Williams). Since 2000 few new processing facilities have been built. As new facilities are built, the industry has utilized additional plant designs that minimize recoveries of the lighter hydrocarbon constituents (C1 through C3) to maximize sales of gaseous hydrocarbons. These plants are designed more to control HDP than to recover large quantities of NGL's. The three processing technologies that have become popular for this application are refrigeration, short cycle adsorption (molecular sieve) and JT (Joules-Thomson) skids. This trend will probably continue into the future as more pipelines institute HDP specifications and if processing margins are negative due to natural gas prices remaining high relative to NGL's.

5.1.6 On the Outer Continental Shelf (OCS), the Minerals Management Service (MMS) promulgated regulations in the late 1950s that eliminated routine flaring of gas production, primarily associated gas. This created a huge pipeline construction boom to recover the formerly flared gas along with construction of the large lean oil straddle plants on these new pipelines from OCS. As production grew in the 1970s on the OCS, the oil embargo and consequent increased prices provided the incentive for increased NGL recovery. Straddle plants for new pipelines built in the mid 1970s (e.g., Blue Water, UTOS and Sea Robin) employed cryogenic technology while the older plants on the other pipelines were not retrofitted.

5.1.7 In summary, available gas processing technology would have the following approximate cricondentherm HDP at the plant outlet:

Technology Vintage	Processing Technology	Achievable Cricondentherm HDP °F
1940-60	Refrigeration	≅ 0
1960-75	Lean oil	≅ -10
1975 on	Cryogenic	≅ -100

Actual cricondentherm HDP in any pipeline at any point in time is determined by the mix of processed and unprocessed gas and the degree of processing of the processed gas.

Section 6 – Determination of Hydrocarbon Dew Point – Measurement and Estimation

6.1 Introduction

6.1.1 This section provides an overview of the determination of hydrocarbon dew point. It can be done in two ways, measurement or estimation. A method referred to as the "chilled mirror" is used to conduct direct determination of the hydrocarbon dew point. Alternatively, **indirect determination** relies on a combination of sampling, analysis and calculations using a simplified equation of state from chemical thermodynamics. This section provides an overview of the merits of each in managing hydrocarbon drop out. Determining the exact temperature that a vapor component in the gas stream condenses does not in and of itself define the basis for controlling hydrocarbon liquid drop out. Knowing the temperature when appreciable amounts of liquids will condense is a useful operational tool. For a procedure establishing a cricondentherm hydrocarbon dew point (CHDP) limit, see Appendix B.

6.2 Direct Determination

6.2.1 The most commonly used direct method of hydrocarbon dew point determination is with a chilled mirror, also known as a dew point tester. The method was developed by the U.S Department of Interior, Bureau of Mines and has been codified into a standard test method by the American Society of Testing and Materials (ASTM)[13]. For many years this device has been used for moisture measurement. A standard for chilled mirror hydrocarbon dew point measurement has also been developed and will appear in the next revision of the American Petroleum Institute (API), Manual of Petroleum Measurement Standards (MPMS) - Chapter 14.1. The device can be used to determine the hydrocarbon dew point at the operating pressure at a specific field location. Some pipeline operators use this as a means of HDP determination and verification. The major advantage of this device is that it provides direct measurement of HDP at a specific operating pressure. For this reason, a pipeline may elect to use chilled mirror as the primary method to determine HDP at a specific pressure, if mutually agreed upon by relevant parties. However, it may not be applicable for determining the cricondentherm. If the cricondentherm is above the operating pressure, the analyst will not be able to determine the exact value. If the cricondentherm is below the operating line pressure, it may be possible to throttle down and determine the cricondentherm but it may take multiple measurements and a considerable amount of time.

6.2.2 The Bureau of Mines dew point tester consists of a small high-pressure chamber (5000 PSI max) through which the gas sample flows. A polished stainless steel mirror is at one end of the chamber and a viewing window is at the other. The chilled mirror is cooled by a refrigerant system. The operator throttles the gas flow through a valve and cools the polished mirror until the hydrocarbon dew point is observed by the formation of a thin film of droplets. The temperature and pressure are then recorded and plotted on a graph.

6.2.3 Determination of the HDP temperature with this apparatus is a subjective test that requires the analyst to watch for the formation of hydrocarbon liquid droplets as the mirror is gradually cooled at the rate of one degree Fahrenheit per minute. This is a very time intensive and tedious process. Chilled mirror dew point testers can be used to determine both water vapor dew point and hydrocarbon dew point. The two types of dew points can be distinguished from one another by the unique location and size of the liquid droplets that form on the mirror surface. These differ because of differences in surface tension between liquid water and liquid hydrocarbons.[14] It may be difficult to distinguish whether the droplets are due to water or hydrocarbons, particularly when the dew points

---

[13] ASTM D 1142-95. 1995. "Standard Test Method for Water Vapor Content of Gaseous Fuels by Measurement of Dew-Point Temperature," Am Soc for Testing and Materials, Philadelphia.

[14] API Manual of Petroleum Measurement Standards, Chapter 14.1 HCDP Measurement Standard

either overlap or are within just a few degrees apart. A typical HDP test may last forty-five minutes to one hour and requires uninterrupted attention to the test apparatus.

6.2.4 Experience indicates that trained and experienced operators can generally reproduce each other's results. Among inexperienced operators the results may vary significantly. Even the most skilled operator may make an error due to the appearance of water droplets, methanol droplets, or glycol droplets on the mirror if these exist in the gas sample stream.

6.2.5 Automatic, continuous online dew point detection units are commercially available. These units are expensive relative to the cost of other online analyzers and unlike gas chromatography; these instruments are currently not part of the existing gas quality analytical infrastructure. The decision to deploy them entails consideration of the economics of purchase, installation and maintenance of the online analyzer versus the use of estimation (described below) in conjunction with periodic manual dew point measurements.

6.2.6 In summary, direct reading instruments are useful tools in determining localized observable hydrocarbon dew points at specific pipeline operating conditions. While this technology has proven useful in the field in diagnosing hydrocarbon dew point conditions, universal application of this technology across the grid may prove challenging due to the variables highlighted above in addition to the wide variety of operating conditions that exist across the nation in all sectors of the industry.

6.3 Indirect HDP Determination

6.3.1 Indirect HDP determination relies on a three-step process, sampling, analysis and calculation. The most common means of sampling and analysis (the first two steps) involves a continuous online system. Permanent sample probes (isokinetic) are installed in the pipeline to obtain a representative sample. The sample probe is connected to a heated sample line that transports the gas to a continuous online gas chromatograph. The most common chromatograph found in field applications uses a combination of columns to analyze for methane through pentane and then treats all compounds with molecular weights greater than pentane as a C6+ fraction, generally using a fixed mole fraction average of C6, C7, and C8[15]. This chromatograph is referred to as a C6+ chromatograph.

6.3.2 Manual sampling with off-site analyses of the samples can be used as an alternative. Samples of the gas are collected in a clean sample cylinder (canister) or on charcoal tubes using standard methods published by GPA[16] and referenced by API[17]. Samples are analyzed using a chromatograph typically using C6+ chromatograph described above. Some labs have chromatographic equipment to analyze to C_9 to C_{11}.

[15] American Society for Testing and Materials standard, ASTM D 1945, and Gas Processors Association, Standard 2261, Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography.

[16] Gas Processors Association Standard 2166, "Obtaining Natural Gas Samples for Analysis by Gas Chromatography," 1986.

[17] American Petroleum Institute, Manual of Petroleum Measurement Standards, Chapter 14, Section 1. "Collecting and Handling of Natural Gas Samples for Custody Transfer," June 2001.

6.3.3 The third step, calculation, is conducted by applying thermodynamic principles and accepted equations of state using the gas analysis from above. An equation of state defines the relationship between state variables (pressure and temperature) and gas properties such as density. Two commonly accepted sets of state equations are Peng-Robinson[18] and Soave-Redlich-Kwong[19]. The effects different calculation methods and of gas composition accuracy on the accuracy of Equations of State are also part of an on-going project with the API Chapter 14.1 Working Group.

6.3.4 The degree to which the three-step process reflects the actual hydrocarbon dew point is dependent upon several factors including the characteristics of the natural gas stream, how well the sample represents the stream composition, the chromatographic equipment, how the heavier hydrocarbons are input into the equations of state, and the equations used. HDP are most sensitive to the mole percentage compositions of the hydrocarbons larger than hexane. In applying a HDP limit using C6+ data, it is prudent to conduct periodic validation based on use of an "extended analysis", through C8 to enable demonstration of the "split". The split is the relative proportion of C6 C7, and C8 in a gas mixture. Some commonly used values for these percentage characterizations are published in a GPA standard[20]. However, recent research[21] has shown that use of the GPA 60/30/10 C6/C7/C8 characterization to compute hydrocarbon dew points will usually underestimate the dew point temperatures and cricondentherm. However, the work conducted by a leading chromatograph manufacturer, Daniels, indicates that a 47:36:17 split is generally applicable, but may vary depending on the source of gas or the degree the gas has been processed[22]. The determination of the appropriate characterization for a given pipeline system may be more accurately derived from the weighted average compositions of the regional supply on that pipeline. An alternative approach is to widen the regional observation, such as including all Gulf Coast production. Such a definition may span several operating pipelines in the region. However, the ability of the average characterization to reflect the true composition of a particular gas within a region depends on the variance of the individual components of all gases throughout that region.

The presence and amount of C9+ components is important in determining the HDP as well. Amounts as low as 0.001 mole percent C9 can have significant impact on the calculated HDP. While characterization data available for C9+ show that these components are generally not present or when present are found in relatively small amounts, it is prudent in applying the indirect method to characterize the C9+ fraction as part of the periodic validation process.

6.3.5 Determining the exact temperature that a vapor component in the gas stream condenses is not of as much value as knowing the temperature that an appreciable amount of liquid condenses. For example, if a sample has 0.001 mole percent of C10, the HDP may

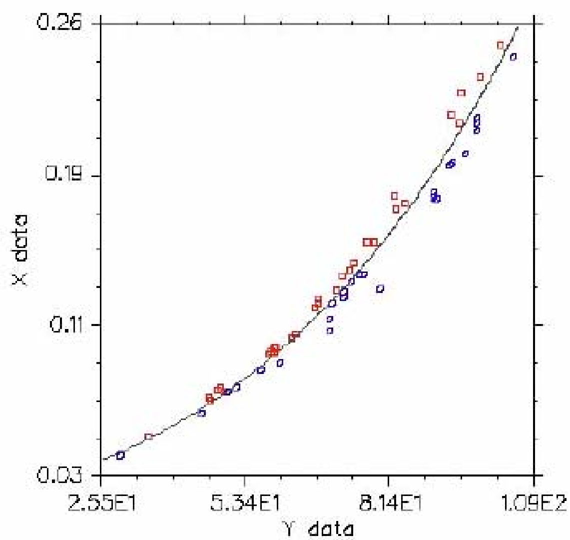
[18] Peng, D. Y. and Robinson, D. B., Industrial and Engineering Chemistry Fundamentals, 15: 59, 1976.
[19] Soave, G., Chemical Engineering Science, 27: 1197, 1972.
[20] Gas Processors Association Standard 2261, "Analysis for Natural Gas and Similar Gaseous Mixtures by Gas Chromatography," 2000.
[21] D. L. George et al., "Metering Research Facility Program: Natural Gas Sample Collection and Handling – Phase IV," Gas Research Institute Report No. GRI-03/0049, September 2004.
[22] Standard configurations programmed into Daniels chromatographs, Daniels, a division of Emerson Electric.

be relatively high, but the volume of liquids contributed will not affect pipeline operations. That is why using a volume number (i.e., GPM) can be of value to pipelines. Developing the relationship between the GPM and HDP is useful, since engineers design and operate facilities around temperature and pressure (7 degrees F per 100 psi reduction). Developing a correlation between C6+ GPM and a CHDP can be done from a gas analysis. This requires a number of different gas streams to be analyzed, using a gas chromatograph. The HDP is calculated for each stream as described in section 6.3.3 above and the C6 + GPM value is calculated by summing the GPM value for each C6+ component using the split methodology described in Section 6.3.4 above. The GPM value for any component in a gas stream is calculated by taking a component's mole fraction (mole percent/100) and dividing it by the volume constant (ft^3) ideal gas/gallon liquid from GPA Standard 2145 and then multiplying by 1000 (scf/Mscf). Once the HDP and C6+ GPM values are determined for the each receipt point in the group, these values can be input to a curve-fitting program. The program can yield a simple equation for determining HDP from the C6+ GPM level. One major advantage to using C6+ GPM is that it correlates to the volume of gas flowing into the pipeline and allows pipelines to determine how much flow reduction from each point will be necessary to maintain an acceptable HDP. To demonstrate the simplicity and accuracy of this approach, a set of 55 unprocessed receipt point samples were selected. The HDP and C6+ GPM values were determined utilizing a Peng-Robinson equation of state program and a 40/40/20 C6+ split. The simplified curve fit equation developed was in the form of

$$y = ax^b + c$$

Where y = HDP, x = C6+GPM
(Constants a, b, and c are 392, 0.159, -210 respectively)

The results are shown in the graph below



As is seen in the graph, this is a simple method for approximating CHDP and is a way to relate gas quality to gas volumes on a pipeline.

Another practical alternative that draws upon the strengths of direct and indirect HDP determination measurement is being evaluated to predict HDP with lesser uncertainty than the either of the direct or indirect methods[23]. Further studies are required to validate this alternative method.

6.3.6 When indirect determination methods are included in a quality specification, there must be a declaration of the equations of state that will apply, the assumptions for Hexane plus composition, and the hydrocarbon dew point temperature. In addition, assumptions made about the relative proportions of hydrocarbons greater than pentane (i.e.- the hexanes plus fraction) must be validated on a periodic basis.

Section 7 - Recommendations

7.1 Technical

7.1.1 Control of hydrocarbon liquid drop out requires use of a control parameter to ensure operational safety and reliability, system integrity, environmental compliance and to minimize impacts on end use equipment.

7.1.2 Of the various methods which could be used as a control parameter, the NGC Task Group found that the C_5^+ approach and the Heating Value approach were not effective means of predicting and controlling hydrocarbon liquid dropout and should not be used as control parameters.

7.1.3 The NGC Task Group found that cricondentherm HDP and C6+ GPM specification were both valid for use as control parameters to control hydrocarbon liquid dropout and recommends using an equation of state with data derived from gas chromatography for calculation of cricondentherm HDP or C_6+ GPM specification.

7.1.4. The NGC Task Group, however, found that using the cricondentherm HDP as the control parameter offered the greatest operational flexibility for all stakeholders.

7.1.5. If the C_6^+ GPM approach is used as the control parameter, then it must be understood that this approach will not give the end-user all of the information needed to design, install and operate their equipment outside of the two-phase region of the gas stream.

7.1.6 The Task Group recommends that, when using a cricondentherm HDP or C_6+ GPM, a plan must be established by the pipeline operator for periodic validation of the assumptions used including proportions of C6 ,C7 & C8, and where applicable, higher molecular weight hydrocarbons.

---

[23] Starling, Kenneth A., Peng-Robinson Equation of State Natural Gas Dew Points, AGA Technical Conference

7.1.7 The Task Group recognizes that determining HDP using the Bureau of Mines method is not practical for automated applications, and is the subject to the practical limitations described in section 6.3.

7.1.8 The NGC Task Group recognizes that in certain instances, parties may be able, to the extent operationally feasible, to change control parameter limits based on ambient conditions, storage operations, meter station and system pressure drops, and the tolerance for heavy hydrocarbon levels within a specific market area, among others.

7.1.9 The NGC Task Group recommends that additional research be conducted in the following areas:

1) Build the database to support use of C6+ split assumptions for heavier hydrocarbons, develop better correlation between direct and indirect HDP determination and to improve the accuracy of commonly used equations of state.

2) Develop a cost effective hydrocarbon-specific direct-reading dew point analyzer because a conventional chilled mirror direct measurement instrument in general can be subject to operator variability and interferences including but not limited to water vapor.

7.1.10 The HDP limits do not presume that gas is Interchangeable. HDP is only one facet of describing gas quality.

APPENDIX A
PARAMETERS TO BE CONSIDERED IN ESTABLISHING CHDP OR C6+ GPM BASED LIMITS

The Work Group defined a set of parameters that may be useful, in establishing the CHDP or C6+ GPM required to avoid hydrocarbon liquid dropout. The parameters are:

- Minimum Flowing gas temperature
- Minimum Ambient air temperature
- Minimum Ambient ground temperature
- Operating pressure requirements
- Pressure reduction
- CHDP levels of gas supplied including those of downstream pipelines
- Experience with monitoring HDP levels and associated problems caused by hydrocarbon liquid drop at various levels
- Presence of heating systems
- Presence separation equipment
- Prevailing and expected flow patterns
- Impact of storage
- End user applications
- LNG liquefaction peak shaving feedstock requirements

The Work Group recognized that implementation of CHDP may require incremental changes to establish a more flexible CHDP as additional data and experience are gained by pipelines and LDCs.

APPENDIX B
PROCESS FOR ESTABLISHING A CRICONDENTHERM HYDROCARBON DEW POINT (CHDP) LIMIT

1. Define an area for which the limit is to be applied (e.g.- market area, energy zone).

2. Review historical data of the area for composition, flowing gas temperature and pressure of delivered gas.

3. Select a candidate CHDP limit based on historical gas quality data
   - Use the full compositional analysis at least through C6.
   - In order of preference, use:

     i. A C6+ split to be established and periodically validated through extended analyses in a C9+ chromatograph, as specified in the White Paper on Control of Hydrocarbon Liquid Drop Out, or
     ii. A 47:36:17% C6/C7/C8 assumed split specified in the White Paper on Control of Hydrocarbon Liquid Drop Out or other published split applicable to a specific region.

4. Develop a phase diagram that represents the gas at the selected CHDP.

5. Apply a line of constant slope that is tangent at a single point to the phase diagram. The slope of the line is the Joule Thomson constant, i.e. – approximately seven (7) degrees of temperature drop per 100 pounds per square inch of pressure drop. This is referred to as the J-T line.

6. Identify the lowest temperature and coinciding highest pressure of flowing gas at each place of pressure reduction and plot the corresponding point on the phase diagram.

   - Consider the effects of existing equipment, such as gas heaters, multi-stage pressure reduction equipment, etc.

7. Applications where the temperature/pressure points fall to the right of the J-T line should not experience liquid drop out.

8. Applications where the temperature/pressure points fall to the left of the J-T line may experience liquid dropout. To prevent hydrocarbon liquid drop out for such applications, either reapply steps 3 through 6 by selecting a lower candidate CHDP or consider alternatives including installation of gas heating or use multi-stage pressure reduction.

9. A review of the established CHDP should be made from time to time as more experience is gained.

The use of the phase diagram and the J-T line as the bound for liquid drop out provide a reasonable basis to establish a CHDP limit.

9.17 Appendix 17 – Texas Administrative Code for Natural Gas Transportation Standards and Code of Conduct

Texas Administrative Code

TITLE 16	ECONOMIC REGULATION
PART 1	RAILROAD COMMISSION OF TEXAS
CHAPTER 7	GAS SERVICES DIVISION
SUBCHAPTER G	CODE OF CONDUCT
RULE §7.7001	**Natural Gas Transportation Standards and Code of Conduct**

(a) Purpose. The purpose of this section is to specify standards of conduct governing the provision of gas transportation services in order to prevent discrimination prohibited by the Common Purchaser Act, Texas Natural Resources Code, §111.081, et seq.; the Texas Utilities Code, Titles 3 and 4, which if violated, as found by the Commission, may constitute evidence of unlawful discriminatory activity. Any exemptions provided in this rule do not diminish statutory prohibitions against discrimination.

(b) Code of conduct. A transporter that provides transportation services for any shipper (including affiliate shippers) shall:

(1) apply any tariff or contract provision for transportation services which provides for discretion in the application of the provision in a similar manner to similarly-situated shippers;

(2) enforce any tariff or contract provision for transportation services if there is no discretion stated in the tariff or contract in the application of the provision in a similar manner to similarly-situated shippers;

(3) not give any shipper preference in the provision of transportation services over any other similarly-situated shippers;

(4) process requests for transportation services from any shipper in a similar manner and within a similar period of time as it does for any other similarly-situated shipper; and maintain its books of account in such a fashion that transportation services provided to an affiliate can be identified and segregated.

(c) Exemptions.

(1) The distribution and transportation activities services performed by a local distribution company are exempt from this section.

(2) In the event that an entity transports only its own gas through its own system, as designated by the transporter's current T-4 permit on file with the Commission, then that system is exempt from this section.

(d) Other requirements. Any transporter subject to the provisions of this section shall make available to the Commission its books and records of transportation service for audit purposes. With at least ten working days notice by the Commission, the transporter shall provide the Commission access to records showing rates which the transporter is charging and any other contractual conditions of transportation service. The transporter shall provide the Commission access on a reasonable basis to information contained in the transporter's records regarding any other relevant conditions of transportation service.

Source Note: The provisions of this §7.7001 adopted to be effective July 29, 2002, 27 TexReg 6687

5(a)

Order Temporarily Waiving Regulations to Raise Blanket Certificate Limits, 113 FERC ¶ 61,179 (2005). On November 18, 2005, the Commission issued an order waiving its regulations, on a temporary basis, to raise the limitations on the costs for projects that natural gas pipelines may construct without prior specific authorization under their Part 157, Subpart F blanket certificates. In order to expedite the construction of infrastructure which may serve to provide access to additional supplies of natural gas in the Gulf Coast region as a result of Hurricanes Katrina and Rita, the Commission increased the cost ceiling for projects that can be constructed under the automatic provisions of blanket certificates from $8 million to $16 million. The cost ceiling for projects that can be constructed under the prior notice provisions of blanket certificates was increased from $22 illion to $50 million.

In addition, the definition of “eligible facilities” that qualify for the above treatment was expanded to include:

mainline facilities;
extensions of a mainline;
facilities, including compression and looping, that alter the capacity of a mainline; and
temporary compression that raises the capacity of a mainline.

The temporary waivers would apply to those projects constructed and placed into service by October 31, 2006.

Order Extending Deadline for Construction of Facilities Pursuant to Temporary Waiver of Regulations Raising Blanket Certificate Limits, 114 FERC ¶ 61,186 (2006). On February 22, 2006, the Commission issued an order extending the previously granted waivers of the limitations in blanket certificate regulations to those projects that would be constructed and placed into service by February 28, 2007.

In addition, the Commission has granted standard of conduct waivers regarding posting and record keeping requirements and emergency waiver of tariff provisions, such as, waiver of penalties, fees or other charges incurred by customers as a direct result of Hurricane Katrina.

OCS-Related Infrastructure in the Gulf of Mexico Fact Book
(Attached in its entirety to email)

This page intentionally left blank.

9.18 Appendix 18 – Tennessee Gas Pipeline Tariff Excerpts

FTA Gas transportation Agreement, Article II:

Transportation Service - Transporter agrees to accept and receive daily on a firm basis, at the Point(s) of Receipt from Shipper or for Shipper's account such quantity of gas as Shipper makes available up to the Transportation Quantity, and to deliver to or for the account of Shipper to the Point(s) of Delivery an Equivalent Quantity of gas.

General Terms and Conditions

Article I, point 15, sheet 303:

15. The term "equivalent quantity" unless otherwise stated in the transportation contract shall mean that during any given period of time the thermal quantities of gas delivered at the Point(s) of Delivery shall be the thermal equivalent of the quantities of gas received at the Point(s) of Receipt for transportation less thermal quantities of gas for Transporter's system fuel and use requirements and gas lost and unaccounted for associated with the transportation service; provided that the equivalent quantity shall not include any plant thermal reduction (PTR) unless the gas to be transported is not subject to a separate PTR Transportation Agreement.

Article II. Quality , Part 1, sheet 305A:

1. The provisions set forth in this Article II Section 1 shall apply to all gas delivered by Transporter under this FERC Gas Tariff.

(a) Heating value: The natural gas shall have a total heating value of less than nine hundred and sixty-seven British thermal units per foot. Transporter, in its own right or in accord with the instructions of Shipper, may subject, or permit the subjection of, the natural gas to compression, cooling, cleaning and other processes and helium, natural gasoline, butane, propane, and any other hydrocarbons except methane may be removed prior to delivery to Shipper. Title to the products will remain with party that has contracted for the processing rights and notified Transporter of such contract; otherwise, title to the products will remain with Transporter. In the event that the total heating of gas, per cubic foot, in any month

Article II, Part 9, sheet 308

Separation, Dehydration and Processing: Transporter at its reasonable discretion may require that some or all of the gas to be transported be processed to remove liquid and liquefiable hydrocarbons prior to delivery to Transporter or may require evidence that satisfactory arrangements have been made for the removal of liquid and liquefiable hydrocarbons at a separation and dehydration and/or processing plant on Transporter's system. In the event that any separation and dehydration and/or processing required by Transporter in accord with this Article II, Section 9 is to occur after delivery of transportation gas to Transporter, then such transportation of liquefiable hydrocarbons shall be done pursuant to a PTR Transportation Agreement in the form included in Transporter's FERC Gas Tariff and transportation of liquid may be done by separate agreement with Transporter.

Article VII, sheet 357

VII. POSSESSION OF GAS

As between Transporter and Shipper, Shipper shall be deemed to be in exclusive control and possession of the gas to be transported (i) prior to receipt by Transporter at the Receipt Point(s), (ii) after receipt by Transporter, when the gas is in the custody of Shipper or Shipper's designee for separation, processing or other handling, and (iii) after delivery by Transporter at the Delivery Point(s); otherwise, Transporter shall be in exclusive control and possession of the gas. The party which shall be in exclusive control and possession of the gas shall be responsible for all injury or damage caused thereby to any third party. In the absence of negligence or willful misconduct on the part of Transporter, Shipper waives any and all claims and demands against Transporter, its officers, employees or agents, arising out of or in any way connected with (i) the quality, use or condition of the gas after delivery from Transporter for the account of such Shipper and (ii) any losses or shrinkage of gas during or resulting from custody of Shipper or Shipper's designee.

Article IX, sheet 362

IX. WARRANTY OF TITLE TO GAS

This Section shall apply to all transportation service unless otherwise provided in the applicable Rate Schedule or transportation contract. Shipper warrants for itself, its successors and assigns, that it will have, at the time of delivery of gas for transportation hereunder, good title or the good right to deliver the gas. Transporter warrants for itself, its successors and assigns, that the gas it warrants hereunder shall be free and clear of all liens, encumbrances and claims whatsoever, that each will have at such time of delivery good right and/or title to deliver the gas, that each will indemnify the other and save it harmless from all suits, actions, debts, accounts, dangers, costs, losses, and expenses arising from or out of any adverse claims of any and all persons to said gas and/or to royalties, taxes, license fees, or charges thereon which are applicable for such delivery of gas and that each will indemnify the other and save it harmless from all taxes or assessments which may be levied and assessed upon such delivery and which are by law payable by and the obligation of the party making such delivery. If Shipper's title or right to deliver gas to be transported is questioned or involved in any action, Shipper shall not qualify for or shall be ineligible to continue to receive service until such time as Shipper's title or right to deliver is free from question; provided, however, Transporter shall allow Shipper to qualify for or continue receiving service under this Tariff if Shipper furnishes a bond satisfactory to Transporter. Title to the gas received by Transporter at the Receipt Point(s) shall not pass to Transporter and title to gas delivered for fuel and use quantities shall pass to Transporter at the Receipt Point(s).

9.19 Appendix 19 – Southern Natural Gas Company Tariff Excerpts

Rate Schedule FT

Previous Next Search

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

Seventh Revised Sheet No. 44
Superseding
Sixth Revised Sheet No. 44

RATE SCHEDULE FT
Firm Transportation Service
(Continued)

5. TRANSPORTATION OF LIQUIDS AND LIQUEFIABLES

(a) Liquids: Any party with the ownership interest to liquids, as defined in the General Terms and Conditions, separated prior to measurement at the Receipt Point(s) may request that such liquids be delivered to COMPANY for transportation by injection of such liquids into COMPANY'S system immediately downstream from said measurement, and COMPANY may, in its reasonable discretion, agree to accept the liquids for transportation. notify COMPANY by 5:00 p.m. CCT at least four (4) calendar days prior to the month when the transportation of liquids is requested to commence, and submit the information required in Section 5(b) below (and shall give COMPANY four (4) calendar days' written notice of any change to this information). In the event SHIPPER injects, or causes to be injected, liquids into COMPANY'S system, SHIPPER shall cause the removal of such liquids from the gas delivered into COMPANY'S system at liquid removal facilities installed and operated by the owners of such liquids or their agents at a mutually agreeable point on COMPANY'S onshore pipeline facilities and subject to mutually agreeable accounting procedures. SHIPPER and COMPANY shall execute a separate Service Agreement for the transportation of said liquids.

Issued by: Glenn A. Sheffield, Director-Rates
Issued on: May 13, 2002   Effective on: September 1, 2003
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP00-476, issued April 11, 2002, 99 FERC ¶ 61,042

Previous Next Search

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

Fifth Revised Sheet No. 44A
Superseding
Fourth Revised Sheet No. 44A

RATE SCHEDULE FT
Firm Transportation Service
(Continued)

(b) Liquefiables: For quantities of gas which are received at a Receipt Point from which the gas enters into a stream of gas which is processed at a processing facility on COMPANY'S pipeline system for the removal of liquefiables, as defined in the General Terms and Conditions, the party with the right to process the ownership interest therein ("SHIPPER") may elect to process such gas for its account subject to the further provisions hereof. SHIPPER shall notify COMPANY by 5:00 p.m. CCT at least four (4) calendar days prior to the beginning of the month if the liquefiables are to be processed for the account of SHIPPER and shall give COMPANY four (4) calendar days written notice of any change to this election prior to the beginning of the month for which the change is to be effective. COMPANY may extend the election deadline on a nondiscriminatory basis in the event (1) SHIPPER brings on a new source of production at or behind a receipt point during the production month or (2) has a change in interest ownership or liquefiables marketing rights, and such election is made prior to the Intraday 2 nomination deadline for the first day of the production month for which the election applies. In its notice SHIPPER shall specify its Liquefiables Transportation Agreement (by contract number), the Receipt Point code and source of the subject gas, the working interest owner of the gas, the duration of the election, the Delivery Point code of the processing plant to which the gas is to be delivered and verification that all processing arrangements are in place if the election is to process. In the event SHIPPER fails to make an election and the liquefiables are not being processed under a direct processing arrangement with the processing plant, COMPANY shall be authorized to act as SHIPPER'S agent in arranging said processing and, at COMPANY'S election, either (i) assess to SHIPPER its allocated share of plant volume reduction and credit SHIPPER with its allocated share of revenues received by COMPANY for said liquefiables, or (ii) replace the allocated share of plant volume reduction in Dth. Such processing arrangements may have a lower processing priority with the processing plant than might be available to SHIPPER by contracting directly with the processing plant for the processing of its gas.

The gas remaining after processing shall be returned to COMPANY'S pipeline at a mutually agreeable point downstream from the processing plant. Such processing shall not cause the gas to fail to meet the quality specifications set forth in the General Terms and Conditions.

SHIPPER shall tender a request for transportation of liquefiables pursuant to the provisions of Section 2 of the General Terms and Conditions. Upon submission of a valid request for service,

Issued by: Glenn A. Sheffield, Director-Rates
Issued on: April 29, 2005 Effective on: March 1, 2005

RATE SCHEDULE FT
Firm Transportation Service
(Continued)

SHIPPER and COMPANY shall execute a separate Liquefiables Transportation Agreement in the form set forth in COMPANY'S FERC Gas Tariff, Seventh Revised Volume No. 1.

6. FACILITIES

In order for COMPANY to receive, measure, transport, and/or deliver the gas to be transported under this Rate Schedule, it may become necessary for COMPANY to install facilities or to modify existing facilities at or near a Receipt Point or Delivery Point ("Interconnection Facilities"). Should SHIPPER request the installation or modification of said facilities and agree to reimburse COMPANY for the entire cost to COMPANY thereof, COMPANY will construct and install, or cause to be constructed and installed, or will modify, or cause to be modified, Interconnection Facilities; provided that, (i) the proposed Interconnection Facilities do not adversely affect Southern's operations; (ii) the proposed Interconnection Facilities and the associated transportation service to or from the interconnection do not diminish service to any of Southern's shippers; (iii) the proposed Interconnection Facilities do not cause Southern to violate or be in violation of any applicable environmental or safety laws, permits or regulations; and/or (iv) the proposed Interconnection Facilities do not conflict with or cause Southern to be in violation of its rights-of-way agreements or any other contractual obligation. In the event SHIPPER does not agree to pay the costs of installing or modifying the Interconnection Facilities, COMPANY will construct or modify such facilities on a nondiscriminatory basis for similarly situated SHIPPERS if the construction or modification of such Interconnection Facilities is economically feasible and the conditions listed above in (i) -(iv) are met. Construction or modification is economically feasible if the proposed transportation service to be provided through the Interconnection Facilities is revenue positive to COMPANY. The proposed transportation service to be provided through said Interconnection Facilities will be deemed revenue positive if the transportation service produces a net revenue gain. The net revenue gain requirement will be met if (a) the total revenues generated over the term of SHIPPER's Service Agreement for the service provided through the new facilities exceed the cost of service of said facilities for the greater of (i) ten years or (ii) the term of SHIPPER's Service Agreement for the service provided through the new facilities and the SHIPPER extends the terms of its existing Service Agreement(s) with COMPANY for a period commensurate with that of its new Service Agreement; provided however, that (1) SHIPPER does not have to extend the remaining term of an existing Service Agreement if said term already exceeds the term of its new Service Agreement, and (2) if the net revenue gain requirement is met over a period less than the term of the new Service Agreement, SHIPPER need extend the term of its existing Service Agreement(s) only for a term commensurate with that shorter period; or (b) COMPANY determines that the construction of the facilities will avoid a significant reduction in revenue when comparing the cost of the construction to the projected amount of revenue which would be lost as a result of a SHIPPER's exercising a right to reduce its firm transportation quantity or as a result of a SHIPPER's failing to extend or renew its existing Service Agreement(s). As used in this provision, the term "cost of service," includes, but is not limited to:

Issued by: Glenn A. Sheffield, Director-Rates
Issued on: June 19, 2001 Effective on: June 4, 2001
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP99-159, issued June 4, 2001, 95 FERC ¶ 61,354

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

Substitute Original Sheet No. 45A

RATE SCHEDULE FT
Firm Transportation Service
(Continued)

(1) a return on all costs associated with the construction of the facilities, including overhead and taxes;
(2) incremental operating and maintenance expenses:
(3) depreciation and amortization of expenses; and
(4) incremental tax expenses.

It is understood and agreed that, if COMPANY pays for the cost of constructing the Interconnection Facilities, title to and ownership of said facilities shall remain in COMPANY, and COMPANY shall operate such facilities as part of its pipeline system.

Where COMPANY competes for transportation of gas under this Rate Schedule, conditions may be such that it is more favorable for SHIPPER to construct, own and operate certain facilities at or near a Receipt Point or Delivery Point. In such case, COMPANY may make a contribution in aid of construction ("CIAC") for such facilities. A CIAC made pursuant to this Section 6 shall not exceed an amount that would constitute an economically feasible investment for facilities constructed, owned, and operated by COMPANY. COMPANY shall make CIACs pursuant to this provision on a nondiscriminatory basis for similarly situated shippers.

7. GENERAL TERMS AND CONDITIONS

All of the General Terms and Conditions contained in this Tariff, including from and after their effective date any future modifications, additions, or deletions to said General Terms and Conditions, are applicable to the transportation services rendered under this Rate Schedule and, by this reference, are made a part hereof. If and to the extent the provisions of this Rate Schedule conflict with provisions of said General Terms and Conditions, the provisions of this Rate Schedule shall prevail.

Issued by: Glenn A. Sheffield, Director-Rates
Issued on: June 19, 2001 Effective on: June 4, 2001
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RP99-159, issued June 4, 2001, 95 FERC ¶ 61,354

General Terms and Conditions

Previous Next Search

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

First Revised Sheet No. 156
Superseding
Original Sheet No. 156

GENERAL TERMS AND CONDITIONS
(Continued)

(c) notice is attempted to be sent by facsimile machine, but the sending facsimile machine does not confirm that the message was sent, in which case COMPANY shall make at least two additional attempts to send the message and the notice shall be deemed given at the time the third attempt is made or at the time the sending facsimile machine confirms that the transmission could not be sent, or

(d) notice is attempted by making at least three telephone calls not less often than fifteen minutes apart, in which case the notice shall be deemed given at the time the third call is made.

18.5 Existing Service Agreements

If COMPANY and SHIPPER are parties to a currently effective Service Agreement which does not contain all of the information required by Sections 18.3(a), 18.3(b), and 18.4, COMPANY and SHIPPER shall provide such information to each other within fifteen (15) days of the date COMPANY commenced operations under this Seventh Revised Volume No. 1 of its FERC Gas Tariff.

19. TRANSPORTATION OF LIQUIDS AND LIQUEFIABLES

19.1 Facilities:

Should any new or additional facilities, alterations or modifications of existing facilities be required to facilitate the processing of gas or the injection or removal of liquids associated with the gas transported, the installation of such new or additional facilities or the alteration or modification of existing facilities, to the extent they affect COMPANY'S pipeline system, will be performed by COMPANY and, upon receipt of billing therefor, SHIPPER agrees to reimburse COMPANY for all costs and expenses incurred by COMPANY in connection with the transportation of liquids and liquefiables for SHIPPER.

Issued by: Glenn A. Sheffield, Director-Rates
Issued on: March 30, 2001 Effective on: May 1, 2001
Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. RM96-1-015, issued November 30, 2000

Previous Next Search

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

Original Sheet No. 157

GENERAL TERMS AND CONDITIONS
(Continued)

19.2 Transportation of Liquefiables:

COMPANY agrees to deliver to SHIPPER for processing a volume of gas containing as nearly as practical the same number of gallons of propane and heavier hydrocarbons as are delivered to COMPANY by SHIPPER at the Receipt Point, less volumes used by COMPANY pursuant to Section 19.5 hereof. If gas other than gas received from SHIPPER hereunder is also being transported through COMPANY'S pipeline, SHIPPER shall have the right to process a quantity of the commingled gas in COMPANY'S pipeline which contains as nearly as practical a quantity of propane and heavier hydrocarbons equal to the propane and heavier hydrocarbons contained in the gas delivered at the Receipt Point. The redelivery of residue gas and the accounting therefor shall be in accordance with procedures mutually satisfactory to COMPANY and SHIPPER. Gas received for SHIPPER'S account at Receipt Points on "wet" lines located upstream of the processing plants located near Toca, Louisiana, will not be processed prior to delivery to COMPANY.

19.3 Transportation of Liquids:

The composition and characteristics of the liquids transported hereunder shall be such that they will not (i) cause the formation of hydrates in COMPANY'S pipeline, (ii) cause damage to said pipeline by internal corrosion, or (iii) cause the gas in said pipeline to fail to meet the quality specifications set forth in Section 3 of these General Terms and Conditions upon receipt by COMPANY or after SHIPPER has removed such liquids from COMPANY'S pipeline downstream of the Receipt Points, and such liquids shall contain not more than one percent (1%) of basic sediment and water. COMPANY shall have the right to commingle the gas and liquids delivered by SHIPPER to COMPANY with gas delivered by others into which gas others have likewise injected liquids, and COMPANY shall likewise have the right to transport such liquid hydrocarbons for others. In such event, there shall be only one point of removal of liquid hydrocarbons on COMPANY'S pipeline, and SHIPPER and such other parties shall remove such liquid hydrocarbons at such point and agree as to the proportionate ownership of the liquid hydrocarbons so removed.

Issued by: Greg P. Meyers, Vice Pres. Rates
Issued on: September 20, 1993 Effective on: November 1, 1993

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

First Revised Sheet No. 158
Superseding
Original Sheet No. 158

GENERAL TERMS AND CONDITIONS
(Continued)

SHIPPER shall furnish COMPANY with monthly statements, or cause the same to be done, setting forth the quantity of its liquids so injected and removed.

19.4 Transportation Rates:

SHIPPER shall pay COMPANY for transporting liquids or liquefiables in COMPANY'S facilities to the liquids removal facility or processing plant site from the point of receipt at the applicable rate or rates set forth in currently effective Sheet Nos. 22 or 34.

If for any reason the Commission or other governmental body having jurisdiction from time to time requires or approves by order of general or specific applicability or otherwise (including an order approving a settlement) a rate or rates higher than those provided above to be charged for the transportation of liquids or liquefiables or assigned to such transportation as a credit against COMPANY'S cost of service, then SHIPPER shall pay to COMPANY such higher rate. If the Commission does not approve a rate to be charged for or assigned to the transportation of liquids or liquefiables but, in the exercise of its cost allocation powers in approving COMPANY'S transportation rates, approves the allocation of a portion of COMPANY'S cost of service to the transportation of liquids and liquefiables, then SHIPPER shall pay COMPANY for the transportation of liquids and liquefiables a rate, if higher than the rate otherwise provided above, which shall enable COMPANY to recover the entire portion and amount of COMPANY'S cost of service allocated or attributable to such transportation. If COMPANY is required by order of the Commission (including order approving settlement) to make refunds to its SHIPPERS arising out of the transportation of liquids and liquefiables hereunder, SHIPPER shall reimburse COMPANY its pro rata share of the entire amount, including interest, that COMPANY is required to refund.

Issued by: Glenn A. Sheffield, Director-Rates
Issued on: April 29, 2005 Effective on: March 1, 2005

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

Third Revised Sheet No. 159
Superseding
Second Revised Sheet No. 159

GENERAL TERMS AND CONDITIONS
(Continued)

19.5 Pipeline Operations:

COMPANY reserves the right to use gas upstream of the point of processing and/or liquid separation as is required for the reasonable and prudent operation of COMPANY'S facilities and the right to make deliveries of gas to others under the provisions of COMPANY'S FERC Gas Tariff to the extent that such deliveries do not significantly reduce SHIPPER'S proportionate share of the liquids or liquefiables transported by COMPANY. It is also recognized that some losses of gas volumes containing liquids or liquefiables may occur as a result of such deliveries and/or the operation of such facilities. SHIPPER'S proportionate part of the liquids or liquefiables so used, delivered or lost shall be deducted from the quantity of liquefiables otherwise deliverable to SHIPPER.

19.6 SHIPPER'S Responsibility:

As between SHIPPER and COMPANY, all operations conducted by or on behalf of SHIPPER in the processing of gas hereunder shall be at SHIPPER'S sole cost, risk and expense, and SHIPPER shall be responsible for the safe handling of the gas while it is in SHIPPER'S custody, or the custody of another on SHIPPER'S behalf, for processing.

20. PREGRANTED ABANDONMENT OF LONG-TERM, FIRM SERVICE AGREEMENTS

The following provisions shall apply to all firm transportation (including storage) Service Agreements which have a primary term of twelve (12) consecutive months or more and a rate of the maximum rate eligible for the applicable service or a discounted rate in effect prior to March 27,2000, except that these provisions shall not apply to those firm transportation Service Agreements which are the result of conversion from firm sales service during the period after February 13, 1991, and before May 18, 1992, and, therefore, are not subject to pregranted abandonment pursuant to Section 284.221(d)(3) of the Commission's Regulations. These provisions shall not apply to any firm transportation or storage Service Agreements which have a negotiated rate as described in Section 34 of these General Terms and Conditions or a discounted rate pursuant to Section 42 of these General Terms and Conditions unless COMPANY and SHIPPER mutually agree under the terms of the negotiated rate or discount exhibit that the rights hereunder shall accrue to SHIPPER. No later than forty-five (45) days prior to the

Issued by: Glenn A. Sheffield, Director-Rates
Issued on: August 31, 2004 Effective on: October 1, 2004

Liquefiables Transportation Agreement

Previous Next Search

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

Third Revised Sheet No. 392
Superseding
Second Revised Sheet No. 392

Agreement No. ________

PRO FORMA

LIQUEFIABLES TRANSPORTATION AGREEMENT

THIS AGREEMENT, made and entered into as of this _______ day of _____________, ______, by and between Southern Natural Gas Company, a Delaware corporation, hereinafter referred to as "Company", and _________________________, a _____________________ corporation, hereinafter referred to as "Shipper".

WITNESSETH

WHEREAS, Company has undertaken to provide open-access transportation service under Part 284 of the Federal Energy Regulatory Commission's (Commission) Regulations; and

WHEREAS, Shipper has requested the transportation of liquefiables by Company pursuant to the terms of this Agreement for processing at the processing plant(a) specified herein and has submitted to Company a request for such service in compliance with Section 2 of the General Terms and Conditions contained in the current Volume No. 1 of Company's FERC Gas Tariff; and

WHEREAS, Company is willing to render such transportation service to Shipper pursuant to the provisions of this Agreement and Subpart G of Part 284 of the Commission's Regulations.

NOW, THEREFORE, the parties hereto agree as follows:

ARTICLE I

QUANTITY OF SERVICE

1.1 Subject to the terms and provisions of this Agreement and the General Terms and Conditions applicable thereto, Shipper agrees to deliver, or cause to be delivered, to Company at the Receipt Point(s) elected by Shipper upstream of the processing plant(s) the quantity of gas (in Dth) that Company schedules at such point(s) for transportation under this Agreement.

Issued by: Greg P. Meyers, Vice-Pres. Rates
Issued on: July 31, 1998 Effective on: September 1, 1998

Previous Next Search

Previous Next Search

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

Third Revised Sheet No. 393
Superseding
Second Revised Sheet No. 393

PRO FORMA
LIQUEFIABLES TRANSPORTATION AGREEMENT
(Continued)

Company's obligation to accept gas at any Receipt Point specified on Exhibit A hereto is limited to the Maximum Daily Receipt Quantity (MDRQ) specified in the General Terms and Conditions hereto.

1.2 Company shall redeliver a thermally equivalent quantity of gas to Shipper at the Delivery Point(s) to the processing plants described on Exhibit A hereto. Company's obligation to redeliver gas at any Delivery Point is limited to the Maximum Daily Delivery Quantity (MDDQ) specified in the General Terms and Conditions hereto.

ARTICLE II

CONDITIONS OF SERVICE

2.1 It is recognized that the hydrocarbons Shipper desires to have processed are produced at each Receipt Point in conjunction with the gas transported by Company under separate Service Agreements under its transportation rate schedules. The transportation services performed under this Agreement must be performed in conjunction with the transportation of such gas stream. In the event Company finds it necessary to allocate capacity in the facilities utilized for Shipper's service hereunder, the allocation of capacity to Shipper's Agreement shall be dependent on the allocation of capacity Company makes, pursuant to the terms of its FERC Gas Tariff, to the transportation agreement(s) under which the gas stream associated with Shipper's liquefiables is being transported. Company shall not change the quantities of gas it will transport hereunder during any day of transportation except upon four (4) hours' prior notice to Shipper.

2.2 At any time the processing plant to which Company is transporting liquefiables on Shipper's behalf is shut down, transportation under this Agreement shall be suspended during the period of shutdown.

2.3 Company makes no representation, assurance or warranty that capacity will be available on Company's pipeline system at any time and Shipper agrees that Company shall bear no responsibility or liability to any person if capacity does not exist on any day to provide service hereunder.

Issued by: Glenn A. Sheffield, Director-Rates
Issued on: August 23, 2004 Effective on: September 22, 2004

Previous Next Search

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

Third Revised Sheet No. 394
Superseding
Second Revised Sheet No. 394

PRO FORMA
LIQUEFIABLES TRANSPORTATION AGREEMENT
(Continued)

2.4 This Agreement shall be subject to all provisions of the General Terms and Conditions, except for Sections 10.2, 10.3, 12.1, 12.2, 13.2, 16.3, 17, 20, 21, 22, 23, 32-35, 41.2, and 41.3 and Appendices B, C, D, and G-J, as such conditions may be revised from time to time. Unless Shipper requests otherwise, Company shall provide to Shipper the filings Company makes at the Commission of such provisions of the General Terms and Conditions or other matters relating to this Agreement. In the event there is a conflict between the provisions of this Agreement and the applicable transportation rate schedule or the General Terms and Conditions, the provisions of this Agreement shall govern.

2.5 Company shall have the right to discontinue service under this Agreement in accordance with Section 15.3 of the General Terms and Conditions contained in Company's FERC Gas Tariff.

2.6 The parties hereto agree that neither party shall be liable to the other party for any special, indirect, or consequential damages (including, without limitation, loss of profits or business interruptions) arising out of or in any manner related to this Agreement.

2.7 This Agreement is subject to the provisions of Subpart G of Part 284 of the Commissions' Regulations. Upon termination of this Agreement, Company and Shipper shall be relieved of further obligation to the other party except to complete the transportation activities underway on the day of termination, to comply with the provisions of Section 14 of the General Terms and Conditions with respect to the resolution of any imbalances accrued prior to termination of this Agreement, to render reports, and to make payment for transportation services rendered.

ARTICLE III

NOMINATIONS AND BALANCING

3.1 For purposes of nominating service hereunder, Shipper agrees that on a day when the gas stream associated with Shipper's liquefiables is scheduled by Company for transportation, Company will provide as a nomination on Shipper's behalf the historical quantity (in Dth) of liquefiables produced from the Receipt Point(s) attributable to the interest from which Shipper has retained or acquired the

Issued by: Glenn A. Sheffield, Director-Rates
Issued on: August 23, 2004 Effective on: September 22, 2004

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

Fourth Revised Sheet No. 395
Superseding
Third Revised Sheet No. 395

PRO FORMA
LIQUEFIABLES TRANSPORTATION AGREEMENT
(Continued)

right to process such liquefiables. This historical daily volume shall be deemed to be Shipper's nomination under this Agreement for transportation to the processing plant(s) specified in Shipper's election on Exhibit A hereto until changed or adjusted by Company prospectively pursuant to an allocation of capacity under Section 2.1 above or an update of the historical plant volume reduction information utilized by Company. Shipper shall notify Company in writing, pursuant to the provisions of Section 5(b) of Rate Schedule IT, of the Receipt Points which it has dedicated to each processing plant prior to the date the gas is scheduled to flow from said Receipt Points. Such Receipt Points elected by Shipper shall constitute Exhibit A hereto from time to time.

3.2 Any imbalances accrued under this Agreement between the quantities received by Company for Shipper's account during a month and the volume of liquefiables processed for Shipper's account at the processing plant during a month shall be resolved pursuant to the provisions of Section 14 of the General Terms and Conditions.

ARTICLE IV

NOTICES

4.1 Except as provided in Section 8.6 herein, notices hereunder shall be given pursuant to the provisions of Section 18 of the General Terms and Conditions to a party at the applicable address, telephone number, facsimile machine number or e-mail addresses provided by the parties on Appendix E to the General Terms and Conditions or such other addresses, telephone numbers, facsimile machine numbers or e-mail addresses as the parties shall respectively hereafter designate in writing from time to time.

Issued by: Glenn A. Sheffield, Director-Rates
Issued on: August 23, 2004 Effective on: September 22, 2004

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

Fourth Revised Sheet No. 398
Superseding
Third Revised Sheet No. 398

PRO FORMA
LIQUEFIABLES TRANSPORTATION AGREEMENT
(Continued)

ARTICLE V

TERM

5.1 Subject to the provisions hereof, this Agreement shall become effective as of the date first written above and shall be in full force and effect for a primary term of ______________________________ and shall continue and remain in force and effect for successive terms of ________________________ each thereafter unless and until cancelled by either party giving _______________ written notice to the other party prior to the end of the primary term or any __________________ extension thereof, provided however, this agreement will automatically terminate if this agreement is not utilized for processing liquefiables during a period of 12 consecutive months.

ARTICLE VI

REMUNERATION

6.1 For transportation services rendered for Shipper each month under this Agreement, Shipper shall pay Company monthly a sum equal to the applicable rate set forth on the currently effective Sheet Nos. 22 or 34 multiplied by the aggregate quantities of liquefiables (in Dth) delivered for Shipper's account each day during the month.

6.2 In addition to the charges specified in Section 6.1 above, Shipper agrees to pay Company the following:

a) Any volumetric charges, surcharges or fuel applicable to firm and/or interruptible transportation services as set forth in Company's FERC Gas Tariff from time to time which are made applicable to the transportation service provided hereunder;

b) Any and all filing or other fees required in connection with transportation under this Agreement that Company is obligated to pay to the Commission or any other governmental authority having jurisdiction.

6.3 The rates and charges provided for under Agreement shall be subject to increase or decrease pursuant to any order issued by the Commission in any

Issued by: Glenn A. Sheffield, Director-Rates
Issued on: April 29, 2005 Effective on: March 1, 2005

PRO FORMA
LIQUEFIABLES TRANSPORTATION AGREEMENT
(Continued)

proceeding initiated by Company or applicable to the services performed hereunder. Shipper agrees that Company shall, without any further agreement by Shipper have the right to change from time to time, all or any part of its FERC Gas Tariff, including without limitation the right to change the rates and charges in effect hereunder, pursuant to Section 4(d) of the Natural Gas Act as may be deemed necessary by Company, in its reasonable judgment, to assure just and reasonable terms of service and rates under the Natural Gas Act. Nothing contained herein shall prejudice the rights of Shipper to contest at any time the changes made pursuant to this Section 6.3, including the right to contest the rates or charges for the services provided under this Agreement, from time to time, in any rate proceedings by Company under Section 4 of the Natural Gas Act or to file a complaint under Section 5 of the Natural Gas Act with respect to such rates or charges.

ARTICLE VII

CREDITWORTHINESS

7.1 If at any time Shipper is or becomes insolvent, or fails to demonstrate creditworthiness, or fails to make payments pursuant to Section 15 of the General Terms and Conditions, Shipper must provide to Company one of the following forms of credit to enter into or maintain in effect this Agreement: (a) a security deposit or other good and sufficient surety, as determined by Company in its reasonable discretion, in an amount equal to the cost of performing the maximum transportation service requested by Shipper for a three (3) month period; or (b) a guarantee from a creditworthy party that said party will be responsible for payment of all charges and penalties assessed by Company but not paid by Shipper hereunder.

ARTICLE VIII

MISCELLANEOUS

8.1 This Agreement constitutes the entire Agreement between the parties and no waiver by Company or Shipper of any default of either party under this Agreement shall operate as a waiver of any subsequent default whether of a like or different character.

Issued by: Greg P. Meyers, Vice-Pres. Rates
Issued on: July 31, 1998 Effective on: September 1, 1998

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

Second Revised Sheet No. 400
Superseding
First Revised Sheet No. 400

PRO FORMA
LIQUEFIABLES TRANSPORTATION AGREEMENT
(Continued)

8.2 The laws of the State of __________ shall govern the validity, construction, interpretation, and effect of this Agreement, without giving effect to any conflict of laws doctrine that would apply the laws of another jurisdiction.

8.3 No modification of or supplement to the terms and provisions hereof shall be or become effective except by execution of a supplementary written agreement between the parties.

8.4 This Agreement shall bind and benefit the successors and assigns of the respective parties hereto. Neither party may assign this Agreement without the prior written consent of the other party, which consent shall not be unreasonably withheld; provided, however, that either party may assign or pledge this Agreement under the provisions of any mortgage, deed of trust, indenture or similar instrument.

8.5 Exhibit A attached to this Agreement constitutes a part of this Agreement and is incorporated herein.

8.6 This Agreement is subject to all present and future valid laws and orders, rules, and regulations of any regulatory body of the federal or state government having or asserting jurisdiction herein. After the execution of this Agreement, each party shall make and diligently prosecute, all necessary filings with federal or other governmental bodies, or both, as may be required for the initiation and continuation of the transportation service which is the subject of this Agreement. Each party shall have the right to seek such governmental authorizations, as it deems necessary, including the right to prosecute its requests or applications for such authorization in the manner it deems appropriate. Upon either party's request, the other party shall timely provide or cause to be provided to the requesting party such information and material not within the requesting party's control and/or possession that may be required for such filings. Each party shall promptly inform the other party of any changes in the representations made by such party herein and/or in the information provided pursuant to this paragraph. Each party shall promptly provide the other party with a copy of all filings, notices, approvals, and authorizations in the course of the prosecution of its filings. In the event all such necessary regulatory approvals have not been issued or have not been issued on terms and conditions acceptable to Company or Shipper within twelve (12) months from the date of the initial application therefor, then Company or Shipper may terminate this Agreement without further liability or obligation to the other party by giving written notice

Issued by: Glenn A. Sheffield, Director-Rates
Issued on: August 23, 2004 Effective on: September 22, 2004

Previous Next Search

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

Second Revised Sheet No. 401
Superseding
First Revised Sheet No. 401

PRO FORMA
LIQUEFIABLES TRANSPORTATION AGREEMENT
(Continued)

thereof at any time subsequent to the end of such twelve-month period, but prior to the receipt of all such acceptable approvals. Such notice will be effective as of the date it is delivered to the U.S. mail for delivery by certified mail, return receipt requested.

8.7 (If applicable) This Agreement supersedes and cancels the Agreement (# ____________) dated ____________________ between the parties hereto.

IN WITNESS WHEREOF, this Agreement has been executed as of the date first written above by the parties' respective duly authorized officers.

Attest/Witness: SOUTHERN NATURAL GAS COMPANY

__________________________ By ____
Its ____

Attest/Witness: (SHIPPER)

__________________________ By ____
Its ____

Issued by: Glenn A. Sheffield, Director-Rates
Issued on: August 23, 2004 Effective on: September 22, 2004

Previous Next Search

Previous Next Search

SOUTHERN NATURAL GAS COMPANY
FERC Gas Tariff
Seventh Revised Volume No. 1

Third Revised Sheet No. 402
Superseding
Second Revised Sheet No. 402

PRO FORMA
LIQUEFIABLES TRANSPORTATION AGREEMENT
(Continued)

Service Agreement No. ______________

EXHIBIT A

PROCESSING ELECTIONS

Receipt Point and Source	Interest Owner	Percent of Working Interest to be Processed (if less than 100%)	Delivery Point/ Processing Plant	Effective Months
------------	----------	--------------------	-----------------	-----------

Shipper verifies that all processing arrangements are in place for the gas set forth above.

____
(SHIPPER)

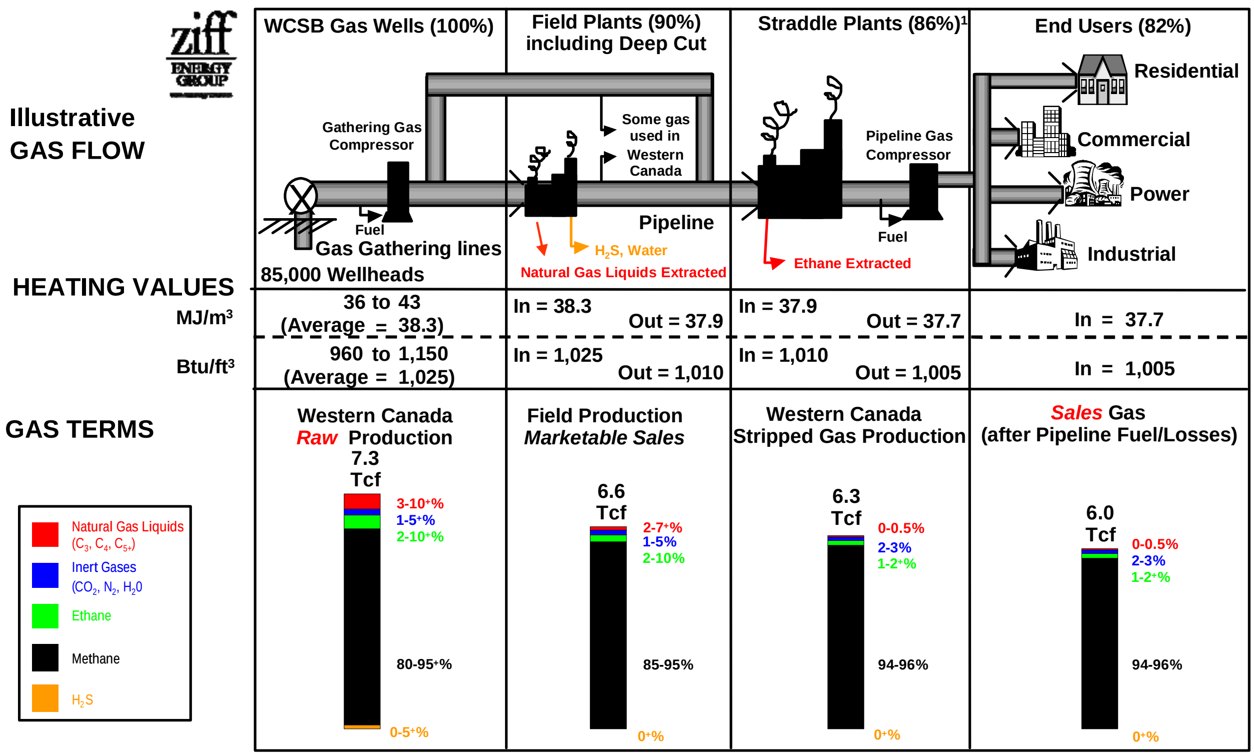
Issued by: Greg P. Meyers, Vice-Pres. Rates
Issued on: July 31, 1998 Effective on: September 1, 1998

Previous Next Search

This page intentionally left blank.

9.20 Appendix 20 – Illustrative Gas Production Terminology

Illustrative Gas Production Terminology



* Shrinkage over the past decade in Alberta has typically averaged 14% (AEUB Statistical Series 99-3)

[1] near Empress and at Cochrane regarding ANG export at ABC

Source: Ziff Energy

This page intentionally left blank.

9.21 Appendix 21 – Glossary of Terms

Associated Gas: Natural gas, commonly known as gas-cap gas, which overlies and is in contact with crude oil in the reservoir.

Bbl: barrel

Bbl/d: barrels per day

Bcf: billion cubic feet

Bcf/yr: billion cubic feet/year

Bitumen: Petroleum in semi-solid or solid forms.

Btu: British Thermal Unit (The amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit.)

Butane: A component of natural gas consisting of four carbon atoms and 10 hydrogen atoms; condenses into a liquid at relatively low temperature and pressure, also referred to as C4.

C1: Methane

C2: Ethane

C3: Propane

C4: Butane

C5: Pentane

C5+: Pentanes and heavier hydrocarbons

Coalbed Methane (CBM): Natural gas generated during the coalification process and trapped within coal seams, commonly referred to as natural gas from coal.

Condensate: A mixture of pentanes and heavier hydrocarbons usually recovered as a liquid from gas before the gas is processed. Condensate is included with oil volumes.

Conventional Crude Oil: Petroleum found in liquid form, flowing naturally or capable of being pumped without further processing or dilution.

Conventional Gas: Natural gas that can be produced using recovery techniques normally employed by the oil and gas industry. The distinction between conventional and unconventional gas is becoming less clear. See also unconventional gas.

Crude Oil: A mixture of hydrocarbons that existed in the liquid phase in natural phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities.

Diluent: Light liquid petroleum fractions blended with heavy oil to facilitate its transport through pipelines.

Dry Gas: Natural gas from the well that is produced without liquids, also a gas that has been treated to remove all liquids; pipeline gas.

EOR: Enhanced Oil Recovery.

Ethane: A component of natural gas consisting of two carbon atoms and six hydrogen atoms, condenses into a liquid at relatively low temperature and pressure, also referred to as C2.

Gas Processing Plant: Any facility which performs one or more of the following: removing liquefiable hydrocarbons from wet gas or casinghead gas; removing undesirable gaseous and particulate elements from natural gas such as H_2S and CO_2; removing water or moisture from the gas stream.

Gas Reserves: Include gas cap, solution, and non-associated gas.

Hydrates: hydrates are solid, crystalline, ice like substances containing methane/water with methane trapped in a water-ice lattice. They form under moderately high pressure at temperatures near freezing, in permafrost areas, sea bottom or under seabeds.

Hydrocarbons: Organic compounds containing only carbon and hydrogen

Hydrogen Sulphide (H2S): A naturally occurring, highly toxic gas with the odour of rotten eggs, sometimes contained in natural gas. See also Sour Gas.

In-situ: In its original place; in position; in-situ recovery refers to various methods used to recover deeply buried bitumen deposits, including steam injection, solvent injection and firefloods.

LDC: Local Distribution Company. An entity that owns a distribution system for the local delivery of energy (gas or electricity) to consumers.

Liquefied natural gas (LNG): Supercooled natural gas that is maintained as a liquid at or below -160°C; LNG occupies 1/640th of its original volume and is therefore easier to transport if pipelines cannot be used.

MBbl: thousand barrels.

Methane: A colourless, flammable, odorless hydrocarbon gas (CH4) which is the major component of natural gas; consisting of one carbon atom and four hydrogen atoms, methane remains in a gaseous state at relatively low temperatures and pressures.

Miscible Flood: An oil-recovery process in which a fluid, capable of mixing completely with the oil it contacts, is injected into an oil reservoir to increase recovery.

MMBbl: million barrels.

Natural Gas: A mixture of hydrocarbons and varying quantities of non-hydrocarbons that exist either in the gaseous phase or in solution with crude oil in natural underground reservoirs. Gaseous petroleum consisting primarily of methane with lesser amounts of (in order of abundance) ethane, propane, butane and pentane, and heavier hydrocarbons as well as non-energy components such as nitrogen, carbon dioxide, hydrogen sulphide and water.

Natural Gas Liquids (NGL): Liquids obtained during natural gas production, including ethane, propane, butanes, and condensate.

Pentane: A hydrocarbon compound consisting of five carbon atoms and 12 hydrogen atoms, also referred to as C5.

Propane: A component of natural gas consisting of three carbon atoms and eight hydrogen atoms, condenses into a liquid at relatively low temperature and pressure, also referred to as C3.

R/P: ratio of natural gas reserves or oil reserves to annual production, expressed in years, also referred to as reserve life.

Raw Natural Gas: A mixture containing methane plus all or some of the following: ethane, propane, butane, pentanes, condensates, nitrogen, carbon dioxide, hydrogen sulphide, helium, hydrogen, water vapour and minor impurities. Raw natural gas is the gas found naturally in the reservoir prior to processing.

Reserves: Recoverable portion of resources available for use based on current knowledge, technology and economics. [F&D Questionnaire: Total proven, working interest reserves data were gathered for Western Canada Conventional activity only. Data relating to tar sands, heavy oil thermal projects, international, and frontier are specifically excluded from the Ziff Energy study. These volumes include the royalty portion. The reporting units for gas reserves are Bcf. Liquids should be reported as millions of barrels (MMBbl) and sulphur as millions of Long Tons (MMLT). Definitions used in this questionnaire are consistent with those contained in NI 51-101 or with SEC standards.]

Resources: Those resources estimated to bed.

Secondary Recovery: The extraction of additional crude oil, natural gas and related substances from reservoirs through pressure maintenance techniques such as waterflooding and gas injection.

Shipper: A party who holds capacity on a natural gas transmission pipeline and has gas shipped on the pipeline, typically referred to as either “Shipper” or “Customer” in pipeline transportation tariffs.

Shrinkage: The reduction in volume of wet natural gas due to the extraction of some of its constituents, such as hydrocarbon products (ethane, butane, propane, pentanes), hydrogen sulphide, carbon dioxide, nitrogen, helium and water vapour.

Solution Gas: Natural gas that is found with crude oil in underground reservoirs. When the oil comes to the surface, the gas expands and comes out of the oil.

Sour Gas: Raw natural gas with a relatively high concentration of sulphur compounds, such as hydrogen sulphide. All natural gas containing more than one per cent hydrogen sulphide is considered sour. About 30% of Canada's natural gas production is sour, most of it found in Alberta and northeastern British Columbia.

Steam-Assisted Gravity Drainage (SAGD): A recovery technique for extraction of heavy oil or bitumen that involves drilling a pair of horizontal wells one above the other; one well is used for steam injection and the other for production.

Straddle Extraction Plant: A gas processing plant located on or near a gas transmission line that removes natural gas liquids from the gas and returns the gas to the transmission line.

Sweet Gas: Raw natural gas with a relatively low concentration of sulphur compounds, such as hydrogen sulphide.

Synthetic Crude Oil: A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from oil sands.

Tcf: trillion cubic feet.

Tight Gas: Gas existing in sand, conglomerate, and carbonates formations that are laterally continuous, gas-saturates, generally thick, and have low matrix permeability (usually less than 0.1 millidarcy). Found in sedimentary layers of rock that are cemented together so tight that it "greatly hinders" the extraction. Getting tight gas out usually requires enhanced technology like "hydraulic fracturing" where fluid is pumped into the ground to make it more permeable. The National Energy Board estimates Canada could have between 89 and 1500 trillion cubic feet (tcf) of tight gas, compared to total gas estimates (excluding tight gas) of 733 tcf.

Tight Gas Sands: Geological formations with low permeability containing natural gas.

Ultimate Potential: An estimate of recoverable reserves that will have been produced by the time all exploration and development activity is completed; includes production-to-date, remaining reserves, development of existing pools and new discoveries.

Unconventional Natural Gas: natural gas from coal formations, natural gas from tight sands and shale gas, conventional gas found in unconventional reservoirs or reservoirs requiring special production methods or technologies; natural gas from gas hydrates, conventional methane in an unconventional form occurring in a conventional reservoir.

Undiscovered Recoverable Resources: Those resources estimated to be recoverable from accumulations believed to exist based on geological and geophysical evidence but not yet verified by drilling, testing or production.

Upgrading: The process of converting heavy oil or bitumen into synthetic crude oil.

Wet Gas: Raw natural gas with a relatively high concentration of natural gas liquids (ethane, propane, butane, pentanes and condensates).

Yr: year.

This page intentionally left blank.

9.22 Appendix 22 – Overview of Ziff Energy

Ziff Energy Group, founded in 1982, is a leading international energy consulting firm providing sophisticated industry and operational business analysis, specialized consulting, and learning services to the world wide energy industry. We have offices in Houston and Calgary, the two principal oil and gas centers in North America. Our staff of 55^+ includes **many senior industry specialists**, with **15 - 25^+ years of domestic and international experience**.

The firm focuses its efforts principally in two areas:

- **Gas Services**; Ziff Energy Group is recognized for its in-depth analysis of North American as well as regional gas markets, gas and liquids supply, transportation, midstream, storage, regulatory affairs, and gas pricing forecasts.
- **E & P**; more than 100 North American upstream producers have been involved in field level operating cost and finding and development cost studies that cover most North America onshore and offshore production basins, and a growing number in foreign countries.

Gas Consulting Services

We are a major provider of natural gas customized consulting services to our growing list of clients. We undertake Gas Consulting assignments that address specific client needs in the areas of operations, strategies, and regulatory matters. Some specifics include:

- comprehensive advice on emerging gas industry issues and developments within North America and elsewhere internationally. Our technical knowledge and detailed analysis are particularly strong
- unbiased opinions on complex natural gas industry issues, supported by an understanding of your business challenges; our candid view of industry trends and developments
- expert testimony regarding gas pricing, supply, transportation, storage, and pipeline tolls
- early reporting on changing business conditions; strong competitive intelligence, especially on "frontier gas"
- clearly written, focused research that can help you identify business opportunities and threats; efficient delivery of knowledge.

Paul Ziff

CEO

Ziff Energy Group
1117 Macleod Trail SE
Calgary, Alberta T2G 2M8

p: (403) 234-4276
f: (403) 261-4631

paul.ziff@ziffenergy.com

Summary of Professional Experience

Mr. Ziff has three decades of assessment experience in the oil and natural gas industry. Before founding Ziff Energy, he worked in the financial sector conducting energy research, and conducted pricing analyses for an Alberta Government agency.

Industry Focus

Prior to founding Ziff Energy Group in 1982, Mr. Ziff's focus was directing energy research for a major investment firm, and gas pricing analysis for a key Alberta government agency. Mr. Ziff is a specialist on natural gas industry strategies, gas supply and markets, and corporate performance of North American exploration and producing companies. He conceived and directed a wide range of benchmarking studies and consulting projects in upstream corporate performance, which have expanded to over 15 countries worldwide. Mr. Ziff's firm is a member of LNG Solutions, along with the major Norwegian firm, Det Norske Veritas (DNV), and the noted Washington law firm, Sutherland Asbill Brennan. He is extensively quoted in business and trade media and has been featured as a guest speaker at energy industry events, conferences, and corporate directors meetings in North America and abroad.

Memberships & Professional Associations

Calgary Council of the Americas
Economics Society of Calgary (Past President)
Harvard Club of Calgary
Houston Energy Association (HEA)
Houston Energy Finance Group
Independent Petroleum Association of America (IPAA)
International Association for Energy Economics (IAEE)
National Association of Petroleum Investment Analysts (NAPIA)
National Energy Services Association (NESA)
Past Director, Petroleum Communication Foundation (PCF; Past Director)
Petroleum Services Association of Canada (PSAC)
Southern Gas Association (SGA)
The Strategic Leadership Forum (past Board Member)

Education

Bachelor of Arts, Economics and Political Science, Honours, Harvard University, Cambridge, Massachusetts, 1973
European Economics, Politics & History, Institut d'Études Politiques, Université de Paris-Sorbonne, Paris, France (original research in France & Algeria on Algerian Energy Development), 1971-1972
Graduate Courses, Kennedy School of Government & Harvard Business School, 1972-1973

W.P. (Bill) Gwozd, P.Eng.

Vice President,
Gas Services

Ziff Energy Group
1117 Macleod Trail SE
Calgary, Alberta T2G 2M8

p: (403) 234-4299
f: (403) 261-4631

bill.gwozd@ziffenergy.com

Summary of Professional Experience

Mr. Gwozd has three decades of industry experience in natural gas and natural gas liquids. He has engineering and technical experience with a major producer and with a diversified Alberta utility and midstream company. Mr. Gwozd currently manages the Gas Consulting practice at Ziff Energy.

Industry Focus

For seven years Mr. Gwozd worked for a major international exploration and production company marketing gas, natural gas liquids (NGL's), and sulphur. For the next twelve years he worked in a management capacity with a diversified Alberta utility and midstream gas and liquids company doing gas supply planning, regulatory, gas control, gas purchasing, and gas storage. Mr. Gwozd has prepared and implemented gas supply and storage strategies, directed gas control functions for supply and transportation arrangements, and prepared written regulatory applications. Other experience includes planning and rationalizing transportation for natural gas liquids pipelines and storage facilities. At Ziff Energy, Mr. Gwozd oversees the North American Gas Strategies Retainer Service, which focuses on long term forecast assessments, semi-annual client briefings, and leads expert witness testimony service offerings. Detailed analysis and consulting assignments include: long term natural gas price outlooks (to 2030), pipeline acquisitions, regional changes in gas markets, North American gas supply and demand forecasts, expert witness testimony, gas storage development, transportation alternatives, and gas price outlooks for regional multi-client assessments. He leads Ziff Energy's multiclient studies including two northern gas assessments. Mr. Gwozd leads on-site client presentations and moderates technical panels at various industry conferences. He (co) authors monthly client-confidential reports and analyses and is a frequent guest contributor to various media, including television, radio, newspapers, and industry publications.

Memberships & Professional Associations

Pacific Coast Gas Association (PCGA – 1997 Gold Medal recipient)
Alberta Professional Engineers, Geologists and Geophysicists of Alberta (APEGGA)
Calgary Chamber of Commerce
NESA

Education

University of Calgary, B.Sc. Chemical Engineering, 1979
Southern Alberta Institute of Technology, Diploma, Chemical Engineering Technology, 1976

David Vetsch, P. Eng.

Senior Associate

Ziff Energy Group
1117 Macleod Trail SE
Calgary, Alberta T2G 2M8

p: (403) 234-6558
f: (403) 261-4631

dave.vetsch@ziffenergy.com

Summary of Professional Experience

Mr. Vetsch has a quarter century of natural gas industry experience, including management positions with a major North American utility, as well as natural gas consulting services to small and large corporations.

Industry Focus

Mr. Vetsch's experience includes supply studies for straddle plants, managing gas contracts, planning and procuring natural gas supplies for major utilities, managing and marketing transportation capacity, storage optimization studies and marketing for a major storage field, advising clients with respect to gas retail market deregulation, and managing all functions of small oil and gas companies through high growth periods and divestments. Consulting assignments have included various long term supply and demand studies, oil sands outlooks for oil and gas requirements, litigation projects, identifying purchase/rate options and rates/regulatory status of retail market deregulation, recommending legislative changes and regulatory interventions, advising oil and gas clients on hedging strategies, negotiating natural gas and crude oil sales and transportation contracts, and economic evaluations of oil and gas projects.

Memberships & Professional Associations

Association of Professional Engineers, Geologist, and Geophysicists of Alberta (APEGGA) since 1980

Education

B.Sc., Mechanical Engineering, University of Calgary, 1980
Courses on energy futures, management development, contract law, negotiation techniques, and oil and gas property evaluation

Simon Mauger, P. Geol.

Manager, Gas Services

Ziff Energy Group
1117 Macleod Trail SE
Calgary, Alberta T2G 2M8

p: (403) 234-4283
f: (403) 261-4631

simon.mauger@ziffenergy.com

Summary of Professional Experience

Mr. Mauger has 30 years experience in the upstream oil and gas industry as an exploration and development geologist in the Western Canadian Sedimentary Basin and other locations.

Industry Focus

Mr. Mauger planned, evaluated and modeled gas resources for a leading international exploration and production company, prepared long term gas supply plans, and developed the regional exploration component for the company's North American integrated natural gas strategy. As a contributing member of the Canadian Gas Potential Committee, Mr. Mauger has evaluated several geological plays for the rigorous assessment of Canadian gas resources potential. At Ziff Energy, Mr. Mauger develops the gas supply outlook for all North American gas producing regions, authors technical research reports on supply, demand, and transport issues, and provides an independent assessment of reports prepared by others. He manages Ziff Energy Group's industry standard Finding and Development Cost Study, which is in it's 22nd year, and undertakes long term supply forecasts for various North American gas basins for private clients to 2030.

Memberships & Professional Associations

Association of Professional Engineers, Geologists and Geophysicists of Alberta
Canadian Society of Petroleum Geologists
American Association of Petroleum Geologists
Society of Petroleum Engineers
Canadian Gas Potential Committee

Education

Bachelor of Science, University of Bristol England, June 1977
Management Development Certificate, University of Calgary, June 1991

Cameron Gingrich

Lead Project Analyst,
Gas Services

Ziff Energy Group
1117 Macleod Trail SE
Calgary, Alberta T2G 2M8

p: (403) 234-4296
f: (403) 261-4631

cameron.gingrich@ziffenergy.com

Summary of Professional Experience

Mr. Gingrich has half a dozen years of natural gas experience in research, analysis and authoring complex gas studies.

Industry Focus

Mr Gingrich is primarily responsible for analytical support and in-depth customized data analysis, trending, and modeling for the Gas Services team. He brings a wealth of insight, diligence and economic knowledge. His efforts toward the North American Gas Strategies Retainer Service, multi-client studies and gas transportation. Custom consulting projects include: authoring topic papers for Ziff Energy's retainer clients on gas demand outlook, power generation outlook, analyzing pipeline tolls, gas supply/storage load duration modeling, and gas price modeling. Mr. Gingrich was the lead analyst on the Northern Gas and Evolution of Dawn Hub multi-client studies, and authored papers on: 2006 Summer Gas Storage Analysis, Canadian Gas Exports to 2020, Natural Gas Price Forecast to 2015, and LNG Outlook to 2015. For Ziff Energy Group private clients, he has undertaken supply, demand, and gas price forecast assessments to 2030. Before joining Ziff Energy Group, Mr. Gingrich worked in the financial and transportation industries.

Education

Bachelor of Science, University of Alberta
Bachelor of Arts (Economics - Strategic Energy and Financial Markets), University of Calgary.
Canadian Securities Course

Edward Kallio

Manager, Gas Consulting

Ziff Energy Group
1117 Macleod Trail SE
Calgary, Alberta T2G 2M8

p: (403) 234-4275
f: (403) 261-4631

edward.kallio@ziffenergy.com

Summary of Professional Experience

Mr. Kallio has over a quarter century of gas industry experience in trading, marketing, portfolio management, supply, forecasting and policy analysis in the private and public sectors.

Industry Focus

Mr. Kallio's experience includes analysis of pipeline rate applications, economic analysis of major domestic and cross-border gas transactions and contracts, and negotiation of storage, transportation and supply arrangements. He has advised clients with respect to natural gas and electricity supply transactions and hedging programs. Mr. Kallio has traded natural gas in several North American gas supply basins and managed production and supply portfolios in eastern and western Canada and the U.S. He has advised Canadian and U.S. companies with respect to deregulation of retail energy markets. Mr. Kallio's public sector experience includes energy policy assignments with the Federal Department of Energy, Mines and Resources, the Alberta Department of Energy and Alberta Petroleum Marketing Commission. At Ziff Energy, Mr. Kallio conducts analyses of gas and liquids issues and fundamentals and participates in on-site client presentations.

Memberships & Professional Associations

Council of Energy Advisors

Education

Bachelor of Arts, Carleton University
Course work in Project Management and Evaluation of Canadian Oil and Gas Properties

Dana Bozbiciu, B.Sc.

Senior Analyst

Ziff Energy Group
1117 Macleod Trail SE
Calgary, Alberta T2G 2M8

p: (403) 234-4290
f: (403) 261-4631

dana.bozbiciu@ziffenergy.com

Summary of Professional Experience

Ms. Bozbiciu has 15 years experience in natural gas and power operations, geophysics, transportation and energy analysis.

Industry Focus

Ms. Bozbiciu is responsible for analytical support to three growing gas service businesses: custom consulting, multi-client assessments, and the North American Gas Strategies Retainer Service. Her professional background includes experience in gas, water, and thermal pipeline installations, seismic operations, and statistical analysis for oil and gas companies. Dana was lead author on an assessment of gas storage costs and winter/summer gas price differentials, a study relating to revenues and costs for gas storage operators, and has performed technical reviews relating to gas storage withdrawals and injections for seven North American regions. Dana has also authored custom projects, including a study of North American pipeline expansion proposals for oil sands and other North American regions. Dana is fluent in several European languages.

Memberships & Professional Associations

Canadian Society of Petroleum Geologists
Association of Professional Engineers, Geologists, and Geophysicists of Alberta (APEGGA) Examination Candidate

Education

Degree in Geological and Geophysical Engineering, Babes-Bolyai University, Romania
Courses in Management Training.

Janet Lynch, Senior Associate

Senior Associate

Ziff Energy Group
1117 Macleod Trail SE
Calgary, Alberta T2G 2M8

p: (403) 234-4297
f: (403) 261-4631

janet.lynch@ziffenergy.com

Summary of Professional Experience

Ms. Lynch is the President and founder of OMNIgas, Inc. an energy-consulting firm founded in 1988. Ms. Lynch works with producers, utilities, marketing and consulting firms and pipelines in the United States Rockies and Gulf Coast regions developing marketing and communications options and energy related investment opportunities. Over the past four years her firm has become a highly recognized authority on the development of natural gas market centers and Internet accessed information systems. Ms. Lynch was responsible for the creation and development of Montana Power Company's Internet accessed OneStep DataTM Service. In addition to those activities, Janet is a frequent guest speaker and lecturer on the new emerging energy marketplace and the Internet.

Zahra Dhalla, B.A., Analyst, Gas Services

Analyst, Gas Services

Ziff Energy Group
1117 Macleod Trail SE
Calgary, Alberta T2G 2M8

p: (403) 234-4291
f: (403) 261-4631

zahra.dhalla@ziffenergy.com

Summary of Professional Experience

Ms. Dhalla is responsible for Research, Analysis, Interpretation, and Data Management for Natural Gas Strategies Retainer Services, custom consulting, and multi-client assessments. Zahra has authored four research papers on the Canadian Natural Gas, Electricity, and Oil markets for the Canadian Energy Research Institute as part of her courses at the University of Calgary. She is currently working towards a B.A. in Economics with concentration in Applied Energy.

Zuzana Jurickova, Ing. , Analyst, Gas Services

Analyst, Gas Services

Ziff Energy Group
1117 Macleod Trail SE
Calgary, Alberta T2G 2M8

p: (403) 265-0600
f: (403) 261-4631

zuzana.jurickova@ziffenergy.com

Summary of Professional Experience

Ms. Jurickova has been a member of Ziff Energy Group since 2005. She has assisted with number of projects in the areas of research and analysis. Over this period she has worked on the Western Canada Reserve Replacement (F&D) Cost Study, a study on North American Cost Inflation for a major producer, and a study of North American pipeline expansions for a major steel producer. She is currently working on North American Gas Supply costs for 20 basins (and LNG). Prior to joining Ziff, Ms. Jurickova worked in corporate credit and finance. Ms. Jurickova obtained her five-year Degree in Economics from University of Economics in Bratislava, Slovakia.

Melody Veinot, Manager, Production

Manager, Production

Ziff Energy Group
1117 Macleod Trail SE
Calgary, Alberta T2G 2M8

p: (403) 234-4293
f: (403) 261-4631

melody.veinot@ziffenergy.com

Summary of Professional Experience

Ms. Veinot has been with Ziff Energy Group since 2000. She is responsible for coordinating and planning the design and publishing of all reports, documents, and presentations, with a focus on quality control. She is currently coordinating the production of several benchmarking and custom reports for clients around the world, and is designing a new website to be launched this year. Ms. Veinot is currently completing a Master Graphic Design certificate from SAIT.

Gareth Slater, Director, Information Services

Director, Information Services

Ziff Energy Group
1117 Macleod Trail SE
Calgary, Alberta T2G 2M8

p: (403) 234-4288
f: (403) 261-4631

gareth.slater@ziffenergy.com

Summary of Professional Experience

Mr. Slater has over fifteen years of information systems management and support experience. Mr. Slater leads Ziff Energy Group's Information Systems & Technology department, and is responsible for overall systems management, corporate data management, and design/development of Ziff Energy's core benchmarking / analysis software and supporting data systems. Most recently Mr. Slater designed and developed Ziff Energy's latest operations benchmarking framework, which is used to support consulting and industry analysis studies.