Exhibit No. 02-013

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September 16, 2005

Alberta Energy and Utilities Board
640 - 5th Avenue S.W.
Calgary, Alberta
T2P 3G4

By electronic filing

Attention: **Lisa Kelly**
Application Officer

Dear Ms. Kelly:

Subject: **NOVA Gas Transmission Ltd. (NGTL)**
2005 General Rate Application Phase 2
EUB Application No. 1396409
Reply Evidence of NGTL

Enclosed for filing with the Board is NGTL's Reply Evidence in this proceeding. It is comprised of company evidence and the Reply Testimony of NGTL's external rate design expert, Dr. J. Stephen Gaske of Zinder Companies, Inc.

NGTL has preassigned Exhibit No. 02-013 to this letter and the company's Reply Evidence, and Exhibit No. 02-014 to the Reply Testimony of Dr. Gaske.

Yours truly,

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

[ORIGINAL SIGNED BY]

Patrick M. Keys
Associate General Counsel, Law
Gas Transmission

Alberta Energy and Utilities Board

IN THE MATTER OF the *Alberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-7, and the Regulations under it;

IN THE MATTER OF the *Gas Utilities Act*, R.S.A. 2000, c. G-5, as amended, and the Regulations under it;

IN THE MATTER OF the *Public Utilities Board Act*, R.S.A. 2000, c. P-45, as amended, and the Regulations under it; and

IN THE MATTER OF an Application by NOVA Gas Transmission Ltd. (NGTL) to the Alberta Energy and Utilities Board for an order fixing final rates, tolls and charges for Alberta System services provided by NGTL from January 1, 2005 to December 31, 2005.

Reply Evidence
of
NOVA Gas Transmission Ltd.

September 16, 2005
EUB Application No. 1396409

NGTL 2005 GRA PHASE 2

TABLE OF CONTENTS

1.0 INTRODUCTION

Q1. What is the purpose of NOVA Gas Transmission Ltd.'s (NGTL) written reply evidence?

A1. NGTL in this written reply evidence (Reply Evidence) responds to and refutes proposals made and positions taken by ATCO Pipelines Ltd. (ATCO Pipelines), the Industrial Gas Consumers Association of Alberta (IGCAA), and the Western Export Group (WEG) in their respective written evidence dated July 22, 2005 (Exhibit Nos. 07-005,07-006, 07-006-01, 22-005-001, and 33-005-001).

Q2. How is NGTL's Reply Evidence organized?

A2. NGTL's Reply Evidence is comprised of company evidence and the Reply Testimony of NGTL's external rate design expert, Dr. J. Stephen Gaske of Zinder Companies, Inc.

NGTL has organized the company evidence to respond to particular positions and proposals presented by certain interveners. Specifically, NGTL addresses the following issues:

Section 2.0	The competitive environment for gas transmission in Alberta;
Section 3.0	ATCO Pipelines' and IGCAA's criticisms of the existing rate design and their proposed alternatives;
Section 4.0	ATCO Pipelines' criticisms of the existing accountability provisions associated with intra-Alberta delivery service and its proposed alternatives; and
Section 5.0	WEG's criticisms of NGTL's energy conversion proposal for export delivery service.

Dr. Gaske, in his Reply Testimony, evaluates and responds to criticisms, economic analyses, and the proposed rate design alternatives of ATCO Pipelines and its consultant, Gordon Engbloom.

Q3. Does NGTL agree with Dr. Gaske's statements as expressed in his Reply Testimony?

A3. Yes. NGTL agrees with Dr. Gaske's statements.

Q4. Does NGTL have any general observations about the interveners' evidence overall?

A4. Yes. The interveners' evidence, considered collectively, illustrates two points important to the context of this proceeding and to the Board's determination of the Application.

First, the evidence highlights the broad range and diverse nature of stakeholder interests and views on cost allocation and rate design issues for the Alberta System. This point is clearly illustrated in the significantly different and contradictory approaches to cost allocation and rate design for intra-Alberta delivery service that are advocated by ATCO Pipelines, IGCAA and WEG. Not surprisingly, these interveners advocate rate designs which would minimize their specific transportation costs or otherwise advance their competitive positions. However, it is clear from the evidence of all parties that the interests of all stakeholders cannot be fully satisfied or otherwise accommodated by any single rate design.

Second, and more importantly, the intervener evidence demonstrates that the existing rate design continues to represent an acceptable balance of interests for the majority of stakeholders. Some parties clearly do not view the existing rate design to be optimal, and, absent any other considerations, would prefer different cost allocation approaches and rate structures. However, most stakeholders accept the existing rate design as an appropriate and reasonable compromise of all competing interests.

Q5. Does NGTL address or respond in this Reply Evidence to all statements or positions of interveners in evidence which NGTL disagrees with or otherwise opposes?

A5. No. NGTL recognizes the primary purpose of reply evidence is for the applicant to provide an evidentiary response to new and previously unaddressed matters which interveners have raised in their evidence.

NGTL has determined it requires no reply evidence to ultimately respond to some statements made and positions adverse to NGTL's interests taken by interveners in their evidence. NGTL will, as appropriate and as required, explore, challenge and respond to the merits of such other issues through cross-examination and argument.

Accordingly, the Board and interested parties should not infer from NGTL's silence in this Reply Evidence on other matters raised by interveners in evidence that NGTL agrees with or is otherwise indifferent to any opposing or contrary positions advanced by interveners. To the contrary, NGTL generally disagrees with such evidence to the extent it differs from NGTL's stated positions to date.

2.0 GAS TRANSMISSION COMPETITION IN ALBERTA

2.1 Introduction

Q6. What is the purpose of this section of NGTL's rebuttal evidence?

A6. NGTL in this section replies to statements made and positions taken by ATCO Pipelines in its evidence about the competitive environment for gas transmission in which it and NGTL operate and the impacts of ATCO Pipelines' FT-A proposal on that environment.

Specifically, ATCO Pipelines has provided extensive evidence on the scope and nature of competition between it and NGTL and the factors which influence that competition. It has suggested, among other things, that:

- Competition between ATCO Pipelines and NGTL has intensified at both the production and market sides of the gas transmission business, in part as the result of an unlevel playing field.[1]
- Producers look at the highest netback and industrials look at the lowest delivered plant gate price when determining on which pipeline to transport gas. ATCO Pipelines suggests that these producer netbacks and industrial delivered plant gate prices depend not only on transmission service rates, but also on on-system gas prices.[2]
- Rate design can have a significant impact on the development of a competitive environment and on whether or not there is a level playing field.[3]
- ATCO Pipelines' proposed FT-A rate design would not provide it with a competitive edge for intra-Alberta delivery volumes – it simply results in an FT-A rate that is more representative of its cost causation.[4]

[1] Exhibit No. 07-005, Written Evidence of ATCO Pipelines, page 1, lines 2-5; and Exhibit No. 07-014, response to CG-AP-1(a).
[2] Exhibit No. 07-005, Written Evidence of ATCO Pipelines, page 14, lines 8-11.
[3] Ibid, page 2, lines 6-7.
[4] Ibid, page 16, lines 5-6.

- ATCO Pipelines' system is primarily designed for delivery of on-system receipts to on-system end users and that ATCO Pipelines does not compete for ex-Alberta service to the same degree that it competes for on-system receipt and intra-Alberta delivery customers.[5]

- ATCO Pipelines and NGTL have each offloaded the other's system in the past.[6]

Q7. What is NGTL's response to these general assertions by ATCO Pipelines?

A7. NGTL agrees with some statements and disagrees with others. ATCO Pipelines has described, sometimes inaccurately, only parts of the overall competitive framework and the factors which influence competition between it and NGTL. NGTL believes it is important that complete and accurate information is available to the Board and others to properly understand and assess the drivers and impacts associated with ATCO Pipelines' criticisms of the existing rate design and ATCO Pipelines' proposed amendments to it.

Q8. How has NGTL organized the evidence in this section?

A8. NGTL has organized its evidence under the following three subsections:

- a description of the competitive environment in which NGTL operates;

- a description of the competitive environment that exists between ATCO Pipelines and NGTL, including the history associated with it; and

- an overview of ATCO Pipelines' past and present rate design and the impact of its proposed FT-A rate design.

[5] Exhibit No. 07-015, response to IGCAA-AP-1(a) and (b).
[6] Exhibit No. 07-005, Written Evidence of ATCO Pipelines, page 1, lines 25-27 and page 2, lines 1 and 2.

2.2 The Competitive Environment

Q9. ATCO Pipelines states in response to information request NGTL-AP-9(b) "While there may be a competitive gas transmission environment outside of Alberta, AP's referenced comments focus on the competition between AP and NGTL within Alberta."[7]

Further, in its response to information request NGTL-AP-33(a), ATCO Pipelines states that NGTL has changed its focus to increasing its intra-Alberta service volumes from its historic focus on receipt and export service.[8]

Does NGTL agree with ATCO Pipelines' characterization of the competitive environment?

A9. No. ATCO Pipelines understates the competitive situation. The competitive environment within which NGTL operates is much larger that just the intra-Alberta industrial marketplace.

To fully understand the business environment facing NGTL, the interaction between NGTL and all other pipelines that serve the WCSB, as well as NGTL's interaction with its various customer constituents must be considered. NGTL has to consider its competitive interface with all of these stakeholders and competitors, not just ATCO Pipelines, when establishing an appropriate rate design for the Alberta System.

Q10. Please describe the competitive business environment in which NGTL operates.

A10. Presently, excess export pipeline capacity is connected to the Western Canada Sedimentary Basin (WCSB). Consequently, both export and intra-Alberta pipelines compete for a limited gas supply that cannot fill all of the available capacity.

NGTL operates within this competitive environment where other pipeline companies, as well as NGTL's customer base, compete to transport gas from supply to markets located

[7] Exhibit No. 07-012, response to NGTL-AP-09(b).
[8] Exhibit No. 07-012, response to NGTL-AP-33(a).

within Alberta, as well as to export pipelines and the markets that they serve outside Alberta.

Q11. What is the result of this business environment?

A11. Customers have an increased level of choice in the present environment. NGTL has observed a change in contracting practices from long-term firm commitments to short-term contracts that provide customers with greater flexibility to switch to and from different pipelines.

NGTL believes that competition exists at receipt points, at the intra-Alberta delivery points and at the provincial export points. NGTL must address through the rate design for the Alberta System many facets of competition, and it recognizes that competition is not merely limited to the interface between it and ATCO Pipelines, or to the intra-Alberta delivery market. If NGTL is not competitive at all of these locations at all times, any one of NGTL's competitors or customers may instead serve the market.

Consequently, NGTL is simultaneously competing to retain existing and acquire new supply, retain existing and acquire new intra-Alberta markets, and retain and grow deliveries to pipelines serving ex-Alberta markets.

Q12. Can NGTL be more specific about the competitive landscape?

A12. Yes. Over the past 10 years, NGTL has experienced increasing levels of competition to provide transportation service to Alberta-based supply, intra-Alberta markets and export pipelines that serve markets outside of Alberta.

Specifically, NGTL has lost receipt volumes, and the associated receipt and delivery revenues, to:

- other pipelines that obtain supply within Alberta, for example, ATCO Pipelines when delivering to its on-system market;

- other pipelines that deliver to export markets, for example, the Alliance Pipeline, the AltaGas Suffield System, and the ATCO Pipelines/Alliance and ATCO Pipelines/TransGas pipeline interconnects; and
- other pipelines that deliver to intra-Alberta markets such as ATCO Pipelines' Muskeg River Pipeline.

Q13. Are these the only examples where NGTL has lost volumes to other service providers?

A13. No. However, there were other proposals to bypass the Alberta System which, for a variety of reasons, did not proceed. These include PanCanadian's Palliser Pipeline, Northstar's Coleman pipeline, ATCO Gas/Shell Crowsnest pipeline, ATCO's Alberta Pipeline Project, and the Petro-Canada Medicine Hat pipeline.

Q14. Has NGTL quantified the level of competition that it has seen over this period?

A14. Yes. Since 1995, the volume for which NGTL has been at risk of physical bypass, or for which competitive pricing has been required in order to retain load, is approximately 5 to 6 Bcf/d of an approximate capacity of 12 Bcf/d.

Since 1995, WCSB supply has increased from approximately 14.7 Bcf/d to 16.9 Bcf/d in 2004. Alberta supply, which consists of only the Alberta portion of the WCSB supply, has increased from 12.2 Bcf/d in 1995 to 13.4 Bcf/d in 2004. Over the same time frame, NGTL's market share of Alberta supply has dropped from approximately 91% in 1995 to 75% in 2004.

2.3 Competition between ATCO Pipelines and NGTL

Q15. In its response to information request NGTL-AP-3(d), ATCO Pipelines indicates that competition between it and NGTL has existed since the mid-1950s, however the competition was relatively dormant until the mid 1980s.[9] Does NGTL agree?

A15. No. NGTL believes that the competition for gas transmission services between it and ATCO Pipelines first materialized in any meaningful way during the mid-1990s and it has escalated, particularly since the late 1990s when ATCO Pipelines was created as a stand-alone transmission business unit separate from its LDC roots. As a result, NGTL and ATCO Pipelines have competed to capture export markets, existing supply as well as growth in supply, and existing intra-Alberta markets and growth in those markets.

Q16. ATCO Pipelines discusses the scope of competition between it and NGTL in several places in its evidence. First, it states in its response to information request IGCAA-AP-1(a) that it does not compete for ex-Alberta service in the same sense that it competes for intra-Alberta delivery and on-system receipt customers.[10] Second, it states in its response to information request IGCAA-AP-1(b) that its deliveries to and from other pipelines are dependant on the imbalance of on-system receipts and deliveries.[11] Lastly, in its response to information request IGCAA-AP-1(a),[12] ATCO Pipelines states "To the extent of these interconnections, AP can be considered to be competing with NGTL for ex-Alberta service, although AP's ability to do so is severely restricted by AP's lack of significant connections to export pipelines." Does NGTL agree with ATCO Pipelines' characterization of the scope of the competition between them?

A16. No. A review of past annual reports of ATCO Pipelines' parent entities, ATCO Ltd. and its operating group, Canadian Utilities Limited (CU), illustrates an interest in the development of pipelines that will bypass both receipt and export markets which NGTL already serves.

[9] Exhibit No. 07-012, response to NGTL-AP-3(d).
[10] Exhibit No. 07-015, response to IGCAA-AP-1(a).
[11] Exhibit No. 07-015, response to IGCAA-AP-1(b).
[12] Exhibit No. 07-015, response to IGCAA-AP-1(a).

First, in its 1996 Annual Report, CU stated that ATCO Gas Pipelines (AGP) "will develop large diameter pipeline systems within Alberta and western Canada." It further stated:

> In December, ATCO Gas Pipelines, Amoco Canada Petroleum Company Ltd. and Shell Canada Limited announced the $450 million Alberta Pipeline Project (APP). The proposed APP involves three pipeline segments in Central Alberta which would enable gas producers to access markets in Alberta, other provinces and the United States at reduced cost. Producers would be able to access the APP through main lines or the transmission systems of Northwestern Utilities and Canadian Western Natural Gas.[13]

CU also stated in its 1996 Annual Report that AGP and Shell Canada had announced plans "for the $30 million Crowsnest Pipeline Project to deliver gas from Shell's Waterton Plant to export facilities just across the B.C. border. AGP would operate the Alberta Pipeline Project and the Crowsnest Pipeline." [14] NGTL notes that the Shell Waterton Plant had been served exclusively by NGTL since its startup in the early 1960s. Both the Crowsnest and the APP were simple bypasses of the Alberta System and would have eliminated the collection of both NGTL receipt and export delivery tolls on the volumes that would have been transported by these projects.

While the proposed projects discussed above were unsuccessful, ATCO Pipelines has successfully connected to export markets via the construction of interconnections to the Alliance and TransGas pipelines. CU describes in its annual reports a succession of projects that have been established to connect gas to the Alliance pipeline. Most recently, in the 2004 Annual Report, CU stated that "ATCO Pipelines signed an agreement in late 2004 to build a fifth interconnection with the Alliance Pipeline."[15] In total, ATCO Pipelines has the ability to deliver more than 275 MMcf/d of gas to the Alliance pipeline. This is equivalent to approximately 25% of the ATCO Pipelines North market. In November 2003, ATCO Pipelines saw peak day nominations of 200 TJ/d into Alliance from Paddle River and Edson alone.[16]

[13] Canadian Utilities Limited, 1996 Annual Report, page 6.
[14] Ibid, page 7.
[15] Canadian Utilities Limited, 2004 Annual Report, page 17.
[16] Canadian Utilities Limited, 2003 Annual Report, page 22.

Similarly, ATCO Pipelines has pursued export markets through the TransGas system in Saskatchewan. In its 2003 Annual Report, CU noted "In April, ATCO Pipelines commenced delivery service to TransGas Limited, the Saskatchewan natural gas transmission company. Firm contracts of 15 TJ/day were signed with deliveries as high as 32 TJ/day in 2003."[17]

Q17. ATCO Pipelines states in its response to information request NGTL-AP-9 that it competes with Alliance.[18] Does NGTL agree that ATCO Pipelines presently competes with Alliance?

A17. No. While ATCO Pipelines may have competed with Alliance for supply when Alliance was first constructed, it now uses the existence of Alliance as an opportunity to develop export deliveries. This practice in turn enables ATCO Pipelines to attract additional supply from elsewhere to satisfy these deliveries.

ATCO Pipelines has repeatedly promoted its interest in the construction of new delivery facilities that tie into the Alliance Pipeline and the provision of gas transmission service to it. An example of this behaviour is the following notice that was published in the Daily Oil Bulletin on January 7, 2004:

> ## ATCO Pipelines Offers Firm Delivery Capacity To Alliance Pipeline
>
> **ATCO Pipelines** is currently entertaining delivery requests for natural gas transportation service from ATCO Pipelines' system to **Alliance Pipeline**. ATCO Pipelines currently has two interconnects with Alliance Pipeline at Edson and Paddle River. These two interconnects are capable of a combined deliveries of up to 165 million cubic feet per day.
>
> This delivery service is highly reliable and customers benefit from the operational balancing agreement that exists between the two pipeline companies. Customers holding firm delivery capacity on ATCO Pipelines for deliveries to Alliance Pipeline have priority access to any incremental delivery capacity that ATCO Pipelines may have on any day.
>
> If you would like to take advantage of this opportunity, please call ATCO Pipelines' **Jim Yaremko** at 245-7317, or **Bob Moore** at 245-7673.

[17] Ibid.
[18] Exhibit No. 07-012, response to NGTL-AP-9.

ATCO Pipelines provides delivery service to the Alliance and TransGas pipelines under its OPDM service, which has a delivery toll of 0¢/GJ provided that the nominated gas actually flows.

These projects connected supply directly to markets, and in these instances the markets are export pipelines. Connecting to these new markets enables ATCO Pipelines to grow its receipt volumes.

Q18. NGTL stated earlier that ATCO Pipelines also competes with NGTL for supply. Please elaborate.

A18. ATCO Pipelines has in recent years significantly increased the amount of directly-connected supply to its on-system markets through a variety of projects. This fact is confirmed by a review of CU's annual reports.

In its 1997 annual report, CU noted that "Northwestern and Canadian Western invested approximately $140 million in capital to increase system capacity, debottleneck existing pipelines, connect new customers and make general improvements to the transmission and distribution pipeline systems."[19]

In its 1998 annual report, CU noted "'Debottlenecking' facilities, installed in 1997, enabled significant growth in northern producer receipts during 1998." It also noted that the "Carseland extension, completed in 1997, facilitated 1998 growth in southern producer receipts." As a result of these and other projects "[t]hroughput on the system increased by 15%."[20]

In its 1999 annual report, CU noted:

> Natural gas transportation throughput on ATCO Pipelines' extensive system reached record levels as gas producers aggressively tied in natural gas in areas adjacent to ATCO Pipelines' system. …
>
> ATCO Pipelines has rapidly grown to become a significant player in the natural gas transportation industry, with over 230 transportation customers. On-system receipts grew by 11% over 1998, to average 981 TJ/day, while industrial deliveries increased to average 926 TJ/day, up 3% from the previous year. …

[19] Canadian Utilities Limited, 1997 Annual Report, page 15.
[20] Canadian Utilities Limited, 1998 Annual Report, page 17.

> For the first time, on-system receipts exceeded the milestone of one billion cubic feet per day (over 1 PJ/day) at the end of the year, indicative of ATCO Pipelines' competitive tariffs and flexible transportation arrangements. …
>
> Other areas of significant growth include service to the new cogeneration facility located at Dow Chemical's Fort Saskatchewan complex, and expanded receipt facilities at Golden Spike, Ferrybank, Rosebud, Keoma, and Bonnie Glen among others.[21]

CU went on to summarize in its 1999 annual report its view of the overall competitive situation as follows:

> The natural gas transmission industry in Alberta is constantly changing and is now highly competitive, with customers requiring more cost effective, flexible transportation service arrangements to meet their needs. ATCO Pipelines is well positioned, both with significant infrastructure and its position in the marketplace, to adapt to these changes and to capture new opportunities that arise from them.[22]

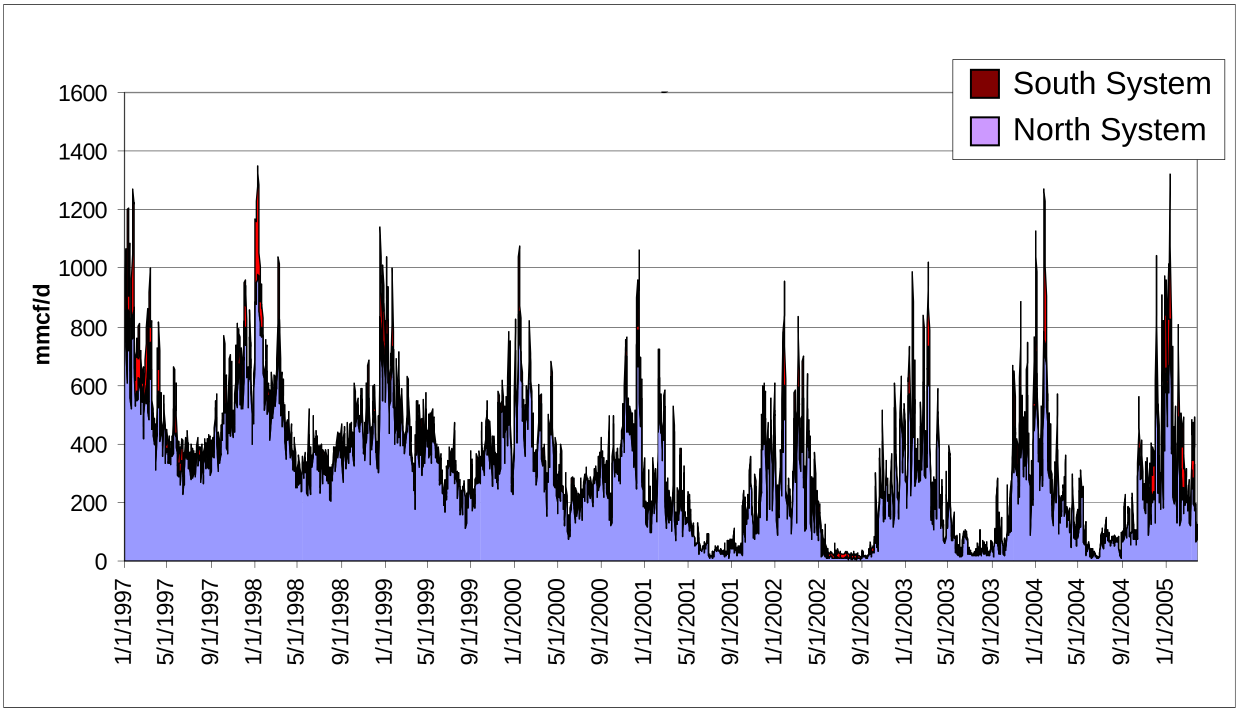
By 2000, ATCO Pipelines had increased its system throughput to approximately 1.3 Bcf/d.[23] These volumes have clearly been sustained based on CU's statement in its 2002 annual report that "on-system receipts totalled 1.3 billion cubic feet per day."[24] This represents receipt point growth of 30% in just three years.

Q19. How did ATCO Pipelines obtain its supply prior to the construction of these projects?

A19. Prior to construction of these projects, ATCO Pipelines' on-system supply was less than its on-system market, more significantly so on the ATCO Pipelines North system. As a result, ATCO Pipelines obtained its shortfall in supply from NGTL. The following graph illustrates the volumes of gas that NGTL has delivered to ATCO Pipelines since 1997.

[21] Canadian Utilities Limited, 1999 Annual Report, page 18.
[22] Ibid.
[23] Canadian Utilities Limited, 2000 Annual Report, page 19.
[24] Canadian Utilities Limited, 2002 Annual Report, page 25.

Figure 2.3-1
NGTL Deliveries to ATCO Pipelines
January 1/97 to July 31/05



As can be seen in Figure 2.3-1, the volumes NGTL has delivered to ATCO Pipelines have declined over time so that NGTL presently provides primarily peaking needs.

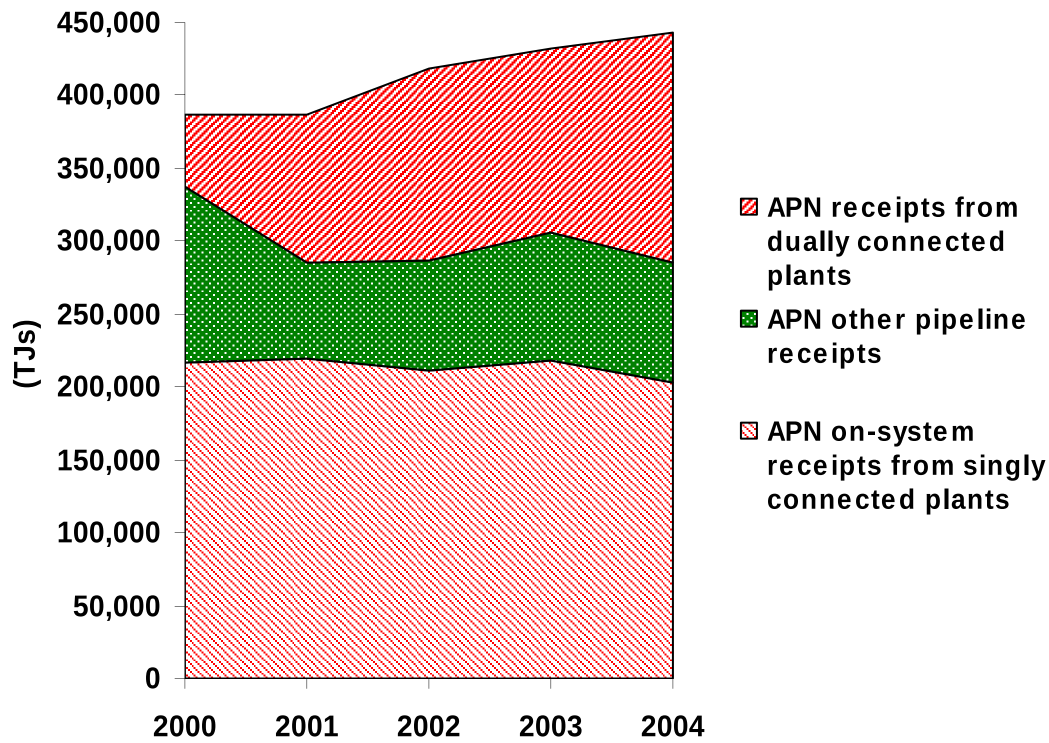
There has been a seven-fold increase in ATCO Pipelines' directly-connected on-system receipts, from slightly more than 200 TJ/d in 1992, to approximately 1400 TJ/d in 2004.[25] Further, there has been a reduction in the amount of gas that ATCO Pipelines receives from NGTL by more than 300 MMcf/d from 1997 to 2004.[26] This means that volumes of gas that were previously received onto the Alberta System for delivery to ATCO Pipelines' system are now directly connected by ATCO Pipelines for delivery to its on-system market and that NGTL has lost both receipt and delivery revenues for these volumes of gas.

The following figure shows how ATCO Pipelines' North on-system receipts from singly connected receipt points have remained relatively static over the past four years, while

[25] Exhibit No. 02-001, NOVA Gas Transmission Ltd., 2005 General Rate Application Phase 2, Figure 2.3-1, page 35.
[26] Ibid, Figure 2.3-3, page 37.

volumes received from receipt points dually connected with the Alberta System have grown significantly and ATCO Pipelines' North system receipts from other pipelines have declined significantly.

Figure 2.3-2
ATCO Pipelines North On-System Receipts 2000 - 2004



In 1999, ATCO Pipelines' dually connected receipt volume was 38,850 TJ/day. This volume increased 26% in 2000, and the total increase to 2004 was over 300%.

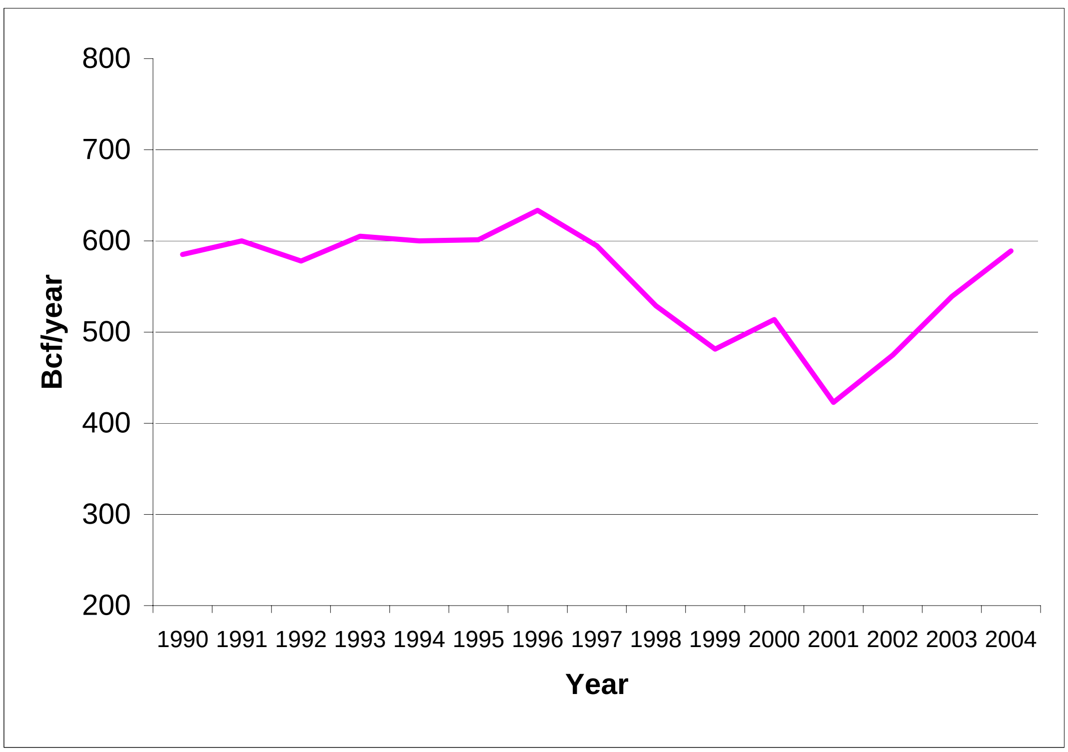
Q20. Has ATCO Pipelines' physical infrastructure grown in recent years as a result of these supply additions?

A20. Yes. ATCO Pipelines has significantly increased its system footprint in the corridor that runs from Edson east to Edmonton. This area is principally a gas production area and has provided much of the increase in ATCO Pipelines' receipts for delivery to core and industrial markets that are almost exclusively located in and immediately east of Edmonton. This same area has been served by NGTL facilities since the mid-1960s.

Q21. ATCO Pipelines states in its response to information request NGTL-AP-33 that in or around 1999, during NGTL's Products and Pricing discussions, NGTL changed its business focus from receipt and export services to increasing intra-Alberta service volumes.[27] Is this an accurate characterization of NGTL's actions at that time?

A21. No. NGTL has provided deliveries to the intra-Alberta marketplace since its inception. In particular, NGTL has historically delivered significant volumes to ATCO Pipelines and its predecessors' systems, which in turn were delivered to industrial and consumer end-users. NGTL provides in Figure 2.3-3 below the aggregate intra-Alberta deliveries from the Alberta System over the past 15 years.

Figure 2.3-3
NGTL Annual Intra-Alberta Deliveries 1990 - 2004



[27] Exhibit No. 07-012, response to NGTL-AP-33.

Q22. ATCO Pipelines states that it "has lost deliveries to seven industrials to NGTL, while NGTL has lost none to AP."[28] Is this a fair reflection of the competitive environment between NGTL and ATCO Pipelines for intra-Alberta deliveries?

A22. No. ATCO Pipelines has successfully competed with NGTL to capture intra-Alberta market. In its response to information request CAPP-AP-2, ATCO Pipelines states that it has gained 24 new industrial customers since the mid-1980s.[29] The following recent examples demonstrate ATCO Pipelines' ability to compete:

- in 1999, ATCO Pipelines constructed facilities to serve a cogeneration plant located in Lloydminister;[30]
- ATCO Pipelines provided service to Dow's new cogeneration plant at Fort Saskatchewan;[31]
- in 2001, ATCO Pipelines constructed the Muskeg River Pipeline to serve Shell's oil sands project as well as an ATCO Power project;[32]
- in 2002, CU announced that ATCO Pipelines would provide service to Shell's Scotford Upgrader in Fort Saskatchewan;[33] and
- also in 2002, ATCO Pipelines installed facilities to serve the Calpine Energy centre located in southern Alberta.[34]

[28] Exhibit No. 07-005, Written Evidence of ATCO Pipelines, page 2, lines 1-2.
[29] Exhibit No. 07-013, response to CAPP-AP-2.
[30] Canadian Utilities Limited, 1999 Annual Report, page 18.
[31] Ibid.
[32] Canadian Utilities Limited, 2001 Annual Report, page 19.
[33] Canadian Utilities Limited, 2002 Annual Report, page 25.
[34] Ibid.

Q23. ATCO Pipelines takes issue with NGTL's evidence regarding plants dually connected to both the Alberta System and ATCO Pipelines' systems and suggests that it and NGTL were the second service providers in approximately an equal number of instances.[35] ATCO Pipelines provides in Table 3.3-1 a listing of dual connections in support of its position. Does this information fairly reflect the competition for receipt volumes at these points?

A23. No. ATCO Pipelines' policy statement and related evidence are misleading, because they imply that NGTL has actively pursued supply volumes already served by ATCO Pipelines. To the contrary, NGTL has been the first service provider and ATCO Pipelines has been the second or third service provider at most of the dually connected receipt points, with ATCO Pipelines being the subsequent service provider at almost all points since 1990. NGTL recreates AP Table 3.3-1 below and provides additional information that includes the meter station locations and dates when ATCO Pipelines and NGTL installed their respective facilities.

[35] Exhibit No. 07-005, Written Evidence of ATCO Pipelines, page 1, lines 25-27 and page 2, line 1.

Table 2.3-1
Dually Connected Receipt Points

ATCO Station Name	NGTL Station Name	First Service	Date of First Service	Second Service	Date of Second Service	Third Service	Date of Third Service
Nevis 38-22-W4	Nevis South SE-03-039-22-W4	APS	1956	NGTL	1959		
Olds 32-1-W5	Olds 03-18-032-01-W5	APS	1956	NGTL	1964		
Tribute 64-11-W5	Judy Creek 14-25-064-11-W5	APN	1963	NGTL	1968		
Jumping Pound 25-5-W4	JP West 12-18-025-04-W5	APS	1951	NGTL	1971		
Sharples 29-22-W4	Gatine 10-08-029-22-W4	APS	1963	NGTL	1989		
Gayford 26-25-W4	Nightingale 10-31-026-23-W4	NGTL	1995	APS	1996		
Bonnie Glen 47-27-W4	Bonnie Glen 15-08-047-27-W4 Formerly known as Springdale 13-33-43-01-W5	APN	1956	NGTL	1998		
Ansel 53-18-W5	Edson SE-11-053-18-W5	NGTL	1965	Alliance	1999	APN	2001
Bear Hills 45-27-W4	Falun NW-11-45-27-W4	NGTL	1978	APN	1999		
Vantage 51-9-W5	Cynthia # 2 SW-21-049-11-W5	NGTL	1994	APN	2000		
Mannville 50-9-W4	Ranfurly 01-28-050-09-W4	NGTL	1972	APN	2000		
Lloyd Creek 44-1-W5	Rimbey NW-32-043-01-W5	NGTL	1961	APN	2000		
Viking 48/49-13-W4	Viking East/North 27/31-049-13-W4 Torlea 01-49-13-W4 Torlea East 06-49-12-W4	NGTL NGTL APN	1976 1982 2001	NGTL	2002		
McLeod River 52-20-W5	Marlboro SE-24-052-20-W5 Marlboro East 01-24-052-20-W5	NGTL	1985	APN	2001		
Sundance Cr. 53-20-W5	Sundance Cr. NW-23-053-20-W5	NGTL	1983	APN	2001		
Hillsdown 38-26-W4	Piper Creek 07-11-038-26-W4	NGTL	1994	APS	2002		
South Carrot Creek 53-13-W5	Lobstick 13-15-53-13-W5	NGTL	1965	APN	2002		
Medicine Lodge 52-21-W5	Hargwen 10-33-52-21-W5	NGTL	1990	APN	<1994		
Bittern Lake 46-21-W4	Bittern Lake 06-30-046-21-W4	NGTL	1990	APN	<1994		
Paddle River 57-8-W5	Paddle River SW-10-056-11-W5	APN	1966	Alliance	1999		

As can be seen in Table 2.3-1, in the last fifteen years ATCO Pipelines has been the second or third service provider at dually connected stations in all but two instances; namely Bonnie Glen and Viking.

ATCO Pipelines has wrongly inferred in its evidence that NGTL offloaded it at the Bonnie Glen receipt point.[36] The construction of NGTL's Bonnie Glen meter station occurred when NGTL acquired the Edmonton Sundre Expansion Pipeline from Imperial Oil Ltd. and relocated the previously existing Springdale meter station to Bonnie Glen. NGTL did not offload ATCO Pipelines at this location. To the contrary, ATCO Pipelines has expanded its Bonnie Glen station and offloaded NGTL at this location since 1999.[37]

NGTL has been providing service in the Viking area since 1976. However, the Torlea East Station was built in 2002 due to a request from Burlington Resources. Burlington increased gas production from this area when it purchased the Viking Kinsella field. Production from this field prior to 2002 had primarily been going to ATCO Pipelines.

In recent history, ATCO Pipelines has pursued receipt volumes/locations that are already served by NGTL. Even in distant history, the aggregate volumes that ATCO Pipelines has obtained from locations previously served by NGTL significantly exceed the volumes that NGTL has obtained from locations previously served by ATCO Pipelines.

Q24. ATCO Pipelines also states that it has lost deliveries to seven industrials to NGTL, while NGTL has lost none to ATCO Pipelines.[38] Is this an accurate reflection of the competitive dynamic for the industrial markets?

A24. No. The information which ATCO Pipelines provides in support of its claim in Table 3.3-2 of its evidence is misleading. ATCO Pipelines wrongly implies that NGTL has significantly offloaded ATCO Pipelines' industrial markets. NGTL has recreated Table 3.3-2 below and has included the volumes associated with these markets and the dates that service was provided.

[36] Ibid, page 17, Table 3.3-1.
[37] Canadian Utilities Limited, 1999 Annual Report, page 18.
[38] Exhibit No. 07-005, Written Evidence of ATCO Pipelines, page 2, lines 1-2.

Table 2.3-2
Service to Industrial Delivery Customers

Industrial Delivery Customer	First Service	Date of First Service	Volumes Lost TJ/day	Second Service	Date of Second Service	Third Service
Turbo Calgary	APS	Unknown	3	NGTL	1984	
CFL Fertilizer Medicine Hat	APS	Unknown	150	NGTL	1986	
NOVA Chemicals Joffre	APS	1985	35	NGTL	1987	TCPL Ventures
Lakeside Packers Brooks	APS	Unknown	1	NGTL	1990	
Swan Hills Flood	APN	1986	5	NGTL	1992	
South Swan Hills Flood	APN	1986	16	NGTL	1992	
Weyerhaeuser	APN	Unknown[(1)]	3	NGTL	Unknown[(1)]	

Note:
(1) NGTL cannot identify the delivery station and determine who was first and second service provider because ATCO Pipelines did not provide the location as requested.

As can be seen in Table 2.3-2, the examples that ATCO Pipelines uses to describe NGTL as the second service provider to industrials are all distant history and with the exception of the CFL market, all involved very small volumes.

With respect to the CFL market, it is important to note it was the result of an unsolicited request from CFL for NGTL to supply CFL's feedstock requirements.

2.4 Impact of ATCO Pipelines' Rates on the Competitive Environment

Q25. ATCO Pipelines states that producers look at the highest netback and industrials look at the lowest delivered plant gate price when determining on which pipeline to transport gas. It also states that producer netbacks and industrial delivered plant gate prices "depend not only on rates but also on on-system market gas prices."[39] Does NGTL believe that there is a link between competition for receipts and competition for markets?

A25. Yes. In this context, NGTL agrees with ATCO Pipelines with response to information request NGTL-AP-28 when it stated "gas cannot be delivered without being received, and gas cannot be received without having a place to be delivered."[40] Consequently, as a

[39] Exhibit No. 07-005, Written Evidence of ATCO Pipelines, page 14, lines 8-11.
[40] Exhibit No. 07-012, response to NGTL-AP-28.

result of this link between receipt and delivery, ATCO Pipelines can become more competitive at the receipt end of the pipe if it can make NGTL less competitive at the delivery end of the pipe.

To be more specific, if NGTL becomes less competitive at the industrial market plant gate, the industrial will be more inclined to source its gas from ATCO Pipelines' on-system supply. This means that the size of the ATCO Pipelines on-system industrial market grows. As "gas cannot be delivered that has not been received," then the demand for ATCO Pipelines' on-system supply grows and the ATCO Pipelines' on-system market price climbs. This in turn means that the ATCO Pipelines' on-system market becomes relatively more attractive to producers and provides a competitive advantage to ATCO Pipelines at the receipt end of the pipe.

Accordingly, competitiveness at the industrial market end of the pipe is clearly linked to competitiveness at the receipt end of the pipe. Further, the rate designs that are in place at any time for ATCO Pipelines' and the Alberta System affect their relative competitiveness and their on-system gas prices. ATCO Pipelines acknowledges this fact in its evidence when it states "rate design can have a significant impact on developing a competitive environment and on whether or not there is a level playing field."[41]

Q26. Is this a new situation?

A26. No. ATCO Pipelines has historically used and continues to use its own rate design as a competitive tool to motivate both the gas producing community as well as the gas consuming community to selectively transport gas on ATCO Pipelines' system. For example, at dually connected receipt points, ATCO Pipelines historically implemented discounted exchange fees specifically calculated to ensure that the producer delivering gas to it for re-delivery to NIT had at least a "one cent advantage" when compared to delivering gas to NIT directly through the Alberta System. This meant that the ATCO Pipelines toll for delivery of gas sourced from a dually connected plant to NIT was less than the equivalent NGTL rate for precisely the same service at that same location. This

[41] Exhibit No. 07-005, Written Evidence of ATCO Pipelines, page 2, lines 6-7.

circumstance encouraged producers to deliver to the NIT market via ATCO Pipelines system rather than through the Alberta System.

ATCO Pipelines is now taking the further step of using this proceeding as an opportunity to seek an increase in NGTL's FT-A rate. If ATCO Pipelines' proposal were adopted, it would result in NGTL becoming less competitive in the gas marketplace, which would improve ATCO Pipelines' relative competitiveness.

Q27. Please explain how NGTL's rate design, and specifically the FT-A rate, in conjunction with ATCO Pipelines' rate design, affects the competitive dynamic.

A27. In 2004, ATCO Pipelines amended its rate design through its 2004 General Rate Application (GRA). This resulted in an incremental improvement in the relative competitiveness of the ATCO Pipelines rate and on-system gas price for producers. ATCO Pipelines now is attempting to change NGTL's rate design, which will further enhance the competitiveness of both ATCO Pipelines' rate and on-system gas price for producers.

A complete description of the mechanics that determine netback and delivered gas prices on ATCO Pipelines' system, and the choices that both producers and intra-Alberta markets have available to them, is contained in Appendix A to this Reply Evidence. NGTL examines through this analysis the competitive landscape that existed prior to the creation of ATCO Pipelines' most recent rate design implemented in late 2004, the competitive landscape under the existing rates, and the competitive landscape which ATCO Pipelines seeks to create through its proposed increase to NGTL's FT-A rate.

Q28. What conclusions can be drawn from this analysis?

A28. The delivered price of gas to an ATCO Pipelines' on-system industrial has changed as a result of the recent changes to ATCO Pipelines' rate design. The changes are described in the table below.

Table 2.4-1
Delivered Gas Prices for ATCO Pipelines On-System Industrials

	Prior to ATCO 2004 GRA	With NGTL rates as applied for	With FT-A rate as proposed by ATCO Pipelines
Delivered price of gas to ATCO Pipelines on-system industrial with gas sourced from NGTL/NIT ($/Mcf)	7.108	7.145	7.185
Delivered price of gas to ATCO Pipelines on-system industrial with gas sourced from ATCO North on-system supply ($/Mcf)	7.028	7.009	7.009
Delivered price of gas to ATCO Pipelines on-system industrial – average of the two alternatives above ($/Mcf)	7.068	7.077	7.097

Note: All of the above calculations are based upon a NIT price of $7.00/Mcf.

As shown in Table 2.4-1, ATCO Pipelines' rate design that resulted from its 2004 GRA increased the cost of gas to an ATCO Pipelines on-system industrial that sourced its gas from NGTL by 3.7¢/Mcf ($7.145-$7.108). An additional 4.0¢/Mcf ($7.185-$7.145) increase would occur if ATCO Pipelines' proposed FT-A rate were to be adopted. In each of these steps, ATCO Pipelines reduces the competitiveness of Alberta System supply for an ATCO Pipelines on-system industrial.

At the same time, the delivered price of gas from ATCO Pipelines on-system supply has dropped by 1.9¢/Mcf ($7.009-$7.028), which enhances the attractiveness of ATCO Pipelines on-system supply to ATCO Pipelines on-system industrials.

On average, the delivered price of gas for ATCO Pipelines on-system industrials has increased by 0.9¢/Mcf ($7.077-$7.068), and would climb by a further 2¢/Mcf ($7.097-$7.077) if NGTL's FT-A rate were increased as proposed by ATCO Pipelines.

NGTL also provides as part of its analysis in Appendix A, a similar analysis of alternatives available to a producer. The results of this analysis are shown in the following table.

Table 2.4-2
Netbacks for ATCO Pipelines On-System Producers

	Prior to ATCO 2004 GRA	With existing NGTL rates	With FT-A rate as proposed
Producer plant gate netback with gas sold at NIT via ATCO Pipelines North ($/Mcf)	6.828	6.787	6.787
Producer plant gate netback with gas sold to ATCO Pipelines North on-system industrial market ($/Mcf)	6.908	6.923	6.963
Producer plant gate netback - average of the two alternatives described above($/Mcf)	6.868	6.855	6.875

Note: All of the above calculations are based upon a NIT price of $7.00/Mcf.

As shown in Table 2.4-2, ATCO Pipelines' rate design that resulted from its 2004 GRA decreased the plant gate netback for a producer that sold its gas to NIT via ATCO Pipelines' North system by 4.1¢/Mcf. This step reduced the attractiveness of the NIT market to producers connected to the ATCO Pipelines system.

At the same time, the plant gate netback to a producer delivering to an ATCO Pipelines on-system market increased by 1.5¢/Mcf with the revisions to ATCO Pipelines' rate design that resulted from the ATCO Pipelines' 2004 GRA. A further increase of 4.0¢/Mcf will occur if ATCO Pipelines proposed FT-A rate were to be adopted.

The overall results of these changes are that the NIT market has become less attractive to ATCO Pipelines North system producers, and ATCO Pipelines on-system markets have become more attractive to producers connected to the ATCO North system. These results would be further magnified if ATCO Pipelines proposed FT-A rate were to be adopted.

Q29. Why wouldn't the ATCO Pipelines on-system producer simply deliver its gas directly to NGTL rather than through ATCO Pipelines' system?

A29. Dually connected producers have the option of delivering their gas directly to NIT through the Alberta System. NGTL has analysed this alternative and determined that the ATCO North on-system market produces better netbacks in all circumstances when compared to those on the Alberta System at dually connected plants. This price premium would be further increased if ATCO Pipelines' FT-A proposal were to be adopted.

Q30. What are the changes to the ATCO Pipelines North on-system price?

A30. The combined effect of these changes becomes apparent when the ATCO Pipelines on-system price is also evaluated. The analysis contained in Appendix A includes a description of the changes that have occurred recently in the ATCO Pipelines North on-system market price. These changes are summarized in the following table.

Table 2.4-3
ATCO Pipelines North On-System Price Relative to NIT

	Prior to ATCO 2004 GRA	Current with NGTL rates as applied for	Current with NGTL FT-A rate as proposed by ATCO Pipelines
ATCO North on-system price ($/Mcf)	6.975	7.006	7.026
NIT Price ($/Mcf)	7.000	7.000	7.000
Premium to NIT ($/Mcf)	(0.025)	0.006	0.026

Note: All of the above calculations are based upon a NIT price of $7.00/Mcf.

As shown in Table 2.4-3, prior to changes that were implemented following ATCO Pipelines' 2004 GRA, the ATCO Pipelines North on-system market price was a 2.5¢/Mcf discount to the NIT price. The revisions to ATCO Pipelines' rates which resulted from the ATCO Pipelines 2004 GRA increased the ATCO Pipelines on-system price by 3.1¢/Mcf, to a slight premium to NIT. The increase to the FT-A rate that has been proposed by ATCO Pipelines would, if adopted, further increase the ATCO Pipelines North on-system price by 2.0¢/Mcf; a premium to NIT of 2.6¢/Mcf.

The overall effect of these changes is that the typical ATCO Pipelines North on-system price has climbed from a discount to NIT to a premium to NIT. If ATCO Pipelines' proposed FT-A rate were to be adopted, the premium would increase further. The combined 5.1¢/Mcf increase under such circumstances would result in an increase of approximately $30 million/year in incremental costs for ATCO Pipelines' core and industrial customers. This impact would be further magnified at today's gas prices which are above the $7.00/Mcf illustrative rate used in this analysis. NGTL provides further explanation of this effect in Appendix A.

Q31. In its response to BR-AP-3, ATCO Pipelines states that it is competitive with NGTL for producer receipts at some but not all receipt points within the province. ATCO Pipelines further states that there are dually connected plants at points where NGTL's rate is lower than ATCO Pipelines' rate and vice versa.[42] Does NGTL agree with ATCO Pipelines' assessment of its competitiveness at receipt points?

A31. No. ATCO Pipelines' answer is misleading. It only compares two scenarios:

1. the dually connected producer's situation (the tolls charged, fuel costs and the producer netback) if it transports to and sells its gas directly at NIT via NGTL; and

2. the dually connected producer's situation (the tolls charged, fuel costs and the producer netback) if it transports to and sells its gas at NIT via ATCO Pipelines.

The appropriate comparison to be made is between the producer's netback calculated in (1) above and the producer's netback where the same dually connected producer transports to and sells at the ATCO Pipelines on-system price via the ATCO Pipelines system. These comparisons set the bookends available to the producer and allow the competitiveness of ATCO Pipelines relative to NGTL to be properly assessed.

NGTL provides the results of this analysis below in Table 2.4-4.

[42] Exhibit No. 07-011, response to BR-AP-3.

Table 2.4-4
Producer Netbacks at Dually Connected Receipt Points

ATCO Pipelines Receipt Point	NGTL Receipt Point	Producer Netback ($/Mcf) Sale to ATCO Pipelines North on-system market via ATCO Pipelines	Producer Netback ($/Mcf) Sale to NIT via NGTL	Competitive service provider (¢/Mcf)
Ansel	Edson	6.849	6.818	ATCO North advantage = 3.1
Bonnie Glen	Bonnie Glen	6.850	6.782	ATCO North advantage = 6.8
Lloyd Creek	Rimbey	6.852	6.831	ATCO North advantage = 2.1
Mannville	Ranfurly	6.853	6.711	ATCO North advantage = 14.2
McLeod River	Marlboro	6.849	6.770	ATCO North advantage = 7.9
S. Carrot Ck.	Lobstick	6.853	6.826	ATCO North advantage = 2.7
Sundance Ck.	Sundance Ck.	6.847	6.763	ATCO North advantage = 8.4
Tribute	Judy Ck.	6.844	6.698	ATCO North advantage = 14.6
Vantage	Cynthia #2	6.853	6.836	ATCO North advantage = 1.7
Viking	Torlea East	6.856	6.761	ATCO North advantage = 9.5

NGTL compares in Table 2.4-4 the dually connected producers' netbacks with the rates and fuel charges currently in place for each of ATCO Pipelines North system and the Alberta System. The data demonstrate that ATCO Pipelines has a competitive advantage over NGTL at every dually connected plant on its North system. This advantage will increase with any increase in NGTL's FT-A rate. Specifically, if ATCO Pipelines' FT-A rate proposal were to be adopted, the ATCO Pipelines North on-system price would increase by 2.0¢/Mcf, which would result in an incremental 2.0¢/Mcf increase in the producer netback if it chose to ship and sell its gas to markets on ATCO Pipelines' system rather than to markets on the Alberta System.

The same analysis of receipt points dually connected to ATCO Pipelines' South system and the Alberta System yields similar results. ATCO Pipelines has a competitive advantage over NGTL under existing rates which would increase if ATCO Pipelines' FT-A rate proposal were to be adopted.

Q32. ATCO Pipelines has said that its proposed changes to the FT-A rate would "not provide AP with a competitive edge for intra-Alberta delivery volumes – it simply results in an FT-A rate that is more representative of its cost causation."[43] Does NGTL agree with ATCO Pipelines' characterization of the impact of its proposal on the competitive environment?

A32. No. The facts contradict ATCO Pipelines' assertion. NGTL's analysis in this section shows clearly that implementation of ATCO Pipelines' proposed FT-A rate, on top of the rate changes resulting from ATCO Pipelines' 2004 GRA, would only further increase ATCO Pipelines' competitive advantage over NGTL.

Specifically, changes in ATCO Pipelines' rate design following its 2004 GRA had the following impacts on the competitive environment:

- increased the tolls for ATCO Pipelines on-system industrials to acquire gas from NIT;
- reduced the delivered cost of gas for ATCO Pipelines on-system sourced gas;
- increased the amount that the ATCO Pipelines North consuming markets pay for gas;
- resulted in ATCO Pipelines on-system supply becoming more attractive than NGTL-sourced supply for ATCO Pipelines on-system markets;

[43] Exhibit No. 07-005, Written Evidence of ATCO Pipelines, page 16, lines 5-6.

- decreased the netback for producers that chose to deliver to and sell at NIT via the ATCO Pipelines North system;
- increased the netback for producers delivering to and selling at the ATCO Pipelines North on-system industrial market;
- resulted in the ATCO Pipelines North on-system market becoming more attractive than the NIT market for ATCO Pipelines' producing customers;
- increased the ATCO Pipelines North on-system market price, in that it went from trading at a deficit to NIT to trading at a premium to NIT; and
- allowed ATCO Pipelines to become the more competitive service provider at all dually connected ATCO Pipelines' North system receipt points.

If ATCO Pipelines' proposal to increase the FT-A rate were to be adopted, all of these changes that have already occurred will be further magnified. ATCO Pipelines will increase its existing competitive advantages over NGTL.

3.0 RATE DESIGN

3.1 Introduction

Q33. What is the purpose of the evidence in this section?

A33. ATCO Pipelines and IGCAA have criticized NGTL's existing rate design and have proposed alternative rate designs. In this section NGTL will first address ATCO Pipelines' criticisms of the existing rate design and then address the flaws in ATCO Pipelines' rate design proposals. NGTL will then address the flaws in IGCAA's rate design proposals and IGCAA's rate design proposals.

3.2 ATCO Pipelines' Criticisms of NGTL's Rate Design are Unfounded

Q34. What criticisms does ATCO Pipelines make?

A34. ATCO Pipelines criticizes various aspects of the existing Alberta System rate design. Its main criticism relates to its assertion that under NGTL's existing rate design methodology, intra-Alberta delivery service is being "subsidized" by other services. Specifically, ATCO Pipelines asserts that "NGTL's rate design allows full-path export delivery shippers to subsidize full-path intra-Alberta shippers."[44]

NGTL contends that this statement is erroneous and unfounded.

Q35. Why is this statement incorrect?

A35. This statement is wrong for two primary reasons.

First, ATCO Pipelines relies on flawed analysis to support this claim. ATCO Pipelines has failed to properly account for the amount of FT-P, FCS and receipt service revenue that should have been included in its analysis. NGTL discusses below instances where ATCO Pipelines has made claims of "subsidization" and why these claims are incorrect.

[44] Ibid, page 2, lines 12-13.

Second, ATCO Pipelines ignores or distorts the fundamental principles that are used to develop NGTL's rate design – principles that have been in place, approved by the Board and supported by the majority of NGTL's customers for over 20 years. NGTL discusses below specific instances where ATCO Pipelines has ignored or contorted these fundamental principles.

Q36. ATCO Pipelines provides an analysis in AP Table 4.1-1 of the impact of intra-Alberta TBOs on NGTL's rates. It claims that AP Table 4.1-1 demonstrates that "intra-Alberta delivery TBO costs," which are not allocated to the FT-A rate are included in the rates paid by receipt and export delivery shippers.[45] Does NGTL agree with this claim?

A36. No. ATCO Pipelines' analysis is flawed, because it wrongfully excludes associated FT-P revenue of $13 million.

To rectify the flaw in ATCO Pipelines' analysis, NGTL has restated ATCO Pipelines' tables (AP Table 4.1-1, AP Table 4.2-1 and AP Table 4.2-2) to properly include the associated $13.0 million of FT-P revenue by subtracting it from the "Without Intra-Alberta TBOs" columns in the corrected tables below. Based on the corrected version of this analysis, it is clear that the full path export delivery shipper is not receiving a "subsidy" as the FT-P revenue of $13 million fully covers the TBO costs of $11.5 million.

[45] Ibid, page 20, lines 1-2.

Table 3.2-1
AP Table 4.1-1 Restated by NGTL
Impact of Intra-Alberta Delivery TBO's on NGTL's Rates
(Table updated to include reduction of costs and revenues)
$ Millions

	With Intra-Alberta TBOs	Without Intra-Alberta TBOs	Difference
2005 Revenue Requirement	1,160.0	1,148.5	11.50
Less: Non-Transportation Revenue	(22.3)	(22.3)	-
Less: LRS Revenue	(47.3)	(47.3)	-
Less: Other Transportation Revenue[1, 2]	(221.1)	(208.4)	(12.70)
Equals Firm Transportation Revenue Requirement	869.1	870.3	(1.20)
Divided by : Firm Contract Demand (Bcf/year)	5,604.85	5,604.85	-
Equals Firm Transportation Price ($/Mcf/d)	0.1551	0.1553	(0.0002)
Multiplied by FT-D CDQ (Bcf/year)	2,684.74	2,684.74	-
Equals Firm Transportation Delivery Revenue Requirement	**416.32**	**416.90**	**(0.58)**
Firm Transportation Price ($/Mcf/d)	0.1551	0.1553	(0.0002)
Multiplied by FT-R CDQ (Bcf/year)	2,920.10	2,920.10	-
Equals Firm Transportation Receipt Revenue Requirement	**452.82**	**453.44**	**(0.63)**

Notes:
1. The change in Other Transportation Revenue is an iterative calculation, with the exception of FT-A revenue which remained the same, there was a change in the revenue of all transportation services.
2. The without Intra-Alberta TBO column results in a decrease in FT-P revenues of $13 million which is FT-P revenue directly attributable to intra-Alberta TBO service. As a result of this reduction in FT-P revenue, revenue from the other on transportation services (with the exception noted above for FT-A service) increased slightly resulting in the total reduction of other transportation revenue of $12.7 million.
3. This table includes both the intra-Alberta TBO costs and the FT-P revenues associated wth the TBO costs.

Table 3.2-2
AP Table 4.1-1 Restated by NGTL
Impact of Intra-Alberta Delivery TBO's on NGTL's Rates
on NGTL's Export Delivery Full-Path Rates
(Table updated to include reduction of costs and revenues)
$ Millions

	With Intra-Alberta Revenue	Without Intra-Alberta Revenue	Difference
FT-R rate ($/Mcf)	0.1551	0.1553	(0.0002)
FT-D Rate - ($/Mcf	0.1551	0.1553	(0.0002)
Total receipt/export delivery full-path rate	0.3101	0.3106	(0.0004)
Delivery Contract Demand (Bcf/year)	2,684.74	2,684.74	-
Total Revenue - ($ Million)	832.6	833.8	(1.15)

Table 3.2-3
AP Table 4.2-2 Restated by NGTL
Impact of Intra-Alberta Delivery TBO's on NGTL's Rates
on NGTL's Export Delivery Full-Path Rates
(Table updated to include reduction of costs and revenues)
$ Millions

	With Intra-Alberta Revenue	Without Intra-Alberta Revenue	Difference
IT-R Rate ($/Mcf)	0.1635	0.1637	(0.0002)
IT-D Rate ($/Mcf)	0.1705	0.1707	(0.0003)
Total receipt/export delivery full-path rate	0.3340	0.3345	(0.0005)
Interrptible Delivery Volumes (Bcf)	380.3	380.3	-
Total Revenue ($ Million)	127.01	127.21	(0.1976)

Q37. ATCO Pipelines also claims that the revenues directly attributable to intra-Alberta delivery service only recover between 40% and 70% of the costs that NGTL has directly attributed to intra-Alberta delivery service.[46] Does NGTL agree with this claim?

A37. No. This claim is incorrect because the revenues attributable to intra-Alberta delivery service actually recover more than 100% of the attributable costs.

ATCO Pipelines did not include all of the associated FT-P revenue or any receipt revenue in its calculations used to develop the analysis in its tables AP Table 5.2-1 and AP Table 5.2-2. In these tables, ATCO Pipelines compares "Cost of Service" and "Revenue" related to the facilities not associated with export, storage or extraction by establishing two "bookends." This comparison is done by dividing the FT-P revenue into a receipt and delivery component. Both of these bookends are wrong because ATCO Pipelines has failed to properly account for the FT-P revenue and has provided no recognition of the related receipt revenue in its analysis.

The first bookend assumed that there was no distance between the receipt points and the delivery point for <u>any</u> FT-P contract, as ATCO Pipelines only included the metering component of the FT-P revenue for all FT-P contracts. This approach would imply that

[46] Ibid, page 4, line 24 to page 5, line 1.

the receipt points and the delivery points are at the same location for every FT-P contract. If this were true, then there would be no need for any service from NGTL. As a result, this bookend significantly underestimates the FT-P revenue.

The second bookend wrongly included only 50% of the FT-P revenue associated with the facilities not associated with export, storage or extraction. This approach is also inappropriate as 100% of the FT-P revenue is directly associated with the delivery point accessed by these TBO agreements. The delivery point is explicitly identified in each FT-P contract. The FT-P contract is not divisible; there is either a contract or there is not. As a result, all FT-P revenue must be used.

Both bookends also wrongly included 100% of the costs attributable to facilities not associated with export, storage or extraction, even though these facilities are used to provide both receipt and intra-Alberta delivery services and not just intra-Alberta delivery service. The fact that these facilities are used to supply multiple services must be recognized in the analysis. This recognition can be accomplished in two ways. One method, which NGTL incorporated in its rate design alternatives 2 and 3, is to include 50% of the costs to reflect the joint use of these facilities. The other method is to recognize the receipt revenue associated with the intra-Alberta deliveries. As ATCO Pipelines acknowledged in response to NGTL-AP-28(a), “gas cannot be delivered without being received.”[47] As a result ATCO Pipelines should have included receipt revenue in its analysis. Correcting for this error would result in a revenue to cost-of-service ratio in excess of 100% and not the 40% - 70% range ATCO Pipelines claims. If ATCO Pipelines’ analysis had been conducted correctly, it would have demonstrated that the revenues attributable to intra-Alberta delivery service actually do recover the attributable costs.

[47] Exhibit No. 07-012, Response to NGTL-AP-28(a)

Q38. ATCO Pipelines claims:

> **In the case of the AP East Edmonton Transportation By Others (TBO) Agreement, NGTL proposes that receipt and export delivery shippers subsidize the East Edmonton TBO cost (15.1¢/GJ or 16.2¢/Mcf in Year 1) while charging the Petro-Canada refinery the "meters only" FT-A rate of 1.4¢/Mcf.[48]**

Does NGTL agree with this claim?

A38. No. This claim is also incorrect. NGTL's receipt and export delivery customers will not subsidize the costs of the East Edmonton TBO used to provide intra-Alberta delivery service. In its analysis, ATCO Pipelines has failed to consider the receipt revenue associated with the deliveries to East Edmonton.

NGTL has structured the TBO agreement with ATCO Pipelines to ensure that gas delivered to the Petro-Canada refinery in East Edmonton is sourced from the Alberta System. Without this TBO, ATCO Pipelines would have been able to supply the refinery from its on-system receipts by further offloading the Alberta System at existing dually connected receipt points. Thus, even though the receipt volume for East Edmonton may not be provided by Petro-Canada, it must still come from the Alberta System. The receipt revenue is therefore directly related to the delivery service provided through the TBO arrangement and must be taken into consideration when conducting a comparison to the costs associated with the TBO arrangement.

It is ironic that ATCO Pipelines recognizes that an increase in deliveries on its system will facilitate additional receipt volumes on its system but suggests that the same relationship doesn't apply to the Alberta System.

For example, in its 2002 Annual Report, Canadian Utilities stated:

> The Company will continue its aggressive pursuit of opportunities to increase deliveries from its pipeline system, facilitating additional receipt volumes on its system.[49]

[48] Ibid, page 2, lines 7-11.
[49] Canadian Utilities Limited, 2002 Annual Report, page 25.

However, when a market that could have been connected to its system is connected to the Alberta System, ATCO Pipelines does not reflect this relationship between intra-Alberta deliveries and the associated receipt volumes.

The fact that deliveries to intra-Alberta markets are provided through the combination of receipt and FT-A services is a fundamental component of NGTL's existing rate design.

Q39. NGTL earlier stated that ATCO Pipelines has ignored fundamental principles of the Alberta System rate design. Please elaborate.

A39. ATCO Pipelines ignores the fundamental relationship between receipt revenue and intra-Alberta delivery service. NGTL's existing methodology has common receipt services (FT-R, FT-RN, and IT-R) that are used to provide full-path service to both ex-Alberta delivery and intra-Alberta delivery shippers. The appropriate rate for ex-Alberta shippers is the combined FT-R and FT-D rate and the appropriate rate for intra-Alberta shippers is the combined FT-R and FT-A rate. Therefore, the combined revenue stream of FT-R and FT-A services must be used in evaluating costs associated with deliveries to intra-Alberta markets.

ATCO Pipelines acknowledges, supports and uses this relationship in its analysis of deliveries to ex-Alberta markets. In its evidence, ATCO Pipelines states:

> Export delivery full-path firm transportation shippers not only pay the FT-D rate, they also pay the FT-R rate. Export delivery full-path shippers pay more per Mcf (incremental $0.0032/Mcf) than intra-Alberta delivery full-path shippers, who only pay an incremental $0.0016/Mcf/d (for the increased FT-R rate).[50]

Using receipt revenue in an analysis of impacts to ex-Alberta delivery shippers and not using receipt revenue in an analysis of impacts to intra-Alberta delivery shippers is inconsistent and ultimately unfair to the intra-Alberta delivery shippers. Receipt revenue should be used in the analysis of both intra-Alberta and ex-Alberta delivery impacts. This approach properly reflects the integrated nature of the Alberta System and the underlying cost relationships that have been incorporated into the existing rate design.

[50] Exhibit 07-005, Written Evidence of ATCO Pipelines, page 22, lines 1-4.

This approach is especially relevant for those intra-Alberta delivery shippers that directly hold both receipt and FT-A services. In particular, NGTL had 41 customers that utilized both receipt and FT-A service in 2004. In aggregate, these customers transported 78,508 MMcf in 2004 utilizing their own FT-A and receipt services, with the associated receipt revenue being approximately $13 million. By failing to take receipt service into consideration in its analysis, ATCO Pipelines wrongly ignores the fact that these shippers directly hold service to transport gas for the full intra-Alberta delivery path.

Q40. ATCO Pipelines claims:

> **NGTL's present and applied-for primary cost allocation for transmission costs is based on a volume-only, postage stamp calculation. Under this methodology, 52.1% of the firm transmission costs are allocated to FT-R and the balance to FT-D.[51] … Such a result is backwards in the sense that a toll relationship establishes cost allocation when it should be the cost allocation that establishes tolls and toll relationships.[52]**

Does NGTL agree with these claims?

A40. No. This claim is incorrect. ATCO Pipelines distorts and confuses the cost relationships that underpin NGTL's existing rate design methodology. These relationships are:

(a) the average transmission component of the service rate (FT-R + FT-D) required to deliver gas to the export market is twice the average transmission component of the service rate (FT-R + FT-A) required to deliver gas to the intra-Alberta market;

(b) the transmission component of the average FT-R rate is equal to the transmission component of the FT-D rate; and

(c) the rate for every service, except FT-X and IT-S services, includes a system average metering component to account for metering costs.

[51] Ibid, page 3, lines 1-4.
[52] Ibid, page 3, lines 12-14.

Q41. How does ATCO Pipelines distort these cost relationships in the statements that it makes?

A41. NGTL allocates the revenue requirement in a manner which ensures that the average transmission component of the combined FT-R and FT-D services is twice the transmission cost of the combined FT-R and FT-A services. This is cost relationship (a) outlined previously. NGTL also allocates the revenue requirement to ensure that the average FT-R rate is equal to the FT-D rate. This is the result of relationships (b) and (c) outlined previously. Both of these relationships are unit relationships. In particular, relationship (a) reflects the relative unit distance between two distinct markets. Distance is a well recognized cost driver that is appropriate to use on the Alberta System.

In allocating the total revenue requirement to the various services, NGTL employs a methodology that preserves both of these relationships simultaneously. The fact that for 2005 this results in 52.1% of the firm transmission revenue requirement being allocated to FT-R is happenstance. It is not reflective of any deficiencies in the methodology. The more important point is that the rates, (which are unit measurements) reflect the underlying relative unit cost relationships.

It is also misleading of ATCO Pipelines to state that this is a "toll relationship" that "establishes cost allocation" when it is a unit cost relationship that has been explicitly embedded in the relationship between the service rates. Instead, it is appropriate to say that the rate relationship explicitly reflects the underlying unit cost relationship.

Dr. Gaske in his reply evidence discusses these concepts in greater detail and concludes that the methodology employed by NGTL to maintain the relative cost relationships amongst the various service rates is superior and preferred to the cost allocation concepts recommended by ATCO Pipelines.

Q42. Are there other examples where ATCO Pipelines distorts the cost relationships of the existing rate design?

A42. Yes. The following statements are further examples:

> When a transmission cost is added to the FT-A, the methodology used by NGTL applies the Distance of Haul (DOH) ratio of 45.5% to unit firm transmission costs and yields unstable results.[53] … When a transmission cost is added to the FT-A and the DOH ratio of 45.5% is applied to annual firm transmission costs, stable results occur.[54]

In these statements ATCO Pipelines distorts and confuses the underlying cost relationships by suggesting that the DOH ratio should be applied on an annual or absolute basis rather than on a unit basis.

As NGTL previously explained, the DOH ratio is a relative unit measurement. It is the average distance that one unit of gas delivered to the intra-Alberta market travels relative to the average distance that one unit of gas delivered to the ex-Alberta market travels. NGTL uses this unit relationship as a reasonableness check to support the cost relationship (a) discussed earlier, which requires that the average transmission component of the service rate (FT-R + FT-D) required to deliver gas to the export market is twice the average transmission component of the service rate (FT-R + FT-A) required to deliver gas to the intra-Alberta market. This cost relationship is a unit cost relationship that ensures that the transmission component of the service rate to transport one unit of gas to the ex-Alberta market via FT-R and FT-D is twice the transmission component of the service rate to transport one unit of gas to the intra-Alberta market via FT-R and FT-A. This relationship has no connection or relevance to the allocation of firm transmission revenue requirement between the FT-R and FT-D services on either a unit or absolute basis.

FT-R service is used to transport gas to both intra-Alberta and ex-Alberta markets. ATCO Pipelines' proposal to allocate costs on an annual basis would take a unit cost relationship between two markets and wrongly apply it to allocate an absolute dollar value between two services where the two services have different relationships within

[53] Ibid, page 3, lines 5-7.
[54] Ibid, page 3, lines 16-18.

each market. The FT-R service is related to both markets, however, the FT-D service is only related to the export market.

Stated more generically, ATCO Pipelines wrongly recommends taking a relative unit relationship between A and B and applying that relationship to allocate costs on an absolute basis between C and D. This approach is not logical. It has no foundation in the tried and true cost relationships which underpin the existing rate design. ATCO Pipelines failed to provide any reasonable foundation for it as an appropriate or applicable rate design approach for the Alberta System.

Only NGTL's existing and applied-for methodology maintains both the equality between the FT-R and FT-D rates and the appropriate unit relationship between the cost to deliver gas to the intra-Alberta and ex-Alberta markets.

3.3 Confer Consulting Rate Design Alternatives

Q43. What are Confer Consulting's proposed alternatives to NGTL's existing rate design?

A43. Confer Consulting presents four cases for consideration, and ultimately recommends Case 4 as its "optimal" alternative, which ATCO Pipelines supports. The FT-A rate and key parameters of these four cases are:

> Case 1: FT-A rate of $0.0457 per Mcf, derived from directly-assigned intra-Alberta transmission costs and system average metering costs in combination with the DOH ratio applied to annual transmission cost of service;

> Case 2: FT-A rate of $0.0595 per Mcf, derived from directly-assigned intra-Alberta transmission costs and directly-assigned metering costs in combination with the DOH ratio applied to annual transmission cost of service;

Case 3: FT-A rate of $0.0464 per Mcf, derived from a combination of system average metering costs and the volume-distance allocation of transmission costs; and

Case 4: FT-A rate of $0.0601 per Mcf, derived from a combination of directly-assigned metering costs and the volume-distance allocation of transmission costs.[55]

Q44. What is NGTL's assessment of these cases?

A44. None of these cases is suitable for the Alberta System.

In Case 1 and Case 2, Confer Consulting improperly uses the DOH methodology to allocate the revenue requirement on an absolute basis between the FT-R and FT-D services. The DOH ratio is a unit measure related to the combination of FT-R and FT-A service versus FT-R and FT-D service. As previously explained, the application of DOH as proposed by Confer Consulting in these cases is not logical. Accordingly, these cases are inappropriate for the Alberta System and should be summarily dismissed.

Case 3 and Case 4 are similarly unworkable. Confer Consulting has inappropriately determined and allocated the revenue requirement between the FT-R, FT-D and FT-A services.

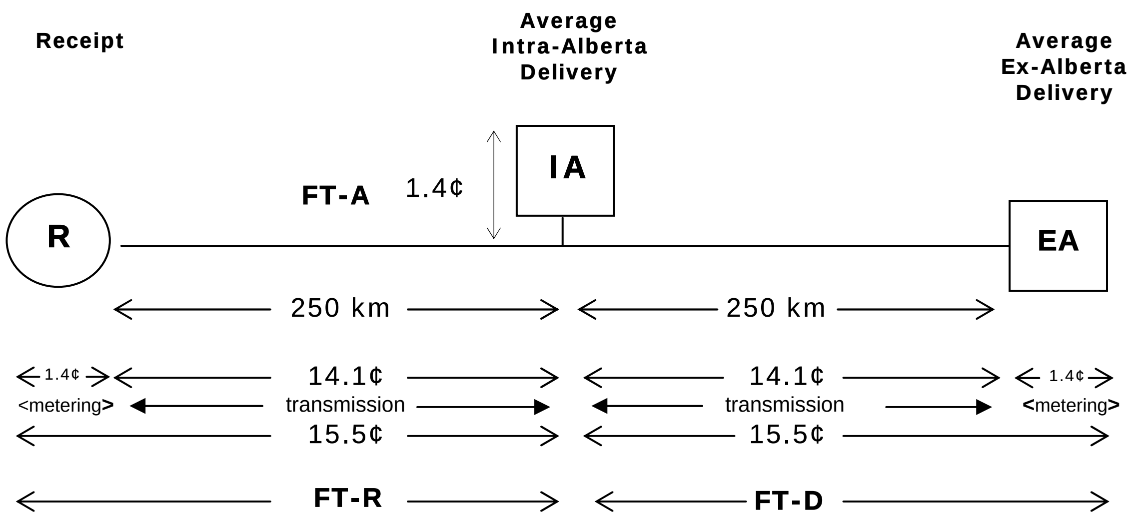
[55] Exhibit 07-006, Written Evidence of Confer Consulting, page 2, lines 37-51.

Q45. Please explain what is wrong with the methodology Confer Consulting has used for Cases 3 and 4.

A45. Confer Consulting fails to properly account for the fundamental cost relationships between NGTL's services. The following diagrams provide illustrations of NGTL's existing and applied-for rate design and the distortions introduced by Confer Consulting's proposals.

Figure 3.3-1

Simplified Alberta System with Existing NGTL Methodology



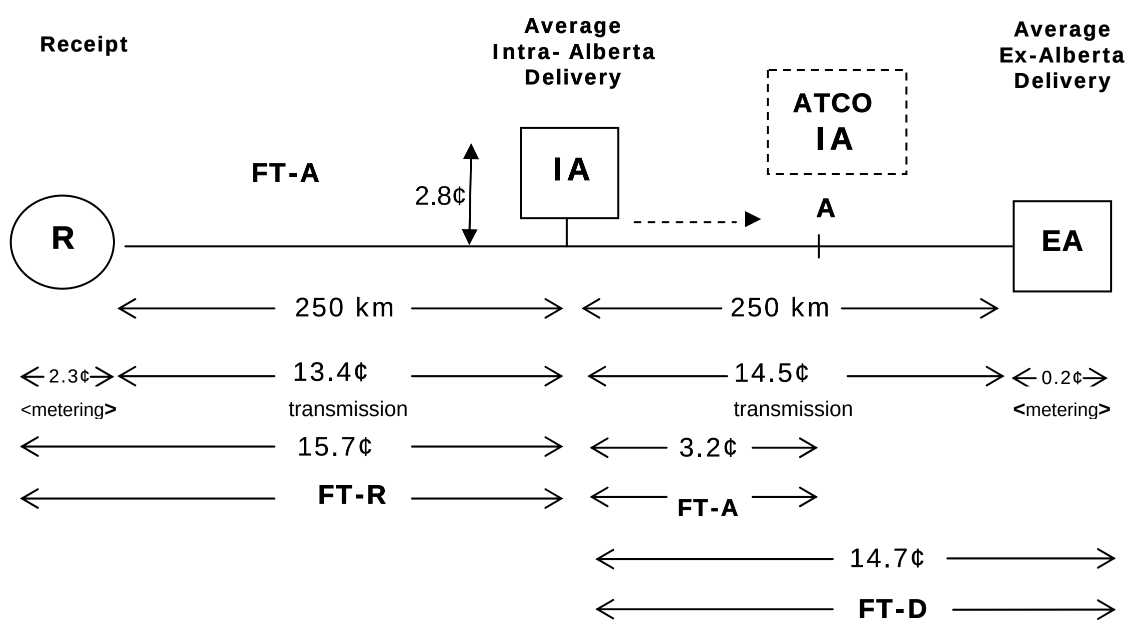
Charge to deliver to intra-Alberta (IA)	= FT-R + FT-A	= 15.5 + 1.4	= 16.9¢/Mcf
Charge to deliver to ex-Alberta (EA)	= FT-R + FT-D	= 15.5 + 15.5	= 31.0¢/Mcf
Transmission charge for intra-Alberta (IA)	= FT-R + FT-A	= 14.1 + 0.0	= 14.1¢/Mcf
Transmission charge for ex-Alberta (EA)	= FT-R + FT-D	= 14.1 + 14.1	= 28.2¢/Mcf

By design, the existing rate design methodology decouples the full-path transportation into receipt (FT-R) and delivery components (FT-D and FT-A). The full-path service combination for ex-Alberta markets is FT-R plus FT-D and the full-path service combination for intra-Alberta markets is FT-R plus FT-A. The charges associated with transportation to intra-Alberta markets are obviously less than the charges to transport to ex-Alberta markets. The results of the DOH study indicates that the average distance gas travels to intra-Alberta markets is approximately one-half of the average distance gas travels to ex-Alberta markets. This is reflected by the 250 km distances between the points labelled R & IA and between the points labelled IA & EA in Figure 3.3-1. This translates to a transmission charge of 14.1 cents/Mcf identified with each 250 km segment in Figure 3.3-1.

It is important to note that although FT-R service provides the same function for deliveries to both intra- and ex-Alberta markets (i.e. receiving gas onto the system), it provides different functions in terms of cost accountability. For ex-Alberta markets, the FT-R rate accounts for approximately one-half of the total associated transmission costs. However, for intra-Alberta markets it accounts for all of the associated transmission costs.

Confer Consulting's proposals in Cases 3 and 4 distort the existing cost relationships by substantially increasing the FT-A rate without appropriate offsetting amendments to the FT-R and FT-D rates. In essence, Confer Consulting's proposals in Cases 3 and 4 would over-charge intra-Alberta users for transmission costs. This impact for Case 4 illustrated in Figure 3.3-2.

Figure 3.3-2: Simplified Alberta System with Confer Consulting methodology



Charge to deliver to intra-Alberta (IA)	= FT-R + FT-A	= 15.7 + 6.0 = 21.7¢/Mcf
Charge to deliver to ex-Alberta (EA)	= FT-R + FT-D	= 15.7 + 14.7 = 30.4¢/Mcf
Transmission charge for intra-Alberta (IA)	= FT-R + FT-A	= 13.4 + 3.2 = 16.6¢/Mcf
Transmission charge for ex-Alberta (EA)	= FT-R + FT-D	= 13.4 + 14.5 = 27.9¢/Mcf

Confer Consulting's proposals in Cases 3 and 4 would have intra-Alberta users pay for transmission to deliver gas further than its actual delivery point. For Case 4, the intra-Alberta market would incur an indirect transmission charge via the FT-R rate of 13.4 cents/Mcf and a direct transmission charge via the FT-A rate of 3.2 cents/Mcf for a total transmission component of 16.6 cents/Mcf or approximately 60% of the transmission component of the charge to export markets (represented by point A in Figure 3.3-2) when the actual DOH is approximately 45%. To preserve the relative relationship between the rates to serve the export-Alberta and intra-Alberta markets and properly reflect the actual system characteristics of the Alberta System, the FT-R rate would have to be decreased by a further 2.6 cents/Mcf for those deliveries being made to an intra-Alberta market. However, as explained in Section 2 of NGTL's Application, this approach would create substantial distributional effects and is not recommended.

Q46. Does NGTL have any other concerns with the methodology Confer Consulting has used for Cases 3 and 4?

A46. Yes. Confer Consulting's proposals do not appropriately account for FT-P service and FCS revenues.

Confer Consulting wrongfully subtracts the FCS and FT-P services revenue from the Total Revenue Requirement.[56] This approach inappropriately allocates the benefit of FCS and FT-P revenues to the primary services in the same proportion as it allocates the Primary Firm Transportation Revenue Requirement to the primary services.

FT-A is not an independent service as it cannot be offered unless a FCS agreement exists at the intra-Alberta delivery point. As a result, the FCS revenue is directly associated with the FT-A service. Consequently, the FCS revenue must be used to directly offset any cost allocated to the FT-A service.

Similarly, FT-P is another firm service that is used for transportation only to intra-Alberta delivery points. As a result, FT-P revenue should not be used to decrease the cost assigned to an export-only service (i.e. FT-D).

Allocating the FCS and FT-P revenue across all services, as Confer Consulting has done, results in a substantial over-crediting of revenue to FT-D service from intra-Alberta only services, as illustrated below in Table 3.3-1.

Table 3.3-1

Allocation of FCS and FT-P Revenue in Cases 3 and Case 4

Primary Service	Volume-Distance Allocation	FCS Revenue ($ million)	FT-P Revenue ($ million)	Total FCS & FT-P Revenue ($ million)
FT-R	49.4%	2.4	11.1	13.5
FT-D	49.1%	2.4	11.0	13.4
FT-A	1.5%	0.1	0.3	0.4
Total	100%	4.9	22.4	27.3

Under Confer Consulting's proposed approach, over 98% of the FCS revenue is not properly allocated to FT-A service even though 100% of the revenue is related to FT-A service. Also, approximately $11.0 million of the $22.4 million FT-P revenue is being used to reduce the FT-D rate even though FT-P service cannot be used to transport gas to the ex-Alberta market. These are fundamental and fatal flaws in Confer Consulting's proposals. A rate design methodology that misallocates this magnitude of revenue credits between the various services is obviously not appropriate.

Q47. Does Confer Consulting provide any rationale for its treatment of FCS and FT-P revenues?

A47. Yes. Confer Consulting states:

> None of these revenue credits that direct the FCS revenue to FT-A service are used in the volume-distance Cases 3 and 4 prepared for this evidence. Instead, FCS and FT-P revenues are treated as revenue credits in the same manner as in NGTL's applied-for case and the alternatives that use DOH.[57]

[56] Ibid, page 17, Table 3.
[57] Ibid, page 2, lines 13-16.

For its part, ATCO Pipelines states:

> The allocation by NGTL of revenue from secondary services, which includes FT-P, has been applied as a revenue credit against total revenue requirements and not as a credit streamed to particular primary services. For example, the revenue from IT-D service is not streamed to FT-D service. AP believes NGTL's current allocation of revenue credits is a reasonable practice.[58]

However, these statements do not support Confer Consulting's treatment of FCS and FT-P revenues.

In NGTL's existing and applied-for methodology, and Alternatives 1 to 3 presented in the Application, the rates are established to maintain specific rate relationships between FT-R, FT-D and FT-A services so the crediting of secondary revenue is moot. In other words, the rate relationship between the combined FT-R and FT-A service and the combined FT-R and FT-D service will be the same, regardless of how the secondary service revenue is credited. However, in Alternatives 4 to 6, where the revenue requirement is allocated based on explicit volume-distance factors, NGTL does stream the secondary service revenue to its associated primary service. This approach is required due to the substantially different revenue relationships between each primary service and its secondary services as well as the relative volume-distance relationships amongst the primary services.

Confer Consulting did not stream the secondary service revenue to its primary service and, as a result, the majority of the FT-P revenue which would account for the costs associated with deliveries to intra-Alberta was wrongly allocated to other services. In particular, FT-D, an export-only service with no relationship to FT-P service, receives a $13.4 million credit for FT-P and FCS revenue, whereas the FT-A service only receives a $0.4 million credit. This approach is not justifiable.

[58] Exhibit 07-012, response to NGTL-AP-24(b) and (c).

Q48. Does Confer Consulting provide any other rationale for its treatment of FCS revenue?

A48. Yes. Confer Consulting states:

> The inclusion of FCS revenue as a revenue credit is part of the illustrative nature of the analysis. If the approved FT-A rate includes transmission costs, AP and Confer recommend that the FCS contracts be amended as per AP's MAV and AMEV proposals to ensure that there is a reasonable balance between revenue under the rate and under the associated FCS contract.[59]

Again, this rationale does not support Confer Consulting's treatment of FCS revenue.

By failing to include the FCS revenue as a direct credit in calculating the FT-A rate, Confer Consulting has inflated the average FT-A rate. Under this design, the shippers who would sufficiently utilize the FCS facilities, such that an FCS charge would not be required, would have paid too much initially via the inflated FT-A rate. There would be no mechanism to reduce this over-payment after the fact. The result is an unreasonable balance between the FT-A revenue and the FCS revenue, which is unfair to the shippers who are appropriately utilizing their FCS facilities.

By crediting the FCS revenue directly against the FT-A service, an appropriate FT-A rate would be generated. In this situation, only those shippers who have not sufficiently utilized their FCS facilities will be subjected to the FCS charge. As the FCS charge is calculated at the end of the year, these customers can be charged whatever is required to ensure adequate cost recovery and no shippers will have been overcharged. Therefore, the FCS revenue needs to be applied as a direct offset to the FT-A rate.

Q49. In its Case 4, Confer Consulting has proposed service-specific metering components for the FT-R, FT-D and FT-A rates. Is this appropriate?

A49. No. In Case 4, Confer Consulting is recommending a service-specific metering component of $0.028/Mcf, which it derived from NGTL's 2003 cost information, and

[59] Exhibit 07-012, response to NGTL-AP-39(a).

forecasted 2005 volumes.[60] The 2003 unit cost for deliveries to intra-Alberta was \$0.0415/Mcf. Based on these two numbers, Confer Consulting is recommending a methodology that would have caused the metering rate to fluctuate by over 30% within two years. This type of rate volatility should be avoided and is a reason why NGTL continues to recommend that a system average metering component be included in the rate of all services except FT-X and IT-S.

Confer Consulting's proposed metering rate would also substantially overcharge the intra-Alberta industrial sub-group. The volume increase from 2003 to 2005 that Confer Consulting used to reduce the average metering charge is primarily the result of increased deliveries to intra-Alberta industrial users.

Q50. If properly applied, could the volume-distance concept advocated by Confer Consulting in Cases 3 and 4 be used to determine the revenue requirement applicable to the intra-Alberta delivery market?

A50. Yes. The volume-distance concept could be used to separate the Alberta System into two subcomponents: one for intra-Alberta and one for ex-Alberta. Table 3.3-2 below illustrates the revenue requirement separated into an intra-Alberta and ex-Alberta component using the volume-distance methodology proposed by Confer Consulting.

Specifically, the revenue requirement is allocated between the two markets based on the relative volume x distance for each market divided by total volume x distance for both markets. The intra-Alberta market contains all deliveries that are currently being made via FT-A, FT-P and FT-X services. The intra-Alberta market is subdivided into extraction and non-extraction components to facilitate an analysis on the non-extraction component of the intra-Alberta market. The non-extraction market appears to be Confer Consulting's main concern as this is the component of the intra-Alberta market served by the FT-A service. The Total Revenue Requirement has been reduced by the forecasted OS, PT and CO_2 revenues as these services are not related to delivery of gas to either the ex-Alberta or intra-Alberta markets.

[60] Exhibit 07-006, Written Evidence of Confer Consulting, page 11, lines 16-21.

Table 3.3-2
Allocation of Revenue Requirement between Ex-Alberta and Intra-Alberta Markets

	2003 DOH (km)	Forecasted Volume ($10^6m^6/y$)	Volume x Distance (km x $10^6m^6/y$)	Revenue Requirement (%)	Revenue Requirement ($ million)
Alberta System	517	121,915	55,615,521	100	1,142.6
Ex-Alberta	559	84,229	47,083,949	91	1,042.9
Total Intra-Alberta	239	18,843	4,503,596	9	99.7
• Intra-Alberta (Extraction)	511	4,370	2,233,324	5	55.3
• Intra-Alberta (Non-Extraction)	124	14,473	1,794,652	4	44.4

As can be seen from Table 3.3-2, the cost allocated to the non-extraction intra-Alberta market under a properly applied volume-distance methodology is $44.4 million, or 4% of the total revenue requirement.

Q51. Do the existing services and rates used to provide transportation to the non-extraction intra-Alberta markets generate sufficient revenues to cover the revenue requirement that would be allocated to this market based on a volume-distance methodology?

A51. Yes. Table 3.3-3 identifies the revenue that is generated from services that are directly related to the ex-Alberta and non-extraction intra-Alberta markets under NGTL's existing and applied-for rate design.

Table 3.3-3
Direct Service Revenue

Direct Service	Ex-Alberta ($ million)	Non-Extraction Intra-Alberta ($ million)
FT-D	416.3	
IT-D	64.8	
LRS	47.3	
FT-P		22.1
FT-A		5.3
FCS		4.9
Total Direct Service Revenue	528.4	32.3
Total Revenue Requirement	1, 042.9	44.4
Percent Direct Revenue of Total Revenue Requirement	**51%**	**73%**

As can be seen from Table 3.3-3, 51% of the ex-Alberta Revenue Requirement is being recovered through direct service revenue, and 73% of non-extraction intra-Alberta revenue is being recovered through direct service revenue. In order for the non-extraction intra-Alberta market to be accountable for its entire revenue requirement, an additional $12.1 million must be accounted for.

As ATCO Pipelines acknowledged in its response to NGTL-AP-028(b)[61], the minimum rate to receive gas onto the Alberta System and deliver it using FT-A service is the FT-R rate. Table 3.3-4 identifies the range of FT-R revenue that can be associated with FT-A service.

Table 3.3-4
FT-R Revenue Associated with FT-A Service

	Floor FT-R	Average FT-R	Ceiling FT-R
FT-R Rate (¢/Mcf)	7.51	15.51	23.51
FT-R Revenue ($ million)	28.1	58.1	88.1

In all cases the FT-R revenue associated with the FT-A service exceeds the $12.1 million non-extraction intra-Alberta revenue requirement that was not recovered from the direct intra-Alberta services. Accordingly, the non-extraction intra-Alberta users are in fact generating sufficient revenue under the existing rate design to account for the entire revenue requirement that would be allocated to the non-extraction intra-Alberta market using ATCO Pipelines'; recommended volume-distance methodology. In addition, as NGTL previously explained, approximately $13 million in receipt revenue was generated from shippers who directly held both receipt and FT-A service or the entire full path intra-Alberta delivery service. As a result there is no need to modify NGTL's existing and applied-for rate design at this time.

[61] Exhibit No. 07-012, Response to NGTL-AP-028(b)

3.4 IGCAA'S Rate Design Proposals

Q52. IGCAA's rate design proposals appear to be based on what IGCAA characterizes as the "principle" that gas delivered to a delivery point came from the nearest upstream receipt points. IGCAA specifically states that:

> **Compression costs and pipe costs are driven by the principle that deliveries on a pipeline network are effectively sourced from the nearest receipt point or points until the delivery volume is satisfied. The hydraulic pipeline models utilized by all pipelines, including NGTL, embody this principle. It is from this principle that energy requirements on a pipeline can be optimized.[62]**

Does NGTL agree with IGCAA's statements?

A52. No. The "principle" advanced by IGCAA does not reflect how gas actually flows on the Alberta System, or how the Alberta System is designed, and is not an engineering principle.

This "principle" is not reflective of how gas flows on the Alberta System because gas is commingled upon receipt, so the gas delivered at a point is a mixture of the gas received at all upstream receipt points. If gas could be coloured, and blue gas were received at an initial receipt point and red gas were received at a second receipt point, then purple gas would be delivered downstream of these receipt points. The red gas does not stay separate and get delivered first because it was most recently received. If this were the case, the heat content at a delivery station would be the same as the heat content at the nearest upstream receipt point, which it is not.

Compression costs and pipe costs are driven by aggregate system receipt and delivery requirements. NGTL designs its system by considering these aggregate requirements, and then minimizing compression and pipe capital, operation and maintenance costs required to meet these aggregate requirements. Because the system is designed to meet aggregate requirements, it is incorrect to state, as IGCAA does, that the optimization of energy requirements is based on the assumption that deliveries come from the nearest

[62] Exhibit 22-005-001, Written Evidence of the Industrial Gas Consumers Coalition of Alberta, page 19, lines 7-11.

upstream receipt points. Furthermore, NGTL's hydraulic model does not embody this "principle" as IGCAA wrongly states, since it is not an engineering principle.

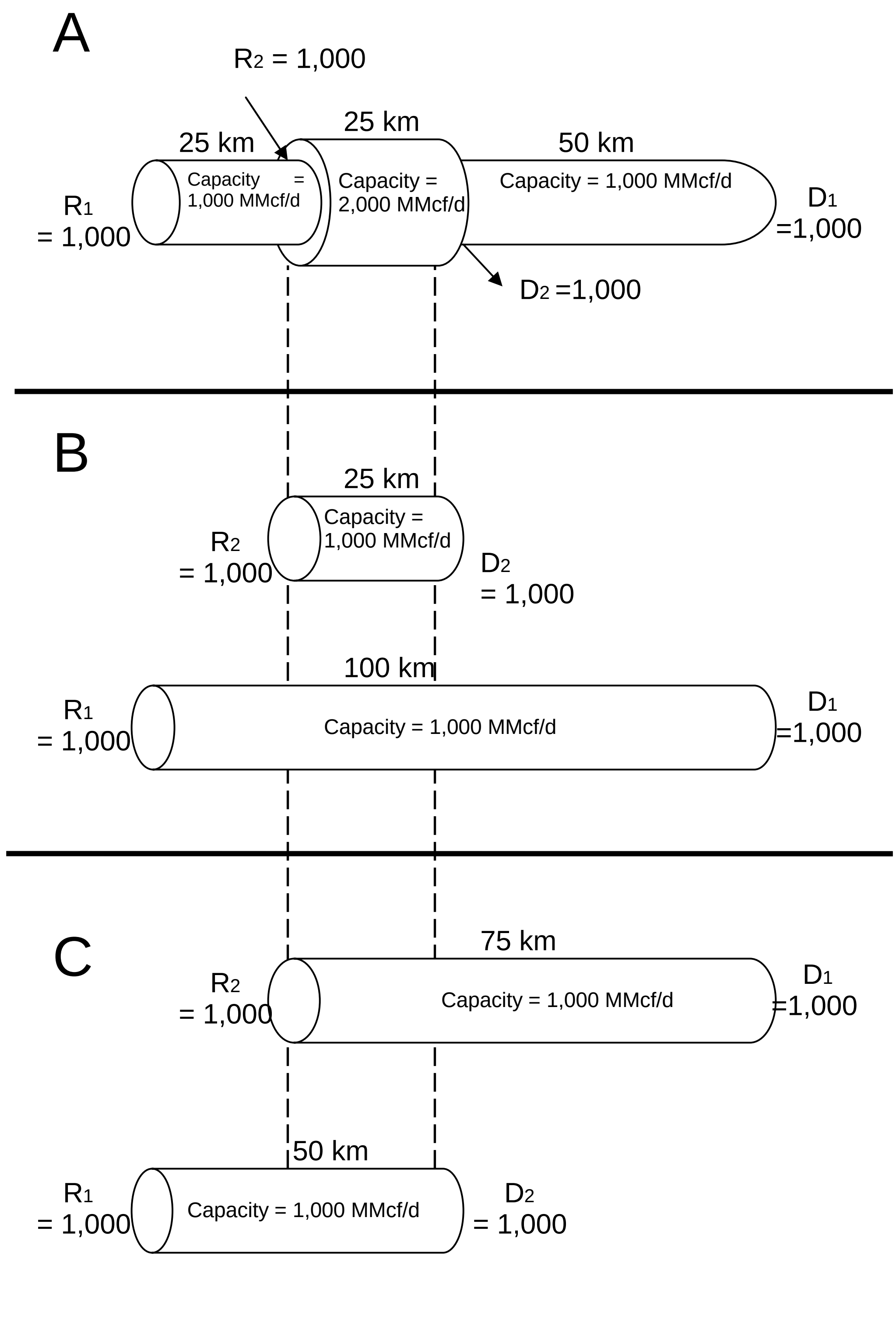
Q53. Does NGTL use this "principle" when it determines facility requirements for the Alberta System?

A53. No. This "principle" is not a factor in determining facility requirements for the Alberta System.

A pipeline often accommodates many different customers in common on a particular segment, and the pipeline logically would be designed to serve all of these customers simultaneously. A simplistic representation to demonstrate this concept is shown by the three diagrams in Figure 3.4-1. Panel A shows a pipeline that is 100 km long. There are two receipt points, R1 and R2, which each put 1,000 MMcf/d into the pipeline. R1 is located at the beginning of the pipeline and R2 enters at a point 25 km downstream. In addition, there are two delivery points, D1 and D2, which each have a demand of 1,000 MMcf/d. D2 is located at the 50 km point on the system and D1 is located at the terminus of the system 100 km downstream from the beginning of the system.

It is not possible to determine that the pipeline is specifically designed to serve one particular delivery point or the other from the nearest upstream receipt point. Panel B illustrates the "principle" put forward by IGCAA where supply at D2 comes from the nearest receipt point at R2, leaving the remaining delivery volume at D1 to be met from supply at R1. Conversely, Panel C shows an example where the delivery at D2 is met with supply from the furthest receipt point at R1, leaving the remaining delivery volume at D1 to be met with supply from R2. In all three panels the combined system requirements to transport gas from R1 and R2 to deliveries at D1 and D2 are the same. Thus, regardless of what is assumed about which receipt point and delivery point combinations the pipeline is designed to physically serve, the end result is that the pipeline shown in Panel A involves the most efficient facilities.

Figure 3.4-1


A
R2 = 1,000
25 km
25 km
50 km
Capacity = 1,000 MMcf/d
Capacity = 2,000 MMcf/d
Capacity = 1,000 MMcf/d
R1 = 1,000
D1 =1,000
D2 =1,000
B
25 km
Capacity = 1,000 MMcf/d
R2 = 1,000
D2 = 1,000
100 km
Capacity = 1,000 MMcf/d
R1 = 1,000
D1 =1,000
C
75 km
R2 = 1,000
Capacity = 1,000 MMcf/d
D1 =1,000
50 km
R1 = 1,000
Capacity = 1,000 MMcf/d
D2 = 1,000

Q54. IGCAA proposes that FT-R and FT-D rates be established using the results of its proposed DOH methodology. Both IGCAA's proposed DOH and Cost of Haul (COH) methodologies are based on the "principle" that intra-Alberta deliveries are sourced from the nearest upstream receipt points. Does NGTL agree with this methodology?

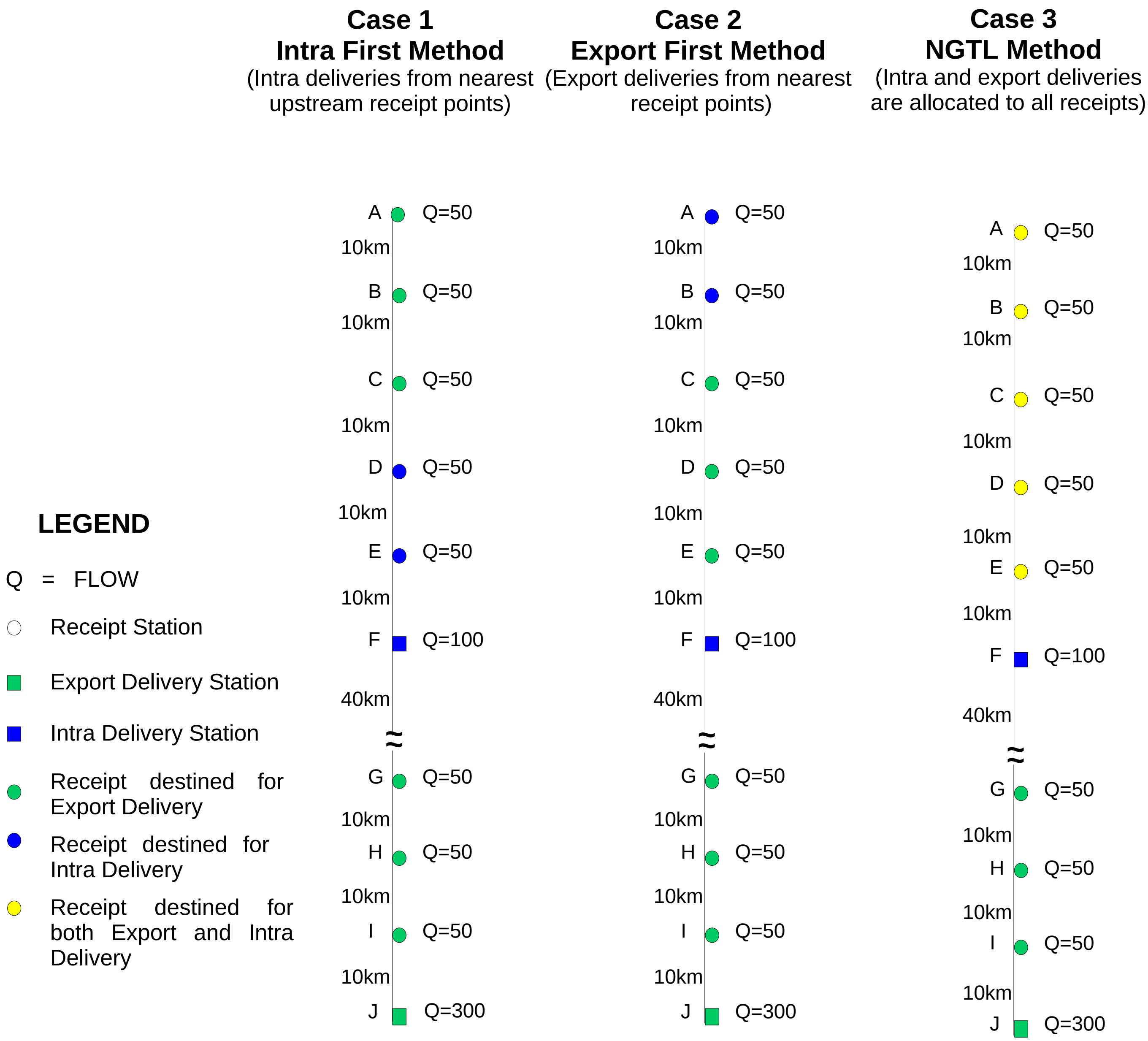
A54. No. As discussed above the "principle" put forward by IGCAA does not reflect how the Alberta System is designed, or how gas flows on the Alberta System. Therefore, it is not an appropriate basis for rate design.

IGCAA's DOH methodology is inappropriate since it is one of two extreme methodologies for calculating distances of haul. IGCAA's proposal is the extreme that results in the shortest distances of haul to intra-Alberta delivery points. The other extreme methodology is for ex-Alberta delivery points to be served by the closest upstream receipt points. This extreme results in the greatest distances of haul to intra-Alberta deliveries.

The molecules at each delivery point are part of a commingled stream. It is for this reason that the NGTL methodology calculates a distance of haul to each delivery point based on the weighted distance from all upstream receipts points. This is a reasonable and balanced approach, and best represents the distance gas molecules travel before being delivered, given the commingled nature of the gas stream.

The following example illustrates the two extreme DOH methodologies and the NGTL DOH methodology.

Figure 3.4-2
Alternate Methods of Determining Distance of Haul



	Case 1	Case 2	Case 3
Average intra distance:	15 km	45 km	30 km
Average export distance:	65 km	55 km	60 km
Receipt/Delivery Allocation:	23/77	81/19	50/50
Ex/Intra Allocation Ratio:	4.3 to 1	1.2 to 1	2 to 1

Case 1 is representative of IGCAA's proposed DOH method. In this case, the DOH is determined by assuming that the intra-Alberta delivery station receives gas from the nearest upstream receipt stations. In this case, gas delivered to the intra-Alberta delivery station F is sourced entirely from receipt points E and D. Gas delivered to the export delivery station J is thus sourced from the remaining receipt stations I, H, G, C, B and A. Using this DOH ratio as a proxy to allocate costs results in more than four times the costs being allocated to the export delivery station than the intra-Alberta delivery station.

In Case 2, the DOH is determined by assuming that the export delivery station receives gas from the nearest upstream receipt stations. In this case, gas delivered to the export delivery station J is sourced from I, H, G, E, D and C. Gas delivered to the intra-Alberta delivery station F is thus sourced from the remaining receipt stations B and A. Using this DOH ratio as a proxy to allocate costs would result in approximately equal costs being allocated to the export delivery station and the intra-Alberta delivery station.

In Case 3, the DOH is determined by assuming that both intra-Alberta and export delivery stations receive gas from all upstream receipt stations. This methodology most accurately reflects the actual operations of the Alberta System. In this case, gas delivered to F is sourced from all upstream receipt stations A, B, C, D and E and gas delivered to J is sourced from all upstream receipt stations A, B, C, D, E, G, H and I.

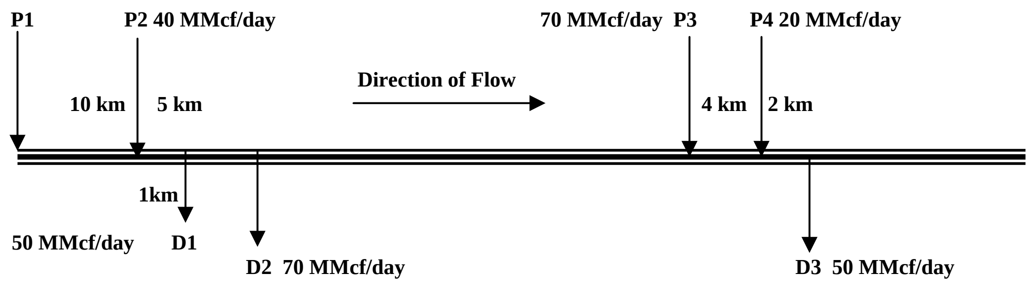
Q55. Does NGTL have any other concerns with IGCAA's DOH methodology?

A55. Yes. IGCAA's DOH methodology uses annual average throughputs as opposed to peak demands. For intra-Alberta deliveries, peak demand can be substantially greater than average flows. Therefore it would require a greater distance to serve peak demands than average demands under IGCAA's DOH methodology. As a result, IGCAA's proposed DOH methodology understates the DOH to intra-Alberta delivery points.

This can be illustrated using the example IGCAA provided in Figure 6 of its evidence,[63] provided below for convenience.

[63] Ibid, page 16.

Figure 3.4-3 (IGCAA Figure 6)



In this example, IGCAA concluded that the distance of haul for D3 based on an average volume of 50 MMcf/d was 6 km. If D3 actually moved 100 MMcf/d for six months and 0 MMcf/d for six months to average 50 MMcf/d, the DOH to serve the peak volume would actually be higher than the DOH to serve the average volume. The deliveries at D3 would actually have to source gas from P2. In this example that distance is 12 km plus the unidentified distance between D2 and P3, so the distance required to meet peak demand would be appreciably greater than the distance required to meet average demand.

Q56. IGCAA also proposes an FT-P rate design which is based on the "principle" that gas delivered to an intra-Alberta delivery point is sourced from the nearest upstream receipt points. Given this "principle," IGCAA proposes that an FT-P rate be based on the cost to flow from the nearest upstream receipt point, regardless of the contracted receipt point.[64] Does NGTL consider this an appropriate approach to calculating FT-P rates?

A56. No. IGCAA's preferred FT-P rate design:

- is inappropriate since it is not reflective of the costs incurred to provide FT-P service;
- would yield unstable results; and
- would be very difficult to implement.

[64] Ibid, page 15, line 33 to page 16, line 31.

Q57. Please explain why IGCAA's preferred FT-P rate design is not reflective of the costs incurred to provide FT-P service.

A57. There are three reasons why IGCAA's preferred FT-P rate design is not reflective of the costs to provide FT-P service. First, it does not reflect actual physical flow on the Alberta System. Given the commingled nature of the gas stream, gas delivered to an individual delivery point has travelled from more than just the nearest receipt point. This concept was discussed in detail above.

Secondly, IGCAA's FT-P rate design wrongly ignores the contractual arrangements behind an FT-P contract. For example, an Alberta System shipper may move gas to an intra-Alberta delivery point from its own source of production 1000 km upstream of its delivery point. Under IGCAA's proposal, this shipper could pay an FT-P rate reflecting only 5 km to the closest upstream receipt point.

Third, IGCAA's FT-P rate design proposal does not reflect the integrated nature of the Alberta System. Under IGCAA's proposal, FT-P shippers would unfairly benefit from the security and reliability of supply that results from having the ability to contract for supply anywhere on the Alberta System. Also, because the Alberta System is an integrated system, all shippers benefit from economies of scale, which reduces the per unit cost of transportation. Under IGCAA's proposal, FT-P shippers would enjoy these benefits but pay rates only associated with a share of the costs for the segment of pipe connecting them to the nearest upstream receipt point. This leaves the costs of the remaining integrated system to be recovered from shippers using other services.

Q58. Please explain why IGCAA's preferred FT-P rate design would result in unstable rates.

A58. IGCAA proposes that individual FT-P rates be calculated based on the distance from the intra-Alberta delivery point to the nearest upstream receipt point (or points), by moving up the pipeline to the next furthest receipt points until the delivery volume is satisfied.[65] With this rate design, the FT-P rate could vary significantly year-to-year due to the

[65] Exhibit 22-006-002, response to CAPP-IGCAA-13(a).

addition and removal of receipts, and changes in the volumes received at receipt points. New receipt points are always being added to the Alberta System with volumes ramping-up initially, while existing receipt points may drop in volume and ultimately be disconnected. The effect that this type of change would have on an FT-P rate can best be described by referring to Figure 3.4-3.

If producer P3 was not connected to the Alberta System when shipper D3 entered into its FT-P contract, the FT-P rate for shipper D3 would be based on the distance between P2 and D3. Suppose that during this FT-P contract producer P3 is connected to the system. When shipper D3 renews its FT-P contract, its FT-P rate would be greatly reduced as it would reflect the much shorter distance between P3 and D3.

The same year-over-year variation in FT-P rates caused by changes in receipt points and volumes received at receipt points could also occur with changes in delivery points, and with changes in the volumes delivered at these points.

Q59. Please explain what difficulties NGTL would encounter if it attempted to implement IGCAA's preferred FT-P rate design.

A59. NGTL would encounter three difficulties implementing IGCAA's preferred FT-P rate design.

First, there is no objective way to determine which receipt points will be paired with which delivery point. Receipt points could be attributed to specific delivery points starting at the bottom of the system and working up, starting at the top of the system and working down, starting at either side, or by starting in the middle. None of these methods are more correct than the others, but each could result in very different FT-P rates for individual shippers. Due to this lack of clarity, there may be disputes regarding which receipt points should be paired with which delivery points.

Second, under IGCAA's proposal a "baseline volume" must be established for a delivery point so that it can be met with the "baseline volumes" from the upstream receipt points. This is unworkable since each FT-P contract would require resolution of what the "baseline volume" is for each delivery point and each upstream receipt points without an objective measure for establishing a "baseline volume."

Third, it would be administratively difficult to keep track of which receipt points had already been paired with a delivery point, which delivery points the receipt points are paired with, and the "baseline volume" assumed for each receipt point. It would be necessary to maintain this data, otherwise a receipt point could have its volumes paired with more than one delivery point.

Q60. IGCAA suggests that its preferred FT-P rate design is new and has not been considered before. Specifically, IGCAA states that it "believes it is necessary to put forward two options [for FT-P service improvements] because it recognizes that Option One includes more fundamental changes [than Option Two] that have not been discussed with stakeholders or reviewed previously by the Board."[66] Does NGTL agree that IGCAA's Option One includes fundamental changes which have not already been discussed by interveners and reviewed by the Board?

A60. No. IGCAA has proposed essentially the same concepts in this proceeding as it did in NGTL's 1999 Products and Pricing proceeding. In the Products and Pricing proceeding, IGCAA based its proposal for Local Delivery Service (LDS) on the assumption that intra-Alberta deliveries are sourced from the nearest upstream receipt point, which the Board found to be inappropriate. Specifically, it stated:

> The Board notes that the proposed LDS is based on a distance of haul assumption that intra-Alberta delivery points are satisfied from the nearest upstream receipt point. In the Board's view, however, this does not realistically reflect what might be expected to occur. For example, the Board notes that more than 50 per cent of intra-Alberta consumption occurs in the southeastern part of the province close to the border delivery points. The Board saw no evidence that would suggest that this natural gas was all delivered into the NGTL system from receipt points immediately upstream of the point of delivery. The relatively large volumes of shrinkage natural gas required by the straddle plants located effectively on the Alberta border are unlikely to have been received from the nearest receipt points. In the Board's view, the premise upon which IGCAA based its modified alternative does not adequately conform to the cost causation principle.

[66] Exhibit No. 22-005-001, Written Evidence of the Industrial Gas Consumers Association of Alberta, page 4, lines 28-33.

> The Board notes that while IGCAA proposed that cost allocation between intra- and ex-Alberta services should reflect the principles underpinning its distance of haul methodology, IGCAA later modified its proposal to better reflect the value added by the fact that an intra-Alberta delivery point could receive natural gas from any receipt point at a uniform LDS rate. As a result, the board believes that the principle upon which IGCAA has proposed to set the cost allocation between the two services is relatively arbitrary, at least in comparison with the NGTL proposal, and could therefore result in rates that are neither equitable nor free from controversy.[67]

Q61. What are IGCAA's proposed changes to FT-P service in Option Two and are these changes appropriate?

A61. IGCAA provides a comparison of the attributes of the current FT-P service and its Option Two proposal.[68] NGTL has reproduced in Table 3.4-1 the proposed changes to those service attributes and summarized its concerns with each. NGTL does not believe any of the proposed changes are appropriate as they:

- do not improve the relationship between what is charged for the FT-P service and the cost associated with providing the FT-P service;
- cannot be practically implemented; or
- provide no additional value.

[67] Alberta Energy and Utilities Board Decision 2000-6, NOVA Gas Transmission Ltd, 1999 Products and Pricing (February 4, 2000), page 50.
[68] Exhibit 22-005-001, Written Evidence of the Industrial Gas Consumers Association of Alberta, page 35.

Table 3.4-1

IGCAA's Proposed Changes to FT-P Service

Service Attribute	Proposed FT-P	NGTL's concerns with Proposal
Rate Design • NIT access • Backhaul	Based on Weighted Avg. Forward Haul Distance Between Receipt and Delivery Pts	Does not properly reflect cost Cannot be practically implemented
Minimum Volumes	28 10^3m^3/day	Cannot be practically implemented
Over-Run $_{\text{Receipt Pt}}$	Max IT-R Rate on Volumes > CD Only	Does not properly reflect cost
Over-Run $_{\text{Delivery Pt}}$	FT-A Rate on Volumes > CD Only	Does not properly reflect cost
Fuel Ratio	Adjusted for Distance	Does not properly reflect cost
Capacity Release	Allowed	Provides no additional value
Relief for Mainline Restrictions	Provided	Provides no additional value
Account Balance	Balance to a Tolerance	Cannot be practically implemented

Q62. In Table 3.4-1, NGTL identified certain attributes of IGCAA's proposal that do not properly reflect the cost of FT-P service. Please elaborate.

A62. First, IGCAA states FT-P service should have access to NIT.[69] This is wrong as FT-P is a linked service. FT-P is designed and priced based on the distance between specified contractual points. NIT provides access to the entire system. Therefore the rate for any service that has access to the entire system should include costs associated with accessing the entire system.

Second, IGCAA states that "much of the gas contracted for delivery to intra-Alberta markets is delivered in part on a backhaul basis."[70] This is not true as only FT-P service actually specifies the receipt and delivery points. All other services specify only a receipt

[69] Ibid, page 17, lines 5-6.
[70] Ibid, page 27, lines 18-19.

or a delivery point so it is impossible to determine if a "backhaul" was involved since there is no "forward haul" in the first place. NGTL designs its system in aggregate to ensure that all volume at all receipt stations can be received and all volumes at all delivery stations can be made. This determination is made without regard to whether there was a contractual relationship between the receipt and delivery points. Since the system is not designed based on a contractual "forward haul" there can be no efficiency or savings associated with a contractual "backhaul."

Third, IGCAA states that "Backhauls do not require fuel"[71] and that the fuel ratio should be based on "the forward haul distance between the delivery point and a specific receipt point."[72] This is wrong as it is based on the assumption that the system was designed on a contractual "forward haul" basis. As mentioned above, NGTL does not design its system based on contractual "forward hauls." Therefore contractual "backhauls" cannot create efficiencies or savings on the Alberta System. Consequently, the cost of fuel for FT-P service will involve the fuel cost to move gas from the receipt point and the fuel cost to move gas to the delivery point; not just the portion of the fuel cost associated with the physical distance the gas actually flows from only the receipt station.

Fourth, IGCAA states "There should be no over run charges levied on FT-P shippers except in circumstances where receipts or deliveries (or both) exceed the contract demand."[73] This is not correct. Over run charges should be levied even if both the receipt and delivery volumes do not exceed the contract demand if the receipt volumes do not equal the delivery volumes. FT-P is a linked service that provides transportation from one or more receipt points to a matched delivery point. If the shipper received more gas than it delivered or it delivered more gas than it received regardless of the contract demand then the shipper is not using just the FT-P service to transport its gas. Any difference between the actual volume received and the actual volume delivered even if both volumes are below the contract demand required the use of a different service from FT-P. Therefore, it is appropriate to charge the cost of the other service that the shipper is actually used, which is what NGTL currently does.

[71] Ibid, page 31, line 31.
[72] Ibid, page 32, lines 6-7.
[73] Ibid, page 31, lines 1-3.

Q63. In Table 3.4-1, NGTL identified certain attributes of IGCAA's proposal that cannot be practically implemented. Please elaborate.

A63. First, the Alberta System has over 1,000 receipt points and over 100 intra-Alberta delivery points. This creates over 100,000 possible receipt-to-delivery pairs. These points are served by over 7,000 individual pieces of pipe. Trying to determine what the "forehaul" distance would be in order to determine what the price and fuel percentage would be is impractical. It is also totally inconsistent with the integrated nature of the Alberta System.

Second, IGCAA states "A more cost-based approach is to determine the monthly FT-P contract demand charge as the volume weighted average of the distance-based tolls to each specified receipt point (based on the above methodology)."[74] This would again require substantial calculations as the various "forehaul" rates for each receipt station within an FT-P contract would have to be multiplied by the actual volume moved at each receipt point. NGTL currently has FT-P contracts with over 100 receipt points so this would be an extensive calculation. Finally, a comparison would have to be done to determine the final bill. NGTL has no ability to automate these calculations, so this would be a very inefficient process. A simpler solution would be to specify only one receipt point in each contract. This option is available to shippers today if they so desire.

Third, IGCAA states "Ideally to be consistent with FT-R and FT-D service, the minimum volume requirement for FT-P service should be eliminated."[75] The minimum volume restriction was not implemented to be consistent with FT-R and FT-D. It was implemented to align with NGTL's rural gas procedures and to minimize the administration associated with the FT-P service. NGTL does not have the ability to process large numbers of FT-P contracts since not all processes are automated and some must be managed manually. However, FT-A service is available for shippers who require smaller volumes.

[74] Ibid, page 31, lines 8-10.
[75] Ibid, page 33, lines 16-18.

Fourth, IGCAA proposes that "FT-P shippers should have the same obligation as FT-R and FT-D to balance within the Balance Zone rather than to zero each day."[76] The Balance Zone for any customer account that can be accessed by FT-R, FT-D and FT-A service is managed through the use of NIT transactions. As FT-P does not have access to NIT, any account that can be accessed by FT-P must be managed by another process.

Q64. In Table 3.4-1, NGTL identified certain attributes of IGCAA's proposal that provide no additional value. Please elaborate.

A64. IGCAA proposes that FT-P have access to Capacity Release and Relief for Mainline Restrictions.[77] These attributes have not been used by any service in at least ten years. It would require time and resources to develop the procedures to implement these attributes for FT-P. NGTL does not believe that this effort is justified.

[76] Ibid, page 33, line 38 to page 34, line 2.
[77] Ibid, page 33, lines 21-34.

4.0 INTRA -ALBERTA DELIVERY ACCOUNTABILITY

4.1 Introduction

Q65. What is the purpose of the evidence in this section?

A65. ATCO Pipelines has raised various concerns about the appropriateness of NGTL's current accountability for intra-Alberta delivery facilities as provided through Facility Connection Service (FCS) and has proposed alternative mechanisms. In this section NGTL will first address ATCO Pipelines' criticisms of the current FCS-MAV mechanism and the inappropriateness of its proposed alternatives, and then address ATCO Pipelines' criticisms of the current FCS-EAV mechanism and the inappropriateness of its proposed alternatives.

Q66. What are ATCO Pipelines' general criticisms and general recommendations for NGTL's intra-Alberta accountability measures?

A66. ATCO Pipelines contends that:

- indirect receipt revenue should not be used in the FCS-MAV revenue calculation for annual volumes delivered;[78]
- cost accountability under the FCS-MAV calculation should be revised to use a one times test in calculating the MAV requirement[79]; and
- the FCS-EAV provision should be revised to establish a primary service term such that the cumulative present value revenue (CPVR) equals or exceeds the cumulative present value cost of service (CPVCOS) for the associated Extension Facilities.[80]

Q67. Does NGTL agree with ATCO Pipelines' statements?

A67. No, NGTL will address each of these contentions in turn.

[78] Exhibit 07-005, Written Evidence of ATCO Pipelines, page 11, lines 15-17 and page 42, lines 8-11.
[79] Ibid, page 40, lines 6-7.
[80] Ibid, page 42, line 5-8.

4.2 Intra-Alberta Delivery Accountability – FCS-MAV Mechanism

Q68. Is it appropriate to include indirect receipt revenue when analyzing intra-Alberta delivery accountability contrary to ATCO Pipelines' assertions otherwise?

A68. Yes. The Minimum Annual Volume (MAV) is based on the fact that the volume of gas delivered represents:

- incremental receipt and/or delivery revenue; and/or
- retained receipt and/or delivery revenue.

These revenues benefit the customers through reduced transportation rates and would not be realized if the incremental volumes were not obtained or the existing load was not maintained.

ATCO Pipelines also recognized, at least for its systems, the relationship between attracting/retaining delivery volumes and attracting/retaining receipt volumes in various proceedings, as indicated in the following statements:

> To maintain current producer receipt, ATCO Pipelines must retain current industrial deliveries. Without on system deliveries, current producer receipts would need to find off-system markets and become subject to dual tolls, exposing ATCO Pipelines to the threat of bypass. (ATCO Pipelines (South) 2001/2002 GRA, Section 3.2, page 8);[81]

> While this results in contract demand revenue of zero, the special contract would provide incentive for NOVA Chemicals to utilize ATCO Pipelines. The physical deliveries on this system will allow the addition of producer receipts. (ATCO Pipelines (South) 2001/2002 GRA, Section 5.1, page 4 of 6);[82]

> It is a situation that plays itself out over our system all over the place, and certainly to be competitive and to retain those industrial volumes is key to us because it is the mechanism by which we can add or retain producer volumes. (ATCO Pipelines (South) 2001/2002 GRA, Transcript Volume 6, page 1179);[83] and

> For every gigajoule of delivery market we get, we can add a gigajoule of producer receipt on. So, we do get – and we have to work hard for it, but

[81] ATCO Pipelines (South) 2001/2002 General Rate Application, Section 3.2, page 8.
[82] Ibid, Section 5.1, page 4.
[83] Transcript, ATCO Pipelines (South) 2001/2002 General Rate Application, Volume 6, page 1179.

> we can get producer receipt revenues, because we get that delivery market. (ATCO Pipelines (South) 2001/2002 GRA, Transcript Volume 6, page 1180).[84]

Q69. ATCO Pipelines produces Table 5.1-1, based on NGTL's response to AP-NGTL-019, in which it recalculates the MAV accountability to exclude indirect FT-R revenue.[85] Does NGTL agree with this approach?

A69. No. The table provided in response to AP-NGTL-019 is correct. As discussed above, the MAV calculation is designed to recognize both the indirect receipt revenues and the direct FT-A revenue. In addition, FT-P is another intra-Alberta service alternative that provides direct revenue for those intra-Alberta delivery stations that have FT-P contracts. When FT-P revenue is included in the MAV calculation, the revenue exceeds the ACS for all scenarios where the flows are greater than zero.

Q70. ATCO Pipelines states "there is no specific customer surcharge if the ACS exceeds the revenue over the contract term."[86] Is this statement correct?

A70. No. The FCS charge is the specific customer surcharge levied if the direct and indirect revenue on an annual basis is insufficient to account for the ACS via the MAV requirement. The calculation to determine the FCS charge is performed annually for each FCS contract for the life of the contract. Although there is no specific term associated with an FCS contract, if a customer wishes to terminate an FCS contract and retire the facilities, the customer must pay the remaining NBV of the facilities plus retirement costs and any accrued FCS charge in the year, which ensures full accountability for those facilities.

Q71. ATCO Pipelines states "the implication of using the two-times factor is that the FT-A rate is understated."[87] Does NGTL agree with this statement?

A71. No. Use of the two-times factor does not imply that the FT-A rate is understated. The two times test was originally associated with accepted historical practice. If the unit cost

[84] Ibid, Volume 6, page 1180.
[85] Exhibit No. 07-005, Written Evidence of ATCO Pipelines, page 30.
[86] Ibid, page 29, lines 9-10.
[87] Ibid, page 29, lines 7-8.

for a facility was less than two times the system average unit cost, it was considered an efficient and cost-effective build-up of the pipeline system.

The two times factor accounts for both the indirect receipt revenues and the direct FT-A revenue.

Q72. ATCO Pipelines proposes that the MAV calculation be based on a one-times factor instead of the two-times factor.[88] Does NGTL agree with this proposal?

A72. No. As indicated in Table 4.2-1 below, ATCO Pipelines' proposal of using the one-times test, based on an estimate for 2005, would result in increases to the FCS-MAV charges ranging from 17% - 40% for intra-Alberta delivery customers if adopted. As illustrated in Table 4.2-1, ATCO Pipelines, as a utility, is part of the customer group which would receive the largest increase of 40%. On average, it is estimated that the FCS-MAV charges would increase by 24%. NGTL does not believe such an increase is warranted and would not advocate such a proposal.

Table 4.2-1
Estimated FCS-MAV Charges for 2005

Customer Type	FCS-MAV Charges using NGTL's Current Methodology ($)	FCS-MAV Charges using ATCO Pipelines' Proposed Methodology ($)	Change from Current Methodology (%)
Producers	2,621,414	3,079,483	17%
Industrials	842,010	1,034,596	23%
Utilities	1,153,223	1,609,277	40%
Total	4,616,647	5,723,356	24%

[88] Ibid, page 40, lines 6-7.

4.3 Intra-Alberta Delivery Accountability – FCS-EAV Mechanism

Q73. ATCO Pipelines states that "since Extension Facilities are most likely to be built for large industrial customers, who typically have high utilization rates, they will likely not pay any revenues towards the ACS of the Extension Facilities built to serve them."[89] Does NGTL agree with this statement?

A73. No. The scenario that ATCO Pipelines portrays is a fallacy.

There is no situation where a large industrial customer will pay nothing towards the ACS of the Extension Facilities built to serve them. In order for a customer not to have EAV charges, the volume delivered must have been at least equal to the EAV, which, for a three year contract, is a minimum volume of 100 MMcf/d. In this situation, industrial customers have paid either FT-A and FT-R rates and FT-P rates associated with these volumes. The transportation revenue from these services contributes towards the ACS of the extension facility used to delivery their gas. Alternatively, if no volumes are delivered, then there will be an EAV charge for the full EAV volume times the average FT-R rate.

Q74. Are there any flaws in ATCO Pipelines' EAV accountability analysis set out in Tables 5.1-2 to 5.1-4?[90]

A74. Yes. ATCO Pipelines has failed to recognize indirect FT-R revenue in its analysis. Its approach is not reflective of the integrated nature of the Alberta System and the underlying cost relationships that have been incorporated in the existing rate design.

Currently, the FT-R and FT-D rates are allocated 100% of the transmission costs. The transmission component of the FT-R rate accounts for the cost of the gas traveling from a receipt point to an intra-Alberta delivery point. Customers paying receipt charges are therefore paying to get their gas transported to the intra-Alberta markets and any intra-Alberta delivery analysis should incorporate these indirect revenues. As part of these

[89] Ibid, page 33, lines 1-3.
[90] Ibid, pages 31-32.

transmission facilities are used for intra-Alberta deliveries, the accountability provisions for extension facilities should recognize the associated indirect revenue.

Further, ATCO Pipelines fails to recognize any direct FT-P revenues in its analysis. NGTL provides later in this section an examination of the FT-P revenue associated with the FCS-EAV contracts for the KV Oils Sands extension and the Aurora Sales extension that were implemented in 2004.

Q75. ATCO Pipelines states: "Clearly, there is no correlation between the revenues charged to intra-Alberta delivery customers and the cost of the facilities required to serve those customers."[91] Does NGTL believe this is a valid concern?

A75. No. ATCO Pipelines' statement is based on its analysis provided in AP Table 5.1-3 and AP Table 5.1-4. However, ATCO Pipelines failed to consider the FCS-EAV accountability in the proper context. Delivery extensions are mainline extensions that provide benefits to the entire system, in the same manner as receipt extensions and export expansions provide benefits to the entire system. As a result the accountability for intra-Alberta delivery extensions (FCS-EAV) is structured in a manner analogous to that used to structure accountability for intra-Alberta receipt extensions and ex-Alberta expansions. The analysis provided in ATCO Pipelines' tables is equally applicable to receipt extensions and export expansions where the accountability is based on a volume and term commitment independent of the actual cost of the facilities. This reflects the integrated nature of the Alberta System and the fact that the Alberta System is tolled on a rolled-in cost basis and not on an incremental cost basis.

[91] Ibid, page 32, lines 3-4.

Q76. ATCO Pipelines apparently rejects NGTL's Option 4 as a potentially viable alternative to the existing FCS-EAV accountability on the basis that it "appears to be directed to NGTL's Alternative 5 rate design."[92] Does NGTL agree with this claim?

A76. No. Under NGTL's Option 4, extension facilities would have to be underpinned by FT-P contracts. Option 4 would not require all intra-Alberta delivery customers to take FT-P service. Under NGTL's Option 4, intra-Alberta delivery customers requiring extension facilities would be required to sign an FT-P contract for a volume that results in the CPVR equalling the CPVCOS of the extension facilities. For any remaining service volumes associated with the facilities, the customer could choose an FT-R/FT-A service combination or FT-P service.

Q77. Has NGTL performed any analysis to determine if, in fact, Option 4 could be incorporated into its existing rate design?

A77. Yes. NGTL examined the EAV commitments for the KV Oil Sands extension and the Aurora Sales extension. As illustrated in Tables 4.3-1 and 4.3-2 below, both these EAV contracts are currently underpinned by FT-P service and the estimated FT-P revenue will exceed the ACS for both of these facilities for 2005. If there is no flow to these delivery points then the EAV charge would also provide revenue well in excess of the ACS for each of these FCS-EAV contracts. This clearly shows that NGTL's Option 4 could be implemented into the existing rate design as it is already included in the accountability that is in place today.

[92] Ibid, page 42, lines 1-3.

Table 4.3-1
Analysis of the FCS-EAV Contract for the KV Oil Sands Extension

Delivery Point	KV Oil Sands
ACS ($ 000)	2,989
FT-P Transmission Revenue ($ 000)	5,337
EAV Maximum Payment ($ 000)	8,187

Table 4.3-2
Analysis of the FCS-EAV Contract for the Aurora Sales Extension

Delivery Point	Aurora Sales
ACS ($ 000)	1,416
FT-P Transmission Revenue ($ 000)	1,767
EAV Maximum Payment ($ 000)	2,339

5.0 ENERGY CONVERSION

5.1 Introduction

Q78. What is the purpose of the evidence in this section?

A78. In this section NGTL responds to WEG's statement that NGTL's energy conversion proposal is unfair. NGTL also responds to WEG's statements about the impact the conversion would have on its members.

5.2 Fairness of Energy Conversion

Q79. WEG states that NGTL's energy conversion proposal is "not fair to shippers who export gas at the ABC border export point."[93] Does NGTL agree?

A79. No. NGTL's energy conversion proposal is fair to shippers at the Alberta/BC (A/BC) border export point and to shippers at all of the other export delivery points.

Shippers at the Empress and McNeil border points are currently paying more to deliver a unit of energy to their downstream connected pipelines and markets than shippers at the A/BC border point. This situation occurs due to the slight difference in the heat content of the gas at the different export delivery points arising from the receipt stream composition, the location of the NGL extraction plants, and the different efficiencies of those extraction plants.

Heat content values at the export delivery points have varied over time, as shown in Table 5.2-1, and will continue to fluctuate.

[93] Exhibit 33-005-001, Written Evidence of the Western Export Group, page 18, lines 19-20.

Table 5.2-1
Heat Content at Export Points

	Average Heat Content (MJ/m^3)		
	Empress	**McNeill**	**Alberta-BC**
1998	37.78	38.15	38.06
1999	37.80	38.16	37.94
2000	37.60	37.98	38.04
2001	37.61	37.69	38.03
2002	37.47	37.54	37.91
2003	37.62	37.55	38.03
2004	37.51	37.58	37.97

NGTL's energy conversion proposal, in addition to providing the benefits outlined in the Application, will eliminate the differentials that result from these fluctuations and achieve an equal FT-D rate per unit of energy, regardless of the delivery point location. This outcome is consistent with a postage stamp FT-D rate design and is fair to all export delivery shippers.

5.3 Financial Impact of Energy Conversion

Q80. In relation to the financial impact of energy conversion on its members, WEG states that "the impact on the WEG members is not $318,000 annually as indicated by NGTL, but closer to $500,000."[94] Does NGTL agree with WEG's assessment?

A80. No. WEG exaggerates the actual impact on WEG members because it does account for potential mitigative factors such as contract assignments, the use of Alternate Access, and contract utilization.

[94] Ibid, page 21, lines 10-11.

Q81. How do contract assignments reduce the financial impact of energy conversion on WEG members?

A81. As indicated in Table 5.3-1 above, in each month from January 2005 to July 2005 WEG members have assigned on average 46 MMcf/d of their contracted capacities to third parties. Due to the fact that WEG members are not flowing gas at A/BC for this portion of these contracts, they are not financially responsible for paying the demand charges associated with this portion of the contracts. This reduces the impact of the energy conversion proposal on WEG by approximately $18,000 per year, in aggregate.

Table 5.3-1
2005 Year to Date

	Jan.	Feb.	March	April	May	June	July	Average
WEG ABC FT-D (MMcf/d)	1,428	1,429	1,428	1,353	1,276	1,308	1,275	1,357
WEG ABC FT-D Assigned (MMcf/d)	6	6	5	45	42	108	110	46
Net WEG ABC FT-D [1](MMcf/d)	1,422	1,423	1,423	1,308	1,234	1,200	1,165	1,311
WEG FT-D used for Alternate Access (MMcf/d)	46	82	92	138	119	130	122	104
Net WEG FT-D Available at ABC[2] (MMcf/d)	1,376	1,341	1,331	1,170	1,115	1,070	1,043	1,207
WEG A/BC Throughput (MMcf/d)	1,164	1,166	1,124	1,009	974	888	963	1,041
WEG A/BC Contract Utilization[3]	82%	82%	79%	75%	76%	68%	76%	77%
WEG A/BC Net Contract Utilization[4]	85%	87%	84%	86%	87%	83%	92%	86%
WEG A/BC FT-D used at Other Borders[5] (MMcf/d)	52	88	97	183	161	238	232	150
WEG Energy Impact at ABC[6] ($/month)	$31,799	$27,991	$30,759	$26,166	$25,768	$23,930	$24,104	$27,217
WEG Energy Impact at Other Border[7] ($/month)	($1,717)	($2,624)	($3,202)	($5,847)	($5,315)	($7,604)	($7,659)	($4,853)
WEG Net Impact ($/month)	$30,083	$25,367	$227,557	$20,320	$20,452	$16,326	$16,444	$22,364
WEG Annualized Impact[8] ($/year)								$268,371

[1] WEG ABC FT-D minus WEG ABC FT-D assigned
[2] Net WEG ABC FT-D minus WEG ABC FT-D used for Alternate Access
[3] WEG ABC throughput divided by WEG ABC FT-D
[4] WEG ABC throughput divided by Net WEG FT-D available at A/BC
[5] WEG ABC FT-D assigned plus WEG ABC FT-D used for Alternate Access
[6] WEG Net FT-D available at ABC converted to GJ ((HV of 37.8 * 1000)/35.49373) multiplied by the number of days in a month multiplied by the impact ($0.0007/GJ as per the 2005 NGTL General Rate Application, Phase 2, Section 3.0, page 9, lines 3-5)
[7] WEG ABC FT-D used at Other Borders converted to GJ ((HV of 37.8 * 1000)/35.49373) multiplied by the number of days in a month multiplied by the impact (-$0.001/GJ as per the 2005 NGTL General Rate Application, Phase 2, Section 3.0, page 9, lines 3-5)
[8] WEG Average monthly Net Impact multiplied by 12 (months)

Q82. How does contract utilization relate to the financial impact of energy conversion on WEG members?

A82. As indicated in Table 5.3-1 above, on average from January 2005 to July 2005, WEG members have utilized their A/BC FT-D contracts at a 77% load factor. If assigned contracts and Alternate Access volumes are considered, the load factor is 86%.

As part of energy conversion NGTL has proposed that shippers be given an opportunity to elect to change their contracted quantity at any export delivery point by ±1% in order to align with their contract quantity on connected pipelines. According to WEG, a 1% reduction in its members' A/BC FT-D contract quantities would result in savings of $864,936.[95] This provides an opportunity to offset the $268,371 impact identified in Table 5.3-1.

Q83. How does Alternate Access reduce the financial impact of energy conversion on WEG members?

A83. As indicated in Table 5.3-1 above, WEG members have as a group utilized an average of 104 MMcf/d of their A/BC FT-D at export delivery points other than A/BC under Alternate Access, for 2005 year to date. The use of Alternate Access reduces the impact of the energy conversion proposal on WEG members by approximately $40,000 per year, in aggregate.

Q84. What is NGTL's estimate of the annualized impact of energy conversion on WEG members?

A84. The aggregated annualized impact of this energy conversion proposal on WEG members is approximately $268,371 per year, as shown above in Table 5.3-1, accounting for the impacts of assignment, and the use of Alternate Access.

[95] Exhibit No. 33-007-003, response to NGTL-WEG-01(c).

Q85. WEG has suggested that energy conversion will result in financial impacts on its members that "can be mitigated by two possible methods: 1) a financial adjustment or 2) adoption of border specific rates"[96] The financial adjustment proposed by WEG is that "…[s]hippers at the ABC border export point would receive a credit equal to the financial impact of the proposed energy conversion. Shippers at other border points (e.g., Empress/McNeill) would pay a surcharge equivalent to the benefits it receives from NGTL's approach to the conversion."[97] Does NGTL agree with WEG's proposal?

A85. No. As shown in Table 5.2-1, heat contents have historically fluctuated at the export points. The effect of implementing the proposed WEG adjustment would be to enshrine a rate advantage for A/BC shippers, even through periods where the heat value at A/BC is lower than the other major export delivery points. This result is not consistent with the postage stamp export delivery rate design.

Q86. Does NGTL agree with WEG's proposal that border specific rates should be used to mitigate the financial impact of energy conversion on WEG members?

A86. No. Border specific rates are not related to energy conversion and should not be tied to this initiative. Although border specific rates may appear to have some merit based on NGTL's DOH study, their consideration requires additional analysis, development, and customer consultation. NGTL is prepared to further explore and initiate customer consultation to further the development of this concept.

[96] Exhibit No. 33-005-001, Written Evidence of the Western Export Group, page 22, lines 2-3.
[97] Ibid, page 22, lines 5-8.

APPENDIX A: Analysis of Intra-Alberta Rates, Pricing and Competition

Introduction

Section 2.0 of the Reply Evidence of NGTL provides a discussion of the factors influencing the competitive environment in which gas transmission pipelines in Alberta operate. It specifically responds to certain claims made by ATCO Pipelines in respect of rate-related competition with NGTL. The purpose of this Appendix is to provide the detailed numerical analysis and data that underpins NGTL's reply evidence in Section 2.0.

This Appendix analyzes the key changes resulting from ATCO Pipelines rate changes from October, 2004 to January, 2005 and as of January, 2005 with ATCO Pipelines' proposed 6¢/Mcf FT-A rate**.** The analysis utilizes ATCO Pipelines' $7.00/Mcf NIT gas price assumption and bookend and midpoint pricing as provided in ATCO Pipelines' evidence and Information Request (IR) responses.

The analysis illustrates the mechanics behind the price to transport volumes on the ATCO Pipelines North ("APN") system and the pricing alternatives available to APN industrial and producer customers. The analysis focuses on APN; however, the implications and conclusions of the analysis are applicable to ATCO Pipelines South.

Summary of Conclusions

The analysis below demonstrates that ATCO Pipelines' proposal to increase NGTL's FT-A rate to 6¢/Mcf would result in an increase to ATCO Pipelines' on-system market price to the detriment of ATCO Pipelines industrial customers and would improve ATCO Pipelines' competitive position to directly connect receipt volumes that would otherwise connect to NGTL's Alberta System.

Key conclusions are as follows:

1. Changes to ATCO Pipelines' rate design as of November 1, 2004 increased the cost of transporting gas delivered onto the ATCO Pipelines system from NIT and increased the cost of transporting gas received onto the ATCO Pipelines system to NIT. ATCO Pipelines' proposed FT-A rate will further increase the cost of transporting gas delivered onto the ATCO Pipelines system from NIT.

2. ATCO Pipelines' rates <u>from NIT to ATCO Pipelines' delivery point</u> set the delivered plant gate "high bookend" price alternative available to ATCO Pipelines' industrial customers. This industrial "worst case" price alternative has (assuming a NIT price of $7.00/Mcf) increased on the APN system from $7.108/Mcf in October, 2004 to $7.145/Mcf in January, 2005. Under ATCO Pipelines' proposed FT-A rate, the industrial's high bookend price will increase further to $7.185/Mcf.

3. ATCO Pipelines' rates <u>from ATCO Pipelines receipt point to NIT</u> set the "low bookend" netback price alternative available to ATCO Pipelines producer customers. This producer "worst case" price alternative, has (assuming a NIT price of $7.00/Mcf) decreased on the APN system from $6.828/Mcf in October, 2004 to $6.787/Mcf in January, 2005 and will remain the same under ATCO Pipelines' proposed FT-A rate.

4. As an alternative to selling gas at NIT, ATCO Pipelines' producer customers may sell gas on the ATCO Pipelines system to ATCO Pipelines' industrial customers. ATCO Pipelines' rates from the ATCO Pipelines receipt point to the ATCO Pipelines delivery point set the "high bookend" netback price alternative available to ATCO Pipelines producer customers. This producer "best case" price alternative has (assuming a NIT price of $7.00/Mcf) increased on the APN system from $6.908/Mcf in October, 2004 to $6.923/Mcf in January, 2005. Under ATCO Pipelines' proposed FT-A rate, the producer's high bookend price will increase further to $6.963/Mcf.

5. Similarly, as an alternative to buying gas at NIT, ATCO Pipelines' industrial customers may buy gas on the ATCO Pipelines' system from ATCO Pipelines producer customers. ATCO Pipelines' rates from ATCO Pipelines receipt point to ATCO Pipelines delivery point set the "low bookend" plant gate price alternative available to ATCO Pipelines industrial customers. This industrial "best case" price alternative has (assuming a NIT price of $7.00/Mcf) decreased on the APN system from $7.028/Mcf in October, 2004 to $7.009/Mcf in January, 2005 and will not change under ATCO Pipelines' proposed FT-A rate.

6. The above analysis illustrates that both ATCO Pipelines' industrial and producer customers have the opportunity to achieve price savings or price premiums by buying and selling gas on the ATCO Pipelines system ("on-system") utilizing ATCO Pipelines transport, as an alternative to buying and selling gas at NIT on NGTL's Alberta System ("off-system") utilizing ATCO Pipelines transport. If both industrial and producer customers equally share the price savings and price premiums available to them, the ATCO Pipelines industrial delivered plant gate price would be calculated as the midpoint between the upper and lower industrial delivered plant gate price bookends. Similarly, the ATCO Pipelines producer netback price would be calculated as the midpoint between the upper and lower producer netback price bookends.

   - The midpoint industrial delivered plant gate price has (assuming a NIT price of $7.00/Mcf) increased on the APN system from $7.068/Mcf in October, 2004 to $7.077/Mcf in January, 2005. Under ATCO Pipelines' proposed FT-A rate, the industrial's midpoint price will increase further to $7.097/Mcf.
   - The midpoint producer netback price has (assuming a NIT price of $7.00/Mcf) decreased on the APN system from $6.868/Mcf in October, 2004 to $6.855/Mcf in January, 2005. However, under ATCO Pipelines' proposed FT-A rate, the producer's midpoint price will increase to $6.875/Mcf.

7. The APN on-system market provides an alternative for APN industrial customers and APN producer customer to holding “full-path transport” via NIT from APN producer receipt point to APN plant gate delivery point. Assuming APN industrial and producer customers equally share the price savings and price premiums available to them, the midpoint APN on-system market gas price has (assuming a NIT price of $7.00/Mcf) increased from $6.975/Mcf (or NIT –2.5¢) in October, 2004 to $7.006/Mcf (or NIT +0.6¢) in January, 2005. Under ATCO Pipelines’ proposed FT-A rate, the midpoint APN on-system market gas price will increase further to $7.026/Mcf (NIT +2.6¢/Mcf).

8. The title transfer of gas between APN customers on-system is facilitated by NGX’s “ATCO Pipelines North Daily Index” product. The NGX-ATCO North Daily Index price, while not illustrative of all transactions between buyers and sellers on the APN system, suggests that the average differential between the NIT price and the APN on-system market price for the period from November 1, 2004 to August 10, 2005 has been at a premium (NIT +2.1¢/Mcf) to the calculated APN midpoint on-system market price of NIT +0.6¢.

9. If the NIT gas price moves higher than the assumed value of $9.00/Mcf, the APN on-system market price will increase further relative to NIT. If APN industrial customers and APN producer customers equally share the price savings and price premiums available to them, the midpoint APN on-system gas price, would (assuming a NIT price of $9.00/Mcf, which is more reflective of today’s market) increase from NIT –2.5¢ in October, 2004 to NIT +1.4¢ in January, 2005. Under ATCO Pipelines’ proposed FT-A rate, the midpoint APN on-system market gas price would increase further to NIT +3.4¢/Mcf.

10. <u>All</u> APN dually connected producers can currently achieve a higher netback by selling to the APN on-system market versus the alterative of utilizing transport on the Alberta System and selling at NIT. Any further increase to the APN on-system market price will only improve ATCO Pipelines’ competitiveness with NGTL at dually connected plants.

11. NGTL observes that the percentage of APN on-system receipts from dually connected plants has increased, according to ATCO Pipelines’ receipt numbers, from 19% of APN on-system receipts in the year 2000 to 44% of APN on-system receipts in 2004.

<u>Discussion</u>

The following discussion will reiterate the conclusions and then set out analysis and data supporting each conclusion.

1. **Changes to ATCO Pipelines' rate design as of November 1, 2004 increased the cost of transporting gas delivered onto the ATCO Pipelines system from NIT and increased the cost of transporting gas received onto the ATCO Pipelines system to NIT. ATCO Pipelines' proposed FT-A rate will further increase the cost of transporting gas delivered onto the ATCO Pipelines system from NIT.**

The primary changes made to APN's rate structure after November 1, 2004 and under ATCO Pipelines' proposed FT-A rate are provided in Table 1 below.

Table 1

APN Transportation Path	October 2004		January 2005		January 2005 with ATCO Pipelines Proposed FT-A Rate	
Cost to move gas from off-system (NIT) onto APN System (APN Market)	OPR	1.5¢	OPR	1.5¢	OPR	5.5¢
			UFG/Fuel	5.9¢	UFG/Fuel	5.9¢
	Subtotal	**1.5¢**	**Subtotal**	**7.4¢**	**Subtotal**	**10.4¢**
Cost to move gas from APN Market to APN industrial plant gate	FSD	4.5¢	FSD	7.1¢	OPR	7.1¢
	UFG/fuel	4.8¢	UFG/Fuel		UFG/Fuel	
	Subtotal	**9.3¢**	**Subtotal**	**7.1¢**	**Subtotal**	**7.1¢**
Cost to move gas from off-system (NIT) to APN industrial plant gate	**Total**	**10.8¢**	**Total**	**14.5¢**	**Total**	**18.5¢**

APN Transportation Path	October 2004		January 2005		January 2005 with ATCO Pipelines Proposed FT-A Rate	
Cost to move gas from APN producer plant gate to APN market	FSR	10.7¢	FSR	9.2¢	FSR	9.2¢
			UFG/Fuel	5.9¢	UFG/Fuel	5.9¢
	Subtotal	**10.7¢**	**Subtotal**	**15.1¢**	**Subtotal**	**15.1¢**
Cost to move gas from APN Market to NIT	Exchange	6.5¢	OPDC	6.2¢	OPDC	6.2¢
	Subtotal	**6.5¢**	**Subtotal**	**6.2¢**	**Subtotal**	**6.2¢**
Cost to move gas from APN producer plant gate to NIT off-system market	**Total**	**17.2¢**	**Total**	**21.3¢**	**Total**	**21.3¢**

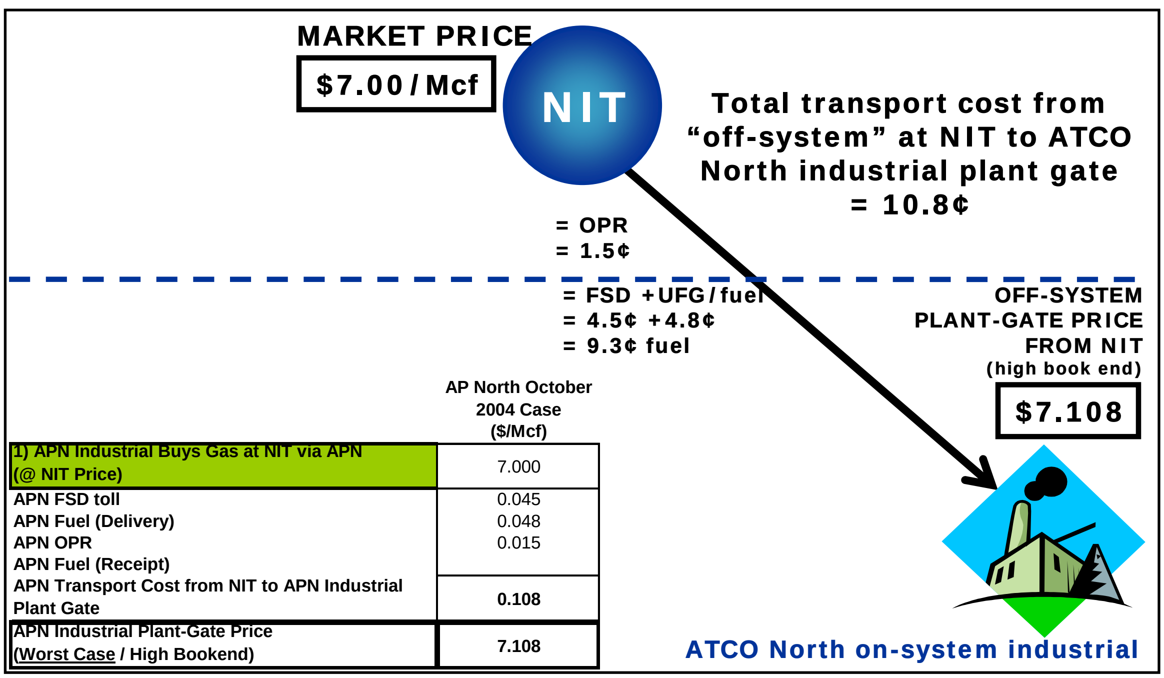
2. **ATCO Pipelines' rates <u>from NIT to ATCO Pipelines delivery point</u> set the delivered plant gate "high bookend" price alternative available to ATCO Pipelines' industrial customers. This industrial "worst case" price alternative has (assuming a NIT price of $7.00/Mcf) increased on the APN system from $7.108/Mcf in October, 2004 to $7.145/Mcf in January, 2005. Under ATCO**

Pipelines' proposed FT-A rate, the industrial's high bookend price will increase further to $7.185/Mcf.

An APN industrial's high bookend plant gate price represents the highest price (or "worst case") that an APN industrial should be willing to pay at its plant gate. The high bookend price represents the delivered price that the APN industrial would have to pay if it had no other alternative but to buy its gas off-system at NIT and utilize APN transport to deliver that gas to its plant gate.

Using the information provided by ATCO Pipelines in its responses to NGTL-AP-15 and, as illustrated on the right side of Figure 1 below for the October 2004 case, the industrial pays the example NIT price of $7.00/Mcf and incurs an Other Pipeline Receipt (OPR) rate of 1.5¢/MCF to move the gas from NIT onto the APN system. Once on the APN system (illustrated in the bottom half of Figure 1 below), the industrial then pays a Firm Service (FSD) Delivery rate of 4.5¢/Mcf plus UFG/Fuel of 4.8¢. The industrial's plant gate delivered price is therefore the NIT price plus the sum of the charges described above, or $7.108/Mcf.

Figure 1
October 2004 case industrial delivered plant gate high bookend price

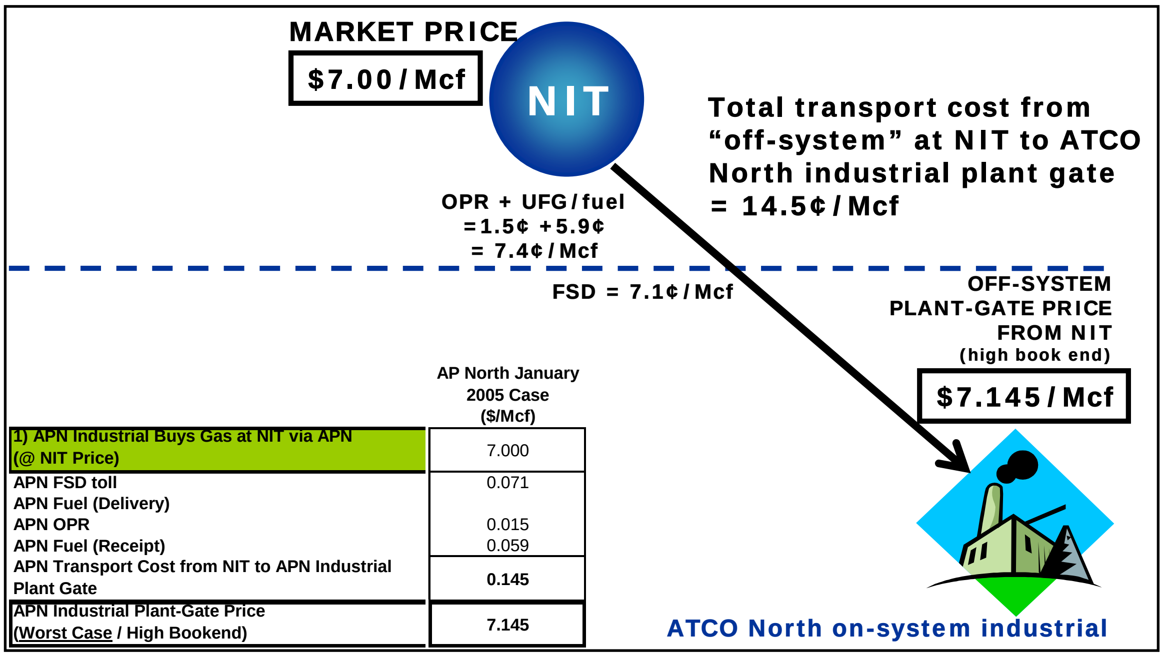


	AP North October 2004 Case ($/Mcf)
1) APN Industrial Buys Gas at NIT via APN (@ NIT Price)	7.000
APN FSD toll	0.045
APN Fuel (Delivery)	0.048
APN OPR	0.015
APN Fuel (Receipt)	
APN Transport Cost from NIT to APN Industrial Plant Gate	0.108
APN Industrial Plant-Gate Price (Worst Case / High Bookend)	7.108

A comparison of APN's rate structure to move gas from off-system at NIT to an APN industrial as of October, 2004 (per Figure 1 above) and January 2005 (per Figure 2 below) illustrates the following changes and implications to the APN industrial's high bookend plant gate price:

1. The UFG/fuel rate increased from 4.8¢/Mcf to 5.9¢/Mcf and is now charged on receipt (OPR) vs. FSD;
2. The FSD rate of 4.5¢/Mcf increased to 7.1¢/Mcf;
3. The <u>total</u> transport cost to move gas from off-system at NIT to an on-system APN industrial customer's plant gate increased by 3.7¢/Mcf from 10.8¢/Mcf to 14.5¢/Mcf; and
4. As the total transport cost to move gas from NIT to the APN industrial customer's plant gate increased by 3.7¢/Mcf, so too does the APN industrial customer's high bookend price from $7.108/Mcf in the October 2004 case to $7.145/Mcf in the January 2005 case.

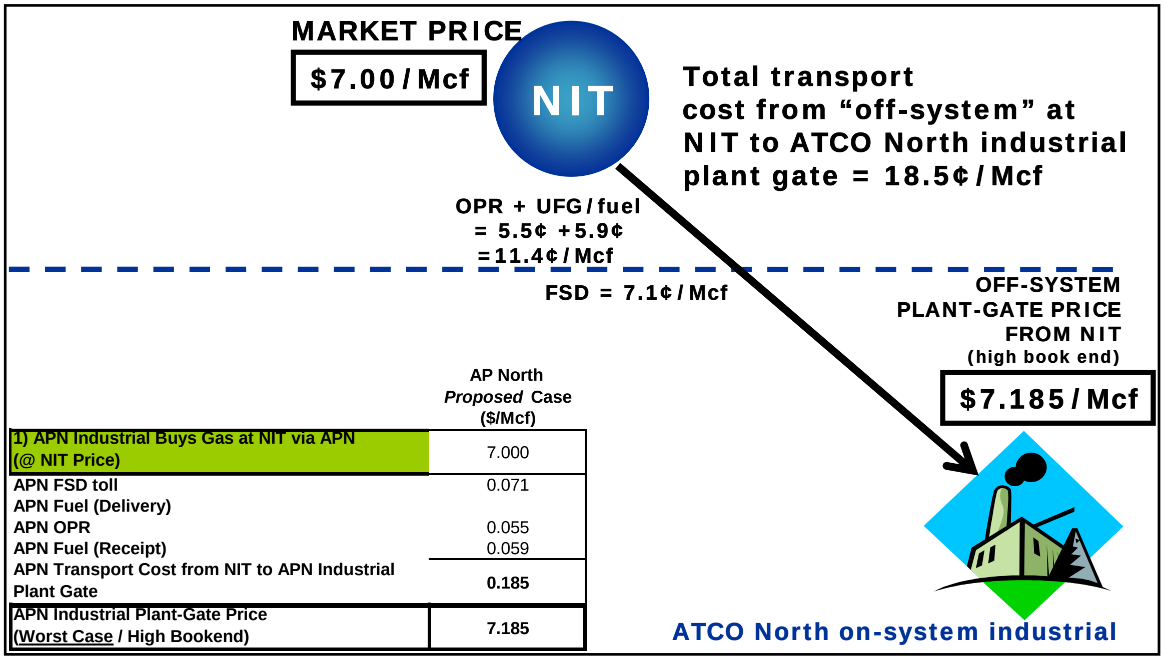
Figure 2
January 2005 case industrial delivered plant gate high bookend price



	AP North January 2005 Case ($/Mcf)
1) APN Industrial Buys Gas at NIT via APN (@ NIT Price)	7.000
APN FSD toll	0.071
APN Fuel (Delivery)	
APN OPR	0.015
APN Fuel (Receipt)	0.059
APN Transport Cost from NIT to APN Industrial Plant Gate	0.145
APN Industrial Plant-Gate Price (<u>Worst Case</u> / High Bookend)	7.145

Under ATCO Pipelines' proposed NGTL FT-A rate, ATCO Pipelines is proposing to increase the APN OPR rate from the current rate of 1.5¢/Mcf to 5.5¢/Mcf. As the OPR rate is one cost component (the other component being UFG/fuel) in the cost of delivering gas from NIT to the APN system, a higher OPR will directly increase the APN industrial's high bookend price. The APN industrial customer's high bookend price will, per Figure 3 below, increase by 4¢/Mcf from $7.145/Mcf in the January 2005 case to $7.185/Mcf with ATCO Pipelines' proposed FT-A rate.

Figure 3
January 2005 case industrial delivered plant gate high bookend price with ATCO Pipelines' FT-A proposal



	AP North *Proposed* Case ($/Mcf)
1) APN Industrial Buys Gas at NIT via APN (@ NIT Price)	7.000
APN FSD toll	0.071
APN Fuel (Delivery)	
APN OPR	0.055
APN Fuel (Receipt)	0.059
APN Transport Cost from NIT to APN Industrial Plant Gate	**0.185**
APN Industrial Plant-Gate Price (<u>Worst Case</u> / High Bookend)	**7.185**

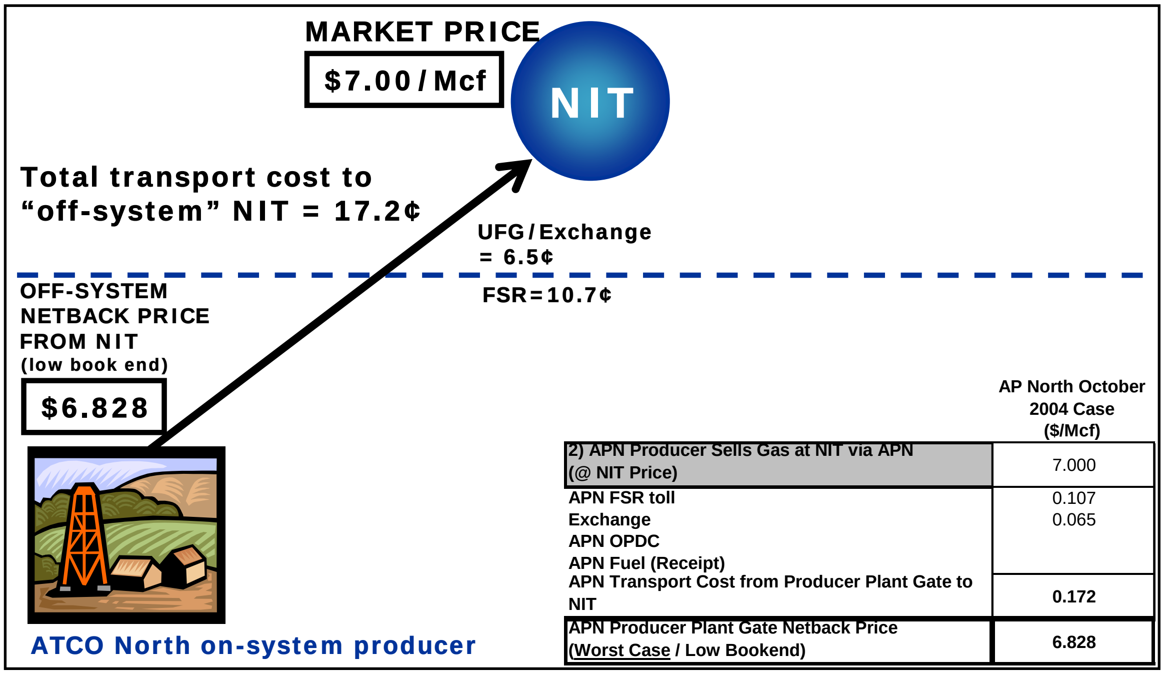
A summary of the results of Figures 1, 2 and 3 is found at Table 7, Box 1.

3. ATCO Pipelines' rates <u>from ATCO Pipelines receipt point to NIT</u> set the "low bookend" netback price alternative available to ATCO Pipelines producer customers. This producer "worst case" price alternative, has (assuming a NIT price of $7.00/Mcf) decreased on the APN system from $6.828/Mcf in October, 2004 to $6.787/Mcf in January, 2005 and will remain the same under ATCO Pipelines' proposed FT-A rate.

An APN producer's low bookend plant gate price represents the lowest netback price that a singly-connected APN producer should be willing to accept at its plant gate. This "worst case" price represents the netback price that a singly-connected APN producer would have to accept if it had no other alternative but to utilize APN transport to deliver that gas from its plant gate to the "off-system" market at NIT.

Using the information provided by ATCO Pipelines in its responses to NGTL-AP-15 and, as illustrated on the left side of Figure 4 below for the October 2004 case, the producer incurs a Firm Service Receipt (FSR) rate of 10.7¢/Mcf to move its gas onto the APN system. The producer then pays a 6.5¢/Mcf Exchange Fee to move its gas "off-system" (illustrated in the upper half of Figure 4 below) to NIT where the producer sells its gas at the example NIT price of $7.00/Mcf. The producer's plant gate netback price is therefore the NIT price less the sum of the charges described above, or $6.828/Mcf.

Figure 4
January 2005 case producer low bookend netback price



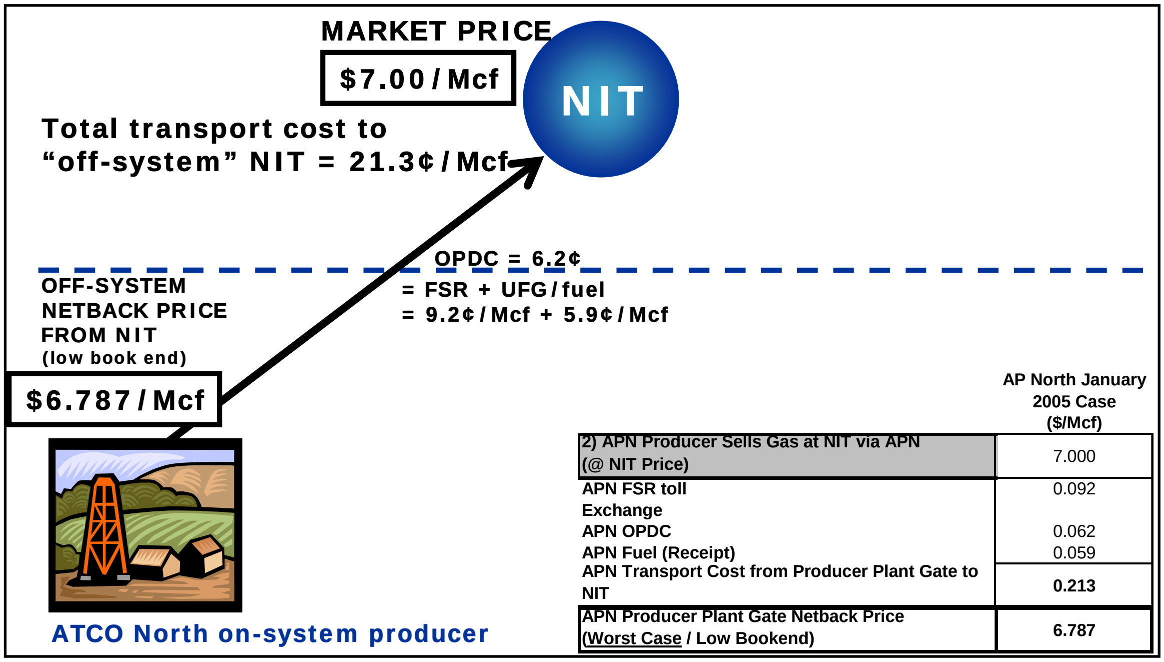
	AP North October 2004 Case ($/Mcf)
2) APN Producer Sells Gas at NIT via APN (@ NIT Price)	7.000
APN FSR toll	0.107
Exchange	0.065
APN OPDC	
APN Fuel (Receipt)	
APN Transport Cost from Producer Plant Gate to NIT	**0.172**
APN Producer Plant Gate Netback Price (Worst Case / Low Bookend)	**6.828**

A comparison of APN's rate structure to move gas from an APN producer's plant gate to the off-system market at NIT as of October, 2004 (per Figure 4 above) and January 2005 (per Figure 5 below) illustrates the following changes and implications to the APN producer's low bookend netback price:

1. The FSR rate of changes from 9.2¢/Mcf to 10.7¢/Mcf;
2. UFG/fuel of is now charged on receipt and increases from 4.8¢/Mcf to 5.9¢/Mcf;
3. The Exchange rate of 6.5¢/Mcf to move gas from the APN system to the off-system NIT market is replaced by an OPDC charge of 6.2¢/Mcf;
4. The <u>total</u> transport cost to move gas from the producer's plant gate to off-system at NIT increases by 4.1¢/Mcf from 17.2¢/Mcf to 21.3¢/Mcf; and
5. As the total transport cost to move gas from the producer's plant gate to NIT increases from 17.2¢/Mcf to 21.3¢/Mcf increases, the APN producer's low bookend price from $6.828/Mcf in the October 2004 case decreases by 4.1¢/Mcf to $6.787/Mcf in the January 2005 case.

Note that ATCO Pipelines' FT-A proposal and associated increase to ATCO Pipelines' OPR rate does not affect the APN producer's low bookend price. While ATCO Pipelines is proposing to increase the APN OPR rate and therefore the cost of delivering gas at NIT onto the APN system (and directly impacting APN industrial's high bookend price), APN is not proposing to change the current rate structure for moving gas from the APN system off-system to NIT. Therefore, there would be no change to an APN producer's low bookend netback price as a consequence of ATCO Pipelines' proposed FT-A rate.

Figure 5
January 2005 case (note ATCO Pipelines' FT-A proposal does not change this case)



	AP North January 2005 Case ($/Mcf)
2) APN Producer Sells Gas at NIT via APN (@ NIT Price)	7.000
APN FSR toll	0.092
Exchange	
APN OPDC	0.062
APN Fuel (Receipt)	0.059
APN Transport Cost from Producer Plant Gate to NIT	**0.213**
APN Producer Plant Gate Netback Price (Worst Case / Low Bookend)	**6.787**

A summary of the results of Figure 4 and 5 is found at Table 7, Box 2.

4. **As an alternative to selling gas at NIT, ATCO Pipelines' producer customers may sell gas on the ATCO Pipelines system to ATCO Pipelines' industrial customers. ATCO Pipelines' rates from the ATCO Pipelines receipt point to the ATCO Pipelines delivery point set the "high bookend" netback price alternative available to ATCO Pipelines producer customers. This producer "best case" price alternative has (assuming a NIT price of $7.00/Mcf) increased on the APN system from $6.908/Mcf in October, 2004 to $6.923/Mcf in January, 2005. Under ATCO Pipelines' proposed FT-A rate, the producer's high bookend price will increase further to $6.963/Mcf.**

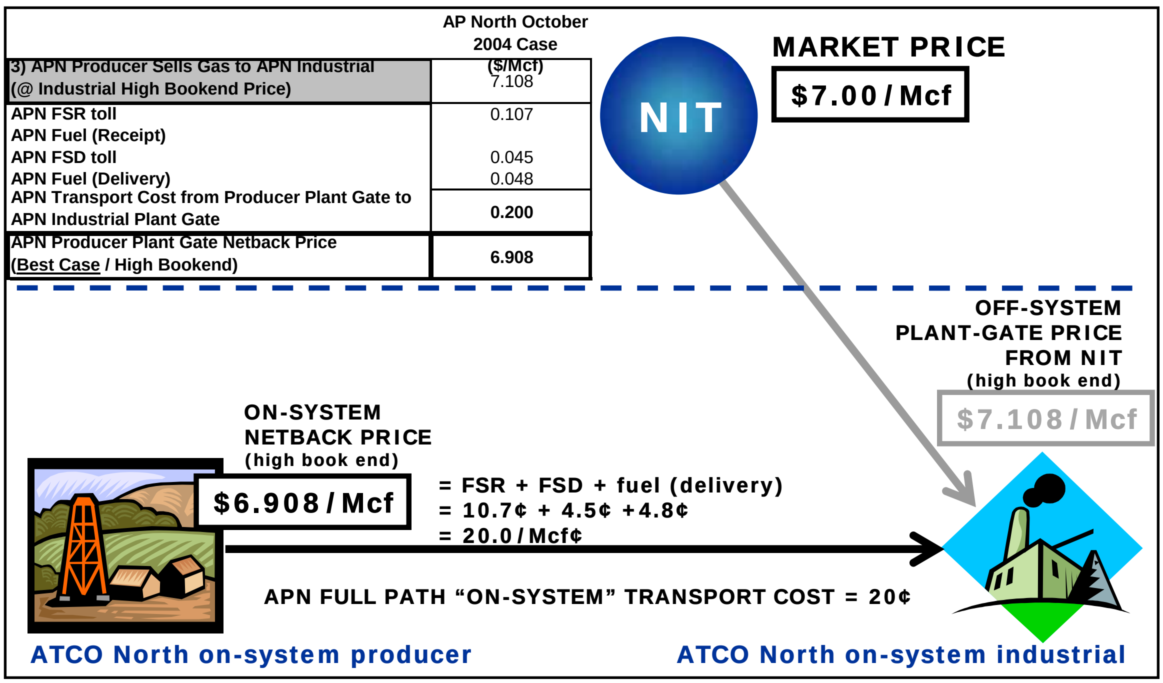
As confirmed by ATCO Pipelines in its response to NGTL-AP-14(a), both the APN industrial and producer have another price alternative available to them and that is to buy and sell the gas "on-system" (as opposed to "off-system" at NIT) from each other. Both the industrial and producer are aware of each other's "off-system" price alternatives and can calculate "on-system" price alternatives.

An APN producer's high bookend plant gate price represents the highest price (or "best-case) that a singly-connected APN producer should be able to achieve at its plant gate. The high bookend represents the netback price that an APN producer could achieve if it could sell gas from to an APN on-system industrial at the industrial's high bookend ("worst case" price) and utilizes APN on-system transport to move that gas from the producer's plant gate to the industrial's plant gate.

Using the information provided by ATCO Pipelines in its responses to NGTL-AP-15 and, as illustrated in Figure 6 below, for the October 2004 case, the producer's high bookend netback price is equal to the industrial's high bookend price less the FSR rate, less the FSD rate, less the UFG/Fuel (delivery) rate to yield an alternative, or "high bookend" netback price of $6.908/Mcf. Using data provided by ATCO Pipelines for October, 2004, in such a scenario the producer would be able to achieve an 8¢/Mcf premium over the producers' "worst case" alternative of selling it "off-system" at NIT (netback price of $6.828/Mcf). This is illustrated in Figure 6 below.

Figure 6
APN high bookend price October 2004 case

	AP North October 2004 Case ($/Mcf)
3) APN Producer Sells Gas to APN Industrial (@ Industrial High Bookend Price)	7.108
APN FSR toll	0.107
APN Fuel (Receipt)	
APN FSD toll	0.045
APN Fuel (Delivery)	0.048
APN Transport Cost from Producer Plant Gate to APN Industrial Plant Gate	0.200
APN Producer Plant Gate Netback Price (Best Case / High Bookend)	6.908



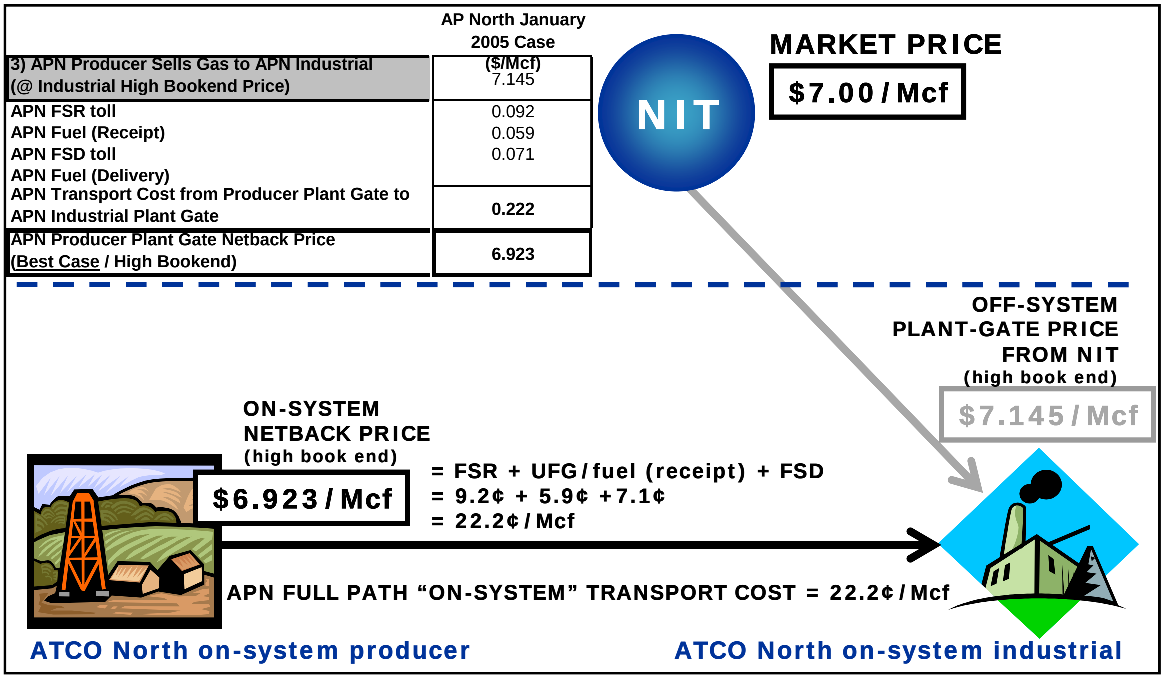
A comparison of APN's rate structure to move gas from an APN on-system producer to an APN on-system end-user as of October, 2004 (per Figure 6 above) and January 2005 (per Figure 7 below) illustrates the following changes and implications to the APN industrial's low bookend plant gate price:

1. The FSR rate of 10.7¢/Mcf to move onto the APN system decreases by 1.5¢/Mcf to 9.2¢/Mcf;
2. UFG/fuel of is now charged on receipt and increases from 4.8¢/Mcf to 5.9¢/Mcf;
3. The FSD rate of 4.5¢/Mcf increases to 7.1¢/Mcf;
4. The total transport cost to move gas from NIT to an APN industrial customer's plant gate increases by 3.7¢/Mcf from 10.8¢/Mcf to 14.5¢/Mcf;

5. The total transport cost to move gas from an APN on-system producer to an APN on-system end-user increases by 2.2¢/Mcf from 20¢/Mcf to 22.2¢/Mcf; and
6. The APN producer's netback price is the APN industrial's high bookend price of \$7.108/Mcf less the cost of APN transport cost of \$0.22/Mcf for an APN producer's high bookend price of \$6.923/Mcf. This represents an increase of 1.5¢/Mcf from the producer's high bookend price in the October, 2004 case of \$6.908/Mcf.

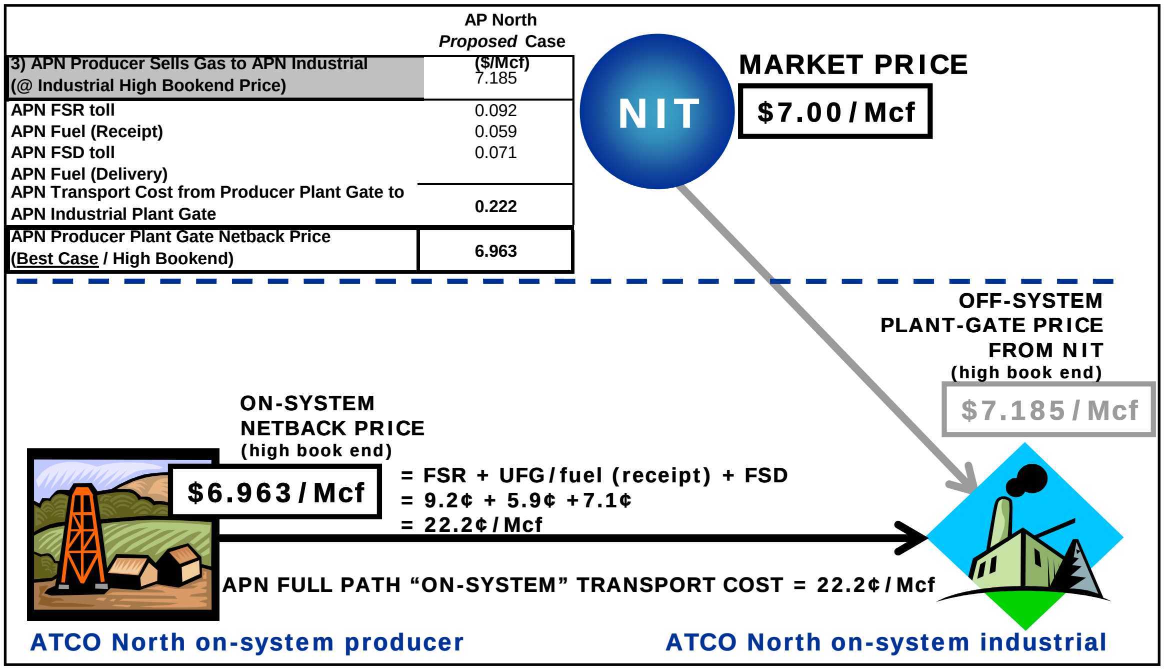
Figure 7
APN producer high bookend price January 2005 case

	AP North January 2005 Case ($/Mcf)
3) APN Producer Sells Gas to APN Industrial (@ Industrial High Bookend Price)	7.145
APN FSR toll	0.092
APN Fuel (Receipt)	0.059
APN FSD toll	0.071
APN Fuel (Delivery)	
APN Transport Cost from Producer Plant Gate to APN Industrial Plant Gate	**0.222**
APN Producer Plant Gate Netback Price (Best Case / High Bookend)	**6.923**



As discussed in Section 2, the APN industrial's high bookend plant gate price is calculated from the adding the cost of APN transport from NIT to the industrial's plant gate. The APN's industrial's high bookend plant gate price increases by 4¢/Mcf under ATCO Pipelines' FT-A proposal from \$7.145/Mcf to \$7.185/Mcf, per Figure 8 below, and the APN producer's high bookend price increases by 4¢/Mcf from \$6.923/Mcf to \$6.963/Mcf.

Figure 8
APN high bookend net back price January 2005 case with ATCO Pipelines' proposed FT-A rate



	AP North *Proposed* Case ($/Mcf)
3) APN Producer Sells Gas to APN Industrial (@ Industrial High Bookend Price)	7.185
APN FSR toll	0.092
APN Fuel (Receipt)	0.059
APN FSD toll	0.071
APN Fuel (Delivery)	
APN Transport Cost from Producer Plant Gate to APN Industrial Plant Gate	0.222
APN Producer Plant Gate Netback Price (Best Case / High Bookend)	6.963

A summary of the results of Figures 6, 7 and 8 is found at Table 7, Box 3.

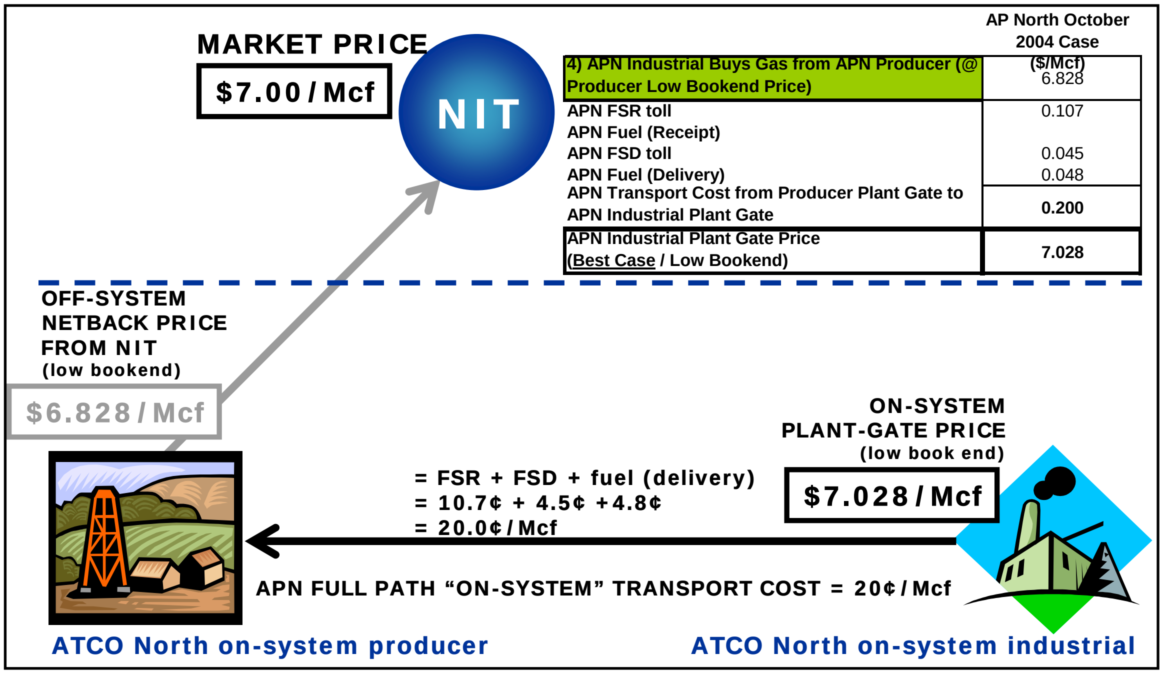
5. **Similarly, as an alternative to buying gas at NIT, ATCO Pipelines' industrial customers may buy gas on the ATCO Pipelines' system from ATCO Pipelines producer customers. ATCO Pipelines' rates from ATCO Pipelines receipt point to ATCO Pipelines delivery point set the "low bookend" plant gate price alternative available to ATCO Pipelines industrial customers. This industrial "best case" price alternative has (assuming a NIT price of $7.00/Mcf) decreased on the APN system from $7.028/Mcf in October, 2004 to $7.009/Mcf in January, 2005 and will not change under ATCO Pipelines' proposed FT-A rate.**

An APN industrial's low bookend plant gate price represents the lowest price (or "best case") that an APN industrial should be able to achieve at its plant gate. The low bookend price represents the delivered price that the APN industrial would pay if it buys gas from an APN on-system producer's low bookend (or producer's "worst case" price) and utilizes APN on-system transport to move that gas from the producer's plant gate to the industrial's plant gate.

Using the information provided by ATCO Pipelines in response to NGTL-AP-15, for the October 2004 Case, the industrial low bookend price would be equal to the producer's low bookend price of $6.828/Mcf plus the FSR rate (10.7¢/Mcf), plus the FSD rate (4.5¢/Mcf) plus the UFG/Fuel (delivery) rate (4.8¢/Mcf) for a delivered industrial plant gate price of $7.028/Mcf. In such a scenario the industrial would be able to achieve an

8¢/Mcf discount over the alternative of buying "off-system" at NIT (delivered plant gate price of $7.108/Mcf). This is illustrated in Figures 9 and 10 below.

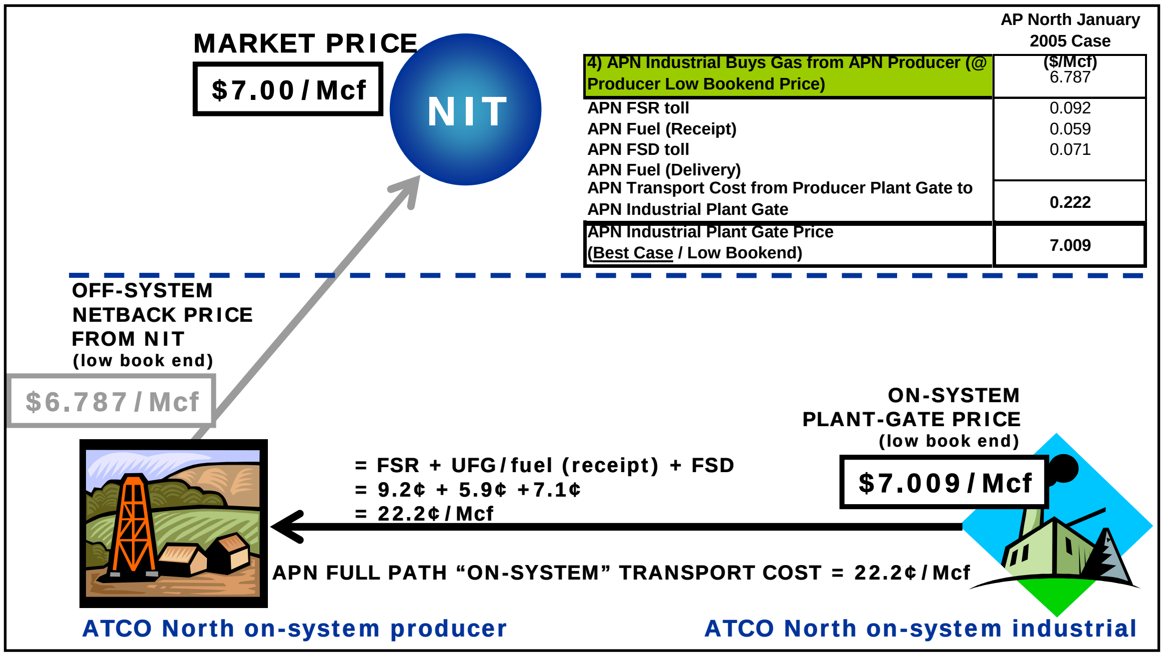
Figure 9
APN low bookend industrial delivered plant gate net back price October 2004 case



A comparison of APN's rate structure to move gas from an APN on-system producer to an APN on-system industrial as of October 2004 (per Figure 9 above) and as of January 2005 (per Figure 10 below) illustrates the following changes and implications to the APN industrial's low bookend plant gate price:

1. The FSR rate of 10.7¢/Mcf to move onto the APN system decreases by 1.5¢/Mcf to 9.2¢/Mcf;
2. UFG/fuel of is now charged on receipt and increases from 4.8¢/Mcf to 5.9¢/Mcf;
3. The FSD rate of 4.5¢/Mcf increases to 7.1¢/Mcf;
4. The total transport cost to move gas from off-system at NIT to an on-system APN industrial customer's plant gate increases by 3.7¢/Mcf from 10.8¢/Mcf to 14.5¢/Mcf;
5. The total transport cost to move gas from an APN on-system producer to an APN on-system end-user increases by 2.2¢/Mcf from 20¢/Mcf to 22.2¢/Mcf; and
6. The APN industrial's low bookend plant gate price is the APN producer's low bookend price of $6.787/Mcf plus the cost of APN transport cost of $0.222/Mcf for an APN industrial's low bookend price of $7.009/Mcf (per ATCO Pipelines' responses to NGTL-AP15(v)(i) and NGTL-AP15(f)(ix)-1). This represents a decrease of 1.9¢/Mcf from the industrial's low bookend price in the October, 2004 case of $7.028/Mcf.

Figure 10
APN low bookend industrial delivered plant gate net back price January 2005 case



As discussed in Section 3, the APN industrial’s high bookend plant gate price is calculated from the adding the cost of APN transport from NIT to the industrial’s plant gate. The APN industrial’s high bookend plant gate price increases by 4¢/Mcf under ATCO Pipelines’ FT-A proposal from $7.146/Mcf to $7.185/Mcf, per Figure 11 below. However, under ATCO Pipelines’ FT-A proposal the APN producer’s netback low bookend (the producer’s worse case price scenario) does not change and, therefore, the APN industrial’s delivered plant gate price low bookend (the industrial’s best case scenario) does not change.

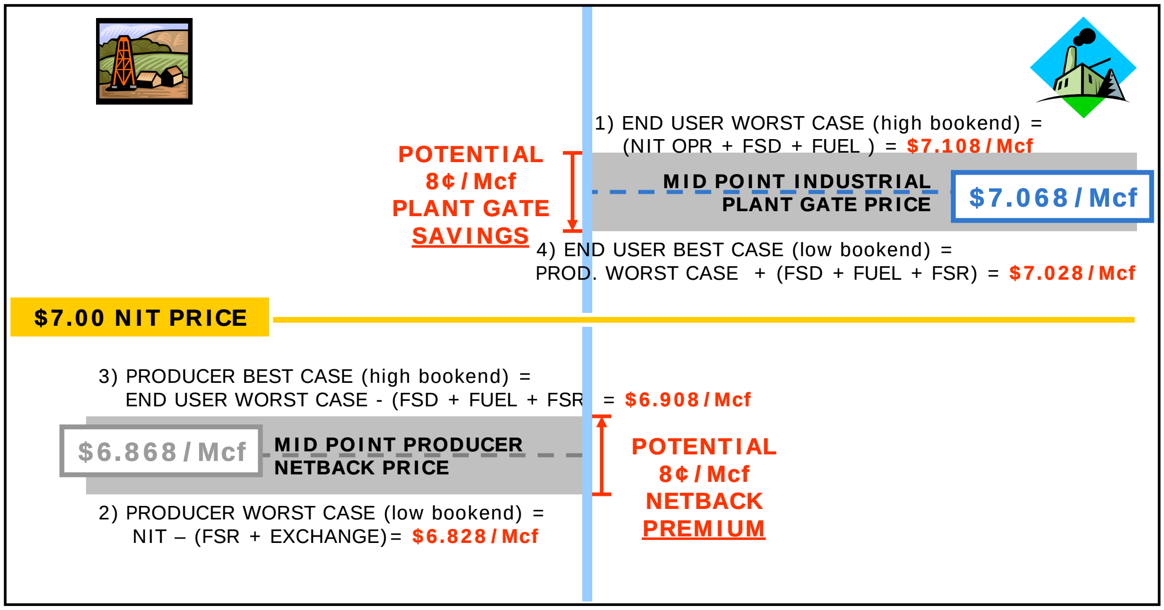
6. **The above analysis illustrates that both ATCO Pipelines’ industrial and ATCO Pipelines producer customers have the opportunity to achieve price savings or price premiums by buying and selling gas on the ATCO Pipelines system (“on-system”) utilizing ATCO Pipelines transport, as an alternative to buying and selling gas at NIT on NGTL’s Alberta System (“off-system”) utilizing ATCO Pipelines transport. If both industrial and producer customers equally share the price savings and price premiums available to them, the ATCO Pipelines industrial delivered plant gate price would be calculated as the midpoint between the upper and lower industrial delivered plant gate price bookends. Similarly, the ATCO Pipelines producer netback price would be calculated as the midpoint between the upper and lower producer netback price bookends.**

- **The midpoint industrial delivered plant gate price has (assuming a NIT price of $7.00/Mcf) increased on the APN system from $7.068/Mcf in October, 2004 to $7.077/Mcf in January, 2005. Under ATCO Pipelines' proposed FT-A rate, the industrial's midpoint price will increase further to $7.097/Mcf.**
- **The midpoint producer netback price has (assuming a NIT price of $7.00/Mcf) decreased on the APN system from $6.868/Mcf in October, 2004 to $6.855/Mcf in January, 2005. However, under ATCO Pipelines' proposed FT-A rate, the producer's midpoint price will increase to $6.875/Mcf.**

The "high bookend" and "low bookend" alternatives available to both the APN industrial customer and APN producer customer for the October 2004 case are illustrated in Figure 11 below. As ATCO Pipelines notes in its evidence on page 14, lines 16 and 17, buyers and sellers look at the "bookends" and then negotiate from those positions. The "midpoints" between the bookends illustrate the price that buyers and sellers would each achieve if they are prepared to equally share the potential price savings of buying gas on the ATCO Pipelines system and the potential price premium of selling gas on the ATCO Pipelines system.

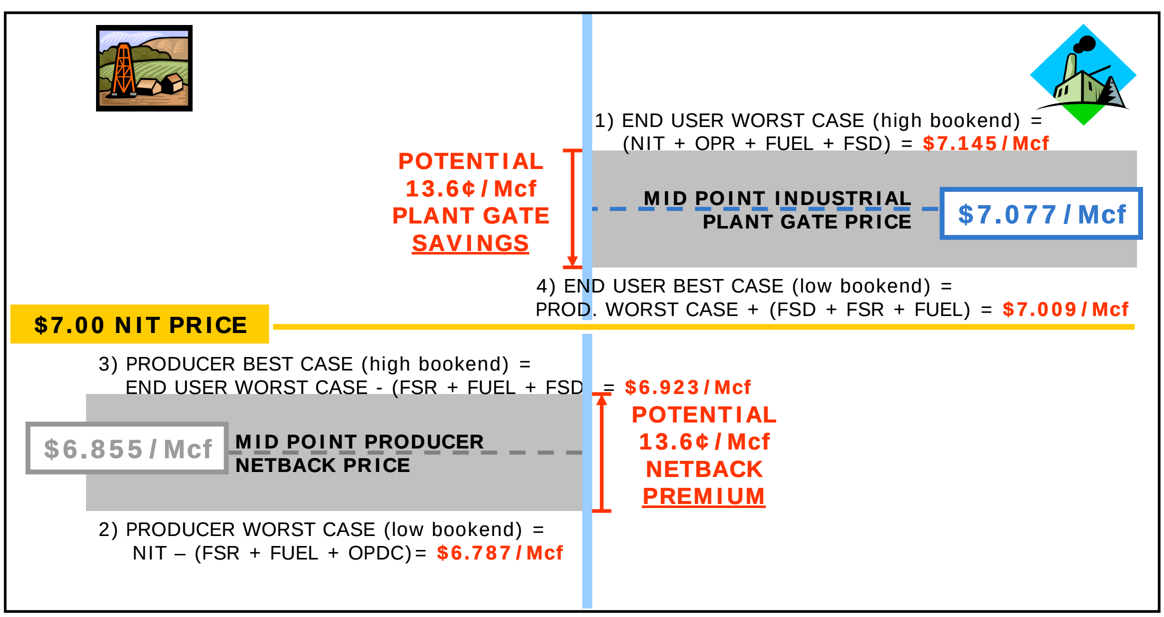
Using the information provided by ATCO Pipelines in response to NGTL-AP-15 and as illustrated in Figure 11 below (and per ATCO Pipelines Table NGTL-AP-15(f)(ix)-1), as of October 2004 the APN industrial plant gate midpoint price is $7.068/Mcf, while the APN Producer netback midpoint price is $6.868/Mcf. In such a scenario the producer may be able to achieve a 4¢/Mcf premium over the alternative of selling "off-system" at NIT and the industrial may be able to achieve a 4¢/Mcf discount over the alternative of buying "off-system" at NIT.

Figure 11
APN industrial plant gate delivered bookend and midpoint price and APN producer netback bookend and midpoint pricing as of October, 2004



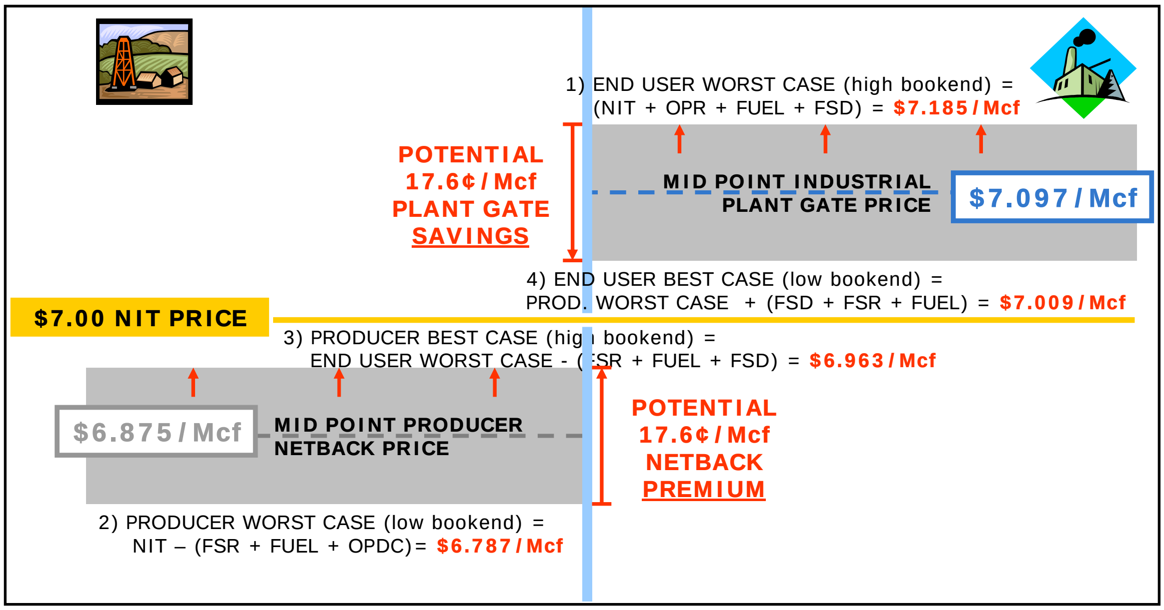
As illustrated in Figure 12 below (and per ATCO Pipelines Table NGTL-AP-15(f)(ix)-1), as of January 2005 the APN industrial plant gate midpoint price increases from $7.068/Mcf to $7.077/Mcf, while the APN Producer netback midpoint price decreases from $6.868/Mcf to $6.855/Mcf. In such a scenario the producer may be able to achieve a 6.8¢/Mcf premium over the alternative of selling “off-system” at NIT and the industrial may be able to achieve a 6.8¢/Mcf discount over the alternative of buying “off-system” at NIT.

Figure 12
APN industrial plant gate delivered bookend and midpoint price and APN producer netback bookend and midpoint pricing as of January, 2005



As illustrated in Figure 13 below (and per ATCO Pipelines Table NGTL-AP-15(f)(ix)-1), under ATCO Pipelines' proposed FT-A rate, the APN industrial plant gate midpoint price increases from $7.077/Mcf to $7.097/Mcf, while the APN Producer netback midpoint price increases from $6.855/Mcf to $6.875/Mcf. In such a scenario, the producer may be able to achieve an 8.8¢/Mcf premium over the alternative of selling "off-system" at NIT and the industrial may be able to achieve an 8.8¢/Mcf discount of the alternative of buying "off-system" at NIT.

Figure 13
APN industrial plant gate delivered bookend and midpoint price and APN producer netback bookend and midpoint pricing as of January, 2005 with ATCO Pipelines' proposed FT-A rate



A summary of the implications of APN's rate structure after November 1, 2004 and under ATCO Pipelines' proposed FT-A rates to bookend and midpoint prices is provided in Table 7 provided at the back of this package.

7. **The APN on-system market provides an alternative for APN industrial customers and APN producer customer to holding "full-path transport" via NIT from APN producer receipt point to APN plant gate delivery point. Assuming APN industrial customers and APN producer customers equally share the price savings and price premiums available to them, the midpoint APN on-system market gas price has (assuming a NIT price of $7.00/Mcf) increased from $6.975/Mcf (or NIT –2.5¢) in October, 2004 to $7.006/Mcf (or NIT +0.6¢) in January, 2005. Under ATCO Pipelines' proposed FT-A rate, the midpoint APN on-system market gas price will increase further to $7.026/Mcf (NIT +2.6¢/Mcf).**

The APN market, while smaller and less liquid than NIT, functions like NIT in that it is the notional point on the APN system where APN on-system producers sell gas and where APN on-system industrials buy gas.

As ATCO Pipelines confirmed in its IR response to NGTL-AP-15 (b), ATCO Pipelines worked with NGX to create the "ATCO Pipelines North Daily Index" product in order to facilitate the title transfer of gas between APN customers at the APN on-system market. The availability of this product facilitates the APN on-system market and price determination at the APN on-system market and provides a viable alternative to APN producer and APN industrial customers from having to hold "full-path" transport via NIT from APN producer plant gate to APN industrial plant gate.

As ATCO Pipelines confirmed in its response to NGTL-AP-15(e), buyers and sellers look at the bookend price alternatives and then negotiate from those positions. Both buyers and sellers on the APN system have the opportunity to achieve premiums or savings based on the pricing (tolls) of APN transportation alternatives to buy and sell gas off-system at NIT or to buy and sell gas on the APN system, bypassing NIT. The midpoint price is the average of the bookend alternatives.

The determination of the "midpoint" price (relative to NIT) for the APN on-system market can be determined in two ways, each yielding the same result.

One way to determine the APN price is, as described in the lower half in Figure 14 below for the October 2004 case, to:

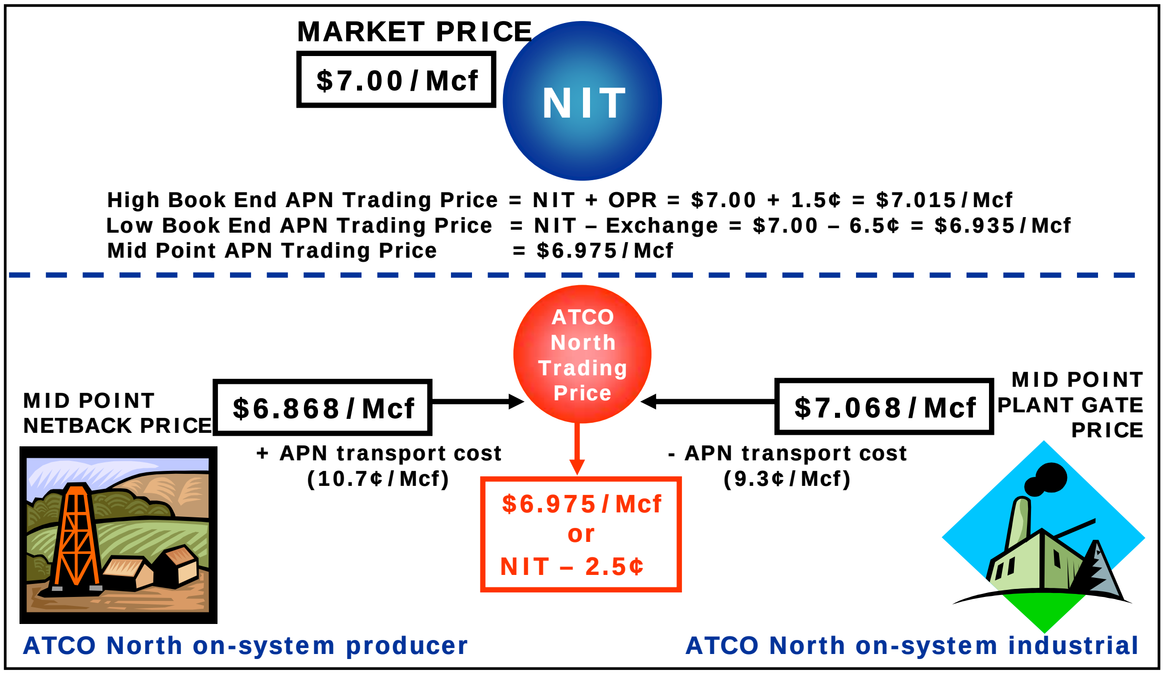
1. First calculate the midpoint netback price at the singly-connected APN producer's plant gate and the midpoint delivered price at the singly-connected APN industrial's plant gate;
2. Add the transport cost (the FSR rate of 10.7¢/Mcf illustrated below) to the producer's midpoint netback price ($6.869/Mcf illustrated below on the left side of Figure 14) to get to the APN on-system market ($6.975/Mcf or NIT - 2.5¢/Mcf); and
3. Deduct the transport cost (the sum of the FSD rate of 4.5¢/Mcf and the UFG/Fuel 4.8¢/Mcf of 9.3¢/) from the industrial's midpoint plant gate price ($7.068/Mcf as illustrated below on the right hand side of Figure 14) to derive the APN on-system market midpoint price ($6.975/Mcf or NIT -2.5¢/Mcf).

A second way to determine the APN price and the way employed by ATCO Pipelines in ATCO Pipelines' IR response to NGTL-AP-15 in Tables NGTL-AP-15(f)(v)-1 and NGTL-AP-15(f)(vi) and as described in the upper half of Figure 14 below for the October 2004 case, is to:

1. Calculate the high bookend APN Trading Price by adding the OPR rate (1.5¢/Mcf) to the NIT price;
2. Calculate the low bookend APN Trading price by subtracting the Exchange Fee (6.5¢/Mcf) from the NIT price;

3. Average of the two bookends to derive the APN on-system market midpoint price ($6.975/Mcf or NIT -2.5¢/Mcf).

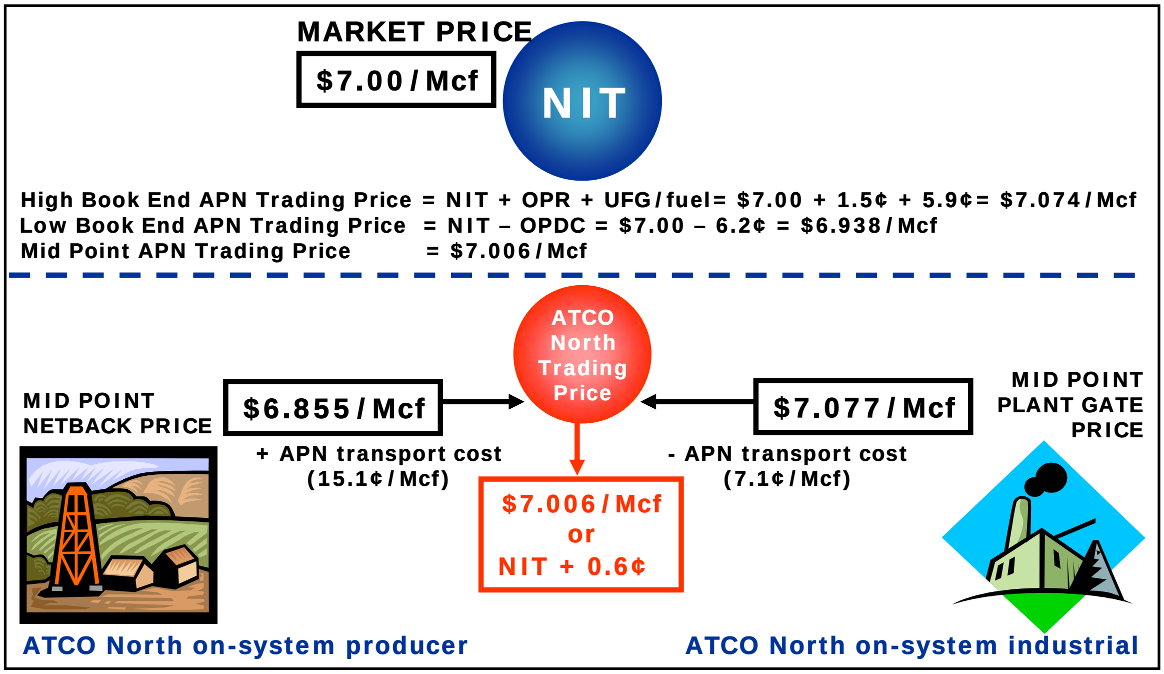
Figure 14
October 2005 Case



The implications of APN's rate structure as of January 2005 to APN on-system market bookend prices and the APN on-system midpoint price are as follows and are illustrated in Figure 15 below:

1. The APN on-system market price (high bookend) increases by 5.9¢/Mcf from $7.015/Mcf to $7.074/Mcf (per ATCO Pipelines Table NGTL-AP-15(f)(v)-1);
2. The APN on-system market price (low bookend) increases by 0.3¢/Mcf from $6.935/Mcf to $6.938/Mcf (per ATCO Pipelines Table NGTL-AP-15(f)(vi)); and
3. The APN on-system market price (midpoint) increases by 3.1¢/Mcf from $6.975/Mcf (or NIT -2.5¢) to $7.006/Mcf (or NIT +0.6¢).

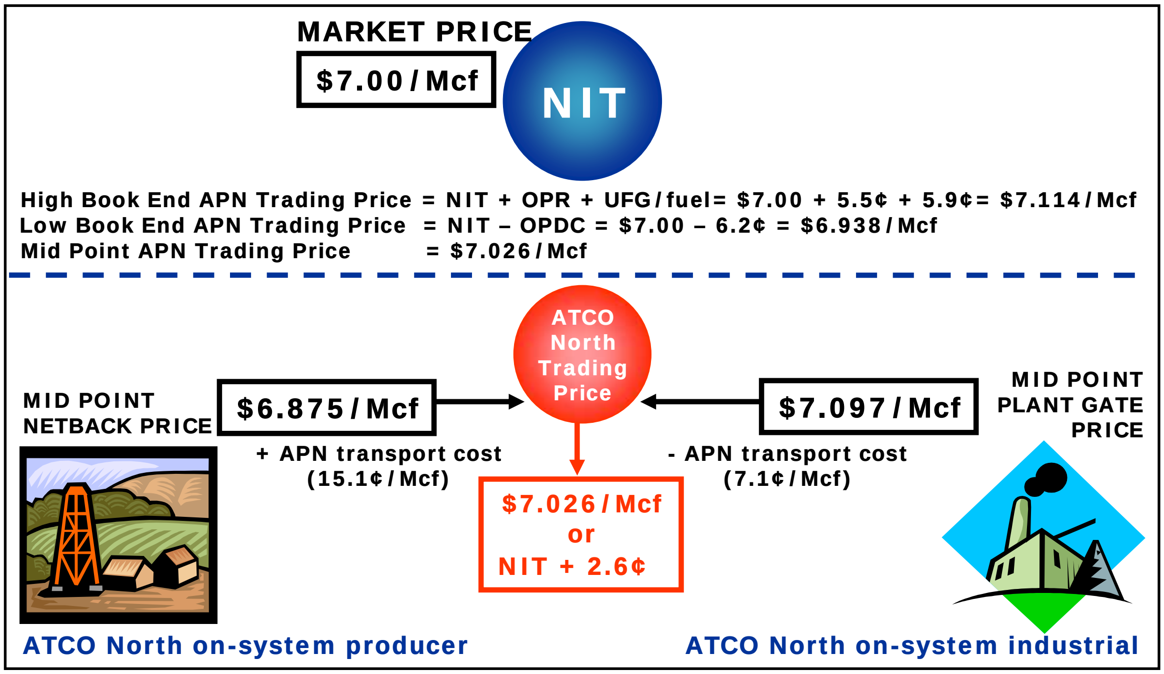
Figure 15
January 2005 case



The implications of APN's rate structure as of January 2005 with ATCO Pipelines' proposed FT-A rate to APN on-system market bookend prices and the APN on-system midpoint price are as follows and are illustrated in Figure 16 below:

1. The APN on-system market price (high bookend) increases by 4¢/Mcf from $7.074/Mcf to $7.114/Mcf (per ATCO Pipelines Table NGTL-AP-15(f)(v)-1);
2. The APN on-system market price (low bookend) does not change at $6.938/Mcf (per ATCO Pipelines Table NGTL-AP-15(f)(vi)); and
3. The APN on-system market price (midpoint) increases by 2¢/Mcf from $7.006/Mcf (or NIT +0.6¢) to $7.026/Mcf (or NIT +2.6¢).

Figure 16
January 2005 case with ATCO Pipelines' proposed FT-A rate structure



The analysis illustrates that the most important factor that influences the APN trading price is the rates that APN charges its customers to transfer gas between NIT and the APN system.

ATCO Pipelines can, by selectively changing these rates, influence ATCO Pipelines' on-system market price and in doing so can directly influence industrial plant gate pricing and producer netback pricing and the competitiveness of the APN system relative to NGTL.

8. **The title transfer of gas between APN customers on-system is facilitated by NGX's "ATCO Pipelines North Daily Index" product.The NGX-ATCO North Daily Index price, while not illustrative of all transactions between buyers and sellers on the APN system, suggests that the average differential between the NIT price and the APN on-system market price for the period from November 1, 2004 to August 10, 2005 has been at a premium (NIT +2.1¢/Mcf) to the calculated APN midpoint on-system market price of NIT +0.6¢.**

Figure 17 below illustrates the NGX –ATCO Daily Index information as provided in ATCO Pipelines' response to NGTL-AP-16(a). Note that for reasons of consistency, NGTL has converted this data from $/GJ to $/Mcf @ 38MJ/$M^3$.

The upper line illustrates the high bookend APN on-system market price as of October, 2004. The lower line illustrates the low bookend APN on-system market price as of

October, 2004. The middle dashed line illustrates the midpoint APN on-system market price as of October, 2004 (as described earlier in Figure 14). This is generally consistent with ATCO Pipelines' observation in their response to NGTL-AP-16(c) that (prior to the change in ATCO Pipelines' rate structure on November 1, 2004) that "ATCO Pipelines has heard from a variety of customers that APN generally traded for NIT less half the exchange fee at the time, plus or minus, depending on various circumstances existing in the market place at the time." While Figure 17 also illustrates that, per ATCO Pipelines' response to NGTL-AP-16(f), the daily APN on-system market price can fluctuate from premium to discount relative to NIT with the changes in seasons, it also suggests that the APN on-system market price has, for the most part, been higher relative to NIT since the introduction of APN's new rate structure on November 1, 2004.

Figure 17
APN on-system market bookend and midpoint prices for October 2004 vs. NGX historical pricing

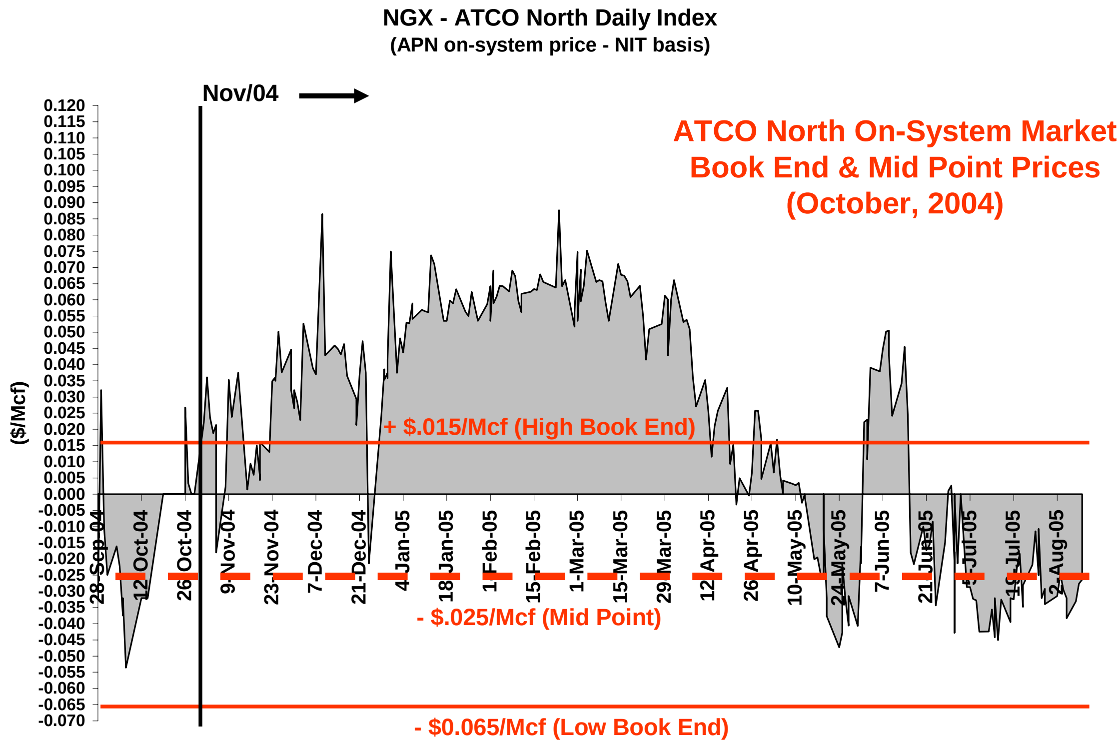


Figure 18 below illustrates the NGX –ATCO Daily Index information as provided in ATCO Pipelines' response to NGTL-AP-16(a) (converted from \$/GJ to \$/Mcf @ 38/MJ/M^3). The upper line illustrates the high bookend APN on-system market price with APN's November 1, 2004 rates in effect <u>as of January, 2005</u>. The lower line illustrates the low bookend APN on-system market price as of January, 2005 (as described earlier in Figure 15). The middle dashed line illustrates the midpoint APN on-system market price as of January, 2005. The high and low bookends provided in APN's responses to NGTL-AP-15 suggest a much wider trading range than would have been the case prior to November 1, 2004 and the NGX data appears to bear this out.

Figure 18
APN on-system market bookend and midpoint prices for January 2005 vs. historical NGX pricing

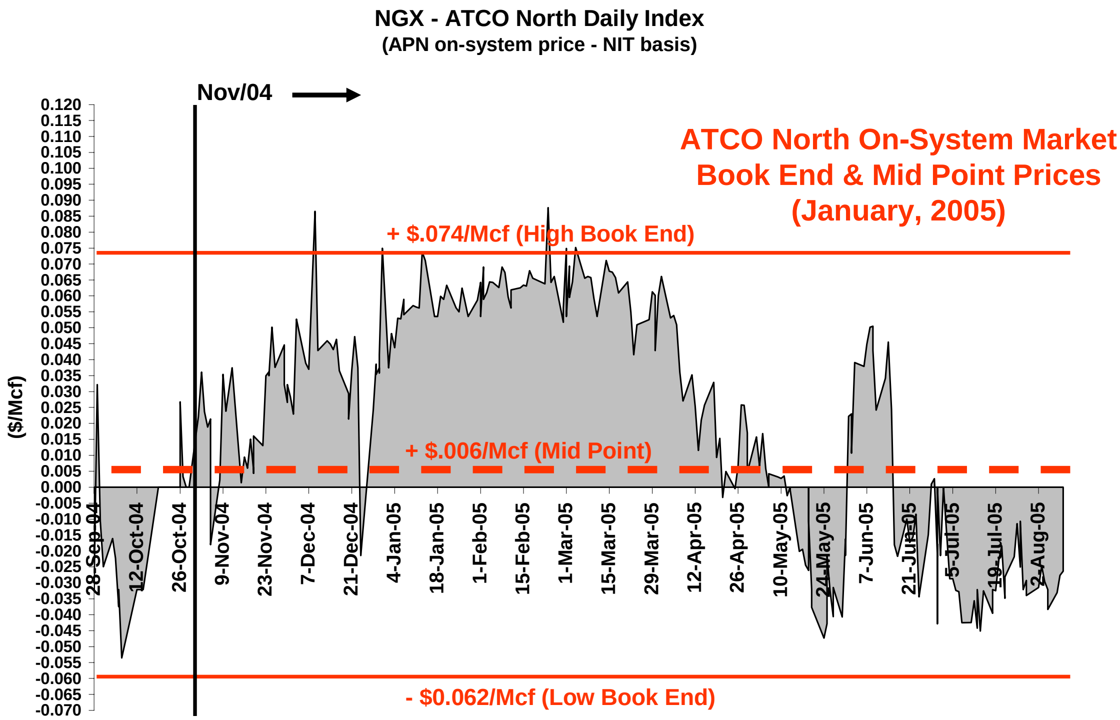


Figure 19 below illustrates the average price from November 1, 2004 to August 10, 2005 period (dashed green line) was NIT +2.1¢/Mcf. This compares with the January 2005 APN on-system market price "midpoint" of NIT +0.6¢/Mcf.

Figure 19
APN average daily index price for the period November 1, 2004 to August 10, 2005

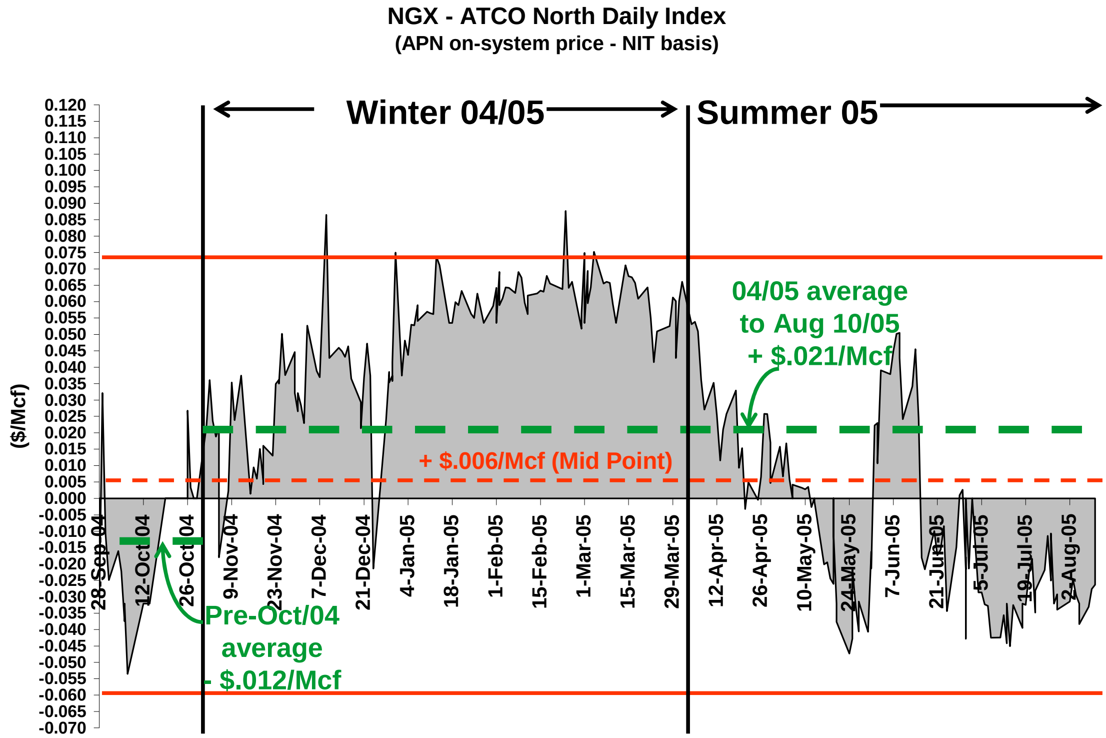
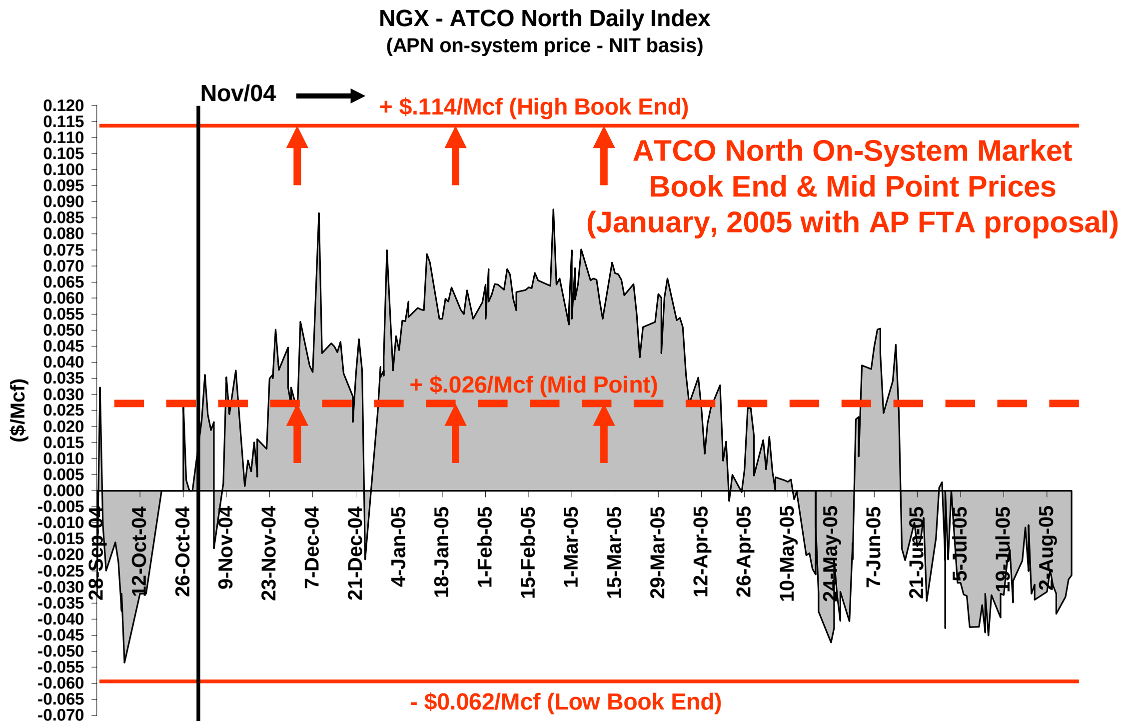


Figure 20 below illustrates the APN high (upper red line), low bookend (lower red line) and midpoint (dashed red line) on-system market prices with ATCO Pipelines' proposed FT-A rate (as described earlier in Figure 16). Figure 20 suggests, should NGTL's FT-A toll increase as proposed by ATCO Pipelines the APN on-system market price will, as discussed earlier, increase even further.

Figure 20
APN on-system market bookend and midpoint prices for January 2005 with ATCO Pipelines FTA proposal



9. If the NIT gas price moves higher than the assumed value of $7.00/Mcf, the APN on-system market price will increase further relative to NIT. If APN industrial customers and APN producer customers equally share the price savings and price premiums available to them, the midpoint APN on-system gas price, would (assuming a NIT price of $9.00/Mcf, which is more reflective of today's market) increase from NIT –2.5¢ in October, 2004 to NIT +1.4¢ in January, 2005. Under ATCO Pipelines' proposed FT-A rate, the midpoint APN on-system market gas price would increase further to NIT +3.4¢/Mcf.

The APN on-system market price will increase further relative to NIT as the NIT price increases. This is because APN's rate structure to move gas from off-system at NIT to the APN on-system market assesses a UFG/fuel charge in addition to the OPR charge. The high and low bookend prices and the midpoint prices for the APN on-system market assuming the NIT price is $9.00/Mcf are provided in Table 2 below.

Table 2

	AP North October 2004 Case ($/Mcf)	AP North January 2005 Case ($/Mcf)	AP North *Proposed* Case ($/Mcf)
APN DERIVED ON-SYSTEM GAS PRICE (High Bookend)	9.015	9.090	9.130
APN DERIVED ON-SYSTEM GAS PRICE (Low Bookend)	8.935	8.938	8.938
APN DERIVED ON-SYSTEM GAS PRICE (Mid Point)	8.975	9.014	9.034

10. <u>All</u> APN dually connected producers can currently achieve a higher netback by selling to the APN on-system market versus the alterative of utilizing transport on the Alberta System and selling at NIT. Any further increase to the APN on-system market price will only improve ATCO Pipelines' competitiveness with NGTL at dually connected plants.

In ATCO Pipelines' response to BR-AP-3, it stated that it is competitive with NGTL at some, but not all, receipt points within the province. ATCO Pipelines notes that location or geographic capture area aside, where ATCO Pipelines has a receipt toll and fuel cost subtracted from the ATCO Pipelines on-system trading price that produces a higher producer netback in relation to the NIT price, ATCO Pipelines should be competitive on a pure netback comparison basis.

Yet, in its response to NGTL-AP-15 (f) (iii)&(iv), in Tables NGTL-AP-15 (f) (iii)&(iv)-1 and 3, ATCO Pipelines only provides netback comparisons for dually connected producers from NIT. NGTL has combined the above referenced tables into Table 3 below to better illustrate APN's competitiveness at dually connected APN and NGTL plants from NIT. Table 3 also indicates which plants have a higher netback if they move gas to NIT via the APN system and which plants have a higher netback if they move gas to NIT via NGTL's Alberta System.

Table 3

AP Receipt Point	NIT Price ($/Mcf)	NGTL Toll* ($/Mcf)	NGTL Fuel ($/Mcf)	NGTL Netback from NIT ($/Mcf)	NIT Price ($/Mcf)	APN OPDC Rate ($/Mcf)	APN UFG/fuel ($/Mcf)	APN FSR Rate ($/Mcf)	APN Netback from NIT ($/Mcf)	Comment
Ansle	7.000	0.117	0.065	**6.818**	7.000	0.067	0.059	0.098	**6.776**	NGTL higher
Bonnie Glen	7.000	0.153	0.065	**6.782**	7.000	0.066	0.059	0.097	**6.778**	NGTL higher
Lloyd Creek	7.000	0.104	0.065	**6.831**	7.000	0.065	0.059	0.095	**6.781**	NGTL higher
Manville	7.000	0.224	0.065	**6.711**	7.000	0.064	0.059	0.094	**6.783**	APN higher
McLeod River	7.000	0.165	0.065	**6.770**	7.000	0.067	0.059	0.098	**6.776**	APN higher
South Carrot Ck.	7.000	0.109	0.065	**6.826**	7.000	0.064	0.059	0.094	**6.783**	NGTL higher
Sundance Ck.	7.000	0.172	0.065	**6.763**	7.000	0.068	0.059	0.100	**6.773**	APN higher
Tribute	7.000	0.237	0.065	**6.698**	7.000	0.070	0.059	0.103	**6.768**	APN higher
Vantage	7.000	0.099	0.065	**6.836**	7.000	0.064	0.059	0.094	**6.783**	NGTL higher
Viking	7.000	0.174	0.065	**6.761**	7.000	0.062	0.059	0.091	**6.788**	APN higher

*** 3 to <5 yr. term**

However, NGTL has also replicated the information provided by APN in the above referenced tables to illustrate, consistent with ATCO Pipelines' response to BR-AP-3, that the APN receipt toll and fuel cost subtracted from the ATCO Pipelines on-system trading price produces a higher producer netback from the NIT price and that APN is more competitive on a pure netback comparison basis with NGTL at all APN dually connected receipt points. This is illustrated in Table 4 below:

Table 4
January 2005 case

AP Receipt Point	NIT Price ($/Mcf)	NGTL Toll* ($/Mcf)	NGTL Fuel ($/Mcf)	NGTL Netback from NIT ($/Mcf)	AP on-system trading price mid point** ($/Mcf)	APN OPDC Rate ($/Mcf)	APN UFG/fuel ($/Mcf)	APN FSR Rate ($/Mcf)	APN netback from APN on-system market ($/Mcf)	Comment
Ansle	7.000	0.117	0.065	**6.818**	7.006	n/a	0.059	0.098	**6.849**	APN higher
Bonnie Glen	7.000	0.153	0.065	**6.782**	7.006	n/a	0.059	0.097	**6.850**	APN higher
Lloyd Creek	7.000	0.104	0.065	**6.831**	7.006	n/a	0.059	0.095	**6.852**	APN higher
Manville	7.000	0.224	0.065	**6.711**	7.006	n/a	0.059	0.094	**6.853**	APN higher
McLeod River	7.000	0.165	0.065	**6.770**	7.006	n/a	0.059	0.098	**6.849**	APN higher
South Carrot Ck.	7.000	0.109	0.065	**6.826**	7.006	n/a	0.059	0.094	**6.853**	APN higher
Sundance Ck.	7.000	0.172	0.065	**6.763**	7.006	n/a	0.059	0.100	**6.847**	APN higher
Tribute	7.000	0.237	0.065	**6.698**	7.006	n/a	0.059	0.103	**6.844**	APN higher
Vantage	7.000	0.099	0.065	**6.836**	7.006	n/a	0.059	0.094	**6.853**	APN higher
Viking	7.000	0.174	0.065	**6.761**	7.006	n/a	0.059	0.091	**6.856**	APN higher

*** 3 to <5 yr. term** **** January 2005**

NGLT has also replicated the information provided by APN in the above referenced tables to illustrate, consistent with their response to BR-AP-3 AP, that APN will become even more competitive on a pure netback comparison basis with NGTL at all APN dually connected receipt points if ATCO Pipelines' FT-A proposal is accepted.

This is illustrated in Table 5 below:

Table 5
January 2005 case with ATCO Pipelines' FT-A proposal

AP Receipt Point	NIT Price ($/Mcf)	NGTL Toll* ($/Mcf)	NGTL Fuel ($/Mcf)	NGTL Netback from NIT ($/Mcf)	AP on-system trading price mid point*** ($/Mcf)	APN OPDC Rate ($/Mcf)	APN UFG/fuel ($/Mcf)	APN FSR Rate ($/Mcf)	APN netback from APN on-system market ($/Mcf)	Comment
Ansle	7.000	0.117	0.065	**6.818**	7.026	n/a	0.059	0.098	**6.869**	APN higher
Bonnie Glen	7.000	0.153	0.065	**6.782**	7.026	n/a	0.059	0.097	**6.870**	APN higher
Lloyd Creek	7.000	0.104	0.065	**6.831**	7.026	n/a	0.059	0.095	**6.872**	APN higher
Manville	7.000	0.224	0.065	**6.711**	7.026	n/a	0.059	0.094	**6.873**	APN higher
McLeod River	7.000	0.165	0.065	**6.770**	7.026	n/a	0.059	0.098	**6.869**	APN higher
South Carrot Ck.	7.000	0.109	0.065	**6.826**	7.026	n/a	0.059	0.094	**6.873**	APN higher
Sundance Ck.	7.000	0.172	0.065	**6.763**	7.026	n/a	0.059	0.100	**6.867**	APN higher
Tribute	7.000	0.237	0.065	**6.698**	7.026	n/a	0.059	0.103	**6.864**	APN higher
Vantage	7.000	0.099	0.065	**6.836**	7.026	n/a	0.059	0.094	**6.873**	APN higher
Viking	7.000	0.174	0.065	**6.761**	7.026	n/a	0.059	0.091	**6.876**	APN higher

*** 3 to <5 yr. term** ***** January 2005 with AP Proposed FT-A Rate**

11. NGTL observes that the percentage of APN on-system receipts from dually connected plants has increased, according to ATCO Pipelines' receipt numbers, from 19% of APN on-system receipts in the year 2000 to 44% of APN on-system receipts in 2004.

In 2004 approximately 44% of APN's on-system receipts are sourced from dually-connected plants.

In its response to CAPP-AP-15 (b) & (c) (2003/2004 General Rate Application Phase 1), ATCO Pipelines itemizes the total receipts at APN dually connected plants for the years 2000 through 2004. Here APN provided 2004 APN receipts from dually connected plants of 121,102 TJs. As the figure was provided by ATCO Pipelines in 2004, NGTL assumes these were forecast data.

In its response to BR-AP-4, APN provides the 2004 flow number for dually connected plants on the APN system of 158,126 TJs. In its response to NGTL-AP-1(b) and (c), ATCO Pipelines indicates that in 2004 APN has 82,565 TJ's of other pipeline receipts and 361,089 TJ's of on-system receipts. These numbers are illustrated in Table 6 and Figure 21 below:

Table 6

Year	APN other pipeline receipts	APN on-system receipts	APN receipts from dually connected plants*	APN on-system receipts from singly connected plants	Percentage of APN on-system receipts from dually connected plants	Total APN receipts
2000	121,066	265,616	49,246	216,370	19%	386,682
2001	65,948	321,083	101,742	219,341	32%	387,031
2002	74,576	344,239	132,310	211,929	38%	418,815
2003	87,175	345,625	127,173	218,452	37%	432,800
2004	82,565	361,089	158,126	202,963	44%	443,654

* Receipts at dually connected plants for years 2000 to 2004 per AP 2004 GRA Phase I, AP response to CAL-AP-15 (b) (c)
Receipts at dually connected plants for the year 2004 per NGTL 2005 GRA Phase II, AP response to BR-AP-4

Figure 21

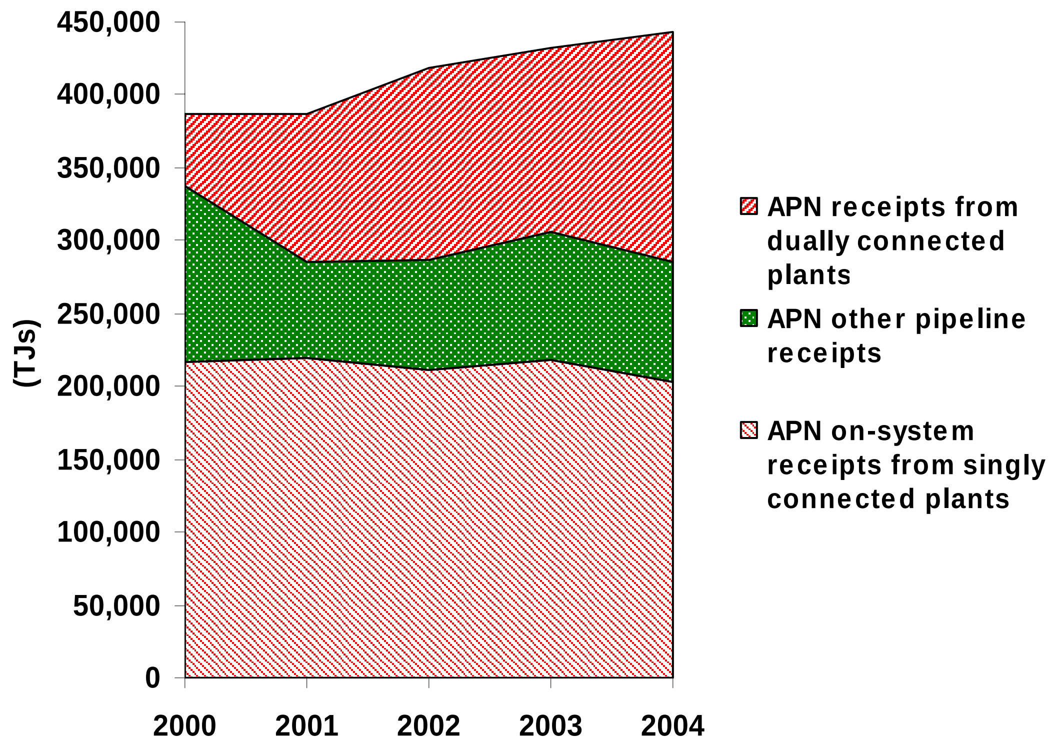


Table 6 above illustrates, approximately 44% of APN's on-system receipts are sourced from dually connected plants and, based on the historical trend, the proportion of APN's on-system receipts sourced at dually connected plants is increasing.

Table 7

COMPARISON OF AP NORTH / NGTL INDUSTRAL PLANT GATE PRICING AND PRODUCER NETBACK PRICING	AP North October 2004 Case ($/Mcf)	AP North January 2005 Case ($/Mcf)	AP North *Proposed* Case ($/Mcf)
1) APN Industrial Buys Gas at NIT via APN (@ NIT Price)	7.000	7.000	7.000
APN FSD toll	0.045	0.071	0.071
APN Fuel (Delivery)	0.048		
APN OPR	0.015	0.015	0.055
APN Fuel (Receipt)		0.059	0.059
APN Transport Cost from NIT to APN Industrial Plant Gate	**0.108**	**0.145**	**0.185**
APN Industrial Plant-Gate Price (<u>Worst Case</u> / High Bookend)	**7.108**	**7.145**	**7.185**
2) APN Producer Sells Gas at NIT via APN (@ NIT Price)	7.000	7.000	7.000
APN FSR toll	0.107	0.092	0.092
Exchange	0.065		
APN OPDC		0.062	0.062
APN Fuel (Receipt)		0.059	0.059
APN Transport Cost from Producer Plant Gate to NIT	**0.172**	**0.213**	**0.213**
APN Producer Plant Gate Netback Price (<u>Worst Case</u> / Low Bookend)	**6.828**	**6.787**	**6.787**
3) APN Producer Sells Gas to APN Industrial (@ Industrial High Bookend Price)	7.108	7.145	7.185
APN FSR toll	0.107	0.092	0.092
APN Fuel (Receipt)		0.059	0.059
APN FSD toll	0.045	0.071	0.071
APN Fuel (Delivery)	0.048		
APN Transport Cost from Producer Plant Gate to APN Industrial Plant Gate	**0.200**	**0.222**	**0.222**
APN Producer Plant Gate Netback Price (<u>Best Case</u> / High Bookend)	**6.908**	**6.923**	**6.963**
4) APN Industrial Buys Gas from APN Producer (@ Producer Low Bookend Price)	6.828	6.787	6.787
APN FSR toll	0.107	0.092	0.092
APN Fuel (Receipt)		0.059	0.059
APN FSD toll	0.045	0.071	0.071
APN Fuel (Delivery)	0.048		
APN Transport Cost from Producer Plant Gate to APN Industrial Plant Gate	**0.200**	**0.222**	**0.222**
APN Industrial Plant Gate Price (<u>Best Case</u> / Low Bookend)	**7.028**	**7.009**	**7.009**
INDUSTRIAL PLANT-GATE MID-POINT PRICE (BETWEEN THE UPPER AND LOWER BOOKEND)	**7.068**	**7.077**	**7.097**
PRODUCER PLANT-GATE NETBACK MID-POINT PRICE (BETWEEN THE UPPER AND LOWER BOOKEND)	**6.868**	**6.855**	**6.875**
APN DERIVED ON-SYSTEM GAS PRICE (High Bookend)	**7.015**	**7.074**	**7.114**
APN DERIVED ON-SYSTEM GAS PRICE (Low Bookend)	**6.935**	**6.938**	**6.938**
APN DERIVED ON-SYSTEM GAS PRICE (Mid Point)	**6.975**	**7.006**	**7.026**