Decision 2004-097

NOVA Gas Transmission Ltd.

2004 General Rate Application
Phase II

October 26, 2004

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2004-097: NOVA Gas Transmission Ltd.
2004 General Rate Application, Phase II
Application No. 1320419

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640 – 5 Avenue SW
Calgary, Alberta
T2P 3G4

Telephone: (403) 297-8311
Fax: (403) 297-7040

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Calgary Alberta

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1 INTRODUCTION

By letter dated November 14, 2003, NOVA Gas Transmission Ltd. (NGTL) filed Phase II of a 2004 General Rate Application (GRA) with the Alberta Energy and Utilities Board (EUB or the Board). In the Phase II application (the Application) NGTL requested approval of the rates, tolls and charges for NGTL's Alberta System (Alberta System) services from January 1, 2004 to December 31, 2004, an extension of the term of the existing Other Service and rate provided by NGTL to TransCanada PipeLines Limited (TransCanada or TCPL) under provision of a gas balancing agreement, and amendments to Rate Schedule IT-S and the General Terms and Conditions of NGTL's Tariff. NGTL is a wholly owned subsidiary of TransCanada.

NGTL, as part of its 2003 Alberta System Revenue Requirement Settlement, committed to file a 2004 GRA as a basis for establishing 2004 rates, tolls and charges. In Decision 2003-051, dated June 24, 2003, the Board directed NGTL to file a comprehensive 2004 Phase II GRA application that would address the following items:

- Appropriateness of the use of Distance of Haul (DOH) for allocation of costs between receipt and delivery functions;
- A Cost of Service Study (COSS);
- The definition of mainline facilities and lateral facilities used to establish NGTL's eligibility to construct a pipeline to industrial customers;
- Payment of fuel costs at receipt points;
- Appropriate customer accountability for storage facilities; and
- Status of the concern over gas quality.

On February 13, 2004, NGTL filed an update of the Application primarily to reflect revisions made to NGTL's Phase I GRA. On June 4, 2004, NGTL filed a subsequent revision to the Application to provide a number of minor corrections.

The EUB's Notice of Hearing, dated November 28, 2003, was distributed by email on that date to all interested parties on the NGTL 2004 GRA Phase I distribution list and was published in the major Alberta newspapers on December 4, 2003. The Notice set out the proposed hearing schedule for this proceeding with the oral portion to commence June 1, 2004. By letter dated February 20, 2004, the Board advised that the commencement date was changed to June 8, 2004 and subsequently by letter dated June 4, 2004, the start date was revised to June 9, 2004.

The public hearing convened in Calgary on June 9, 2004 before Ms. C. Dahl Rees (Presiding Member), Mr. T. McGee (Member), and Mr. M. W. Edwards (Acting Member). Parties filed written argument on July 8, 2004 and reply argument on July 29, 2004. Accordingly, the Board considers July 29, 2004 was the close of record for this proceeding.

Those parties who participated in the proceeding are listed in Appendix A.

1.1 Procedural Issues and General Matters

The Board noted in its opening remarks to the hearing on June 9, 2004 that there was some overlap in the issues lists which it provided for the Phase I and Phase II proceedings, including mainline and lateral classifications on NGTL and the rate implications of the same. The Board considered it appropriate that these issues be examined in both Phase I and Phase II of the NGTL rate case. Accordingly, the Board incorporated by reference material related to mainline and lateral classifications from the Phase I proceeding into the record of the Phase II proceeding.

Similarly, the issue of least cost alternative (LCA) was raised in the NGTL Phase I proceeding, however, as this issue was not easily separated from the issue of cost accountability in rate design, and since ATCO Pipelines (ATCO) had filed specific recommendations in this portion of the proceeding, the Board considered that it was appropriate to consider this issue in the Phase II proceeding.

1.2 Decision Overview

There are certain fundamental matters which are typically addressed by the EUB in a Phase II decision, namely cost allocation and rate design. As the Board noted in its recent decision on the ATCO 2004 GRA Phase II:

> Traditionally, a GRA Phase II decision will consider and determine how to apply the appropriate rate design criteria for the determination of just and reasonable rates to collect the utility's approved revenue requirement, determine the rates for the proposed services and establish the appropriate terms and conditions for these services. Certain of those rate design criteria address the accuracy of the cost allocation methodologies used to support the collection of a share of revenue requirement from each class through rates. The primary tool utilized in determining an appropriate cost allocation is a cost of service study (COSS). A COSS will ordinarily analyze the costs incurred in providing regulated services, categorize or functionalize these costs and then determine an appropriate set of methodologies for the allocation of these costs. An appropriate allocation may be done in one of any number of ways, including on a fully allocated cost basis for all costs or a mixed allocation of costs with costs that can not be attributed to a single customer class (general system costs) being allocated on a fully allocated basis and costs that can be attributed to a single customer class being direct assigned to that class.[1]

In the present Application, NGTL has filed DOH and Cost of Haul (COH) studies, in response to Board directions in Decision 2003-051. NGTL also filed a COSS. These studies, and any directions for future refinement to them, are discussed by the Board in Section 2 of this Decision.

NGTL has also proposed rates and terms and conditions for its regulated services. Section 3 of this Decision will address NGTL's cost allocation and rate design criteria.

There are other matters which have been of concern with respect to NGTL's rates for services on the Alberta System. These relate to cost accountability and LCA, which are addressed in

[1] Decision 2004-079, page 5

Sections 4 and 6 respectively. Section 5 will consider changes to NGTL's Fuel Policy which were proposed by CG in the proceeding. Section 7 will consider the appropriateness of changes proposed by NGTL to certain terms and conditions of service and rate schedules.

Section 8 deals generally with this Decision in the context of broader competitive pipeline issues and the future proceeding (Competitive Proceeding) which the Board intends to hold to address these issues.

2 COST OF SERVICE STUDIES

2.1 Cost of Service Study

As indicated above in Section 1.2, typically a COSS will analyze the costs incurred in providing regulated services, categorize or functionalize these costs and determine an appropriate set of methodologies for the allocation of these costs. The allocation of costs to service classes, based on consideration of the COSS, becomes the first step undertaken by the Board in determining just and reasonable rates. The consideration of an appropriate rate design is typically the next step in the Phase II process.

With respect to NGTL, the Board considers that the submission of a fully allocated COSS has been one of the fundamental concerns raised in recent years in relation to proper cost accountability and cost allocation among receipts, intra-Alberta deliveries, and ex-Alberta deliveries. In 2004 this issue has been raised in both the NGTL Phase I and Phase II proceedings.

In the current proceeding, NGTL submitted that it is difficult, if not impossible, for it to identify specific cost components with any particular service due to the integrated nature of the Alberta System. NGTL also submitted that it specifically used the COSS to determine the system average metering cost which formed the basis for the FT-A service rate.[2] NGTL suggested that other methodologies, including ATCO's view of a fully allocated COSS, would not provide any better reflection of the underlying costs of services than the application of NGTL's existing methodologies.[3]

ATCO has contended in this and other recent proceedings that appropriate rates for NGTL's services cannot be properly determined because NGTL has failed to conduct a fully allocated COSS.[4] The Board acknowledges ATCO's position that NGTL can only achieve a fully allocated COSS if NGTL allocates transmission and compression costs across each class of service. ATCO acknowledged that NGTL provided a fully allocated COSS for its metering costs.[5]

ATCO also submitted that an integrated system allows costs to be rolled-in, however it does not prevent a COSS from being undertaken. Joint-use or shared facilities prevail on all pipeline and electrical transmission systems.

While the Board recognizes NGTL is an integrated system, the Board also notes that other regulated utilities do perform fully allocated COSSs. To subject a lower standard of COSS for

[2] Exhibit No. 002-07(c), response to ATCO-NGTL-8(d).
[3] Exhibit No. 040-25.
[4] Exhibit No. 007-08(b), response to BR-ATCO-5; and Exhibit No. 007-08(i), response to NGTL-ATCO-10.
[5] Exhibit No. 007-08(b), response to BR-AP-5.

NGTL against that required for other utilities is inconsistent with the normal regulatory scrutiny of the Board. The Board considers that, whatever ultimate rate design might be adopted, it is ordinarily considered beneficial to understand where costs are created and where they might be fairly allocated on a regulated system.

With respect to the need for a fully allocated COSS, Calgary submitted that a COSS should identify the cost of providing the primary services provided by a pipeline. It is up to the pipeline to identify its primary service offerings and then conduct its cost of service (COS) analysis to show the cost of providing each service. The Board agrees with Calgary that the results of a fully allocated COSS should translate into more transparent rates for each service offering for which NGTL incurs costs.

The Board notes that in principle, the CG supported the concept that a COSS should be as comprehensive as possible in terms of its level of detail in order to present as complete a basis as possible for development of rates. However, the CG also indicated that there are some very significant constraints with respect to NGTL rates that would make it very difficult to implement any significant changes in receipt or export delivery rates. For this reason, the CG questioned the usefulness of any more detailed COS analyses by NGTL than those that have already been presented.

The Board agrees with ATCO, BP and Calgary, among other parties, that there are still concerns regarding appropriate cost accountability, cost allocation, and price transparency for the Alberta System. A comprehensive fully allocated COSS would provide a more quantitative basis than is available at present for determination of costs attributable to intra-Alberta, ex-Alberta, and receipt services.

The Board notes that BP agreed with ATCO's concerns about transparency and cost accountability principles. However, BP suggested that a COSS is not possible on the NGTL system since it is not possible to attach costs "perfectly" to all items on the system as suggested by ATCO and its consultants.[6] IGCAA agreed with NGTL that based on NGTL's rate design and the services it offers, its COSS is a fully allocated COSS. The Board has some reservations with these positions taken by IGCAA and BP with respect to the NGTL COSS. The Board agrees with BP that no COSS allocates costs perfectly, but a detailed COSS should assign or allocate all costs based on cost causation principles. The Board is of the view that a delivery rate with zero transmission or compression costs for intra-Alberta customers would generally not reflect cost causation.

IGCAA argued that one would have expected that if there was any unfairness or cross-subsidy associated with recent expenditures by NGTL on providing intra-Alberta service, ex-Alberta shippers would have complained. Further, the Board notes PG&E and TGI's submission[7] that the current COSS and cost allocation represents a fair and reasonable balance of cost allocation among all customer groups. However, despite the number of shippers supporting NGTL's rate design, the Board agrees with Calgary and ATCO that a proper COSS should be provided as a more transparent starting point to determine how cost allocations are reflected in rates to all customer groups.

[6] BP Argument, page 7.
[7] PG&E and TGI Argument, pages 1-2

The Board does not fully accept NGTL's argument that it is unable to separate costs of its integrated pipeline system. The Board agrees with the statement made by NGTL's rate design witness Dr. Gaske, that when possible one should directly assign costs to a class of customers if it is clear that the customer class is solely responsible for such costs[8]. The Board recognizes that direct assignment of costs is often done by regulated utilities, and that cost allocation (where direct assignment is not possible or appropriate) is a distinctly different undertaking, but is also one which is well understood by regulated utilities. Accordingly, the Board considers that lack of a physical demarcation between FT-A, FT-D, and FT-R services would not prevent NGTL from allocating costs to specific services or classes of customers within these service groups. The Board recognizes that no COSS perfectly assigns costs and agrees with Mr. Engbloom's submission that no one developing or using a COSS would claim those costs are exact, precise or "actual" in an absolute way. The question is whether the COSS would reflect reasonable assessments of cost causation. The Board considers that allocation of costs to various services and classes of customers should be based on the most reasonable assessment of cost causation.

In this case there appears to be little connection between NGTL's COSS and the proposed rate design beyond meter costs. This leaves NGTL's allocation of its transmission related costs to be based, in a general way, on the appropriateness of the DOH study as support for the fundamental NGTL rate design. The Board also recognizes that the COH methodology is used as a basis for specific receipt point rate derivation from the average FT-R rate.

NGTL, as the applicant, bears the onus of proving the costs to be paid by ratepayers are fair and reasonable. The Board agrees with ATCO that NGTL's 2004 COSS failed to meet the Board's expectations for a COSS in the 2004 GRA, as expressed at page 26 of Decision 2003-051:

> In summary, the Board believes that the 2004 GRA should provide the Board and interested parties a better opportunity to extensively examine all aspects of NGTL's revenue requirement and provide better information in order to facilitate a detailed COS analysis. The COS analysis will undoubtedly assist NGTL, parties, and the Board in the review of cost accountability and cost allocation, and provide information that should assist in review of competitive issues and rate design. As indicated, the Board expects NGTL to submit a comprehensive 2004 GRA by September 30, 2003, including matters addressed in this Decision.

The Board does not believe that NGTL has provided a transparent methodology with respect to the allocation of its costs (which include transmission and compression, as well as metering) to customer classes or services.

As a consequence, and as set out in more detail in Section 3 of this Decision, the Board will direct NGTL to file a 2005 Phase II GRA including a fully allocated COSS to support NGTL's cost allocation and rate design. The Board directs NGTL to include in the 2005 Phase II filing an updated DOH study, an updated COH study, and a detailed fully allocated COSS that includes the following:

[8] 1T157, lines 10-14.

- Functionalization of all costs including Compression, Transmission and Metering, and the allocation of all indirect costs such as General Plant, Working Capital Accounts, General and Administration
- Assignment and allocation of costs to all service classes (including FT-A, FT-R, FT-D, and FT-P)
- Assignment and allocation of costs (fixed and variable) among each firm service by contract demand, throughput or another justified allocator
- Assignment and allocation of income credits for non standard rates.

2.2 Distance of Haul Study

The purpose of the DOH study was to determine average distances of haul for transportation of gas on the Alberta System during the 2002 calendar year. NGTL filed its DOH study and also filed a COH study, as an alternative to the DOH methodology.

NGTL provided a DOH study which was revised from its prior DOH study methodologies, and stated that it eliminated simplifying assumptions, making the analysis more robust, more automated, simpler and less costly to produce. The Board considers that the revised DOH methodology provides a more accurate DOH calculation than NGTL's previous DOH study. The revised DOH study results for 2002 indicated that the average distance of haul for:

- intra-Alberta deliveries was 255.8 km;
- ex-Alberta deliveries was 569.4 km; and
- all deliveries (intra-Alberta and ex-Alberta) was 535.6 km.

The average intra-Alberta DOH was found to be 44.9% of the average DOH for ex-Alberta deliveries.

In Decision 2003-051, the Board directed NGTL to file an analysis and evaluation of three potential changes and one alternative to its DOH methodology. NGTL analyzed the following three potential changes to the existing DOH methodology discussed in its 2003 Tariff Application:

i. DOH for a subset (the mainline component) of the Alberta System using three definitions of mainline pipe as follows:

    - a functional definition;
    - a physical definition of 24 inches in diameter or greater; and
    - a physical definition of 12 inches in diameter or greater;

ii. calculating DOH for the entire system but with deliveries to extraction facilities excluded from the calculations; and

iii. calculating the DOH by satisfying the demand of the intra-Alberta deliveries before the export deliveries or vice versa.

The Board sees no evidence to suggest that any of the potential changes or alternatives analyzed by NGTL were definitively superior to NGTL's revised DOH study, nor were they preferred by NGTL or interested parties. Therefore the Board considers the revised DOH study utilized by NGTL is appropriate.

NGTL submitted that the DOH methodology was the essential starting point in its rate design under which it established the fundamental transmission component costs for, and the relationships between, firm receipt and delivery services. NGTL stated that the results of the revised DOH study confirmed the continued reasonableness of NGTL's fundamental allocation of costs between intra-Alberta and ex-Alberta services. NGTL set the transmission-related component of the average receipt rate equal to the transmission-related component of the export delivery rate.[9] NGTL argued that this apportionment recognized that both FT-R and FT-D services were equally required to transport gas destined for export markets, with the majority of gas received on the Alberta System moving to export markets.[10] This approach was consistent with rate designs used for the Alberta System since 1980.[11]

NGTL indicated that it considered the DOH methodology more appropriate at this time than the COH methodology, as DOH was supported by the stakeholders involved in the 2003 Tariff Settlement, which was approved by the Board in Decision 2003-051.[12] NGTL further submitted that the DOH methodology has been utilized by NGTL since 1989 and its continued use provides rate stability for Alberta customers whereas the use of the COH methodology could have significant distributional effects.

ATCO submitted that no rigorous DOH methodology was employed in NGTL's rate design. Rather, DOH was simply used to support, in a general way, NGTL's postage stamp 50/50 allocation of unit transmission costs between FT-R and FT-D services. ATCO noted that the postage stamp approach existed since 1980, prior to any DOH studies, and that the DOH studies were used only as reasonableness checks of the postage stamp approach[13].

The Board agrees with ATCO's submission that the DOH study is not the fundamental underpinning of NGTL's rate design, but acts as a reasonableness check of NGTL's 50/50 apportionment of transmissions costs between receipt and export delivery customers. This conclusion is supported by the fact that the DOH methodology has only been utilized by NGTL since 1989, while NGTL's current 50/50 apportionment of transmission costs has been used in rate design since 1980.

IGCAA argued that no parties disputed that the DOH was relevant to cost allocation on the NGTL system. IGCAA asserted that intra-Alberta gas consumers should have the benefit of relatively low gas transmission costs because of their proximity to the province's gas supply. IGCAA submitted that all NGTL transmission facilities must be considered as part of an integrated transmission system which should not be segregated into assets used for intra-Alberta service on the one hand and assets used for export service on the other. Just as in the past when intra-Alberta gas users have faced higher rates associated with building infrastructure for export service, in the future when more facilities are needed to provide intra-Alberta service, these assets must remain integrated general system assets allocated based on the DOH methodology. IGCAA suggested that if there is merit in the justification for applying the equal pro-ration assumption, NGTL cannot use the COH to allocate costs to intra-Alberta service.

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9 Exhibit No. 002-06(c), Application, section 2.3, page 15, ll. 15-16; Exhibit No. 002-07(a), response to BR-NGTL-5(a).

10 Exhibit No. 002-06(c), Application, section 2.3, page 15, ll. 18-21.

11 Exhibit No. 002-06(c), Application, section 2.3, page 15, ll. 18-21.

12 BR-NGTL-012(a)

13 NGTL Argument, page 12.

The CG, PG&E and TGI supported the current 50/50 revenue requirement split between receipt and delivery shippers based on NGTL's DOH study. The 50/50 split is based on an essential element of previous rate design principles, is simple to apply, and has been recognized by the Board in past decisions, most recently in the Products and Pricing Decision 2000-6, as reasonable and fair. However, the CG noted that, while DOH is the primary factor used to calculate the cost allocation for FT-R, FT-D and FT-P rates, there is no DOH cost allocation methodology inherent in the FT-A Rate, which is the rate primarily used for intra-Alberta deliveries. For the purpose of methodological consistency and rate fairness, the CG submitted that there should be elements of DOH cost allocation in the FT-A Rate.

The Board notes that it has historically accepted the DOH methodology as an appropriate verification of the average DOH ratio of ex-Alberta deliveries to intra-Alberta usage.[14] It has also accepted NGTL's use of a 2:1 ratio for rate setting purposes despite variations in the ratio from year to year.[15] In this context, the Board stated in Decision 2000-6:

> The Board therefore finds that using this distance as a proxy to set the intra-Alberta charge at 50 per cent of the ex-Alberta charge is reasonable. The Board considers this ratio as a proxy for rate setting and would not find it advisable, for rate stability reasons, for the cost allocation to vary on an annual basis to reflect the actual ratio as demonstrated by annual distance of haul study. The Board, therefore, concludes that the 2:1 ratio as a proxy for the cost allocation between intra- and ex-Alberta services remains appropriate.[16]

The Board is of the view that no evidence was presented by parties which undermined the continued utilization of NGTL's DOH based on the technical merits of the methodology, with most shippers in support of maintaining the DOH study.

For the 2004 test year, the Board is satisfied that the DOH methodology remains an appropriate cost allocation concept. The Board considers that any future determination on the appropriateness and applicability of NGTL's DOH should be weighed against a more detailed COSS that provides a higher standard of cost segregation than NGTL's current COSS.

The Board directs NGTL to file an updated version of its DOH study as a reasonableness check of NGTL's COSS in the 2005 Phase II GRA.

2.3 Cost of Haul Study

In compliance with Decision 2003-051, NGTL provided the COH study as an alternative methodology to its DOH study.

The COH study was done for the 2002 calendar year, with the primary objective being to indicate the relative cost of transporting gas between intra-Alberta and ex-Alberta deliveries. Distance was taken into account by tracking the flow of gas. Diameter was taken into account by applying a relative cost index against the length of each pipe diameter that was used to transport the gas.

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[14] EUB Decision U96055, page 48; and EUB Decision 2000-6, page 47.
[15] EUB Decision U96055, page 48.
[16] EUB Decision 2000-6, page 47.

NGTL analyzed a COH methodology as an alternative to the DOH methodology under the following scenarios:

i. for the entire system;
ii. for the mainline component of the Alberta System using three definitions of mainline pipe as follows:

- a functional definition;
- a physical definition of 24 inches in diameter or greater; and
- a physical definition of 12 inches in diameter or greater; and

iii. calculating the COH for the entire system but with deliveries to extraction facilities excluded from the calculations.

The Board considers that none of the COH alternatives were shown to be definitively superior, nor were they supported by NGTL or interested parties, over the COH study of the entire system. The Board therefore considers that the COH study of the entire system and the revised DOH study offer the most reasonable direct comparison of the two different methodologies.

The COH study results indicated that the average COH for intra-Alberta deliveries is 67.9% of the average COH for ex-Alberta deliveries. The intra-Alberta COH to ex-Alberta COH ratio was higher than the intra-Alberta DOH to ex-Alberta DOH ratio, which is 44.9%. This resulted from the fact that on average intra-Alberta deliveries utilize a higher percentage of smaller diameter, less cost efficient, pipe than ex-Alberta deliveries.

The CG agreed with NGTL that there is no need to adopt the COH methodology in place of the DOH methodology. The CG supported the longstanding principle of 50/50 sharing of costs between FT-R and FT-D rate classes and strongly submitted that a rate design based on that tenet should be preserved. If COH was adopted in the place of the DOH methodology, the CG argued that the FT-R rate would increase from $0.184/Mcf to $0.248/Mcf and the total intra-Alberta rate would increase from $0.202/Mcf to $0.266/Mcf. The CG also noted that the FT-D rate would decrease from $0.184/Mcf to $0.12/Mcf. The results would clearly distort the 50/50 sharing principle between FT-R and FT-D and unfairly increase the total intra-Alberta rate.

NGTL and IGCAA both indicated that if NGTL were to use a COH methodology to allocate costs between intra and ex-Alberta services, then the economies of scale realized through the use of large diameter pipe would not be appropriately shared between all customers. Instead, most of the benefits of the lower unit costs facilities would end up being allocated to ex-Alberta service. IGCAA indicated that it was impossible to justify the application of COH in circumstances where DOH is calculated using the equal pro-ration assumption.

IGCAA submitted that application of the COH methodology is entirely inconsistent with promoting the use of least cost alternative pipeline capacity and preventing pipeline proliferation. IGCAA also noted that Mr. Engbloom explained in 1999 and again in this proceeding that COH leads to distortions and unfairness in rates.[17]

ATCO disagreed with these assertions. ATCO submitted that NGTL's economies of scale were first and foremost realized in its revenue requirement. ATCO argued that the issue that IGCAA

[17] IGCAA Argument, page 6.

raised is whether DOH or COH factors better allocate the benefits of NGTL's economies of scale among the different services it offers, which is an issue for a COSS to examine.

ATCO argued that IGCAA's submission, that no one understood exactly how COH worked and those with the greatest knowledge conceded that it was subject to far more variability than the DOH methodology, was unfounded[18]. ATCO submitted that the COH methodology was presented, tested, opposed and approved in the 1999 Products and Pricing proceeding. Since 1999, it has been used to set specific receipt point rates for FT-R service. Those rates generate over $500 million in annual revenue from FT-R shippers, more than any other shipper class of service.[19] Even though CAPP, which has many members with FT-R service, and EnCana and BP, which have large FT-R positions, were active in this proceeding, they did not state any misunderstanding with the COH methodology or that it was subject to controversy.

The Board notes that the COH methodology was accepted by the Board as an appropriate method for determining receipt-point specific rates in Decision 2000-6. Specifically, it stated:

> NGTL's proposed receipt point specific rates appropriately account for the significant cost factors of pipeline distance and diameter. The Board considers the NGTL approach in using distance and diameter as a proxy for costs actually incurred by customers using the facilities to be reasonable.[20]

The Board notes that NGTL's witness, Mr. Johnston, in 1999 indicated that using the diameter-distance COH methodology better reflects costs to intra-Alberta shippers because the advantage those shippers have with shorter distances may be more than offset by higher costs of smaller diameter pipe.[21] However, the Board is concerned that utilization of the COH methodology may not appropriately allocate the benefits of the economies of scale of the NGTL system to all customers. In addition, the Board is uncertain whether application of the COH methodology would be consistent with promoting the use of least cost alternative pipeline capacity. Before applying the COH methodology to NGTL's rate design, the Board believes that more extensive evidence would be required, given that most shippers continue to support the DOH methodology. The Board also considers that adopting the COH methodology could possibly lead to rate shock for intra-Alberta customers.

The Board is generally supportive of the technical merits of NGTL's COH study, but has some reservations regarding the impact of the Economic Life Index on the results of the COH study. The Board is also concerned about potential variability associated with the COH methodology, and notes that NGTL and ATCO did not agree as to this point. NGTL suggested that, while the results of the COH study were not inaccurate, there was some uncertainty as to the possible variability associated with the COH methodology, while ATCO disagreed and argued that the variability in the intra- to ex-Alberta factors for the DOH study exceeded those for the COH study.[22]

The Board is of the view that, while the COH study offers an alternative to NGTL's DOH methodology, it has not been established as definitively superior or more reasonable for

[18] IGCAA Argument, paragraph 16, page 7.
[19] Application: Figure 5.1-1.
[20] EUB Decision 2000-6, page 47.
[21] 2T299, line 10 to 2T300, line 22.
[22] 6T1096, lines 2 to 25.

allocating costs, nor is it supported by the majority of shippers as a primary methodology. The majority of NGTL shippers continue to support NGTL's DOH methodology, with only ATCO recommending the utilization of NGTL's COH methodology.

The Board therefore considers it appropriate to use the DOH study as a primary rate design methodology at this time, with the COH study acting as an alternative mechanism for comparison purposes, as well as a proxy for costs for receipt point specific rates.

The Board directs NGTL to file in the 2005 Phase II GRA an updated revised COH study to allow parties to examine the results of the COH study as compared to the DOH study. The Board expects NGTL's update to include any extensions or expansions that may impact the results of the studies (for example the Simmons Pipeline).

3 COST ALLOCATION AND RATE DESIGN

The Board considers that cost allocation and rate design are major issues for consideration in this proceeding. By their very nature these issues incorporate many of the other matters addressed by all parties. In this section the Board will provide direction on cost allocation and rate design with reference to the COS studies and cost accountability issues which are specifically dealt with in other sections of this Decision.

3.1 Cost Allocation

As the Board has indicated, typically the Board's starting point in determining rates is a COSS, which ordinarily would analyze the costs of providing regulated services, categorize or functionalize these costs and then determine an appropriate set of methodologies for the allocation of these costs. COSS methodologies and related issues are addressed more fully in Section 2 of this Decision.

The Board notes that proper allocation of costs to regulated services has been an issue for several years in relation to NGTL's rate design. The following extracts from Board decisions indicate that cost allocation among NGTL services, and in recent years, cost allocation to intra-Alberta delivery service in particular, have been of concern.

In Decision 2002-16, in respect of NGTL's application for Fort McMurray Service via a TBO with TransCanada Ventures, the Board stated:

> Above all, the Board believes that the desire to satisfy the need for service by a rapidly growing industrial activity in the province has to be balanced with the desire to foster competition, by providing the right market signal and transparency in pricing of the service provided. The Board is therefore prepared to approve the proposed TBO arrangements, but is only prepared to approve the inclusion of their costs over the term of the Settlement. The Board expects that either an agreement will be submitted regarding proper cost allocation among receipts, intra-Alberta and ex-Alberta deliveries, or an application will be filed with the Board for its consideration on or prior to expiration of the Settlement on December 31, 2002. Should NGTL wish to provide additional intra-Alberta delivery service prior to the establishment of a new intra-Alberta rate design, the

> Board believes that the issue of measures to ensure full accountability for the arrangements or facilities contemplated, would have to be addressed.[23]

In Decision 2003-051, in respect of NGTL's 2003 Tariff Settlement application, the Board stated:

> The Board notes NGTL's claim that the proposed rate design and service changes were well supported on the merits by the evidence, such as the COS Study, and the analysis provided in the Tariff Settlement. As noted earlier, the Board believes that NGTL has fallen short of the standards set out in the Guidelines as to sufficiency of evidence to be provided. For example, the Board sees little connection between the results of the two COS studies and the proposed rate design. In fact, very little information was used from the COS Studies as support for the proposed changes in the Tariff Application.[24]
>
> …The Board notes ATCO Pipelines' concern that the Board's directions on cost accountability and cost allocation were not addressed in the Tariff Settlement. As noted earlier, the Board believes some progress has been made through the Tariff Settlement and expects further changes to be made after the 2004 NGTL GRA proceeding.[25]
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> …In moving toward full cost allocation and a possible rate design shift away from NGTL's current DOH methodology, the Board believes that it would make sense that pipelines and metering facilities clearly related to intra-Alberta delivery service should be recovered through the FT-A toll. The Board does not see any benefit to arbitrarily assigning pipeline costs to the FT-A until various COS studies are tested. Therefore the Board directs NGTL to address this issue in its 2004 GRA filing.[26]

As noted in Section 2.1 of this Decision, the Board does not believe that NGTL has provided a transparent methodology with respect to the allocation of its costs (which include transmission and compression, as well as metering) to customer classes or services. The Board therefore directed that a fully allocated COSS be provided in the next Phase II GRA, which the Board is directing to occur in 2005. For purposes of this Decision, the Board accepts that that the DOH study directionally supports the current 50/50 allocation of costs between FT-R and FT-D services. However, as indicated in Section 2.2 of this Decision, the average intra-Alberta DOH was found to be 44.9% of the average DOH for ex-Alberta deliveries. The Board believes that this is an updated allocation that should be considered as a basis for future NGTL rate design, as discussed in Section 3.3.5.

3.2 Rate Design Criteria

As discussed in Section 1.2, a Phase II decision will consider and determine how to apply the appropriate rate design criteria for the determination of just and reasonable rates to collect the utility's approved revenue requirement, determine the rates for the proposed services and establish the appropriate terms and conditions for these services.

23 Decision 2002-16 pg. 21
24 Decision 2003-051 pg. 28
25 Decision 2003-051 pg. 33
26 Decision 2003-051 pg. 34

The EUB, from time to time, has considered Professor Bonbright's criteria for structuring rates. Dr. Gaske's summary[27] of Bonbright's criteria is consistent with the Board's comments in Decision U96055[28] on these criteria:

> The Board agrees with parties that the basic attributes of an appropriate rate design include simplicity, understandability and public acceptability; freedom from controversy; effectiveness in achieving revenue sufficiency and in providing revenue and rate stability; fairness in the apportionment of total costs and avoidance of undue discrimination; and the encouragement of efficiency. The weight to be given to each of these characteristics will depend largely on the desired balance between various goals, objectives and interests. The Board does not believe that there exists a rate design which will accommodate all interests and satisfy each and every individual shipper.

The Board has recognized in past decisions the need to strike a balance in order to meet the interests of all stakeholders, and that the circumstances for each application are different from other applications.

With respect to this Application, the Board believes that, owing to the lack of transparent COS analysis in this case, it is somewhat difficult to proceed with traditional steps in the rate design process, which typically commences with the COSS, allocates costs to various services and then addresses rate design, often with reference to revenue to cost ratios and other fairness criteria.

Further, the Board recognizes Dr. Gaske's submission that NGTL's rate design is somewhat unique:[29]

> In my estimation, the basic cost apportionment framework that emerged from NGTL's Products and Pricing Proceeding, refined further by the collaborative process and settlement-derived changes thereto that followed, constitutes a workable, reasonable framework of fully allocated cost distribution. NGTL is not the typical North American pipeline company. NGTL has an atypical functional and contractual separation of receipt and delivery functions. NGTL has a unique menu of services built around that unique functional and contractual separation. NGTL differs fundamentally from AP, as explained herein and elsewhere in the NGTL evidence. These foregoing unique features for NGTL have allowed the NIT mechanism to grow and flourish. The nature and dimensions of this arrangement is unique in North America.
>
> In this very specific historical context, a commensurately unique cost apportionment and ratemaking framework for NGTL has arisen.

The Board notes that major shippers on the Alberta System support the rate design approach taken by NGTL. Others have cautioned that, while intra-Alberta cost accountability could be improved, NGTL rates are inter-related and alterations should only be made in the rate design

[27] Prepared Rebuttal Testimony of J. Stephen Gaske on Behalf of Nova Gas Transmission Limited submitted May 21, 2004 pages 7-8.

[28] Decision U96055 NOVA Gas Transmission Ltd. 1995 General Rate Application - Phase II dated June 12, 1996 at page 24.

[29] Prepared Rebuttal Testimony of J. Stephen Gaske on Behalf of Nova Gas Transmission Limited submitted May 21, 2004, page 15.

after extensive consultation, as has been undertaken with major shifts in rate methodology in the past. This consultative process was supported by several parties.[30]

3.3 Rate Design in Present Case

In considering an appropriate rate design for NGTL for 2004, the Board has had regard for the typical overall rate design criteria as referenced above, while considering a number of different rate design options. In particular, ATCO and the CG brought forward specific proposals which would alter the NGTL intra-Alberta delivery rates. The Board also considered other options and potential modifications to NGTL's current rates, which will be addressed below.

The rate design options considered by the Board can be described in the following list:

1. NGTL Rate Design
2. ATCO Proposal
3. Consumer Group Proposal
4. Allocation of Alberta Delivery Meters to FT-A
5. Other Potential Modifications to NGTL Rate Design

The Board will discuss each of these rate design options in turn.

3.3.1 NGTL Rate Design

NGTL submitted that the proposed 2004 final rates, tolls and charges for services were based on the rate design methodology approved by the Board in Decision 2003-051, to which NGTL did not propose any rate design changes. NGTL noted that the Board had previously recognized the integrated nature of the Alberta System and its influence on the determination of an appropriate rate design.[31] NGTL also claimed that the existing rate design was fair and reasonable on its own merits.

NGTL further submitted that changes to its rates and services implemented, based on the 2003 Tariff Settlement (Decision 2003-051) had increased customer cost accountability and price transparency for its services, while preserving and reflecting the unique attributes and benefits of the Alberta System that are valued by its customers.[32] NGTL submitted that significant weight should be given to the continued stakeholder support for the 2003 Tariff Settlement and the associated rate design. However, NGTL also acknowledged the Board's continued concern about cost allocation matters for intra-Alberta delivery service expressed in Decision 2003-051.[33]

NGTL stated that it was important to recognize that FT-A service does not exist as a service by itself; rather it is an integral and inseparable part of a combined FT-R and FT-A service model.[34] Accordingly, NGTL claimed that costs are not allocable to FT-A service on a stand-alone basis.[35]

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[30] EnCana Argument page 1; BP Energy Canada Argument page13 and Argument of Imperial Oil Resources pages 1-2.

[31] The predecessor of the EUB, the PUB, cited the integration of the system as one reason for its determination in Report E78100 that postage stamp rates were an acceptable alternative. The EUB affirmed this attribute in Decision U96055 at page 37.

[32] Exhibit No. 002-06(c), Application, section 2.0, page 1, section 2.4, page 24, and section 2.8, page 55.

[33] EUB Decision 2003-051, page 34.

[34] T88, ll. 17-25; and see also T94, ll. 9-16.

[35] T213, ll. 1-3.

As a result NGTL had designed the FT-R rate to recover all the transportation costs associated with delivering gas to the doorstep of intra-Alberta delivery stations.[36] This maintained the split of transmission costs between intra-Alberta and export deliveries, as corroborated by NGTL's revised DOH methodology. This allocation also enabled FT-R service holders to access all intra-Alberta delivery markets, and in a corollary sense, it enabled FT-A service holders to access supplies from the entire Alberta System.[37]

The Board notes the ATCO submission that conventions, rather than cost-based rates, were used to establish rates for firm services, in particular extraction and intra-Alberta deliveries under the FT-A rate. ATCO specifically pointed to the continued allocation of transmission costs between receipt and ex-Alberta delivery services on the assumption of a 50/50 split defended using a DOH Study that calculates an actual intra-Alberta to ex-Alberta percentage of 44.9%[38]. Further, the detailed data on metering costs for intra-Alberta delivery service was significantly higher than the average metering cost used to determine the intra-Alberta rate of 1.8 cents/Mcf.[39] As well, ATCO noted NGTL's unwillingness to make any assumptions or judgments relating to a reasonable allocation of transmission costs in a COSS and subsequent rate design.

ATCO further submitted that the use of an overly low FT-A rate and inadequate cost accountability harms customers of other pipelines and customers of NGTL. The need to compete with an overly low FT-A toll results in other pipelines, particularly ATCO, offering to selected customers low competitive rates that do not recover their fully allocated costs. Those un-recovered costs are placed onto the shoulders of other customers. In the end, all rates are inefficient – the below-cost competitive rate and the above-cost other rates.[40] ATCO submitted that an overly low FT-A toll encourages demand for such service, and, as is apparent from NGTL's first Fort Saskatchewan application and Phase I of its 2004 Application, major costs of dedicated or joint-use facilities are being incurred to serve that demand. Getting the rate and cost accountability of such service correct is fundamental to sound resource allocation in competitive markets and a regulated environment.[41]

ATCO also recommended that the Board only approve the applied-for FT-P toll until NGTL's next GRA, at which time, if a COSS is available, a short-haul toll based on a COSS can be examined and a relationship between allocated costs and toll design can be achieved.

The CG submitted that NGTL had not been responsive to the clear Board direction first identified in Decision 2000-6[42] and reinforced in Decision 2003-051[43] wherein the Board desired an intra-Alberta rate structure that would be more transparent with respect to costs. The CG also agreed in principle with ATCO with regard to the need for more transparent identification of intra-Alberta transmission costs in the FT-A rate.

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36 T233, ll. 9-14; and see also T245, ll. 20-23.
37 T274, ll. 4-8.
38 Application: Section 2, Table 2.3-2, page 17.
39 Application: Section 2, Table 2.7-4, page 52.
40 6T1042, line 7 to 6T1043, line 3.
41 6T1026, line 1 to 1T1030, line 10.
42 Section 3, page 50 where the Board states: "The Board is, however, also of the view that NGTL should continue to endeavour to eliminate this misconception and to ensure that Alberta services are priced in a manner that is both cost reflective and perceived to be cost reflective."
43 Section 6.3, pages 30 and 31.

Devon argued that without changes to NGTL's FT-A rate and cost accountability, the market will continue to receive improper price signals. It noted that NGTL had not taken any further steps with respect to its FT-A toll methodology or its accountability provisions despite clear indication from the Board in various decisions.

BP Canada, IGCAA, CAPP, Syncrude, Rate 13 Group, EnCana, PG&E, TGI and Imperial Resources all supported NGTL in retaining the existing cost allocation and rate design methodologies. These parties considered that the existing rate design was developed with customer consultation representing a balance of stakeholder interests, and that the other mechanisms in the 2003 Tariff Settlement adequately address the cost accountability issues. These parties also raised concerns about the potential impacts to Alberta businesses and consumers of any changes to the NGTL rate design.

3.3.2 ATCO Proposal

ATCO submitted that without a more transparent price signal that included reasonable transmission costs, and without reasonable cost accountability, FT-A service requests would be made based on an overly low FT-A rate and soft cost accountability. As a result, ATCO proposed an alternative FT-A rate design, based on a COH methodology, and recommended a postage stamp, commodity FT-A rate of 8 cents/Mcf.[44] This was based on its submission that intra-Alberta deliveries use more smaller diameter pipe than export deliveries and the NGTL COH Study[45] demonstrated that smaller diameter pipe has a higher per unit cost. The result was that intra-Alberta deliveries entailed higher per unit costs than did export deliveries.

ATCO claimed that under its proposal, the FT-A rate would recover the additional cost and there would be no requirement for a penny-for-penny offset. The proposed 8 cents/Mcf FT-A rate would reduce the FT-D rate, which is the only rate that affects NIT prices according to IGCAA[46], by 0.4 cents/Mcf. ATCO claimed that this amount would not affect the NIT price.[47]

NGTL disagreed with the ATCO proposal stating that it was fundamentally flawed on a number of grounds, including the following:

- Improper and Unfair Allocation of Transmission Costs – The ATCO proposed FT-A rate resulted in transmission charges for intra-Alberta customers that are too high overall, and also too high at the margin.[48] As well, the ATCO proposal ignored the fundamental relationships between receipt and delivery services supported by the DOH study.

- An Arbitrary Rate Derived from Inconsistent Methodologies – ATCO's proposed FT-A rate was based on neither of the two methodologies provided by Confer Consulting Ltd. (Confer) which produced rates of 7.7 cents/Mcf and 9.7 cents/Mcf.[49] ATCO arbitrarily set the rate at 8 cents/Mcf. These two methodologies inappropriately mixed concepts that are inconsistent with each other, and that are inconsistent with other analyses and views expressed by Confer and ATCO.

[44] Exhibit No. 007-04, Evidence of ATCO Pipelines and Exhibit No. 007-05, Evidence of Confer Consulting Ltd.
[45] NGTL Application, Section 2, Table 2.5.2-3, page 38.
[46] IGCAA Evidence, page 7, lines 14-18.
[47] IGCAA-Confer 9(b).
[48] Exhibit No. 002-14, NGTL Rebuttal Evidence, pages 25-26; and Prepared Rebuttal Testimony of J. Stephen Gaske, page 34, ll. 7-10.
[49] Exhibit No. 007-05, Evidence of Confer Consulting, Appendix B.

- Failure to Consider the Overall Rate Design – ATCO had failed to look at the Alberta System as a whole and recognize and account for the integration of NGTL's services.

- ATCO's Self-Interest – The ATCO FT-A rate proposal was significantly influenced by its competitive self-interest, to the exclusion of the interests of its customers, NGTL's customers, and the public interest generally. ATCO is one of the largest FT-A customers on the Alberta System and would be responsible for a significant portion of the overall increase in FT-A revenues if its proposal were adopted, but as a connecting pipeline to the Alberta System, ATCO would pass these costs through to its own customers. Specifically, its distributing customers, who are captive to its system, would take the brunt of the impact.

  Presently, the average full-path toll on the Alberta System is approximately 4 to 7 cents/Mcf higher than the full-path toll for industrial and distribution companies on ATCO's systems.[50] Under ATCO's FT-A rate proposal, it would increase this existing advantage by an additional 6 cents/Mcf, resulting in a total toll advantage of 10 to 13 cents/Mcf over the alternative services available from NGTL.[51]

The CG, BP, IGCAA, CAPP, Syncrude, Rate 13 Group and Imperial Resources all opposed the ATCO proposal for some of the same reasons put forward by NGTL as well as the concern that there was no agreement among customers. They further submitted that the competitive issues should be addressed in the Competitive Proceeding the Board has planned.

The Board agrees with many of the concerns raised by parties with regard to the ATCO proposal. The proposal did not adequately consider the integrated nature of the NGTL rate design. As well, as discussed in Section 2.3 of this Decision, the Board is concerned about use of the COH for other than the previously approved receipt point specific pricing.

3.3.3 Consumer Group Proposal

The CG accepted the 50/50 allocation basis between receipts and ex-Alberta deliveries, and proposed that NGTL apply the DOH methodology to produce specific delivery point rates for intra-Alberta delivery points (including those served under FT-X service) that would vary from a fraction of a cent/Mcf in some areas of the province to the full transmission cost. The CG submitted that in aggregate, NGTL would then be recovering explicitly from intra-Alberta customers through the FT-A rate the same amount of transmission revenue requirement that it now recovers through the explicit FT-R rates. The CG's proposal provided further that, to avoid double recovery by NGTL of the revenue requirement related to the transmission component of the intra-Alberta delivery service, NGTL would then need to remove, from the revenue recovered under the FT-R rate, the same amount of revenue recovered by NGTL under the transmission component of the FT-A rate. The CG proposed that NGTL would do this by applying a revenue credit equal to the average transmission component of the receipt charge which would be 16.7 cents/Mcf.

The CG submitted that it would be reasonable to apply a floor (4.7 cents/Mcf) and ceiling (28.7 cents/Mcf) for the transmission component of the FT-A rate based on the present average cost of

[50] Exhibit No. 002-14, NGTL Rebuttal Evidence, pages 16-17, Table 3.0-1.
[51] Exhibit No. 002-14, NGTL Rebuttal Evidence, pages 16-17, Table 3.0-1.

16.7 cents/Mcf. The CG proposed that the transmission component would be charged on a commodity basis as is presently the case with the metering component of the FT-A toll.

The Board notes NGTL's arguments that the CG proposal would, if adopted, create inefficient price signals for FT-A service.[52] This was supported by Dr. Gaske's explanation that the CG proposal would provide incentives that would be highly inefficient and destructive,[53] the result of significant variability where shippers rates would vary between negative charges and significantly increased positive charges at various intra-Alberta delivery points. Rate shock, due to significant redistribution of costs among existing FT-A service holders, was another undesirable potential result of the proposal. Parties could adjust their loads to minimize commitments at points where there would be a higher cost for the service or might also construct facilities to bypass points with ceiling rates and connect to points with floor rates. NGTL also noted that shifting fixed transmission charges from a demand rate to a commodity charge was not appropriate. NGTL also indicated that the net benefit to the Utility class of customers was not significant and in the end had little positive impact on the parties the CG represents.[54]

No other party indicated support for the CG proposal. The Board agrees with NGTL that the CG proposal would increase variability and introduce complexity, which could lead to volatility on the system. Based on these concerns the Board has determined that adoption of the CG proposal would not provide an efficient solution to increase cost accountability for transmission costs for the FT-A rate.

3.3.4 Allocation of Alberta Delivery Meters to FT-A

The Board notes that the metering costs associated specifically with the FT-A rate were stated to be 6.78 cents/Mcf based on NGTL's COSS study.[55] This contrasts with the overall system average metering costs of 1.8 cents/Mcf, which is currently reflected in the FT-A rate.[56] Although it appears a fairly evident possibility as a foundation for an adjustment to the design of the FT-A rate, no party proposed or supported increasing the FT-A rate to 6.78 cents/Mcf in this proceeding to reflect specific cost accountability for meters for intra-Alberta delivery customers, nor was this option developed through consultation with NGTL's established collaborative process.

The Board would not propose to implement an option of this kind based on NGTL's submissions that there was a large variability in the costs of metering facilities among various customer groups.[57] In addition, no customers expressed support for having their services explicitly account for specific metering costs.

3.3.5 Other Potential Modifications to NGTL Rate Design

The Board reviewed an option that the current NGTL rate design could potentially be modified to reflect the current DOH study in the allocation of costs for determination of the intra-Alberta and ex-Alberta rates. This would require roughly 45% of the transmission costs to be allocated to intra-Alberta service (FT-R plus FT-A rates) and 55% of the transmission costs to be allocated to

52 T430 ll. 9-16.
53 Exhibit No. 002-14, Prepared Rebuttal Testimony of J. Stephen Gaske, page 39, ll. 5-22.
54 Exhibit No. 40-12, page 4.
55 Exhibit No. 002-06(c) Revised Evidence page 53 of 55 Table 2.7-5
56 Exhibit No. 002-06(c) Revised Evidence pages 9 and 18-19 of 55
57 Exhibit No. 002-06(c) Revised Evidence pages 53 of 55

the FT-D rate. This option should essentially preserve the full path rate. The Board considers, based on the view of NIT pricing advanced by IGCAA and others, that the increase in the FT-D rate would result in a corresponding decrease in the NIT price.

Further, the Board is of the view that it would be appropriate to increase the FT-A rate in order to provide for some recovery of intra-Alberta transmission costs in addition to the proposed 1.8 cents/Mcf for metering. The Board recognizes that given the integrated nature of NGTL's rate design, the increased FT-A rate and revenue would necessitate some adjustment to the FT-R rate, which the Board anticipates could be fairly minor given the respective volumes involved with FT-A and FT-R services. These adjustments would aim to maintain the intra-Alberta cost at 45% of the ex-Alberta cost as supported by the latest DOH study, and at the same time essentially preserve the full path rate.

With respect to the current record, the proposals for transmission costs to be included in the FT-A rate range from zero (NGTL) to 8 cents/Mcf (ATCO). The Board considers that the addition to the FT-A toll of an amount that is close to the midpoint between these two proposals may represent a reasonable approximation of intra-Alberta transmission costs, with this charge to be possibly further refined by reference to more detailed COS information in future.

The Board wishes to raise with all parties for consideration this potential future modification to NGTL's rate design, which the Board believes may increase cost accountability for intra-Alberta delivery services in the future and would reflect the results of the DOH methodology, which appears to be favoured by most parties.

3.4 2004 Rate Design

As indicated in prior years and decisions, the Board believes it should address what appear to be deficiencies in cost accountability in rates as designed by NGTL. However, the Board considers that the lack of transparent COS information, as discussed earlier, together with the desire to ensure the Board and parties understand the implications of shifts in NGTL's rate design, constrain any fundamental alterations in rate design at this time.

Accordingly, for the 2004 year, the Board will approve NGTL's applied for rate design. As discussed earlier in this Decision, this methodology uses a 50/50 allocation of costs between receipt and delivery rates and utilizes the COH Study to determine receipt point specific rates.

As indicated in Section 3.3.5, the Board considers it important that parties consider any proposed shift in rate design and comment on it prior to any determination by the Board that it be implemented. The Board wishes to ensure that it understands the potential impacts of a rate design change, such as economic bypass for example, prior to making such a change. Further, the Board does not wish to assign pipeline costs to the FT-A service until parties have had an opportunity to examine more transparent COS information, as and when provided, or have had an opportunity to address the impacts of potential changes such as those suggested by the Board in Section 3.3.5.

Therefore the Board directs NGTL to submit a Phase II application for 2005 on or before April 1, 2005. In this application, which will include a COSS as directed in Section 2.1, the Board further directs NGTL to address a reasonable allocation of transmission costs greater than zero to the FT-A rate and other relevant changes as set out in Section 3.3.5, as one option for NGTL's rate design for consideration by the Board.

The Board recognizes, as indicated in Decision 2003-051[58], that strong differing views of parties would likely make it challenging to successfully resolve the cost accountability for intra-Alberta transmission costs and rates collaboratively. The Board considers that NGTL may want to address 2005 rate design issues with parties within the setting of a technical meeting prior to or contemporaneously with the filing of its 2005 Phase II application or related processes. In any event, the Board considers that parties should address an appropriate allocation of transmission costs to FT-A service within the context of the integrated design of the FT-A, FT-R and FT-D rates, and in particular the Board would encourage parties to provide their views as to the potential changes to NGTL's rate structure as suggested by the Board in Section 3.3.5 of this Decision.

At this time, the Board considers that these suggested modifications represent a reasoned potential approach given the evidence at hand. In the absence of practical alternatives to the Board's proposal, the Board would likely see it as a sensible direction to take in the development of NGTL's rate design for 2005 and beyond, unless persuaded that there are *bona fide* reasons to choose a different option. The Board anticipates that submissions of parties to the 2005 rate design proceeding would be based on evidence of potential impacts.

4 COST ACCOUNTABILITY

Cost accountability on NGTL's Alberta system has been an issue since NGTL's 1995 GRA. Since that time the Board has considered various aspects of cost accountability in the 1999 Products and Pricing Proceeding as well as the Fort McMurray proceeding[59] and the Fort Saskatchewan proceeding.[60] In the NGTL 2003 Tariff Application, NGTL proposed cost accountability for intra-Alberta delivery extensions through the Extension Annual Volume (EAV) provisions. The Board, in the resulting Decision 2003-051, recognized the importance of cost accountability in rate design[61], and directed NGTL to provide a detailed COSS in its 2004 GRA to allow for a satisfactory review of cost accountability issues.[62]

In its review of cost accountability on the NGTL system, the Board recognizes the overlapping nature of cost accountability with LCA policy, COS analyses, cost allocation and rate design. The Board has addressed these issues in more detail in other sections of this Decision.

NGTL submitted that current cost accountability measures for the Alberta System are adequate and are acceptable to the majority of its stakeholders.[63] NGTL's view is that the current measures ensure that its facilities are used and useful and that an appropriate contribution is made to the Alberta System revenue requirement.

NGTL submitted that customer accountability was first determined through the Facility Liaison Committee's Guidelines for New Facilities (the Guidelines). The Guidelines address what new facilities NGTL may construct. NGTL noted that cost accountability for new facilities is also

58 Decision 2003-051, page 30
59 Decision 2002-16, page 16
60 Decision 2002-058
61 Decision 2003-051, page 27
62 Decision 2003-051, page 35
63 Exhibit No. 002-07(c), response to ATCO-NGTL-39(b).

ensured through NGTL's determinations of how best to provide service (i.e., the LCA and optimal tie-in point analyses), and an economic viability review.[64]

NGTL submitted that customer accountability was then determined for specific facilities through requirements such as primary and secondary term obligations for receipt service, a minimum term obligation for export delivery service, the Minimum Annual Volume (MAV) and EAV obligations for intra-Alberta delivery service, and contributions in aid of construction.[65]

The Board notes the submission of NGTL that it has taken a number of steps over the past few years to increase customer cost accountability on its system in response to concerns raised by the Board and other parties.[66] Most recently, in October 2003, NGTL noted that it had increased cost accountability for intra-Alberta delivery facilities by increasing the MAV threshold for metering and related facilities, introducing an EAV obligation for mainline extension facilities, and introducing FT-P service.[67]

The Board also notes that BP, IGCCA and Imperial Resources generally support the view of NGTL that cost accountability has increased for intra-Alberta service through the changes made to the EAV and MAV mechanisms as they are applied to Facility Connection Service (FCS) contracts. The Board also notes BP's suggestion that the FT-P and FT-A rates and the new levels for MAV and EAV went a long way toward addressing the accountability concerns of the Board.

NGTL submitted that the MAV commitment applies to metering and associated connecting facilities that are constructed for the delivery of gas to locations in Alberta, including intra-Alberta delivery points, storage facilities and extraction facilities.[68] For each such facility, an Annual Cost of Service (ACS) is calculated, which includes operating costs, maintenance costs, municipal taxes, depreciation, income taxes, and return on rate base.[69] The MAV is then calculated based on the ACS to establish a threshold level that is used to determine if the particular facility has been sufficiently utilized to recover costs. Should the MAV or greater volumes not have been delivered to the facility by the end of the year, the customer must pay an FCS charge to cover the portion of the ACS not recovered. As well, when facilities subject to an MAV obligation are retired, the customer must reimburse NGTL for the remaining net book value, if any, of the facilities.

In calculating the MAV, NGTL submitted that it takes into account both direct revenues generated through FT-A service and indirect revenues generated through FT-R service. The underlying assumption is that the volumes necessary to satisfy the MAV will usually be transported by way of FT-R and FT-A services. NGTL noted that if FT-P service was used in addition to the combination of FT-R and FT-A services, direct accountability for the facilities would be increased, because more revenue would be collected directly from the customers who specifically contract for service utilizing those facilities.

64 Exhibit No. 002-14, NGTL Rebuttal Evidence, page 27, ll. 1-8.
65 Exhibit No. 002-14, NGTL Rebuttal Evidence, page 37, ll. 1-8; Exhibit No. 040-02, NGTL Tariff, Rate Schedule FCS, Attachment 1.
66 Exhibit No. 002-06(c), Application, section 2.2, pages 5-6.
67 These changes were implemented on October 1, 2003, in accordance with EUB Decision 2003-51.
68 Exhibit No. 002-06(c), section 2.2, page 6, ll. 10-12.
69 Exhibit No. 002-06(c), section 2.6, page 49, ll. 3-7.

NGTL stated that the EAV commitment applies to mainline extensions associated with intra-Alberta deliveries.[70] For each such facility, customers must commit to flow either a minimum volume of 36.5 Bcf per year for a minimum term of three years, or 109.5 Bcf spread over five years, with a volume commitment of 36.5 Bcf in at least one of those years.[71] This minimum volume requirement is met based on the aggregate of all customer deliveries associated with the intra-Alberta extension facilities in question. NGTL noted in some cases, such as when the customer requests a facility that is larger than what NGTL has determined is the optimal design, the EAV may be set above the minimum EAV amount.[72] NGTL stated that should the EAV threshold not be met in any year, then the customer will be required to pay an FCS charge to account for costs associated with the extension facility.[73]

NGTL submitted that the FCS charge is based upon indirect revenues that would be generated from FT-R service if the required volumes were transported. As with the MAV calculation, the FCS calculation is based on the assumption that transmission service is provided through the combination of FT-R and FT-A services, although transmission could also be provided through FT-P service.

NGTL argued that accountability provisions for intra-Alberta delivery services are also appropriately aligned with the accountability provisions for receipt services. Both the primary term obligation for FT-R service, and the MAV commitment for intra-Alberta delivery service, account for the full cost of service of metering and associated facilities.[74] Similarly, the EAV commitment for intra-Alberta delivery extensions is consistent with the customer commitment for mainline receipt extension facilities, as both require a minimum three-year, 100 MMcf/d commitment.[75]

In regard to the MAV provision, ATCO noted that the minimum required annual volume is established by dividing the ACS by two times the FT-A rate. ATCO argued that, as a result of using the two times factor, if the shipper delivers the MAV only 50% of the ACS will be recovered[76]. ATCO suggested that when a delivery customer flows volumes between 1% and 199% of the MAV, NGTL will not recover the entire ACS.[77] ATCO proposed that the MAV be calculated without using the two times factor by dividing the ACS by the FT-A rate, not two times the FT-A rate.

ATCO also submitted that NGTL's accountability requirements for pipeline extensions hinge on its mainline/lateral determination, which, in turn, is affected by the four criteria in the Guidelines.[78] ATCO submitted that of the four Guidelines criteria, NGTL requires that any two or any three be satisfied in order to allow NGTL to construct.[79] ATCO argued that each criterion

70 Exhibit No. 002-06(c), Application, section 2.2, page 6, ll. 12-14.
71 Exhibit No. 040-02, NGTL Tariff, Rate Schedule FCS, Attachment 1, section 3.5.
72 T409, ll. 21-23 and T410, ll. 6-9; Exhibit No. 002-14, NGTL Rebuttal Evidence, page 42, ll. 6-8.
73 Exhibit No. 040-02, NGTL Tariff, Rate Schedule FCS, Attachment 1, sections 2.6 and 3.7.
74 Exhibit No. 040-02, NGTL Tariff, Appendix E; Exhibit No. 002-14, NGTL Rebuttal Evidence, page 39, ll. 8-11.
75 Exhibit No. 002-14, NGTL Rebuttal Evidence, page 39, ll. 13-22.
76 Evidence of Confer Consulting Ltd., page 30, lines 10 to 16.
77 NGTL-ATCO-51(a) Attachment: NGTL Panel: [Column C / MAV (17,798,913 Mcf)] x 100%. Column H shows the under-recovery extending to an annual load factor of over 80%.
78 NGTL 2004 GRA - Phase I Proceeding: 3T459 to 3T481.
79 ATCO-NGTL-041(e); NGTL 2004 GRA - Phase I Proceeding: 3T469, lines 1-9.

was flawed or not relevant to defining a customer specific facility.[80] ATCO proposed principles as to what would constitute a customer specific facility.[81]

ATCO noted that once a facility meets the Guidelines so that NGTL can build, NGTL then determines whether EAV accountability applies. ATCO argued that the definition of an extension facility is simply a facility that extends NGTL's facilities[82]. ATCO submitted that such a definition may result in a situation where additional facilities to serve a very large incremental delivery customer could automatically be defined as mainline expansion facilities and would require no accountability.[83]

The EAV test, ATCO argued, was flawed on the basis that the EAV calculation does not rely on the cost of extension facilities, but instead relies on the use of indirect revenue from the FT-R rate. ATCO submitted that NGTL's EAV test is independent of the size or cost of an extension facility. ATCO submitted that full accountability would only be achieved through assured revenue from the customers' direct service commitments.[84]

ATCO also took issue with NGTL's alignment of direct rate revenue and incremental costs of customer-specific facilities. In NGTL's calculation of FCS charges under the MAV and EAV provisions, ATCO submitted that NGTL uses indirect FT-R revenue to justify investments in customer-specific facilities for FT-A service. For every Mcf of expected FT-A service, NGTL credits revenue from one unit of FT-R service. ATCO submitted that NGTL's Alberta System currently operates in an environment where demand from markets exceeds supply. ATCO suggested that once the available supply is put onto the system, more deliveries to one market divert deliveries from another market. This suggests that additional deliveries do not mean that additional receipts are added.

ATCO proposed the introduction of a new test, Annual Minimum Extension Volume, that would include a primary term concept to delivery extensions similar to that currently applicable to FT-R and FT-P services.

The CG agreed directionally with the changes proposed by ATCO, but recommended that the CG proposed re-design of the FT-A rate be used instead of the AP re-design of the FT-A rate.

The Board recognizes that NGTL's EAV and MAV provisions under FCS contracts are considered by most shippers in this proceeding to be a reasonable measure of cost accountability for intra-Alberta delivery service.

The Board accepts that NGTL's MAV provision has a basis in cost causation through the calculation of the ACS for those facilities. However, the Board agrees with ATCO that NGTL's calculation of the MAV by dividing the ACS by two-times the FT-A rate does not present a fully persuasive rationale for direct accountability. In regard to the EAV provision and the calculation of the FCS charge the Board also notes ATCO's concern over the use of indirect receipt revenues in the determination of cost accountability for customer specific facilities. The Board generally

[80] NGTL-ATCO-22.
[81] ATCO Pipelines Evidence, Attachment 1.
[82] NGTL Tariff, Rate Schedule FCS, Attachment 1, page 11. NGTL 2004 GRA – Phase I Proceeding: 4T671, lines 11-14.
[83] NGTL 2004 GRA - Phase I Proceeding: 4T706, line 16 to 4T708, line 9.
[84] NGTL-ATCO-12(b) and (e).

accepts that only direct incremental receipt revenues should be appropriately used in support of incremental delivery costs. This finding is consistent with the Board's view in Decision 2002-058 in its consideration of the proposed Fort Saskatchewan extension.[85]

The Board also agrees with Devon's submission that the current accountability provisions do not represent enough of a change since the 2003 Tolls and Tariff Settlement to address the long-standing concerns with NGTL's intra-Alberta delivery rates. The Board agrees with the general principle, as submitted by the CG, that customers must be held responsible for costs they create on the system. The Board notes that accepted rate making principles generally require rates, for a customer class, to be set at 95% to 105% revenue to cost ratio. In response to AUMA/EDM/PICA–NGTL 4, NGTL provided its interpretation of revenue to cost ratios demonstrating that except for the existing FT-A rate all NGTL rates did fall within a 95% to 105% ratio.

Overall, the Board agrees with a number of the concerns raised by ATCO in regard to the EAV and MAV provisions for cost accountability. However the Board considers that these provisions cannot be considered in isolation from NGTL's rate design, including the FT-A, FT-R and FT-P tariffs. The Board recognizes the interrelated nature of a utility's rate structure where one part should not be adjusted without recognizing the impact on the whole.

The Board also agrees directionally with the CG and NGTL that a combination of rate design, examination of LCA, MAV and EAV provisions should provide an overall balance of cost accountability. In reviewing NGTL's cost and rate structure as outlined in Sections 2 and 3 of this Decision, the Board believes all of the receipt, intra-Alberta delivery, export and other services must be considered, with a view to reaching an appropriate balance of costs, revenues and benefits for all producers and consumers on the system.

Since the Board has addressed the requirement for more transparent COS evidence and a potential method of altering NGTL's rate design in Sections 2 and 3 of this Decision, to be further considered in the 2005 Phase II proceeding directed by the Board, the Board is prepared at this time to accept the current cost accountability mechanisms found in NGTL's 2004 tariff. However, the Board would anticipate a possible further review of the cost accountability issue in future if the anticipated improvements in cost transparency and a more cost accountable FT-A toll are not satisfactorily addressed in the 2005 Phase II proceeding.

5 FUEL POLICY

In Decision 2003-051 the Board directed NGTL to address, in its 2004 GRA, the North Core Consumer Group's (NCG) "…submission that intra-Alberta customers will continue to pay 100 per cent of fuel costs as long as 100 per cent of fuel is recovered at receipt points."[86] Specifically, NCG stated in its April 4, 2003 letter to the Board regarding NGTL's 2003 Tariff Settlement Application that "[t]he allocation of 100% of fuel costs to receipt is inconsistent with the basic 50/50 cost allocation principle underlying NGTL rate design."

NGTL collects aggregate Alberta System fuel requirements from services that have a receipt component. Shippers using receipt services supply the Alberta System with fuel in kind on a

85 Decision 2002-058, page 21

86 EUB Decision 2003-051 (June 24, 2003), Appendix 5.

daily basis. The amount of fuel that must be supplied is based upon NGTL's estimated daily fuel requirement and is expressed as a percentage (fuel rate) of the gas that each shipper delivers to the Alberta System. At the end of each month adjustments are made to reconcile the amount of fuel provided within the month with the actual amount of fuel used within the month.

Instead of providing fuel in kind, FT-P shippers pay a monthly charge for fuel. FT-P shippers cannot provide fuel in kind because NGTL's systems are designed to apply the same fuel rate to all receipt volumes. The fuel rate for FT-P shippers is 50% of the fuel rate for receipt services. Accordingly, the monthly fuel rate charged to FT-P shippers is based on 50% of the fuel rate for receipt services multiplied by the monthly average NIT price.

NGTL submitted that the current fuel policy has been in place since 1990 and has a long history of customer acceptance. It was most recently discussed with stakeholders during the consultative process that led to the development of the 2003 Tariff Settlement,[87] where it was accepted by the majority of NGTL's customers.

The CG submitted that recovery of 100% of the fuel gas requirement at the receipt point is inconsistent with the general principle underpinning the NGTL rate design of a 50/50 allocation of transmission costs between receipt and export delivery. The CG recommended that 50% of the cost of NGTL fuel requirements be recovered through an additional fuel charge to be levied as part of the FT-D export delivery toll. Under the CG's proposal, the full fuel requirement would still be supplied in kind by FT-R contract holders, but they would receive an offset to their toll equal to the fuel charge recovery made by NGTL as part of the FT-D toll, resulting in the financial equivalent of a 50% provision of fuel by FT-R shippers. The CG argued that this revised approach to fuel gas recovery would be fairer to intra-Alberta customers since they would only be paying a 50% share of the fuel cost. This would be the level of cost that is implicit in the NIT pool price.

The Cities of Calgary and Edmonton, the FGA, PICA, AUMA and the CCA supported the CG fuel proposal.

The Board notes that NGTL shippers including BP, CAPP, PG&E and TGI were opposed to any changes to NGTL's fuel policy. BP indicated that the current fuel policy was negotiated and any further change in allocation should be the subject of discussions amongst various interested parties. CAPP submitted that the current fuel policy is consistent with the operational nature of the NGTL system, which differs significantly from that of ATCO.

NGTL indicated in its testimony that fuel is not part of its revenue requirement and is not recovered through rates. Rather, it is a matter of negotiation between buyers and sellers purchasing at NIT. PG&E and TGI submitted that changing the fuel allocation, by increasing the FT-D rates based on the 50/50 allocation that underpins NGTL's rate design, should not be part of this hearing as it could intrude on the dynamics of the market. CAPP argued that the CG proposal would take away both producers' and consumers' options to contract around the fuel gas issues.

[87] Application No. 1289773 (January 20, 2003, as amended March 31, 2003).

The Board notes that the CG proposed both in the present proceeding and in the recent ATCO 2004 GRA Phase II proceeding (resulting in Decision 2004-079, dated September 24, 2004) that fuel be shared between receipts and deliveries. The Board stated in Decision 2004-079:

> …the Board considers there is some appeal in principle to the CG's UFG/Fuel concept. However it does not appear that this concept and its potential ramifications on negotiated gas prices has been fully considered by all parties. While the CG proposal may have merit for future consideration in greater depth, for the present time the Board considers that consistency between interconnecting pipelines is a positive objective….The Board agrees with CG that the point of UFG/Fuel recovery has a competitive impact, and believes the issue could usefully be discussed in the Competitive Proceeding, where both regulated pipeline companies and interveners could debate the appropriate recovery mechanism and whether consistency between pipelines is a key factor.[88]

The Board believes the foregoing comments are also applicable here. However in the case of NGTL it would appear that an additional important factor is that fuel is not a component of its revenue requirement. Rather, fuel arrangements are determined in the market between buyers and sellers. In this case the CG's recommendation could add administrative complexity to fuel recovery. The Board also notes that CAPP, the key beneficiary of the CG's proposal, opposed the CG's recommendation and suggested that the current fuel policy appropriately recognizes the operation of the NGTL system. The Board notes that the recovery of fuel costs via receipt customers is supported by shippers on the NGTL system.

In summary, the Board considers that recovery of 100% of the fuel gas requirement at the receipt point, as set out in NGTL's fuel policy, continues to be reasonable and is consistent with ATCO's fuel policy which was approved by the Board in Decision 2004-079. The Board is cognizant that shippers have indicated that fuel is an issue that is best addressed via negotiations between buyers and sellers in the market.

In respect of the Competitive Proceeding, the Board intends to canvass parties in due course as to the appropriate scope and issues for that proceeding. The Board considers that parties may suggest the inclusion of the point of recovery of fuel as an issue if it remains a matter of concern at that time.

6 LEAST COST ALTERNATIVE

The Board considers that LCA has been one of the fundamental concerns raised in recent years in relation to the development of new gas transmission services and the competitive interface between the regulated gas transmission pipelines in Alberta. In 2004 this issue has been raised in the NGTL Phase I and Phase II proceedings as well as in the ATCO Phase II proceeding.

In the current proceeding, NGTL submitted that LCA policy was not a proper issue for consideration, as it had already been addressed in the NGTL 2004 GRA Phase I proceeding. NGTL noted that ATCO had specifically requested that the Board include LCA as an issue in the current proceeding.[89] NGTL considered that the Board denied ATCO's request, noting that LCA

[88] EUB Decision 2004-079, ATCO Pipelines 2004 General Rate Application – Phase II, p.87/88.
[89] Exhibit No. 007-02.

was “covered within the scope of the NGTL GRA Phase I and covered on the issues list of that proceeding.”[90]

NGTL further submitted that the Board should properly determine least cost policy issues in NGTL’s GRA Phase I proceeding. In the alternative, NGTL submitted that should the Board find itself unable to determine this issue in NGTL’s GRA Phase I proceeding, then the issue should be deferred to the proposed Competitive Proceeding.

ATCO recommended that the Board provide direction and guidance on the implementation of an LCA policy respecting facilities that would apply to all competing gas transmission pipelines under the Board’s jurisdiction. ATCO’s recommended policy would require each pipeline to enter into contractual arrangements for transportation service on other pipelines when this option offered the LCA as determined by long-term owning and operating costs. ATCO considered that such a policy would minimize the toll impact to shippers and would also control the proliferation of facilities.

The LCA policy recommended by ATCO[91] required a pipeline proposing facilities of $1 million or more to provide details of the proposed facilities to all other pipeline operators in the area and to solicit bids from these operators on all or a portion of the transportation requirement. The proposing pipeline would include an LCA analysis and bid information with its facilities application to the regulator. ATCO proposed a cumulative present value cost of service (“CPVCOS”) analysis to determine the LCA. ATCO recommended that inputs to the LCA model be standardized to the maximum extent possible for all competing pipelines. ATCO submitted that the details of the LCA methodology or protocol could be addressed in the Competitive Proceeding, where all interested parties would have an opportunity to provide input. IGCCA suggested that further consideration of ATCO’s proposal regarding LCA be undertaken in conjunction with consideration of NGTL’S TBO policy in the Competitive Proceeding. This would allow all parties to consider ATCO’s proposal more fully before the Board took any specific action on an LCA policy.

With respect to whether LCA is an issue for this proceeding, the Board notes its letter to all interested parties dated January 29, 2004, regarding the preliminary issues list and the question of whether there would be a rolling record between the Phase I and Phase II proceedings. In that letter, the Board noted that to the extent issues overlapped between the two phases of the NGTL proceedings, those issues would be placed on the issues lists for either or both proceedings as they were developed. The Board also refers to the opening remarks of the Chair at the outset of the NGTL Phase II hearing, indicating that the Board considered it appropriate to examine the issue of LCA in the Phase II as well as the Phase I proceeding.

The Board agrees with ATCO that an LCA policy should discourage the over-capitalization of pipeline facilities in the basin while controlling pipeline shipper costs and facilities proliferation and encouraging the use of existing facilities. The Board also agrees with IGCAA that an LCA policy must be capable of providing a reasonable level of service not inconsistent with the level of service accorded generally on the pipeline system.

[90] Exhibit No. 001-03, Board letter dated January 28, 2004.
[91] Evidence of ATCO Pipelines, pages 19-20.

The Board believes there is merit in some of the ATCO recommendations for determining the LCA in pipeline proposals. The Board agrees directionally with ATCO that more uniform and transparent costing and pricing methods could provide greater assurance that least cost results were being achieved. The Board however, also agrees directionally with IGCAA's concern that the requirement for a utility, in ATCO's proposal, to disclose the CPVCOS prior to any bidding process may cause higher acquisition prices in some cases.[92]

NGTL indicated that it would not object to the Board introducing a protocol for regulated pipelines that sets out procedures to introduce an LCA policy that might include some direction on a standard economic test, providing the protocol was not overly prescriptive.[93] The Board considers that the components and mechanics of an LCA policy have not been fully addressed by parties to date. Further, parties either supported, or were not opposed to, having the issue of LCA addressed further within the Competitive Proceeding. In consideration of this the Board finds that an appropriate LCA policy for NGTL and other parties should be addressed in the Competitive Proceeding.

The Board also notes that the issue of duplicate facilities is of considerable importance to the CG. The Board has considered the CG's submissions that the Board should provide a clear definition of LCA policy, and until the Competitive Proceeding has been held with a clear policy discussed, no applications for line extensions that could potentially create duplicate facilities should be approved by the Board.

In recognition that the Competitive Proceeding has not yet occurred the Board is of the view that until such time that an LCA policy has been discussed at the Competitive Proceeding each facilities application before the Board will continue to be reviewed on its own merit.

7 SERVICE AND TARIFF AMENDMENTS

NGTL seeks approval in the Application of certain minor service and Tariff amendments. Specifically, NGTL seeks Board approval to:

- extend the term and rate of Rate Schedule OS, Other Service – Schedule No, 2003-00452-2 (the Gas Balancing Agreement (GBA), or GBA Service) to March 31, 2009; and
- amend specific provisions of Rate Schedule IT-S and the General Terms and Conditions of the Tariff.[94]

7.1 Gas Balancing Agreement

The Board notes that the GBA between NGTL and TCPL was first approved by the Board on August 21, 1997, at a time when the companies were not related. The approval authorized NGTL to provide the GBA Service in accordance with the terms and conditions of the GBA from November 1, 1998 to October 31, 2003 at a fixed rate of $83,333.00 per month. On April 23, 2003 NGTL applied to the Board to extend the term of the GBA Service from November 1, 2003 to March 31, 2004, with the rate and all other terms and conditions of service remaining unchanged. The Board approved the extension of the GBA Service and rate as applied for on

[92] NGTL Phase I Transcript Vol. 5, pages 769 – 771 (Incorporated by Exhibit 40-15 to this proceeding).
[93] NGTL 2004 GRA – Phase I: 3T526, lines 13-16.
[94] Exhibit No. 002-06(d), Application, section 3.1, page 1.

April 10, 2003. Revenue from the GBA Service is applied as an offset to NGTL's revenue requirement.

NGTL sought to extend the term and rate of Rate Schedule OS, Other Service – Schedule No, 2003-00452-2 (the GBA or GBA Service) to March 31, 2009.

The Board notes that no parties to the proceeding opposed the continuation of NGTL's GBA Service to TCPL as applied for by NGTL. NGTL argued that the GBA Service will not adversely impact NGTL's obligations to provide firm service deliveries to the Empress/McNeill border delivery point or storage delivery. NGTL further stated that GBA Service would not impact NGTL's supply/demand balancing process because the transported volumes are balanced to zero each day, no additional facilities would be required, nor are there material additional operating costs in connection with the GBA Service. In this context, the provisions in section 6 of the GBA provide NGTL's customers reasonable protection against the risk of potential curtailment arising from the GBA Service. Specifically, section 6 states:

> TransCanada and NGTL recognize that the purpose of this Agreement is to enhance service to both TransCanada and NGTL's customers and agree to use reasonable efforts to ensure that the use of the Agreement does not result in a curtailment of transmission services to any of NGTL's customers on NGTL's system.
>
> In the event there is a curtailment of firm service to any of NGTL's customers on the NGTL system, NGTL may at its sole option fully or partially reduce the Service if providing the Service would have reduced the available capacity for NGTL firm service customers (or any other transportation service of equivalent priority) at Empress.

The Board considers that, based on NGTL's submissions and the provisions of section 6 of the GBA, NGTL's customers are not negatively impacted by the GBA Service but benefit from the revenue associated with the GBA Service as an offset to NGTL's overall revenue requirement.

The Board is therefore prepared to approve the extension of the term of Rate Schedule OS, Other Service – Schedule No, 2003-00452-2 (the GBA or GBA Service) to March 31, 2009, with the existing rate and other terms and conditions remaining unchanged.

7.2 IT-S Service and Other Amendments

Rate Schedule IT-S specifies the applicable rates a customer shall pay at a storage receipt point for volumes received by NGTL. NGTL proposed to amend Rate Schedule IT-S to include applicable rates for volumes delivered by NGTL to a storage delivery point.

The proposed amendments to Rate Schedule IT-S would enable NGTL to ensure that it can properly allocate volumes delivered to or received from storage facilities to the appropriate service and charge the appropriate corresponding rates. NGTL's storage service customers bear the responsibility under Rate Schedule IT-S to ensure that the storage operator provides NGTL with appropriate information about the gas being received by or delivered to NGTL.

NGTL proposed to add Demmitt #2 Interconnect to the definition of Export Delivery Point in Section 1.30 of the Tariff. NGTL proposed to designate Demmitt #2 Interconnect as an Export

Delivery Point in order that NGTL could properly allocate and charge for volumes delivered from the Alberta System at that point that are destined for export from Alberta.

NGTL sought approval in this Application of certain minor Tariff amendments that are consequential to the proposed amendments to Rate Schedule IT-S and the General Terms and Conditions, or are of a “housekeeping” nature. These other minor amendments affect Rate Schedule IT-S, the General Terms and Conditions, and Appendix D of the Tariff.

The Board considers that the amendments to Rate Schedule IT-S and the General Terms and Conditions of the Tariff appear to be administrative in nature. The Board further notes that interested parties provided no submissions on these matters.

With respect to the amendment of the General Terms and Conditions of the Tariff in relation to the Demmitt #2 Interconnect, the Board is of the view that NGTL’s proposal to designate it as an Export Delivery Point is reasonable. The Board considers that NGTL will thereby be better able to properly allocate and charge for volumes delivered from the Alberta System at this interconnect point, recognizing customer usage and the possible export opportunity that exists via the Alliance Pipeline system interconnect with Demmitt storage.

The Board therefore approves the above described amendments to Rate Schedule IT-S, and amendments to General Terms and Conditions of the Tariff including the designation of Demmitt #2 Interconnect as an Export Delivery Point.

7.3 Minimum Operating Pressures

The CG submitted that operating pressures are paramount to the operating requirements of gas co-ops and other CG customers. The CG was concerned that NGTL did not maintain a guaranteed minimum operating pressure for its delivery customers.

In Decision U2004-136, the Board approved an application filed by NGTL in the matter of approval of amendments to the NGTL Rates and General Terms and Conditions of the Tariff to incorporate the provision of temporary Pressure-Temperature Service. As noted in Decision U2004-136, the Federation of Alberta Gas Co-ops Ltd. and Gas Alberta Inc. (FGA) filed an objection dated April 15, 2004, to NGTL’s application based on the issue of pressure maintenance, particularly the lack of designated or specified minimum operating pressures and its effect on the security of supply for intra-Alberta delivery customers. The FGA withdrew its objection by letter dated April 26, 2004, based on NGTL's commitment that existing customers would be consulted and allowed a reasonable opportunity to comment prior to implementation of a proposed service offering, and that any objection based on harm to the affected customer would result in the service being denied.

The CG noted that the FGA would continue to work in collaboration with NGTL and other customers. Should an appropriate resolution of the concerns not be reached through the collaborative process, the CG or the FGA may bring that concern before the Board for necessary direction.

The Board recognizes that matters relating to minimum operating pressures may have to be dealt with at a later date if parties fail to reach an agreement. However, at this time, the Board supports the continuation of the collaborative process between the FGA and NGTL.

8 MATTERS OF APPROACH AND POLICY

8.1 Integration of NGTL Phase II Proceeding with Other Proceedings; Competitive Proceeding

The Board believes that in this Section it should briefly address the relationship of the current Application with other proceedings, namely the 2005 Phase II proceeding, which the Board has directed be undertaken by NGTL in Section 3 of this Decision, and the Competitive Proceeding.

As parties will be aware, the Board has confirmed in recent rate proceedings and decisions its intention to address competitive regulated pipeline issues for the years 2005 and beyond in a Competitive Proceeding. In the recent ATCO 2004 GRA Phase II Decision the Board addressed the relationship of that application with other proceedings as follows:

> With respect to this Application in the context of other proceedings, the Board tends to agree with IGCAA that the most efficient process is to make rate determinations in the respective AP and NGTL Phase II proceedings, and to use the Competitive Proceeding for AP, NGTL and their customers to react to the respective rate designs. At that time parties may propose further measures that might be necessary to address competitive issues between the two companies.
>
> As the Board recently indicated in Decision 2004-069 (NGTL 2004 GRA Phase I), the Board considers that there are a number of unresolved competitive issues, and confirms its intent to conduct a Competitive Proceeding involving the years 2005 and beyond. Following this proceeding it may be that further rate proceedings for either or both of AP and NGTL would be appropriate. The Board again confirms that it will canvass interested parties, likely in the fall of 2004, to assist in developing the scope of the Competitive Proceeding. [95]

Given that NGTL's basic rate design will not be altered for 2004, and would be altered in future only after parties have had an opportunity to address the issues in the NGTL 2005 Phase II proceeding, it appears to the Board that the most sensible approach would be to hold the NGTL 2005 Phase II proceeding as soon as reasonably practicable in 2005, with the Competitive Proceeding to follow. In that way parties would be able to approach the Competitive Proceeding having considered the then current rate designs on both ATCO and NGTL, which should affect the nature of the issues that would be raised by parties.

9 SUMMARY OF BOARD DIRECTIONS

1. As a consequence, and as set out in more detail in Section 3 of this Decision, the Board will direct NGTL to file a 2005 Phase II GRA including a fully allocated COSS to support NGTL's cost allocation and rate design. The Board directs NGTL to include in the 2005 Phase II filing an updated DOH study, an updated COH study, and a detailed fully allocated COSS that includes the following:.. 5
    - Functionalization of all costs including Compression, Transmission and Metering, and the allocation of all indirect costs such as General Plant, Working Capital Accounts, General and Administration.. 6

[95] Decision 2004-079, page 158.

- Assignment and allocation of costs to all service classes (including FT-A, FT-R, FT-D, and FT-P) 6
- Assignment and allocation of costs (fixed and variable) among each firm service by contract demand, throughput or another justified allocator 6
- Assignment and allocation of income credits for non standard rates. 6

2. The Board directs NGTL to file an updated version of its DOH study as a reasonableness check of NGTL's COSS in the 2005 Phase II GRA. 8

3. The Board directs NGTL to file in the 2005 Phase II GRA an updated revised COH study to allow parties to examine the results of the COH study as compared to the DOH study. The Board expects NGTL's update to include any extensions or expansions that may impact the results of the studies (for example the Simmons Pipeline). 11

4. Therefore the Board directs NGTL to submit a Phase II application for 2005 on or before April 1, 2005. In this application, which will include a COSS as directed in Section 2.1, the Board further directs NGTL to address a reasonable allocation of transmission costs greater than zero to the FT-A rate and other relevant changes as set out in Section 3.3.5, as one option for NGTL's rate design for consideration by the Board. 19

10 ORDER

IT IS HEREBY ORDERED THAT:

1) NOVA Gas Transmission Ltd.'s rate design methodology for its 2004 rates for Alberta System services is approved.

2) NOVA Gas Transmission Ltd.'s Rate Schedule OS, Other Service is approved to March 31, 2009, with the existing rate and other terms and conditions remaining unchanged.

3) NOVA Gas Transmission Ltd.'s amendments to Rate Schedule IT-S and the General Terms and Conditions of NGTL's Tariff are approved.

4) NOVA Gas Transmission Ltd. shall comply with all Board directions in this Decision.

5) NOVA Gas Transmission Ltd. shall file a 2004 Phase II GRA compliance filing (Compliance Filing) within two weeks of the Board issuing its Decision on NGTL's 2004 Phase I GRA compliance filing.

6) In the Compliance Filing, NOVA Gas Transmission Ltd. shall include all necessary supporting schedules for the Board to make its final determination respecting NOVA Gas Transmission Ltd. 2004 rates. The Compliance Filing shall be at a level of detail sufficient to reconcile with the original Application and to demonstrate compliance with the Board's findings and directions in Decision 2004-069.

Dated in Calgary, Alberta on October 26, 2004.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

C. Dahl Rees
Presiding Member

(original signed by)

T. M. McGee
Member

(original signed by)

M. W. Edwards
Acting Member

APPENDIX A – PROCEEDING PARTICIPANTS

Principals and Representatives (Abbreviations used in Report)	Witnesses
NOVA Gas Transmission Ltd. P. Keys J. Nichols	S. Pohlod N. Bowman D. Murray T. Eisele J.S. Gaske
Abcom/ Care Centre Group (CCG) A. Ackroyd	
Alberta Department of Energy C. Nykolyn	
Alliance Pipeline R. Power	
AltaGas Services Inc. L. Meyer	
ATCO Pipelines N. Gretener	E. Jansen D. Belsheim G. Engbloom
BP Canada Energy Company A. Hollingworth N. Berge C. Worthy	
Canadian Association of Petroleum Producers (CAPP) L. Manning	
Cargill Power & Gas Markets T. Lange	
City of Calgary B. Meronek L. Cusano	
Consumers Coalition of Alberta (CCA) J. Wachowich	
Consumers Group (CG) Alberta Urban Municipalities Association (AUMA)/City of Edmonton (EDM) J. Bryan	R. Liddle G. Garbutt
Public Institutional Consumers of Alberta (PICA) N. McKenzie	

Principals and Representatives (Abbreviations used in Report)	Witnesses
Coral Energy K. McKnight	
Direct Energy Regulated Services K. Miller	
Devon Canada Corporation T. Caraher	
EnCana Corporation D. Davies	
Federation of Alberta Gas Co-ops/Gas Alberta Inc. T. Marriott	
Imperial Oil Resources K. L. Pybus	
Industrial Gas Consumers Association of Alberta B. Roth	N. MacMurchy R. McNeil
Pacific Gas & Electric Company D. Ellerton	
Producers Marketing Ltd. J. Gerwing	
Nexen Marketing S. Young D. Cameron	
Rate 13 Consumer Group K. Wyke	
Talisman Energy Inc. F. Basham	
Terasen Gas Inc. D. Ellerton	
Shell Canada Ltd. R. Gall	
Syncrude Canada Ltd. A. L. McLarty, Q.C.	K. Versfeld
Union Gas R. Mukherjee	

Principals and Representatives (Abbreviations used in Report)	Witnesses
Westcoast Energy K. Jaron	
Alberta Energy and Utilities Board Board Panel C. Dahl Rees, Presiding Member T. McGee, Member M. W. Edwards, Acting Member Board Staff R. Marx, Board Counsel L. Kelly D. Popowich M. McJannet A. Laroiya	