# DECISION 2001-65

## ATCO GAS – NORTH
## A DIVISION OF ATCO GAS AND PIPELINES LTD.

## SALE OF CERTAIN PETROLEUM AND NATURAL GAS RIGHTS, PRODUCTION AND GATHERING ASSETS, STORAGE ASSETS AND INVENTORY:

## REASONS FOR DECISION 2001-46

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## CONTENTS

**ALBERTA ENERGY AND UTILITIES BOARD**
**Calgary, Alberta**

| | |
|---|---|
| **ATCO GAS – NORTH** | **Decision 2001-65** |
| **A DIVISION OF ATCO GAS AND PIPELINES LTD.** | **Application Nos. 2001017,** |
| **SALE OF CERTAIN PETROLEUM AND NATURAL** | **2001020, 2001030 & 2001070** |
| **GAS RIGHTS, PRODUCTION AND GATHERING** | **File Nos. 6405-14, 6405-15,** |
| **ASSETS, STORAGE ASSETS AND INVENTORY** | **6405-16 & 6405-18** |

## 1 INTRODUCTION

By letters dated January 22, 2001, January 25, 2001, February 2, 2001 and March 6, 2001, respectively, ATCO Gas – North[1] (AGN), a division of ATCO Gas and Pipelines Ltd., submitted applications (collectively, the Applications) to the Alberta Energy and Utilities Board (the Board) for approval of the following:

- Application No. 2001017 - Sale of certain petroleum and natural gas rights and production and gathering assets in the Viking Kinsella field to Burlington Resources Canada Energy Ltd. (Viking Application)

- Application No. 2001020 - Sale of certain petroleum and natural gas rights and production and gathering assets in the Westlock, Peace River Arch, Phoenix and other fields not operated by AGN to Trioco Resources Inc. (Westlock Application)

- Application No. 2001030 - Sale of certain petroleum and natural gas rights and production and gathering assets in the Beaverhill Lake and Fort Saskatchewan fields to NCE Petrofund Corp. and NCE Energy Corporation. (Beaverhill Application)

- Application No. 2001070 - Sale of certain petroleum and natural gas rights and production and gathering assets, storage assets and inventory in the Lloydminster field to AltaGas (Sask.) Inc. and AltaGas Services Inc. (Lloydminster Application)

AGN's request for approval of the Applications for the sale of its petroleum and natural gas assets (collectively, the P&NG assets) was made pursuant to section 25.1 of the *Gas Utilities Act* (GU Act),[2] which provides, inter alia, that no owner of a gas utility may dispose of its property without the approval of the Board unless it is in the ordinary course of the owner's business.

The Board published Notices of the Hearing for the Viking, Westlock and Beaverhill Applications in daily newspapers having a general circulation in AGN's service areas. Notice of Hearing for the Viking Application was also published in the *Viking Weekly*. The Board also served the Notices on intervenors and interested parties registered on the mailing list of AGN's last Gas Cost Recovery Rate (GCRR) Application.

[1] ATCO Gas – North was previously a division of Northwestern Utilities Limited. Effective January 1, 2001 Northwestern Utilities Limited (NUL) was wound up into ATCO Gas and Pipelines Ltd.

[2] R.S.A. 1980, c. G-4, as amended.

Because of time constraints with respect to the hearing schedule, the Board served a Notice for Objections in respect of hearing the Lloydminster Application in conjunction with the other three Applications. That Notice was served on the interested parties already served with the Notice of Hearing for the other Applications. The Board received no objections to including the Lloydminster Application in the hearing of the other three Applications. Therefore, the Applications were heard concurrently.

The Applications were considered by the Board at a public hearing in Edmonton, Alberta lasting six days, commencing on April 5, 2001, before Board Members B. F. Bietz, Ph.D., B. T. McManus, Q.C., and T. McGee. A list of those who appeared at the hearing and the abbreviations used in this Decision are as set out in Appendix 1.

The Applications included agreements for sale of the P&NG assets that contemplated closing dates no later than May 31, 2001 for the Viking Application and June 1, 2001 for the Westlock, Beaverhill and Lloydminster Applications. The agreements for sale in the Viking, Westlock and Beaverhill Applications also included price adjustment clauses that diminished the proceeds with any delay in closing after January 1, 2001.

Due to the foregoing time constraints, the Board felt compelled to issue Decision 2001-46 on May 29, 2001, in which it denied the Viking and Beaverhill Applications and approved the Westlock and Lloydminster Applications. The Board indicated that reasons for its decisions in relation to each Application, including conditions with respect to the two approved Applications, would follow. For convenience, Decision 2001-46 is reproduced in Appendix 7 to this Decision.

This Decision sets out the Board's reasons and conditions in respect of Decision 2001-46.

## 2 PARTICULARS OF THE APPLICATIONS

### 2.1 General

AGN provided a general rationale for its decision to sell the P&NG assets. It explained that the Viking producing properties had been owned and operated by AGN and its predecessors since 1923. In the early years of the company, Viking provided the entire gas supply requirements for AGN's customers. AGN advised that its gas supply load factor has been eroded since the early 1980s. This was due to large industrial customers using transportation service and core market customers using direct purchase from gas retailers. Consequently, for the past number of years, company owned production (COP) had been used only to supplement AGN's market purchases of natural gas. AGN noted that it had set a target of using approximately 15% of COP in its aggregate sales portfolio.

AGN stated that the P&NG assets were used generally for operational, rather than price, considerations. However, AGN submitted that, as the natural gas market place had changed in nature, its P&NG assets were no longer required for even those purposes. AGN believed that the market had become sufficiently liquid to allow it to meet all of its utility obligations without the need for COP.

AGN considered that, with natural gas prices being at historically high levels at the time of the Applications, its decision to offer the properties for sale would allow it to capture the increased value of all of the gas reserves in the ground.

AGN was of the view that its decision to dispose of the properties also reflected past legislative and policy direction. In particular, AGN stated its belief that it would be directed by the Government of Alberta to exit the gas sales function within five years. AGN noted that existing gas retailers have also often expressed concerns about the impact that its COP has on the development of the retail natural gas market.

AGN advised that it engaged two separate independent consultants, Waterous and Company and McDaniel and Associates Consultants Ltd. (McDaniel) to provide it with assistance in preparing bid packages and reserve reports, respectively, for the P&NG assets. The P&NG assets were considered to include "intangible assets", such as petroleum and natural gas (P&NG) rights and seismic data, and "tangible assets", such as production and gathering equipment and gas processing facilities.

### 2.2 Viking Application

The Viking Application related to AGN's interest in the Viking Kinsella area in:

- the Viking P&NG rights and associated infrastructure, which comprised a land base in excess of 314,000 acres of predominantly 100% working interest in the Viking zone, and

- all remaining non-Viking zones, the majority of lands of which included P&NG rights surface to basement, but with varying interval ownership.

AGN provided the following financial information ($000s) with respect to the proposed sale of Viking:

| | |
|---|---|
| Gross proceeds | 490,000 |
| Cost of disposition | (5,414) |
| Proceeds associated with seismic | (1,500) |
| Proceeds for P&NG rights | (7,670) |
| Net proceeds | 475,416 |
| | |
| Allocation of proceeds: | |
| Customers – gain on sale | 204,958 |
| | |
| Shareholders: | |
| Recovery of net book value | 39,664 |
| Gain on sale | 230,794 |
| | 270,458 |
| Total | 475,416 |

The Viking agreement for sale contained a price adjustment clause that reduced the sale proceeds in an amount of $6.50 per mmbtu[3] multiplied by the interim production for the period commencing on January 1, 2001 to the earlier of the closing date or May 31, 2001. After May 31, 2001 the price adjustment amount increased to $8.50 per mmbtu.

AGN advised that it was seeking approval to apply the so-called "TransAlta Formula"[4] to determine the appropriate disposition of the proceeds of the sale if it were approved. It further advised that if the disposition of the proceeds was controversial, it was requesting that approval of the sale not be delayed by any subsequent decision regarding the disposition of the proceeds.

AGN stated that the value of the Viking production to customers, if those assets were to remain in utility service, was approximately $167.5 million. It also estimated that the value of the customers' share of proceeds if the assets were sold would be $215.2 million, including a return of $10.2 million of deferred income taxes related to production income. Based on comparison of these two values, AGN concluded that the proposed sale of the Viking assets would meet the no-harm standard, a principle considered in detail by the Board in Section 5 of this Decision.

### 2.3 Westlock Application

With the Westlock Application AGN provided a list of the gas fields included in the proposed sale. With respect to these properties AGN noted the following:

- all were non-operated and cost control was limited,
- all were considered to be non-core,
- production represented about 7% of its total annual production, and
- over the period 1996 – 2000, average growth in capital expenditures exceeded 50%.

AGN provided the following financial information ($000s) with respect to the proposed sale:

| | |
|---|---|
| Gross proceeds | 15,400 |
| Cost of disposition | (286) |
| Proceeds for P&NG rights | (35) |
| Net proceeds | 15,079 |
| | |
| Allocation of proceeds: | |
| Customers – gain on sale | 6,746 |
| | |
| Shareholders: | |
| Recovery of net book value | 8,333 |
| Total | 15,079 |

The Westlock agreement for sale contained a price adjustment clause that reduced the value of the sale proceeds by $2,700,000 if closing was made on or after June 1, 2001.

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[3] Millions of British thermal units.

[4] See Section 3.3.

AGN estimated a value to customers of the non-operated production, assuming those assets were to remain in utility service, of $678,000, including the rate base value of retired assets. It also estimated that the value of the customers' share of proceeds would be $8.9 million, including a return of $2.2 million of deferred income taxes related to production income. Based on a comparison of these two values, AGN concluded that the proposed sale of the non-operated assets would meet the no-harm standard.

### 2.4 Beaverhill Application

The Beaverhill Application referenced AGN's interests in the Beaverhill Lake area including:

- a 95.548% gas Unit working interest,
- a 100% working interest in P&NG rights, surface to basement, in approximately 11,400 acres, and
- a 100% working interest in natural gas rights, surface to basement, in approximately 2,560 acres outside the Unit boundaries.

For the Fort Saskatchewan area, the Beaverhill Application related to:

- a 100% working interest in 12 producing wells and 4 suspended wells,
- a 75% working interest in 1 producing well, and
- an 88% working interest in 1 producing well.

AGN advised that production from those properties represented approximately 15% of its total annual COP and that they were core production properties.

AGN provided the following financial information ($000s) with respect to the proposed sale:

| | |
|---|---|
| Gross proceeds | 37,000 |
| Cost of disposition | (265) |
| Proceeds for P&NG rights | (37) |
| Net proceeds | 36,698 |
| | |
| Allocation of proceeds: | |
| Customers – gain on sale | 26,247 |
| | |
| Shareholders: | |
| Recovery of net book value | 8,128 |
| Gain on sale | 2,323 |
| | 10,451 |
| Total | 36,698 |

AGN noted that the Beaverhill agreement for sale contained a price adjustment clause that reduced the sale proceeds by $7,884,000 if closing was made on June 1, 2001, and by $2,090,000 for each month thereafter. Accordingly, AGN requested that approval of the sale be made as soon as possible, even if that would result in approval of the associated disposition of the proceeds being addressed at a later time.

AGN estimated the value of the production to customers if the assets were to remain in utility service to be $8.9 million. It also estimated that the value of the customers' share of proceeds would be $28.3 million, including a return of $2.1 million of deferred income taxes related to production income. Based on comparison of these two values, AGN concluded that the proposed sale of the Beaverhill Lake and Fort Saskatchewan assets would also meet the no-harm standard.

### 2.5 Lloydminster Application

AGN advised that in 1996 it had discontinued production from the Lloydminster wells and use of the storage facility, but that the wells were not abandoned as some remaining reserves were recoverable. However, it noted that achieving this recovery would involve additional capital investment. AGN considered that the proposed sale would allow it to maximize the value of those assets.

AGN provided the following financial information ($000s) with respect to the proposed sale:

| | |
|---|---|
| Gross proceeds | 3,800 |
| Cost of disposition | (69) |
| Proceeds for P&NG rights and storage inventory | (135) |
| Net proceeds | 3,596 |
| | |
| Allocation of proceeds: | |
| Customers – gain on sale | 1,798 |
| | |
| Shareholders: | |
| Recovery of net book value | 1,085 |
| Gain on sale | 713 |
| | 1,798 |
| Total | 3,596 |

AGN determined that there was no potential future value to customers from retaining the assets. It noted that the proposed sale would not only reduce the cost of the revenue requirement to customers, but also provide them with direct proceeds of $1.8 million and indirect proceeds of $258,000 through a recovery of deferred income taxes related to production income. AGN thus submitted that the proposed sale of the Lloydminster assets would meet the no-harm standard.

# 3 REGULATORY POLICY AND GENERAL PRINCIPLES

The Board considers it to be useful at the outset of this Decision to set out some of the general regulatory policy considerations associated generally with the evolution of a competitive retail market for natural gas in Alberta, and which have been raised with respect to the Applications.

The Board also wishes to set out some of the general principles to which it intends to have regard in relation to the four Applications before it. These general principles relate primarily to the so-called no-harm test and to the allocation of proceeds from any dispositions approved by the Board. The Board will, in Section 4 of the Decision, address the issue of jurisdiction and also the more specific questions raised by the Applications with respect to these principles.

## 3.1 Regulatory Policy

Since 1985, policy barriers in Alberta to the development of a competitive wholesale market for natural gas have been steadily reduced. Small industrial consumers have been able to purchase their gas from a choice of suppliers since 1988. In 1990, the GU Act was amended to provide all Alberta consumers with the right to choose their gas suppliers. The *Gas Utilities Core Market Regulation*[5] was enacted under the GU Act in 1995 to establish rules for the exercise by core consumers of their right to choice. Residential gas retailers began to enter the Alberta marketplace in 1998.

As previously noted, AGN expressed the view that its decision to dispose of the P&NG assets was consistent with this policy and reflected past legislative direction. In addition, AGN has stated on several occasions its belief that within five years it will be directed by the Government of Alberta to exit the gas sales function entirely. However, despite the views of AGN and of other parties with respect to the future direction of government policy, the Board is less certain whether any further legislative change with respect to the natural gas marketplace in Alberta will be forthcoming in the near term.

The Board is comfortable, however, that the existing legislative framework for natural gas has been designed to encourage and foster retail competition. In that regard the Board has convened two hearings[6] subsequent to this proceeding in order to explore, among other things, ways to ensure that independent gas marketing companies are provided a fair opportunity to provide alternative service to gas customers. In those proceedings, this goal has been referred to as providing a "level playing field" for retail gas market competition.[7] In the two convened hearings, the Board has attempted to ensure that regulatory barriers to the development of a competitive market are identified and appropriately addressed.

[5] AR 44/95, as amended.

[6] Application No. 2001040 – Methodology for Managing Gas Supply Portfolios and Determining Gas Cost Recovery Rates (Methodology Proceeding); Application No. 2001093 – Gas Rate Unbundling (Unbundling Proceeding).

[7] Unbundling Proceeding, Tr. p. 67.

While neither the exact methods to remove these remaining regulatory barriers to retail competition, nor the associated timelines for their implementation, have as yet been determined by the Government of Alberta, the Board does consider the overall Government policy direction in this regard to be clear. The Board believes that it is necessary to reconfirm these views since it is concerned that the disposition of the Applications may somehow be considered an indicator of the Board's general appetite for advancing retail competition in natural gas.

The Board notes that in the Methodology Proceeding, which occurred during the Board's deliberation regarding the Applications, ATCO announced its intention to seek a purchaser for its electric and gas retail functions. During those proceedings, ATCO suggested that approval of the proposed sale of its electric and gas retail functions, along with approval of a proposed application to remove the Carbon Storage facility from regulation, and of the sale of COP, provided the Board with the opportunity to bring a fully functioning gas retail market place to Alberta.

While the Board does agree that approval of the Applications may arguably help to facilitate the development of additional competition in the natural gas market, the Board also remains bound to weigh all competing factors, including the impact on customers, in determining whether to approve the Applications. And while the encouragement of the development of competition may be an important policy goal, it is not over-arching. Furthermore, the Board notes that interveners have advanced a credit rider proposal to reduce the impact of COP on potential retail service providers that could accomplish the same goal as the Applications.[8]

The Board also notes that ATCO Gas made it clear during the Methodology Proceeding that the Board's decision with respect to the Applications would in no way effect the proposed sale of the retail assets.[9] Therefore, the Board is comfortable that neither approval nor denial of all or any of the Applications will adversely impact the future development of retail competition significantly, nor should it be considered a reflection of the Board's approach to furthering such retail competition.

### 3.2 The No-Harm Standard

The Applications before the Board were made by AGN pursuant to section 25.1 of the GU Act. This section requires a designated owner of a gas utility to obtain Board approval before disposing of its property outside the ordinary course of its business. AGN is an operating division of ATCO Gas and Pipelines Ltd., which is a designated owner of a gas utility for purposes of section 25.1 of the GU Act.[10] Therefore, AGN requires Board approval to dispose of the various assets that form the subject of the Applications if the dispositions are outside the ordinary course of AGN's business.

[8] See Section 7.1 of this Decision.
[9] Methodology Proceeding Tr. p. 355
[10] *Designation Regulation*, AR 104/2000, section 1(c)

The Board has held that sales of major rate base assets, where the frequency of disposition is low and the proceeds material, are not within the ordinary course of business.[11] The Board considers that the sale by a gas utility of gas production properties having material value (whether actually producing or not) are outside the ordinary course of business and, therefore, require approval pursuant to section 25.1(2)(d) of the GU Act.

Section 25.1(2)(d) of the GU Act is virtually identical in terms to section 91.1(2)(d) of the *Public Utilities Board Act* (PUB Act).[12] In Decision 2000-41,[13] the Board held that it must be satisfied that the proposed transaction will either not harm customers or, on balance, leave them at least no worse off than before the transaction in terms of financial impact and reliability of service.

The Board distilled this principle from several decisions made by it pursuant to section 25.1 of the GU Act.[14] In those decisions, the Board had developed what has come to be known as the no-harm test, but in Decision 2000-41 the Board recognized that it should conduct a balancing of both the potential positive and negative impacts of the transaction to determine whether it is in the overall public interest. Specifically, the Board held:

> As a result, rather than simply asking whether customers will be adversely impacted by some aspect of the transactions, the Board concludes that it should weigh the potential positive and negative impacts of the transactions to determine whether the balance favours customers or at least leaves them no worse off, having regard to all of the circumstances of the case. If so, then the Board considers that the transactions should be approved.[15]

The Board considers that a similar analysis of potential positive and negative impacts should be conducted in relation to the Applications. The Board's consideration of these issues is set out in Section 5 of this Decision.

Of particular importance to the Applications is the Board's statement in Decision 2000-41 with respect to the financial mitigation of potential harm to customers:

> In appropriate circumstances, it might be open to the Board to mitigate or offset any of these potential risks by apportioning some of the gain on sale to customers.[16]

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[11] Order E93023, *Re Northwestern Utilities Limited* (March 17, 1993), p. 12.

[12] R.S.A. 1980, c. P-37, as amended.

[13] Decision 2000-41, *TransAlta Utilities Corporation, Sale of Distribution Business* (July 5, 2000), in which the Board approved the sale by TransAlta Utilities Corp. (TransAlta) of its electric distribution business to UtiliCorp Networks Canada (Alberta) Ltd. (UtiliCorp).

[14] Decision 2000-41, p. 8.

[15] Decision 2000-41, p. 8.

[16] Decision 2000-41, p. 9.

Otherwise, the Board concluded, the treatment (i.e. allocation) of any gain or loss on the disposition of the assets is to be determined according to a somewhat different set of principles. Particularly for purposes of the jurisdictional question discussed hereafter, the Board emphasizes the difference between the no-harm test and the principles otherwise applied to the allocation of sale proceeds among shareholders and customers.

The no-harm test determines whether a proposed sale can proceed in a fashion which ensures customers are left at least no worse off. Some form of mitigation may be necessary to ensure this occurs. The allocation principles are applied to allocate the proceeds of a sale between customers and shareholders, whether or not some potential harm to customers must be mitigated.
In Decision 2000-41, the Board was able to attach appropriate conditions to its approval of the transaction to satisfy itself that any potential harm to customers was adequately mitigated. It was unnecessary in that case for the Board to apportion to customers any of the gain on sale. In dealing separately with the allocation question, in the circumstances of that case, the Board concluded that the gain on sale properly belonged to shareholders rather than customers.[17]

The difference between the no-harm test and the Board's approach to allocating sale proceeds can better be understood by consideration of a few examples.

The first example posits a situation where the Board is asked to approve the sale of a utility asset (e.g. a facility) that no longer provides a useful utility service or function and where the Board is satisfied that there is no risk of harm to customers either in relation to rates or reliability of service. This kind of case has been common, and there being no harm to customers, the Board would likely exercise its discretion to approve the sale. Nevertheless, although there is no harm to customers, they could be entitled to a share of any sale proceeds. According to the so-called "TransAlta Formula" (discussed in Section 3.3 of this Decision), customers would be entitled to a share of the proceeds in excess of net book value (NBV). As noted later, the historical rationale for this approach is that the difference between original cost and NBV represents excess depreciation paid by customers, which should be returned to them.

A second example would occur when the utility proposes to sell its entire utility business as a going concern – the fact situation of Decision 2000-41. In those particular circumstances, if the sale were approved, shareholders would ordinarily be entitled to all of the sale proceeds and customers would receive nothing. However, if the Board also found that the sale would expose customers to a risk of harm, the Board might also conclude, without requiring customers to be compensated out of the sale proceeds, that the harm could be mitigated by attaching appropriate conditions to its approval of the sale.

A third, somewhat similar example, would occur where the Board concludes that customers face the risk of harm as a result of the sale of a going concern but determines that the only way it can mitigate this risk is by allocating to customers some of the proceeds that otherwise would have gone to shareholders.

[17] The circumstances being that TransAlta's distribution business was being sold as a going concern and would continue to be a fully regulated service in the hands of the purchaser, UtiliCorp: Decision 2000-41, p. 28.

In these circumstances, notwithstanding that customers would get nothing according to the "allocation of proceeds" principles, the Board might, nevertheless, allocate a portion of the proceeds in mitigation of the harm, thereby clearing the way for approval of the sale. In this case, customers would only be entitled to the no-harm amount.

In the Board's view, it is clear that a case may arise in which the Board is satisfied:

(a) that customers face a risk of harm from the asset disposition that can only be mitigated by compensating them out of the sale proceeds; and

(b) that customers would **otherwise** be entitled to share in the proceeds according to the TransAlta Formula.

In the Board's view, the interplay of these two considerations could lead the Board to allocate to customers an amount exceeding that determined to represent the "harm" to which they are exposed by the disposition.

In the case of the Applications before it, the Board is of the view that, should it determine that shareholders would otherwise be entitled to the sale proceeds, the unique nature of the Assets and their historical impact on the rates paid by AGN's customers might require the Board to exercise its discretion to allocate some of the proceeds to customers in order to mitigate the risk of harm. In that circumstance, the Board must reconcile the no-harm payment to customers with the principles it has developed in relation to the allocation of sale proceeds since, as already noted, these are different than the principles embodied in the no-harm test.

### 3.3 Allocation Of Net Sale Proceeds Upon Disposition of Utility Assets

Because there is considerable controversy in this case regarding entitlement to the proceeds of any approved sale, the Board considers it useful to revisit the views set out in Decision 2000-41 with respect to allocation of utility asset sale proceeds.

The Board emphasized in that Decision that the treatment of any gain or loss on sale of utility assets would depend on the merits of a particular case. It was noted, however, that prior to the decision of the Alberta Court of Appeal in *TransAlta Utilities Corporation v. Alberta (Public Utilities Board),*[18] the Board had adopted a general rule that any difference between the NBV of utility assets included in rate base and the sale proceeds of those assets should accrue to customers, whether the difference was positive or negative. As an example, the Board noted the following passage from Order E84115:

> In Alberta, under the provisions of the *Public Utilities Board Act*, all utility assets that are used or required to be used to provide service to utility customers are permitted to be included in the rate base of the utility at the original cost of those assets (assuming the original cost is prudent).

[18] (1986) 68 A.R. 171 (TransAlta Appeal).

> In fixing and approving customer rates, the Board is required to fix a fair return on the rate base. The fair return forms part of the revenue requirement of the utility.
>
> The Board also fixes the depreciation rate to be applied to the assets which form the rate base and the resulting depreciation expense also forms part of the revenue requirement of the utility. The revenue requirement is funded through customer rates which are approved as just and reasonable by the Board.
>
> Through this process or mechanism, the Board is required to be satisfied that the owner of the utility is given the opportunity to earn a return ***of*** his investment in the utility assets and a fair return ***on*** his investment in those assets. At the same time the Board is required to be satisfied that the customers are paying just and reasonable rates for the utility service they receive.
>
> The Board generally takes into account, *inter alia*, any relevant evidence with respect to inflation or deflation in the test year or test years in fixing the fair return on rate base.
>
> Therefore, as a general rule, the Board considers that any profit or loss (being the difference between the net book value of the assets and the sale price of those assets) resulting from the disposal of utility assets should accrue to the benefit of the customers of the utility and not to the shareholders of the utility.[19]

In the TransAlta Appeal, the Court of Appeal held that the Board had erred in that case in allocating all of the gain on disposition of assets to customers. The Court agreed, in principle, that shareholders were entitled to a return of the NBV and customers were entitled to a return of depreciation expense paid through their rates. However, the Court held that compensation should be in terms of current dollars, with current dollars being measured by the ratio of the actual sale price to original cost of the assets.

In Decision 2000-41, the Board summarized its interpretation and subsequent application of the TransAlta Appeal as follows:

> In subsequent decisions, the Board has interpreted the Court of Appeal's conclusion to mean that where the sale price exceeds the original cost of the assets, shareholders are entitled to net book value (in historical dollars), customers are entitled to the difference between net book value and original cost, and any appreciation in the value of the assets (i.e. the difference between original cost and the sale price) is to be shared by shareholders and customers. The amount to be shared by each is determined by multiplying the ratio of sale price/original cost to the net book value (for shareholders) and the difference between original cost

[19] Order E84115, *Re TransAlta Utilities Corporation* (October 12, 1984), p. 10-12.

> and net book value (for customers). However, where the sale price does not exceed original cost, customers are entitled to all of the gain on sale.[20]

This approach to the allocation of sale proceeds has been referred to by several parties to the current proceedings, including AGN, as the "TransAlta Formula". The Board will use this phrase for ease of reference.

In Decision 2000-41, the Board summarized what it considers to be the general rule with respect to allocation of gains or losses on sales of utility assets:

> The Board accepts that where particular rate base assets are being sold so that they are no longer part of the regulated rate base, the disposition of the gain on sale should, as a general rule, be treated according to the principle set out by the Court of Appeal in the TransAlta Appeal and subsequently applied by the Board.[21]

For the purpose of this Decision, the Board confirms this general rule but notes once again that it will be subject to the particular circumstances of the case.

## 4 JURISDICTION

The Board heard argument from AGN, the NCC, Calgary, and Canfor regarding the issue of the Board's jurisdiction to utilize proceeds of the sale to satisfy the no-harm test and to otherwise allocate the proceeds of sale.

### 4.1 Positions of the Parties

#### AGN

AGN clearly acknowledged that the Board does have jurisdiction to condition approval of the sales on the basis that a portion of the sale proceeds be utilized to ensure that customers suffer no harm from the sales. However, AGN argued, the Board does not have jurisdiction to order the allocation of proceeds to customers over and above the amount required to ensure no harm to customers.

AGN's jurisdictional argument had three main components. First, AGN argued that the Board, as a creature of the Legislature, does not have any powers other than those conferred by statute. As the Board's enabling statutes do not contain an express power to allocate the proceeds of sale to customers, the Board does not have this power.

Second, AGN argued that an order purporting to deal with the proceeds over and above what is required to ensure the customers suffer no harm would constitute an expropriation without compensation, which is not authorized by law. Legislation that impairs individual rights is, as a matter of public policy, strictly and narrowly construed. Based on the law regarding

[20] Decision 2000-41, p. 26-27.
[21] Decision 2000-41, p. 28.

expropriation, AGN argued that the Board's enabling statutes would require clear and unambiguous language in order to empower the Board to deprive the company of the ownership or full benefit of its own assets. In law, AGN stated, there is a presumption against expropriation without compensation. Neither the GU Act nor the PUB Act provide any basis for allocation of any portion of the proceeds of sale of a utility's assets. As a result, AGN argued, the Board does not have the power to allocate the proceeds over and above the no-harm threshold.

Finally, AGN argued that the Board's rate-making powers are prospective, not retrospective and an order of this nature would constitute retroactive rate-making.

**NCC**

The NCC argued that the Board does have the jurisdiction pursuant to section 25.1 of the GU Act to approve the proposed sales with conditions allocating the proceeds to customers.

The NCC cited *ATCO Ltd. v. Calgary Power Ltd.*[22] in which the Supreme Court of Canada recognized the broad jurisdiction of the Board to "safeguard the public interest in the nature and quality of the services provided to the community by public utilities" which it described as being "of the widest proportions". The NCC argued that the Board has the power to allocate proceeds to customers "by necessary implication",[23] based on the wording of the Board's enabling legislation. The NCC noted that this jurisdiction is required for the Board to accomplish its mandate and furthermore, that there are no contrary provisions in other statutes or the GU Act. The NCC argued that section 25.1 of the GU Act is intended to give authority to the Board to ensure that regulated assets–encumbered by the regulatory compact or "affected with a public interest"–are not disposed of without due regard for resulting harm to customers. The NCC argued that as a result, the Board has jurisdiction under section 25.1 of the GU Act to approve the sale with conditions to ensure that customers were held harmless.

The NCC noted that the P&NG assets AGN proposed to sell were purchased for utility service, not for private consumption, and that AGN's interest is, therefore, encumbered by the regulatory compact. In support of this argument the NCC cited the text, "The Economics of Public Utility Regulation", in which I.R. Barnes states that "utilities are distinguished from other businesses by the formal obligations to the public which are imposed upon such companies."[24]

The NCC also rejected the argument of AGN that a Board order allocating proceeds to customers would constitute retroactive rate-making. The NCC noted that the Applications seek approval for sales to occur in the very near future. The Board, the NCC believed, must consider the impact on customers in the present and future, which in its view, has nothing to do with retroactivity.

[22] [1982] 2 S.C.R. 557 at 576.

[23] Macaulay R. W. and Sprague J.L.H. "Practice and Procedure before Administrative Tribunals" (2001) Carswell Publishing – Thomson Canada Limited) at 29-4, citing *Bell Canada v. Canada (Canadian Radio Television and Telecommunications Comm.)* [1989] 1 S.C.R. 1722, 38 Admin L.R. 1 at 33.

[24] Barnes, Irston R. "The Economics of Public Utility Regulation". (Appleton – Century-Crofts, Inc. New York 1942) at p. 43.

In response to the argument of AGN that the allocation of proceeds to customers would be an expropriation without compensation, the NCC stated that this principle has no application to the case at hand. The NCC stated that there was no analogous deprivation of rights, as no one was forcing AGN to sell the assets against its will. In fact, these were voluntary sales and it was AGN that was seeking approval from the Board. The NCC observed as well that none of the cases cited by AGN dealt with an allocation of proceeds of sale of regulated assets used by a regulated utility.

**Calgary**

Calgary also argued that the allocation of proceeds to customers does not constitute expropriation. Calgary stated that section 83(1)(a) of the PUB Act gives the Board the power to consider all revenues of the utilities under its jurisdiction. No expropriation is involved, Calgary observed, because AGN will receive back its full investment in the assets and has been compensated for the purchasing power tied up in those assets. Furthermore, the legislature gave the Board the authority to interfere in the right to property if a public utility or gas utility is the owner of that property. Calgary noted that, based on sections 91.1 of the PUB Act and 25.1 of the GU Act, AGN must seek the approval of the Board in order to sell these assets.

Calgary also argued that the allocation of proceeds to customers does not constitute retroactive rate making, because giving customers the benefit of the proceeds now in their rates does not have the effect of changing rates that have already been collected.

**Canfor**

Canfor argued that AGN's argument on jurisdiction is inconsistent with the past practice of the Board in other decisions and with AGN's position in past applications to the Board. Canfor also noted that the assets in question are not private assets, but regulated assets in utility service, and therefore AGN did not have the right to deal with the assets in the same way it would if it owned them outright.

### 4.2 Views of the Board

As discussed in Section 3 of this Decision, the no-harm test and the allocation of sale proceeds are separate steps in the Board's consideration of an application for approval pursuant to section 25.1 of the GU Act. The no-harm test represents a discretionary threshold: the Board must be satisfied that, with or without mitigation, the impacts of the proposed disposition will leave customers at least no worse off. If the Board is satisfied that customers will be at least no worse off, the Board must then determine how the proceeds of sale should be allocated between utility shareholders and customers. The two steps may be, but are not necessarily, linked.

As noted, the Board's no-harm test has been developed over the years to provide some structure to the exercise of its discretion pursuant to section 25.1 of the GU Act and section 91.1 of the PUB Act. In Decision 2000-41, the Board established that, in appropriate cases, it may allocate to customers proceeds that would otherwise flow to shareholders.

The Board considers that its power to mitigate or offset potential harm to customers by allocating part or all of the sale proceeds to them, flows from its very broad mandate to protect consumers in the public interest. This mandate has been recognized by the Alberta Court of Appeal[25] and the Supreme Court of Canada.[26] It has also been referred to recently on a number of occasions by the Board.[27] In keeping with this broad mandate, section 10(3)(d) of the *Alberta Energy and Utilities Board Act*[28] authorizes the Board to attach conditions to any order that the Board considers to be in the public interest. In the Board's view, conditions allocating sale proceeds to customers in order to mitigate harm caused by proposed asset dispositions are fully within its jurisdiction as characterized by the courts and reflected in the Board's governing legislation.

Over the years, the Board has approved a number of utility asset dispositions in relation to which the Board was satisfied either that customers would not, on balance, be harmed or, if they did face some risk of harm, appropriate conditions could be attached to the Board's approval to mitigate the harm. In these cases, customers were not required to be compensated in order to mitigate the harm.

In many (if not most) of these cases, however, the Board did allocate some or all of the net sale proceeds to customers according to the general rules previously noted. In the Board's view, the allocation of proceeds in these cases was distinct from the threshold question of harm to customers.

The Board's jurisdiction to allocate proceeds according to the TransAlta Formula has never been seriously questioned, even where customers will either not be harmed by the disposition or can be protected from harm by other appropriate approval conditions. This is not surprising, since the Board's historical approach is based on equitable principles rooted in the regulatory compact. In the Board's view, this general rule received more than tacit approval from the Court of Appeal in the TransAlta Appeal. The Board considers that the Court of Appeal has accepted that the Board has jurisdiction to include as a revenue offset an amount equal to accumulated depreciation to be returned to customers (even in circumstances where the no-harm test is not an issue).[29] The Board does agree, however, with AGN that, if shareholders would otherwise be entitled to all of the sale proceeds, the Board's jurisdiction to allocate funds to customers should be limited to compensating them for any identified risk of harm that cannot otherwise be mitigated.

AGN has contended that in those cases where an amount greater than the no-harm amount is allocated to customers, the Board is unlawfully expropriating a utility's property. The Board notes, however, as was pointed out by the NCC, that none of the expropriation cases cited by AGN deal with an allocation of proceeds of the sale of regulated assets of a regulated utility. Therefore, the Board does not find them particularly helpful.

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[25] *Dome Petroleum Ltd. v. Alberta (Public Utilities Board)* (1976) 2 A.R. 453, *affd.* [1977] 2 S.C.R. 822.

[26] *ATCO Ltd. v. Calgary Power Ltd.* [1982] 2 S.C.R. 557, at 576 (per Estey J.).

[27] For example, Decision 2000-41, p 7; and Decision 2000-46, *ESBI Alberta Ltd., 2001General Tariff Application, Phase I & II, Part A: System Support Services – Thermal Power Purchase Arrangements (Appendix E)* (July 11, 2000), p. 9.

[28] S.A. 1994, c. A-19.5, as amended.

[29] TransAlta Appeal, at 181-182.

The fact that a regulated utility must seek Board approval before disposing of its assets is sufficient indication of the limitations placed by the legislature on the property rights of a utility. In appropriate circumstances, the Board clearly has the power to prevent a utility from disposing of its property. In the Board's view, it follows that the Board can also approve a disposition subject to appropriate conditions to protect customer interests.

As to AGN's argument that allocating more than the no-harm amount to customers would amount to retrospective rate-making, the Board again notes the decision of the Court in the TransAlta Appeal. The Court of Appeal accepted that the Board could include in the definition of "revenue" an amount payable to customers representing excess depreciation paid by them through past rates. In the Board's view, no question of retrospective ratemaking arises in cases where previously regulated rate base assets are being disposed of out of rate base and the Board applies the TransAlta Formula approved by the Court of Appeal.

# 5 APPLICATION OF THE NO-HARM STANDARD

As indicated in Section 3.2 the Board must consider the impact of the Applications on customers in terms of both service and rates to determine whether they will be held harmless from the effects of a proposed sale of utility assets.

In this section of the Decision, the Board first considers whether disposition of the P&NG assets by AGN will affect the service levels currently available to customers. Second, the Board considers whether disposition of the P&NG assets will create a risk of financial harm to customers through an increase in their cost of gas supply.

## 5.1 Impact on Service Levels

### 5.1.1 Positions of Parties

**NCC**

The NCC stated that it was opposed to the sales of the P&NG assets on the basis that the sales would result in harm to customers. Consequently, the NCC urged the Board not to approve the Applications.

In the NCC's view, these properties were used and useful utility assets. AGN or its predecessors had been providing utility service since 1923. The NCC argued that the most appropriate use for the COP was to continue in its present function of providing lower cost gas supply. NCC pointed out that while AGN stated several times during the hearing that the P&NG assets were no longer required for utility service, the statement contradicted AGN's definition of utility service, which included the provision of gas supply at the lowest possible cost.

The NCC stated that the amount AGN proposed to pay customers to keep them from harm as a result of the sale was inadequate. The NCC stated that customers would have to receive more than 100% of the sale proceeds to provide any measure of assurance that no harm will result. The NCC noted that AGN had calculated the no-harm threshold using a higher gas cost than what customers were currently paying.

The NCC argued that this was clear evidence that the P&NG assets were still used and useful and an integral component of providing utility service at the lowest possible cost.

The NCC noted that the price forecasts presented in these proceedings assumed open market natural gas prices would be higher than the cost of COP in the future. The NCC's position was that there was a clear upward trend in natural gas prices. The NCC argued that in a high price environment, customers would benefit if AGN were to continue operation of the P&NG assets. Approval of the Applications would result in customers losing the value or benefit of COP.

The NCC noted that customers paid for the P&NG assets during periods when gas prices were low, and that it was not in the interest of consumers to sell these assets when gas prices were high and customers were benefiting from low cost production. The NCC stated that a one-time benefit arising from the sale of the fields would be inferior to the benefit of ongoing production from those fields.

The NCC noted that the value of COP to customers via the GCRR from January 1, 2001 to May 31, 2001 was about $49.1 million and that it would only take four similar five-month intervals to equal the no-harm value proposed by AGN. For this reason, the NCC suggested that it would be prudent for the Board to reject the proposed sales and keep the P&NG assets for the benefit of customers. The NCC also noted the production levels used to determine the $49.1 million, and stated that additional value would flow to customers if production levels were not constrained at recent historical levels.

The NCC recognized that a situation might arise where the price of natural gas drops below the cost of COP. In that situation, value would be lost, as customers could purchase gas supply more cheaply from the open market. To remedy this situation, the NCC stated that production could be decreased until market prices increased enough to justify higher output levels. This risk was one that the NCC stated it was willing to take.

The NCC noted that AGN was reluctant to continue in its role as a provider of natural gas and to continue ownership and operation of the P&NG assets. The NCC also noted that AGN was fairly paid in the past through rates for the service provided. However, the NCC acknowledged that, in the long-run, it may not be in the best interests of customers to require AGN to sell natural gas, manage operations, and retain ownership of the assets, particularly if these functions were not consistent with AGN's business strategy.

The NCC suggested an alternative to this situation, whereby AGN would retain ownership of the assets but a third party would operate the P&NG assets on a fee basis through some form of contractual arrangement. The NCC pointed out that this was the same type of concept used by ATCO Gas - South (another division of ATCO Gas and Pipelines Ltd.) with respect to its Carbon Storage facilities.

The NCC stated that it was prepared to enter into negotiations with AGN to devise an incentive type plan that would encourage AGN to maintain ownership and operation of the P&NG assets. The NCC saw this proposal as a natural extension of the North Core Agreement, which specifically provided incentives to AGN for good performance.

The NCC identified that "leakage" of benefits outside of the Province was another reason not to permit the sale of the P&NG assets in their present function. If the sale of assets were to be approved, approximately $120 million would be lost to income taxes. In addition, a portion of the gain on sale would ultimately be paid to non-Albertan shareholders.

The NCC summarized its position by stating that continued ownership provides the maximum financial security of supply at the lowest cost and protection against future risk. A member of the NCC Policy Panel stated that:

> In essence, no payment can guarantee what a bird in the hand will provide in the long term, if the gas is ours today and the gas is ours 20 years from now or 30 years from now, you can't possibility [*sic*] replicate that. You only make assumptions and economists are economists and so I think the point being that with 100 percent payment, we still will not know that we've achieved the full value of that field.[30]

#### Aboriginal Communities

The Aboriginal Communities stated that they were concerned about the high cost of natural gas, would like lower natural gas prices and wanted to increase production from the fields. Accordingly, the Aboriginal Communities supported the position of the NCC that the sales should not be allowed and that AGN should be directed to increase production.

The Aboriginal Communities stated that they were not seeking a windfall gain as a result of the sales and were not requesting the sales, which were being proposed by AGN's shareholders. The Aboriginal Communities stated that they would rather see the *status quo* maintained, or preferably an increase in production, thereby increasing the future benefits of COP.

The Aboriginal Communities argued that by rejecting the sales, the Board did not have to deal with sharing formulas, jurisdictional arguments, and property rights. Presumably, the Aboriginal Communities argued, the threat of future litigation that might arise if the sales were approved and an allocation of proceeds not in AGN's favour would also be avoided. They also argued that the proposed sales should be rejected so that the benefit of COP continued for future generations of Aboriginal Community members.

#### Calgary

Calgary noted that one of the decisions facing the Board was the determination of what was in the public interest. Calgary suggested that the public, being customers, should determine what was in the public interest. Calgary stated that there was a clear consensus of what customers wanted, namely that it was not in their interest that the properties be sold.

[30] Tr. p. 299-300

Calgary stated that there was no clear direction from the Alberta Government that these properties should be sold. It suggested that the introduction of the proposed *Natural Gas Price Protection Act* was an indication that the Government wanted to maintain a regulatory involvement in natural gas and shield customers from higher prices. Calgary argued that COP accomplished this goal, and therefore the sales should not be allowed.

Calgary stated that AGN did not have the right to unilaterally dispose of the properties under the governing legislation. It argued that the public was better off with these properties continuing in utility service. Furthermore, Calgary believed that the Board was not statutorily constrained and could introduce complex alternatives to maintain the public interest.[31]

Calgary argued that the sale of the properties was also premature. It noted that AGN anticipated providing natural gas supplies to customers for at least five years. Under the circumstances, it would be unreasonable to sell utility assets that would provide substantial benefits to those customers over that time period.

#### Canfor

Canfor argued that the Viking gas field was a useful tool in AGN's supply portfolio. The Viking field, it suggested, provided a relatively low-cost and stable supply of gas that was economic to produce. Canfor also argued that it would be economic to expand COP. Canfor noted that the Board should consider that customers paid for the costs of COP in previous years when those costs were higher than market prices.

### Mr. Wolosinka

Mr. Wolosinka, a resident of the Town of Viking, expressed two concerns about the sale of the Viking P&NG assets. First, he noted that the gas produced by AGN helped cushion consumers from recent high prices for natural gas. In his view, a sale to a commercial producer might have a detrimental affect on prices to consumers in the future. Second, Mr. Wolosinka observed that the field provided significant economic benefits to the Viking community. A sale to a commercial producer, that could result in the depletion of the gas field faster than it would be depleted if AGN retained it, might have a negative impact on the well being of Viking. He considered that having AGN retain the Viking P&NG assets would represent a win-win situation for everyone.

#### AGN

AGN argued that, as it lost the role of a monopoly gas supplier in Alberta, COP was an aspect of that former monopoly function that was no longer required for utility service. With respect to gas supply, AGN's view was that the competitive market protected the interests of customers. AGN noted that one of the NCC witnesses also agreed with its position that the P&NG assets, in the physical sense, were no longer needed for utility service.

[31] Tr. p. 1031-1032

AGN submitted that the sale of the P&NG assets was also consistent with the continuing evolution of gas deregulation in the province, where the merchant and supply functions previously performed by gas utilities were being replaced by open-market competition in the form of direct sales. AGN considered that it had become effectively a default supplier, and could be displaced entirely from the merchant function at any time.

AGN argued that if the P&NG assets were sold, customers would be better off than they would be if the assets remained in regulation. AGN noted that gas producing properties carried with them risk and uncertainty with respect to price and to cost of production and, accordingly, considered that capturing fair market value at historically high levels conferred benefits and mitigated risk to customers in recognition of their historical reliance on its assets. AGN also noted that, with the removal of the P&NG assets from its cost of service, its distribution rates would be reduced.

### 5.1.2 Views of the Board

The Board notes that the P&NG assets have been used and useful in providing a source of natural gas to customers since 1923, when P&NG assets in the Viking Kinsella field were acquired. The P&NG assets were originally used by AGN to provide monopoly gas supply service to its core customers. During that period, customers had no alternative source of supply and had to rely on their integrated gas utility to meet their needs.

The Board agrees that, since the acquisition of the P&NG assets, the gas supply market has evolved significantly. Customers are now no longer tied to their local distribution company for gas supply and may choose to purchase gas from a retail marketer. Gas utilities with supply obligations to customers also have options and need not own gas producing properties to meet those obligations. Instead, gas utilities such as AGN, can readily purchase gas on the open North American wholesale market.

With these developments, the role and usefulness of COP has also evolved. Because AGN procures most of the gas needed to supply its customers on the open market, COP has, for the past 30 years or more, been used to reduce the cost of gas to AGN's customers. COP reduces costs to customers because, unlike the case for gas purchased on the open market, there is no mark up on the cost of production.

With regards to security of supply, AGN's position is that, since gas supplies are readily available on the open market and can be purchased on either a short or long-term basis, the P&NG assets in question are no longer required for utility service. As a result, AGN argued, there is no concern regarding security of supply. The Board notes the general agreement among parties with AGN's position regarding security of supply, although the NCC Policy Panel did suggest that the existence of COP did give customers an additional sense of security or "comfort".[32]

[32] Tr. p. 277-278

With respect to the impact of COP on gas costs, the Board notes that even in periods of relatively low market prices, AGN historically continued to use COP. During eight of the ten years between 1987 and 1996, the market price of gas was less than the cost of COP. During these periods, however, AGN maintained a level of production that was in the order of 12-13% of total supply requirements.

At times when market prices have exceeded the cost of COP, COP has historically accounted for approximately 15% (on average) of AGN’s gas supply portfolio. Despite several requests by customers over the years, AGN has resisted increasing production significantly beyond these levels. AGN has maintained the position, until now, that COP is a “legacy asset” which should be used only as needed, in order to preserve its benefits for future generations of AGN customers.

The Board noted in Decision 2000-10 that retail gas marketers are not “gas utilities” within the meaning of the GU Act.[33] Although some regulated utilities such as AGN continue to own gas producing properties, the supply and merchant function is no longer a regulated, monopoly function. Having regard to the development of the competitive wholesale and retail natural gas markets over the last several years, the Board agrees with AGN that COP is no longer required in order to provide regulated utility service to customers. The Board does not believe that either the safety or reliability of service customers would receive from AGN would be materially affected (if at all) by the sales of the P&NG assets. Accordingly, all other things being equal, the Board would not deny any of the Applications because of impacts on service levels.

The Board also notes that AGN has indicated that it no longer wishes to own and operate the P&NG assets. The Board accepts that if these assets are no longer required for utility service, the lack of corporate motivation to optimize the value of these assets is unlikely to produce beneficial results for customers. The Board also notes, however, the willingness of customers to allow AGN, if it no longer desires to operate the fields, to enter into a fee for service contract with a third party. Customers indicated that they would also be willing to provide AGN with an incentive to manage this contract. The Board would encourage AGN to consider this option if it continues to retain control of these assets over the near- to mid-term.

### 5.2 Loss of Benefits to Customers from COP

Although no longer required for utility service, the Board is also of the view that since 1996 sales customers have benefited from the cost of COP being lower than market prices. In particular, the Board notes that savings to customers will occur when natural gas prices exceed $2/GJ, since the cost allocated to the GCRR for COP covers only royalties (Crown and freehold), which are significantly less than the market price. In this sense, COP does provide a real hedge against increasing market prices and, to that extent, it continues to be a “useful” asset from the customer’s perspective. Therefore, given the real benefit enjoyed by customers as a result of AGN’s ownership and production from the P&NG assets, the loss of those benefits does expose customers to a significant risk of material harm in the form of substantially higher gas prices.

[33] Decision 2000-10, *Apollo Gas Complaint Against Northwestern Utilities Limited and ATCO Gas and Pipelines Ltd. Operating as ATCO Gas with respect to Termination of Billing Service* (February 28, 2000), p. 2.

In the Board's view, it is this risk of harm which is critical to its consideration of the Applications. The Applications before the Board present a unique problem. On the one hand, AGN seeks to dispose of gas producing rights and the associated production and gathering assets, which it says it no longer requires to provide regulated service to its customers.[34] On the other hand, it is beyond doubt that, by virtue of AGN's ownership of these rights and the gas production realized pursuant to those rights, AGN customers have benefited over the years by a lower cost of gas than they would have had their gas utility been procuring gas supply strictly on the open, North American market.

As already noted, the Board considers that the potential impact of the loss of COP benefits as a result of the proposed sales of the P&NG assets is a key factor in these Applications. Over time, customers will lose the benefit of gas costs being reduced by COP and that lost benefit must be quantified. Since the lost benefit represents a potential risk of material financial harm, it must be either offset or mitigated to the satisfaction of the Board before the Application creating the risk of harm can be approved.

Most of the hearing was taken up by evidence relating to the quantification of the risk of harm to customers as a result of the sale of the various P&NG assets. The Board notes that there was general agreement among the parties, including AGN, that in this case the no-harm test should be based on a calculation of the net present value of benefits from COP that customers would expect to receive if the P&NG assets were to remain in utility service over their useful life. The net present value of COP to consumers was calculated using estimated production levels (including cost of production), price forecasts, and an appropriate discount rate over an appropriate time period. It was in relation to these four parameters that parties had significantly different positions.

### 5.2.1 Positions of Parties

#### NCC

The NCC commented that the most important decision that the Board would make in this proceeding was to determine the appropriate **production level** that should be used in the forecasts of future utilization of the P&NG assets. These forecasts, it was argued, would play a significant role in determining the value of the no-harm test.

The NCC stated that its position regarding forecast levels of production was that there needed to be unconstrained production to optimize the cost reduction for customers. The NCC agreed that the reports prepared by McDaniel & Associates Consultants Ltd. (McDaniel Report)[35] and submitted by AGN was reasonable with respect to capital, operating, and production rates.

The NCC argued that there was no credible basis to establish that a predetermined production level of 15%, as had been the practice of AGN, existed.

[34] AGN's position is that it can meet its obligation to supply and deliver gas to its customers by procuring the gas supply on the open market – i.e. without itself having to own the rights to exploit natural gas reserves.

[35] Refer to response to BR-ATCOGAS-V.2(b) for McDaniel Report.

The NCC noted that five of the six Board decisions used by AGN to support their 15% COP ratio make no reference to the term "target ratio," nor was there any reference to a longer-term production ratio. Any reference to these ratios, the NCC suggested, was simply an acknowledgement by the Board that the production ratio was applicable to a particular year.

The NCC also noted the general policy statements made by AGN in previous proceedings regarding COP:

- production levels were dictated, at least in part, by the cost of alternative supply.[36]
- production levels would change as supply and demand changes.[37]
- as contractual obligations have to be met, if the weather is warmer than normal, COP would be reduced.[38]
- subject to contractual requirements relative to earlier purchases as to how much supply can be taken to the extent that COP can be increased, then it would be sourced first.[39]

The NCC stated that the general policy statements indicated that a variety of factors impacted the level of COP. It argued that there was no policy intended to cap production at 15% or any other level. The NCC noted that where COP was concerned, the production ratio was set in response to the circumstances of the time. The NCC argued that circumstances set COP for the past 77 years, and that circumstances should also continue to dictate the level of COP now and in the future.

The NCC noted the historical COP levels also confirmed that AGN did not have target production ratios.

| Year | COP Percentage |
|---|---|
| 1945 | 97 |
| 1963 | 33 |
| 1966 | 21 |
| 1967 | 17 |
| 1970 | 36 |
| 1983 | 16.5 |
| 1984 | 11.84 |
| 1985 | 11.96 |
| 1997 | 18 |

The NCC noted that there was no evidence indicating that there were physical constraints to increasing production, or that customers were reluctant to pay the costs of enhancing production levels. The NCC pointed out that it had initiated applications to the Board to require AGN either to increase production or to compensate customers for acting imprudently by not increasing COP in times of record high prices.

[36] NCC-ATCO.5(b) (c) (d) Attachment 3, pg 10-11 of 17
[37] NCC-ATCO.5(b) (c) (d) Attachment 3, pg 12 of 17
[38] Tr. p. 97-98
[39] Tr. p. 98

The NCC noted that value would be lost if COP was not increased to take advantage of the available reserves. There was no justifiable reason, the NCC believed, for AGN to curtail COP in the context of utility operations. The NCC stated that AGN's argument of constraining COP so that future customers could benefit from this resource actually resulted in a greater benefit for shareholders. Constraining COP, the NCC believed, allowed millions of dollars to flow to shareholders, who bore minimal risk in the investment and operation of the P&NG assets.

The NCC pointed out that AGN had conducted an internal study in 1998 that examined the economics of increased production. The result of the study indicated that increased production was economically justified. By increasing production, AGN would maximize the asset value of the field, increase gas recovery, and improve system flexibility.

With regard to the impact of **price forecasts** in calculating the no-harm test, the NCC noted that there were several sources for these forecasts. The available price forecasts ranged from conservative to aggressive, depending on the source.

The NCC suggested that the most appropriate price forecast to use was McDaniel's January 1, 2001 forecast, as it coincided with when the sales agreements were dated. This view was confirmed during cross-examination.[40]

With regard to **discount rates** to use in calculating the no-harm threshold, the NCC argued that the appropriate discount rate was the 8% weighted average, with mid-year discounting. In determining the appropriate discount rate, the NCC suggested that a weighted average be used. The NCC stated that in arriving at the proposed discount rate, it had divided gas consumers into broad categories, namely residential, commercial, industrial, and distribution, and then applied a weighting factor, determined by market share, to appropriate discount rates for each class.

The following table demonstrates the calculations used by the NCC to determine the proposed discount rate:

| | Market Share% | Assumed Discount Rates |
|---|---|---|
| Residential | 44 | 7 |
| Commercial | | |
| Apartment Buildings | 10 | 7 |
| Public Institutions | 18 | 6 |
| Small Businesses | 18 | 12 |
| Subtotal | 46 | |
| Industrial | 5 | 12 |
| Transportation | 5 | 8 |
| Weighted Average | | 8.02 |

[40] Tr. p. 697

The NCC argued that in determining discount rates, it was appropriate to use a weighted average of both before- and after-tax discount rates. Alternatively, discount rates specific to each customer class could be applied to a weighted portion of customer benefits to determine the no-harm value. To simplify the exercise, a weighted average of discount rates could be used.

The NCC noted that AGN did not disagree with the weights used by the NCC in determining the weighted average, and also agreed that the different customer classes would have different discount rates.

The NCC noted the position of AGN regarding the use of end-of-year discounting, and the idea that all revenues and expenditures could be assumed to occur on December 31. The NCC did not agree with this position, and noted that consumers were billed for gas purchases on a monthly basis, making end-of-year discounting inappropriate. The NCC calculated that, in the context of a 12% discount rate, using mid-year discounting would result in a net present value of the no-harm test that was approximately 6% greater than if end-of-year discounting was used.

**AGN**

In AGN's view, the McDaniel Report represented the type of evaluation that would normally be used by a commercial production company in evaluating production assets. AGN did not consider, however, that any production company would, or should, take into consideration in its evaluation the intricacies or nuances associated with the cost structure of a regulated utility. Therefore, AGN argued that the NCC determination of no harm, which was premised on the McDaniel evaluation, was to some extent based on the assumption that a commercial production company owned the P&NG assets, instead of AGN. AGN noted that if the P&NG assets remained in rate base, customers would expect AGN's cost structure, and not that of a commercial production company, to be used in reference to continuing COP.

With respect to the COP profile, AGN argued that the key aspect of the no-harm calculation related to the appropriate **production levels**. In arriving at its no-harm calculation, AGN provided an estimate of the expected stream of benefits that customers had enjoyed on a historical basis at least since 1983 and submitted that the historical COP profile over the mid-eighties to the present was the appropriate level of customer use which should be recognized in the no harm determination. AGN acknowledged that in the past it had determined the appropriate level of COP to be used and that COP was operated in a range of 15% of total sales customer requirements, a level that has been consistent, and accepted by the Board, for at least eighteen years. It also submitted that the P&NG assets were viewed on an inter-generational equity basis, as legacy assets, and that COP was intended for the long-term benefit of customers. AGN also stated that it had always resisted the attempts of then present customers to sequester all or a disproportionate share of the benefits of COP at the expense of future generations of customers and that it had actually constrained production that it could have brought on to the system. AGN noted that, given market and capacity constraints, it had in fact maximized production rates over the last five to eight years.

With regard to the appropriate **price forecast** for the no-harm calculation, AGN noted that the price forecast assumed would have a significant impact on the calculation of the future value of the P&NG assets. AGN stated that it used a price forecast at October 1, 2000 because, in its view, this forecast was the one considered by the various parties which had submitted bids for the various properties included in the Applications, and therefore was embedded into the decision-making process of the purchasers.

By comparison, AGN noted that it also undertook a sensitivity analysis in order to assess the impact of using a more conservative price forecast, such as the January 1, 2001, Banker's Mean. Using this price forecast for the utility no harm evaluations, the amount for the Viking Application was reduced from $182.4 million to $113.8 million, the amount for the Westlock Application became a negative $3 million, and the amount for the Beaverhill Application dropped from $11.4 million to $3.5 million. AGN submitted that this level of conservatism was more consistent within the utility framework and ought not to be ignored when the impact of price forecasts on the no harm evaluation was considered.

AGN stated that the selected **discount rate** represented a conservative estimate of the long-term, before-tax weighted average cost of capital for the company. As it was the company investing in the P&NG assets, the calculation of the no-harm test should use the corporate weighted average cost of capital.

AGN also noted that the cost of capital was the cost that would flow to customers through rates in the event that the production assets continued in utility service. Also, benefits arising from continued utility production would be used to offset other utility costs to customers, which would be based on AGN's cost of capital.

AGN stated that the discount rate used in the no-harm test should not be confused with the interest rate that might be achieved by customers in the event that proceeds were returned over time. The 12% discount rate allowed a comparison between the value of retaining the assets in utility service and a sale of the assets. The investment of customer funds to be refunded over time was a separate issue, requiring a distinct analysis to compare the various investment alternatives.

AGN submitted that for the purpose of valuing the P&NG assets, the NCC analysis was neither consistent nor coherent. AGN stated that the selected discount rate must be designed so as to allow the company to compare the sale option against the net stream of benefits which would be expected to be derived from continued COP, including the effect of continued incremental investment by AGN to maintain COP. It submitted that none of the valuations of the P&NG assets made by the independent consultants that it engaged had subscribed to the proposition that a social discount rate should be used.

AGN noted the distinction between a discount rate used for investment purposes and one used to determine social benefits. AGN rejected the NCC approach that used a social discount rate and argued that the discount rate used should be one used in deriving an investment decision, not a social discount rate involved in a social benefit cost analysis. AGN further argued that the original analysis of the NCC was flawed and suffered from a number of errors.

### 5.2.2 Views of the Board

As already indicated, the Board is not persuaded that continued ownership by AGN of the P&NG assets is strictly necessary for utility service and customers would not likely experience a reduction in service levels if the sales were approved.

Nevertheless, the Board has concluded that each Application does expose AGN's customers to a risk of financial harm as a result of the lost benefit of COP. Therefore, the Board has considered the evidence and submissions with respect to the net present value of the lost benefits in relation to each Application and has made determinations with respect to each Application.

In each case, based on the evidence, the Board has determined what it considers to be the appropriate parameters (production level, gas price forecast, discount rate and discount period) and calculated the net present value of the lost benefits based on those parameters. That net present value represents, in each case, the no-harm threshold for the Application. If the sale proceeds available for allocation to customers[41] exceed the no-harm amount determined by the Board, then the Board believes that the risk of harm to customers from each proposed sale can be mitigated. That is, customers can be compensated out of the net sale proceeds in an amount equal to the no-harm amount, leaving them at least no worse off and, therefore, satisfying the no-harm test.[42]

These no-harm thresholds have been computed using both accounting data and assumptions. The accounting data, such as NBV and depreciation, are subject to some disagreement between the parties, but the differences are not as significant as the differences in the assumptions used by AGN and the NCC in their determinations of the no-harm thresholds. As already noted, the key assumptions used in the calculations involve the selection of the appropriate production levels, price forecast, discount rate and period.

#### 5.2.2.1. Production Level

In giving its final approval to the GCRRs proposed by AGN in the past, the Board generally accepted the levels of COP established by AGN. Based on the evidence presented in these proceedings, the Board is satisfied that the COP levels were historically set in the range of approximately 15% of total gas supply.

However, the Board agrees with the views expressed by all of the parties to the hearing that the natural gas market is evolving. The Board is particularly cognizant of the substantial volatility in the market prices for gas that has recently occurred. The Board is also aware that the NCC previously approached AGN, in light of this price volatility, to initiate discussions for increasing COP. The Board also notes that the NCC has since formally objected to the GCRRs proposed by AGN using those historical levels of production.

[41] See Appendix 2 for calculations of these amounts.

[42] As discussed below under Section 6 ("Allocation of Proceeds for Approved Sales"), the no-harm threshold is, however, only a minimum that must be paid to customers in order to satisfy the no-harm test. Customers may be entitled to a greater amount by virtue of the TransAlta Formula.

The Board acknowledges the position taken by AGN in these proceedings that, historically, it considered these assets to be "legacy assets", i.e. that they should be preserved for the benefit of future generations of AGN customers. However, during these proceedings, three separate reports were submitted confirming that increased levels of COP were feasible:[43]

(a) an internal report prepared by Northwestern Utilities Limited in May 1998 entitled "Viking Kinsella Field Development Proposal" (NUL Report);

(b) a report prepared by Fekete Associates Inc. in September 1998 entitled "Technical and Economic Evaluation of Production and Gathering Properties as at September 1, 1998"; and

(c) the McDaniel Report.

The Board notes that the Viking field, in particular, has been in production for almost 80 years, significantly longer than one might expect of a commercial natural gas operation. It is clear that there has already been a significant inter-generational benefit from these assets and that their legacy aspect has and continues to be realized. The Board also notes and concurs with the view in the NUL Report that, in order to optimize recovery of the reserves, improvements in the field's deliverability are necessary. Furthermore, even with these proposed increased production levels, the Viking field is expected to still be producing in 2025.

The Board is satisfied that an increase in the level of production, which will ensure the optimal reserve recovery, will still provide a significant legacy for future customers.

The Board notes that, for its calculations, AGN used a starting point of production levels of about 15% of the sales volume. Over a ten year period, the sales volumes were reduced by about 45% in anticipation of reductions in the level of sales customers due to their migration to retail gas marketers. The Board does not believe that for the purposes of estimating no harm from the sale of COP that this approach was realistic. It assumes that future open market gas prices will not be higher than the costs of COP and that COP production levels must be kept at 15%, assumptions that appear to be inconsistent with much of the evidence provided in the hearing regarding both the future price of natural gas and the production capability of the fields.

The increased level of COP proposed by the NCC would amount to approximately 30% of total gas supply in the initial year and would decline to approximately 16% in about 6 years, if unrestrained. The Board recognizes that under actual operating conditions this level would need to be varied by AGN in accordance with the variable components of gas supply that may require future restrictions in COP at any particular time. Over the time period in question, however, the Board is prepared to accept that this represents a reasonable average decline rate.

The Board notes that the McDaniel Report was accepted by both AGN and the NCC as being a reasonable estimate of production levels that can be achieved and was used by the NCC for their production levels. The Report was, in fact, also provided to the prospective buyers in order for them to evaluate the properties.

[43] All three reports are attached to the response to BR-ATCOGAS-V.2(b).

While the Board accepts that, historically, the approximate production level of 15% COP was consistent with AGN's stated view that COP was a "legacy asset", the Board now believes, particularly in light of the requests by customers, the significant changes in gas prices and the fact that such an increase will optimize resource conservation, that an assumed increase in COP is appropriate in determining the net present value of the lost benefit of COP to customers. For the purposes of the no-harm test, the Board, therefore, with one exception, considers it appropriate to use the levels of COP proposed by the NCC.

The exception relates to the Westlock Application. In this case, the Board notes that AGN has a working interest in the properties of 50% or less, with the majority being less. For these properties, the Board acknowledges that AGN cannot unilaterally increase the production levels. It would require a majority of the owners to agree before any expenditures, as contemplated by the McDaniel Report, could be made. In this case the Board believes that the production forecast as set out by AGN in the Westlock Application is not unreasonable in the circumstances.

The Board also notes that the present value analyses performed by AGN and the NCC for the Westlock Application both produced negative customer benefits in the final years of the studies. These results indicate to the Board that the value to the customer will not be of a prolonged nature, making the proposed expenditures to increase production of questionable value to customers. Finally, the Board notes that both analyses used decline rates of about 15%, which is consistent with that of AGN's established operations. Therefore, for the purpose of evaluating the Westlock Application with respect to the no-harm test, the Board has concluded that the AGN production schedule should be used.

#### 5.2.2.2. Price Forecasts

The Board was presented with two price forecasts as being appropriate for determination of the no-harm test. AGN argued that the McDaniel forecast as of October 1, 2000 should be used, as it was one of the forecasts available to prospective buyers to use in their evaluation of the properties to establish their bids. The NCC argued that the McDaniel forecast as of January 1, 2001 should be used to evaluate the no-harm test as it was available when the Applications were made and was relevant in the evaluation of the test from the customers' perspective.

The Board also notes that other estimates of future prices, both higher and lower than the McDaniel forecasts, were available from industry parties. The McDaniel forecasts, having been prepared by a reputable, independent expert, were accepted by both AGN and the NCC as being representative.

In the Board's view, the timing of the forecast is significant and the selection process must take into account its purpose. In this case, the Board's objective is to determine the value that must be available to customers in order to save them harmless if the sales are to proceed. Since it is the value of the lost benefit of COP to customers that is being evaluated, the Board is of the view that it is reasonable to use the most recent forecast available at the time the Applications were made to the Board.

In this case, therefore, the Board has concluded that the January 1, 2001 McDaniel forecast as presented by the NCC[44] should be used to calculate the no-harm amount for the Applications. For the Viking, Beaverhill and Lloydminster Applications the first fifteen years will be used and for the Westlock Application the first ten years will be used (see below).

To value the reserves remaining after 15 years, the Board notes that the NCC used $1.51 per gigajoule, which was based on the McDaniel Report and was described in their evidence.[45] AGN had used $0.50 per gigajoule, which was substantially lower than the values provided by McDaniel. The Board is of the view that, by valuing the remaining reserves using the McDaniel Report, the NCC was consistent in their approach. For purposes of the no-harm test, the Board will accept the evaluation as proposed by the NCC.

As it was in relation to production levels, the Westlock Application is again the exception. The AGN analysis produces a negative net present value for remaining reserves while the NCC analysis produces a positive value, notwithstanding that during the final years at the end of both analyses the values are negative. Neither result is improbable, but they do indicate that a range of values is possible for the remaining reserves.

The value placed on the remaining reserves, of course, can influence the calculation of the no-harm value. However, since the final years of the analyses by both parties yield negative values, the Board considers it reasonable to use a “breakeven” value (for production costs and market value) for the remaining reserves in the Westlock Application. In effect, therefore, the Board has determined that the value of the remaining reserves should have no practical impact on the no-harm analysis and will assume a value of zero for the Westlock Application.

#### 5.2.2.3. Discount Rate

As noted in relation to the choice of production levels, the Board considers that it must evaluate the proposed sales from the perspective of the customers, who are at risk by virtue of the lost benefit of COP.

AGN took the position that a discount rate that would be applied by a utility evaluation of a capital investment should be used. In its case, that rate was suggested to be 12%. In the Board’s view, the selection of a 12% discount rate ignores the fact that it is the lost benefit to customers that must be evaluated, not the net present value to the utility of an income stream from a capital asset. Therefore, the Board does not consider the 12% discount rate applied by AGN to be reasonable or appropriate for the no-harm test in these circumstances.

The choice of an appropriate discount rate in any case is difficult. Any rate used has an inherent element of arbitrariness. However, the Board is satisfied that the 12% rate urged by AGN is too high and does not reflect the value of COP to customers (though it may represent the value to AGN or its purchasers). Instead, the Board agrees with the NCC that the discount rate should reflect the customer’s perspective when determining the net present value of the benefit.

[44] NCC Evidence, March 9, 2001, section 2 B, Table 9 attachment
[45] NCC Evidence, March 9, 2001, page 49, section 2.5; Tr. p. 396-401; Exhibit 94

The NCC presented a calculation of a weighted average discount rate that took into account the before- and after-tax funds the various customers would have available to them to pay for their gas supply. The result of the NCC position is similar to one using a no-risk rate plus an inflation factor.

The Board also acknowledges that no single discount rate is appropriate for each of AGN's customers. The Board generally accepts the approach to weighted average discount rates proposed by the NCC as a reasonable basis for determining a discount rate for all of AGN's customers for the purposes of the no-harm test.

The Board notes that the discount rate may be applied mid-year or at year-end. The Board considers that mid-year discounting appropriately reflects cash flows experienced by consumers, and accepts the methodology of mid-year discounting as proposed by the NCC.

In the Board's view, therefore, the NCC's proposed mid-year discount rate of 8% is reasonable in the circumstances and will be used to evaluate all four Applications.

#### 5.2.2.4. Discount Period

The parties did not expressly address the appropriate period over which to discount the other parameters. AGN discounted over a 10-year period in the Applications. In their analysis, the NCC discounted over a 15-year period.

When choosing between 10 and 15 years, the Board notes that the discounted values for years 11-15 are still material, especially when using an 8% discount rate. Therefore, the Board considers that, for the Viking, Beaverhill and Lloydminster Applications, 15 years is an appropriate discounting period.

In the case of the Westlock Application, as noted earlier, the discounted values in the final years are negative and are not material to the no-harm calculation. Accordingly, the Board is of the view that the Westlock Application should be evaluated using AGN's production levels over a 10-year period.

The Board notes that the reserves are valued in the year following the last production period using mid-year discounting.

### 5.2.2.5. No-Harm Thresholds

In the following table, the Board has summarized its determinations with respect to each parameter to be used in evaluating each Application for purposes of the no-harm test:

| Parameter | Viking, Beaverhill & Lloydminster Applications | Westlock Application |
|---|---|---|
| Production Levels | per McDaniel Report | per AGN's Application |
| Price Forecast | McDaniel – January 1, 2001 | McDaniel – January 1, 2001 |
| Discount Rate | 8% | 8% |
| Discount Period | 15 years | 10 years |

Based on these parameters, the following no-harm thresholds were calculated by the Board for each of the Applications:

| Application | No-Harm Threshold[46] ($000) |
|---|---|
| Viking | 460,339 |
| Westlock | 1,742 |
| Beaverhill | 37,409 |
| Lloydminster | 1,220 |

Both AGN and the NCC provided calculations of the proceeds available to be allocated. Although the data used by each was from sources provided by AGN, the results were not the same, making direct comparisons somewhat difficult. An explanation of the differences follows.

AGN determined the amount available by subtracting from the gross proceeds the cost of disposition, the petroleum rights, and NBV. In all cases AGN used a NBV that was net of negative salvage. In the Viking Application AGN also subtracted the seismic costs. In the Westlock Application, AGN also subtracted the NBV of the retired production assets, and in the Lloydminster Application, the storage inventory.

When making the same determination, the NCC subtracted the petroleum rights in only the Viking Application and were unable to reconcile the NBVs from information provided to them by AGN. Also, the NCC did not remove the negative salvage or the NBV for retired production assets. In the table below, the Board has shown the different amounts of the proceeds available to be allocated that can be calculated for each Application based on the information as presented by AGN and the NCC, respectively. The table also shows the negative salvage amounts that AGN has removed from the NBVs, consistent with its proposal to retain negative salvage for future reclamation costs.

46 Refer to Appendices 3, 4, 5, and 6 for greater detail.

The major difference between the two calculations is that AGN has removed negative salvage and the NCC has not. The remaining differences can be attributed to treatment of such items as petroleum rights and NBV of retired production assets. Even though all the information was provided by AGN, the NBVs have not been reconciled. Therefore, it will be necessary for AGN to reconcile the differences when it files the final transaction results and provides final rate base values for the Applications that are approved, as will be directed by the Board.

| Application | Party | Proceeds Available for Allocation ($000) | Negative Salvage ($000) |
|---|---|---|---|
| Viking | AGN | 396,832 | 5,800 |
| | NCC | 402,215 | |
| Westlock | AGN | 4,046 | 764 |
| | NCC | 5,625 | |
| Beaverhill | AGN | 20,736 | 958 |
| | NCC | 21,731 | |
| Lloydminster | AGN | 2,511 | 111 |
| | NCC | 2,757 | |

The proceeds available for allocation shown in the table above have been adjusted by the amounts shown below to take into consideration the delay in closing the sales after January 1, 2001.

| Application | Price Adjustment [47] ($000) |
|---|---|
| Viking | 38,920 |
| Westlock | 2,700 |
| Beaverhill | 7,834 |
| Lloydminster | NA |

The Board notes that further reductions to the available proceeds are likely. Each Agreement for Purchase and Sale contemplated reductions for title defects and environmental liabilities. During the hearing, AGN was unable to quantify the reductions as they were still being negotiated at the time the hearing ended. The Board has made further directions with respect to these amounts in Sections 7.3 and 8 of this Decision.

Comparing the proceeds remaining (as known at the end of the hearing), with or without negative salvage, to the no-harm thresholds for each Application demonstrates that both the Lloydminster and the Westlock Applications will have sufficient proceeds to exceed the no-harm value. According to similar comparisons, the proceeds available to customers in the Viking and Beaverhill Applications are insufficient to meet the calculated no-harm thresholds.

[47] Price adjustment values were taken from each of the Agreements for Purchase and Sale.

Therefore, based on its calculation of the net present value of the lost benefit of COP to customers, the Board concluded that the proceeds available to customers in the Viking and Beaverhill Applications are insufficient to save customers harmless from the loss of the benefits. In the case of the Westlock and Lloydminster Applications, there are sufficient proceeds to compensate customers for the estimated lost benefit and, therefore, to save them harmless from the impacts of the sales.

### 5.3 Impacts on Retail Competition

In Section 3.1, the Board noted some policy considerations with respect to the relationship between the Applications and the development of a fully-functioning retail gas supply market.

AGN submitted that selling the P&NG assets is consistent with the continuing evolution of gas deregulation in the province whereby the merchant and supply function previously performed by gas utilities are replaced by open-market competition in the form of direct sales.

AGN submitted that its ownership of COP had inhibited the development of a fully-functioning retail market. To the extent that a fully developed retail market was in the public interest, AGN argued that the proposed sales were therefore to the benefit of customers and should be approved.

The Board agrees that the present treatment of COP could be considered as an impediment to full retail competition and acknowledges that a change to that treatment may be necessary to remove that impediment. However, the Board is not persuaded that whatever impediment to retail competition might be removed by the sale of the P&NG assets is sufficiently material from the customer's perspective to offset the risk to customers of financial harm as a result of the sale. Moreover, the customers proposed a solution to any potential market impacts, which is dealt with briefly later in this Decision in Section 7.1. In the Board's view, therefore, the overriding consideration in these applications is the impact on customers of the lost benefit of COP.

### 5.4 Conclusion With Respect to the No-Harm Standard

Having regard to the magnitude of the potential impacts on customers from the Viking and Beaverhill Applications, the Board was not persuaded that any potential positive impacts on the development of a retail market, as suggested by AGN, were sufficient to offset the unmitigable negative impacts of those Applications.

For these reasons, in Decision 2001-46, the Board denied the Viking and Beaverhill Applications, and approved the Westlock and Lloydminster Applications.

# 6 ALLOCATION OF PROCEEDS FOR APPROVED SALES

As outlined in Section 3, if the Board concludes that a sale should not be approved because it cannot meet the no-harm test, no question of the allocation of proceeds arises.

In relation to the Westlock and Lloydminster Applications, however, the Board is satisfied that customers can be kept from harm by compensating them out of the available sale proceeds in an amount at least equal to the no-harm threshold. How those proceeds should actually be allocated among customers and utility shareholders is addressed in this section of the Decision.

## 6.1 Positions of Parties

### NCC

In the NCC's view, the P&NG assets should not be sold at all. However, if the Board determined that a sale was warranted, compensation to which customers were entitled should be determined based on the particular circumstances of each Application. The NCC stated that the no-harm test should be used to determine whether a sale should be approved, not how the gain on sale should be apportioned.

The NCC stated that, in accordance with its view of the regulatory compact, the distribution of a gain or loss on the sale of a utility asset should be allocated based on who took the financial risk associated with the asset.[48] The NCC argued that the portion of sale proceeds that AGN proposed to go to shareholders far exceeded the nominal risks to which they were exposed. The NCC did, however, acknowledge that any funds available for sharing should be net of the costs directly attributable to the sale, including commissions, legal and other costs, title defect costs (subject to an appropriate review), penalties resulting from delay in sale, and the net book value of the assets.

The NCC argued that, based on its assessment, there would be harm to customers even if they were to receive 100% of the net proceeds from all sales. Given this position, and the fact that the NCC had not collectively addressed appropriate sharing between the various customer groups, it did not find it necessary to further address the issue of proceeds disposition.

The NCC noted the differences between this proceeding and the findings in Decision 2000-41. In Decision 2000-41, the NCC noted, the Board was able to reach a conclusion of no harm because the assets being sold continued in regulated service. In that Decision, the Board also imposed a number of conditions to ensure that there would be no harm to customers in the future.

In this proceeding, the NCC noted that the Board was being asked to determine the quantum of future harm. The Board was also required to determine the compensation that must go to customers without any clear evidence of the actual risk to customers in the event that the assumptions regarding production levels, price forecasts, and discount rates proved to be

[48] Referring to Decision 2000-41, p. 28.

incorrect. The NCC argued that, if the assumptions are incorrect, the costs to customers could potentially be in the hundreds of millions of dollars.

In regard to the TransAlta Formula, the NCC noted that first, the compensation paid to Trans Alta resulted from the forced taking and subsequent reduction in their service area. Second, the application was made pursuant to the *Hydro and Electric Energy Act*, which does not contain provisions similar to those in the GU Act. Third, compensation was more than payment for the physical assets. And finally, the decision was not intended to apply to every disposition of utility assets.

The NCC submitted that the end result of Decision 2000-41 was that sharing of the gain should be based on the relative financial contributions of the parties. The gains to customers should be reflected in accumulated depreciation and to shareholders by way of unrecovered NBV. The NCC noted that the TransAlta Formula also did not take into account contributions made to construction or border flowback funds.

The NCC argued that the most appropriate and comprehensive method of sharing the proceeds would use the TransAlta Formula on tangible assets and the regulatory compact principle of reward following risk for the intangible assets.

The NCC stated that AGN's shareholders were fully compensated for their risk and investment through the allowed return on equity. Customers bore the risks and costs of the exploration and development of these production facilities and the ongoing operational risks. Payment of any portion of the gain on sale to shareholders would result in a windfall gain to them because they would be compensated for risk they would not have been prepared to take.

In the NCC's view, the reward follows risk principle is fair and relatively straightforward. Allocating 100% of the net proceeds to customers would reflect the risk which customers have borne since the Viking Kinsella field–the first property acquired by AGN–was developed.

The NCC noted two particular regulatory decisions from the United States that reflected the reward follows risk principle. In the first, the Court said:[49]

> Thus if customers are to bear the risk that a dramatic industry transformation such as restructuring under order 636, will force the realizations of losses on specific assets, it is hard to see a reason why they should not reap the benefits from forced realization of gain.

[49] *Williston Basin Interstate Pipeline Company v. FERC*, 115 Fed.3d (1997).

The Court went on to say:

> In Democratic Central Committee… we relied on the principle that the right to capital gains on utility assets is tied to the risk of capital losses. Moreover, a rule assigning the firm the benefit of good outcomes and customers the burden of bad ones, a kind of heads-I-win/tails-you-lose rule, would seem to give the utility management an unhealthy incentive to gamble.

In the second case, the Massachusetts Department of Public Utilities said:[50]

> The fact that land is a nondepreciable asset, because its useful value is not ordinarily diminished through use, is, we find, irrelevant to the question of who is entitled to the proceeds of the sale of the land. The fact that it has been rated as an above the line item and included in rate base while in the company's possession, we find warrants above-the-line treatment of the net proceeds from this sale.

The decision went on as follows:

> The company and its shareholder have received a return on the use of these parcels while they have been included in rate base and are not entitled to any additional return as a result of their sale. To hold otherwise would be to find that a regulated utility company may speculate in nondepreciable property and, despite earning a reasonable rate of return from its customers on that property, may also accumulate a windfall through its sale. We find this to be an uncharacteristic risk reward situation for a regulated utility to be in with respect to its plant in service.

From these decisions, the NCC noted that the treatment of gains on sale is evolving, and the TransAlta Appeal is of little value in the Applications before the Board. However, the NCC reiterated that the risk follows reward principle is fair, relatively straightforward and reflects the risks which customers have borne since the Viking field was developed.

The NCC identified five issues regarding the distribution of customer compensation that may arise if the Board were to approve one or more of the proposed sales:

1. the proportion of compensation that should flow to each of the North Core rate groups;
2. whether payment to these customer groups should be paid out over a period of years or by a one-time payment;
3. the appropriate investment criteria and method of managing the balance of any undistributed funds;
4. whether or not the investment vehicle could be structured to avoid income tax; and
5. the appropriate cost of service reduction resulting from the sale of P&NG assets.

The NCC stated that, irrespective of the amount of compensation paid to customers, the funds must be managed to ensure that the no harm concept is maintained throughout the payout period.

[50] *Boston Gas Company*, 49 PUR.4$^{th}$ (1982).

The NCC noted that it might be difficult for customers to be kept from harm because it might be difficult to earn a return that duplicates the discount rate of 12% used by AGN.

The NCC referred to provisions in the North Core Agreement providing that all disputes under the Agreement be submitted to the North Core Committee for resolution. Any disputes at that level which cannot be resolved are then submitted to the Board for resolution. The NCC submitted that both they and AGN agree that all matters relating to the mechanics of the disposition of customer compensation should be dealt with pursuant to the terms of the North Core Agreement and that the Board does not need to rule on this matter.

The NCC stated that if the Board approves any of the sales, it should establish an interim credit rider to prevent an increase in gas costs to customers for the interim period. The interim credit rider could be paid monthly based on a continuation of the level of current benefits received from COP. Funds to support the interim credit rider would come from the customers' share of the sale proceeds, which would be prudently invested in the short term.

**Calgary**

Calgary argued that if any of the sales were approved, all proceeds in excess of NBV should be returned to customers. Calgary argued that proceeds from the sale are income for accounting and income tax purposes. Proceeds in excess of NBV are utility income, and customers should receive the benefit of utility income in their rates. In addition, under the regulatory compact, AGN would have the value of its invested capital returned to it in the form of NBV in addition to having received a fair return on the P&NG assets over the years.

Calgary also noted that the allowed return on common equity includes a component for inflation. Allocating the gain on sale to shareholders would compensate shareholders a second time for inflation, and deny customers the benefits of recovering costs through the sale, which have already been paid. Allocation of any part of the gain on sale to shareholders would reward them for risks that were not taken by them and would result in customers paying twice for a portion of the service provided.

Calgary stated that AGN used successful efforts in accounting for its gas properties, which Calgary submitted was relevant in two ways. First, customers paid the costs associated with unsuccessful exploration. Second, the amounts of AGN's investment and the amount of accumulated depreciation were much lower than they would have been if the full cost accounting method had been used. Therefore, in Calgary's view, applying the TransAlta Formula would result in a significant difference in the amount allocated to customers compared to the amount that would go to customers if the full cost method had been used.

Calgary argued that AGN must return to customers the depreciation and depletion collected from them in today's dollars. The return of funds should also include unsuccessful exploration expenses charged to customers through the rates and unsuccessful exploration expenses collected from customers through border flowback funds.

It noted that these funds could have been treated as income and used to reduce rates. Calgary also argued that if these funds had been paid out, income tax would have been avoided and customers would have received approximately one third of the amount recorded and used to write off unsuccessful costs, capped and unconnected costs, and the allowance for funds used during construction.

**Canfor**

Canfor noted that, in the past, the Board considered that any profit or loss, being the difference between the net book value of the assets and the sale price of those assets resulting from the disposal of utility assets, should accrue to customers. It noted that, after the TransAlta Appeal, the Board applied the TransAlta Formula to determine the sharing of proceeds.

Canfor argued that to exclude customers from a share of the net proceeds would be rewarding AGN twice–through the sale proceeds and by recovering excess depreciation paid by customers through rates. Relying on the *Democratic Central Committee* case, Canfor argued that utility shareholders do not have a legally protected interest in the increased value of utility assets.

**AGN**

In the Applications, AGN proposed that the sale proceeds be allocated between shareholders and customers according to the TransAlta Formula. However, during the hearing, AGN altered its position, submitting instead that customers should only receive the no-harm amount plus the accumulated deferred income taxes associated with the P&NG assets.[51] AGN changed its position on the basis of its view that the Board had no jurisdiction to appropriate value for customers that otherwise belonged to AGN shareholders. In AGN's view, the most that customers could be entitled to would be compensation for the no-harm amount.

[51] However, should any one of the Applications not be approved, AGN recommended that no refund of the deferred income taxes should occur: The issue of deferred income taxes is discussed in Section 7.2 of this Decision.

AGN's revised determinations of the allocations were as follows:

| | ($000s) | | | | |
|---|---|---|---|---|---|
| | Viking Application | Westlock Application | Beaverhill Application | Lloydminster Application | Total |
| Sale proceeds to customers | 182,371 | 459 | 11,414 | 0 | 194,244 |
| Add - Recovery of deferred income tax to customers | 10,224 | 2,162 | 2,062 | 258 | 14,706 |
| Total to customers | 192,595 | 2,621 | 13,476 | 258 | 208,950 |
| Shareholder - Petroleum rights | 7,670 | 35 | 37 | 42 | 7,784 |
| Shareholder - Other | 253,381 | 6,287 | 17,156 | 2,511 | 279,335 |
| Seismic | 1,500 | | | | 1,500 |
| Net book value (excluding negative salvage) | 39,664 | 7,553 | 8,128 | 1,085 | 56,430 |
| Net book value of retired production assets | - | 780 | - | - | 780 |
| Storage inventory | - | - | - | 93 | 93 |
| Total to shareholders | 302,215 | 14,655 | 25,321 | 3,731 | 345,922 |
| Total | 494,810 | 17,276 | 38,797 | 3,989 | 554,872 |
| No-Harm Threshold | 182,371 | 459 | 11,414 | 0 | 194,244 |

### 6.2 Views of the Board

As noted in Section 4.2, the Board is of the view that the no-harm amounts calculated for each Application are threshold amounts. In other words, they represent the minimum amount that must be paid to customers to save them harmless from the impacts of the proposed sales. However, in some circumstances, the Board is of the view that customers may be entitled to more than the no-harm amount. For the reasons given in Section 4.2 of this Decision, the Board considers that it has the jurisdiction to do so.

In the Board's view, if the TransAlta Formula yields a result greater than the no-harm amount, customers are entitled to the greater amount. If the TransAlta Formula yields a result less than the no-harm amount, customers are entitled to the no-harm amount. In the Board's view, this approach is consistent with its historical application of the TransAlta Formula.

As explained in Decision 2000-41, according to the Board's application of the TransAlta Formula:

- shareholders are entitled to a return of NBV;
- customers are entitled to a return of excess depreciation (i.e. the difference between NBV and original cost); and
- any excess of sale proceeds over original cost should be shared according to the ratio prescribed by the Court of Appeal in the TransAlta Appeal.

It should be noted that it is only when sale proceeds are greater than original cost that a "current dollar" sharing of proceeds is necessary pursuant to the TransAlta Formula.

In the Applications, AGN initially used the TransAlta Formula to share any gain where the available proceeds exceeded the original cost of the assets after deducting the cost of disposition, petroleum rights, and (in the case of Lloydminster) storage inventory. Where the proceeds were less than the original cost of the assets, the remaining balance, after shareholders received the NBV of the assets, went to customers. However, as noted earlier, AGN altered its recommended allocation of proceeds during the hearing. AGN argued that the amount to be given to customers should be equivalent to its calculated no-harm threshold. As already noted, the foundation for the change of position was that the Board lacked jurisdiction to award more than the no-harm amount.

The NCC offered another approach. The NCC categorized the gross proceeds from the sales into tangibles and intangibles, consistent with the split defined in the purchase and sale agreements underlying the Applications. The NCC also split the cost of disposition and the petroleum rights between tangibles and intangibles in the same proportion as the gross proceeds in order to arrive at a net proceeds value in each category. The NCC then used the answer to NCC-ATCOGAS.53 to distribute the original cost and accumulated depreciation between tangible and intangible assets before calculating the NBV of each. Then, similarly to AGN, the NCC applied the TransAlta Formula, but only to the tangible portion of the proceeds. For the intangible portion, the NCC deducted only the NBV, with the remainder allocated to customers.

In those cases where the NBV exceeded the allocation to shareholders using the TransAlta Formula, the shareholders were allocated the full NBV. This latter situation would occur when the "current dollar index" is less than one.[52]

The Board again notes the discrepancy between the NBV used by AGN in its Applications and that used by the NCC. The NCC based their information on schedules provided in the answer to NCC-ATCOGAS.53 and updated in the response to information request NCC-ATCOGAS.69. As directed in this Decision, a reconciliation of the NBV will eventually be necessary for the approved Applications.

[52] In this context, "current dollar index" has the meaning given to it by the Court of Appeal in the TransAlta Appeal.

In its Westlock Application, AGN stated that it still carried a rate base value of $780,000 (excluding negative salvage) for unsuccessful exploration costs of production assets that had previously been retired. In its Lloydminster Application, AGN stated that the sale included the gas in inventory which had a book value of $93,000. AGN proposed to recover the value of these two items from the proceeds of the sale. The NCC did not deal specifically with the treatment of the NBV of retired production assets in the Westlock Application or the storage inventory in the Lloydminster Application.

With respect to the reduction in proceeds outlined in the agreements as adjustments for closing after January 1, 2001, in the case of Westlock, AGN proposed that it should be deducted from the customers' portion. The NCC did not specifically address the issue.

The Board notes that in its Applications, AGN did not split the tangible and intangible assets. For the purposes of the TransAlta Formula, the Board considers this approach to be reasonable for at least two reasons. First, in order to maximize tax and other benefits, the values assigned to the intangible and tangible assets are potentially subject to manipulation by the utility and the purchaser of the assets. They will not be negotiated with the interest of the customer in mind. Second, the Board sees no practical distinction between the intangible and tangible assets in this context. In addition to the tangible assets, the Board believes that, in fact, customers have also paid for the costs associated with the development of the intangible gas producing rights. Accordingly, the Board has treated the intangible and tangible assets together in its application of the TransAlta Formula.

The Board notes that the Applications characterized the petroleum and seismic rights as "non-utility" assets. This characterization is consistent with past applications for disposition of producing properties considered by the Board.[53] Therefore, the Board considers that the petroleum and seismic rights are appropriately dealt with as non-utility assets in both the Westlock and Lloydminster Applications. The Board also considers it appropriate to treat the storage inventory similarly in the Lloydminster Application. As a result, these values are deducted from the gross proceeds when determining the net proceeds.

The Board disagrees with AGN that the price adjustment for closing in the Westlock Application should be deducted from the share of proceeds allocated to customers. In the Board's view, AGN's argument confuses the no-harm and the allocation of proceeds principles. Since the adjustment is to the price (i.e. the sale proceeds flowing to AGN) the Board considers it appropriate to treat the adjustment as a reduction in the proceeds available for allocation among shareholders and customers according to the TransAlta Formula. Accordingly, the adjustment will be deducted from gross proceeds when determining the net proceeds available for allocation.

[53] EUB Orders: E95095 dated September 28, 1995; E95110 dated November 9, 1995; E95111 dated November 9, 1995; U96033 dated April 12, 1996; U97103 dated September 8, 1997; and U98026 dated February 2, 1998.

As noted earlier, according to the TransAlta Formula, shareholders are first entitled to be allocated the NBV of the assets out of the net proceeds. Any excess over NBV is to be paid to customers and any excess of net proceeds over original cost of the assets is to be shared between shareholders and customers. In the Westlock Application, the net proceeds exceed NBV, but do not exceed original cost. Therefore, no current-dollar sharing of any such excess occurs. It is only in the Lloydminster Application that net proceeds exceed the original cost of the assets and a current-dollar sharing according to the TransAlta Formula must occur.[54]

Based on the foregoing, the Board has determined that the shareholders are to be allocated proceeds (net of the cost of dispositions) as follows:

| | **Westlock ($000)** | **Lloydminster ($000)** |
|---|---|---|
| TOTAL to Shareholders | 8,368 | 1,934 |

The customers share of the proceeds net of cost of dispositions and closing price adjustments is as follows:

| | **Westlock ($000)** | **Lloydminster ($000)** |
|---|---|---|
| TOTAL to Customers | 4,046 | 1,797 |

Greater detail for these calculations can be found in Appendix 2 to this Decision.

The Board notes that in both cases, the proceeds allocated to customers exceed the no-harm threshold established for each Application. Therefore, if customers are allocated the amount to which they are entitled according to the TransAlta Formula, they will at least be saved harmless.

The Board notes that the North Core Agreement provides for Re-openers which may be triggered by the disposition of these assets or by the amounts to be distributed to customers. The Board agrees with the NCC that it is appropriate for the parties to that Agreement to negotiate the mechanism for distribution to customers of the amounts allocated to them in accordance with this Decision. The North Core Committee is expected to meet and negotiate the method of distribution to customers. Any settlement reached would then be submitted to the Board for evaluation and approval.

[54] The Board notes that its approach to the allocation of proceeds in this case is consistent with its decision in relation to the disposition by NUL of assets in the Fairydell/Bon Accord Field: Order E93023, *Re Northwestern Utilities Limited* (March 17, 1993).

# 7 OTHER ISSUES

A number of smaller issues arose during the course of the proceedings which the Board wishes to deal with in this section. Those issues are the NCC's credit rider proposal, deferred income taxes, title defects and environmental liabilities, and negative salvage.

## 7.1 Credit Rider

### 7.1.1 Positions of the Parties

The NCC proposed that a COP Credit Rider be applied as a negative adjustment to all billings made to all core customers served by AGN. The Credit Rider would serve to capture the net cost advantage (disadvantage) created by the inclusion of COP within the GCRR calculation. Enron and EESAI (both gas retailers) supported the NCC proposal, as did Canfor.

AGN opposed the Credit Rider, suggesting that the Credit Rider proposal lacked a principled foundation and would result inequitable treatment of different classes and generations of customers.

### 7.1.2 Views of the Board

As noted earlier in this Decision, the Board agrees that the present treatment of COP could act as an impediment to effective retail competition. The NCC proposed, with support from both customer groups and natural gas retailers, the use of a credit rider as one possible solution. While the Board considers that the NCC's proposal has merit, the Board is of the opinion that the Credit Rider is only one element of the broader issue of the unbundling of rates. Accordingly, the Board has determined that this proposal will be best dealt with in the decision resulting from the Unbundling Proceeding.[55]

## 7.2 Deferred Income Taxes

In respect of the P&NG assets, AGN had recorded estimates of federal income taxes that should otherwise be payable in future years. These future income tax liabilities, which have been referred to as deferred income taxes, arose because of the higher statutory rates of deduction allowed in previous years for the P&NG assets for income tax purposes compared to the related deductions recorded for financial statement purposes. Customers have paid for the deferred income taxes through AGN's distribution rates.

### 7.2.1 Positions of the Parties

The NCC submitted that AGN should be directed to follow the advice of its own corporate tax department and reflect all available tax pools in a determination of the deferred income tax refund. The NCC added one caveat: all tax pools related to AGN should be used to determine the deferred income tax refund associated with the P&NG assets. This refund would contribute to the total proceeds allocated to AGN customers and, to the extent that customers incur future tax liabilities, the deferred income tax refund could also be included in a trust that would provide future revenue to offset future tax costs.

[55] The Board notes that the entire record of the present proceedings has been incorporated into the record of the Unbundling Proceeding.

The NCC argued that whether one or all of the properties are sold, the use of tax pools should be maximized to ensure AGN customers derive the optimal benefit of these tax deductions. Given that this determination was not critical at this point in time, the NCC suggested that the Board could defer this issue to the whole North Core Committee for resolution in a non-confrontational setting.

AGN recommended that, unless the Board approved all of the Applications, no amounts of the accrued federal deferred income taxes associated with the P&NG assets should be refunded to customers. AGN reasoned that the sale of only certain of the P&NG assets would likely use the majority, if not all, of the existing income tax deductions that arose as a result of the acquisition of these assets. AGN stated that, as it would continue to use such remaining P&NG assets in the provision of utility services, the retention of all of the deferred income taxes to some extent would shelter customers for the income tax cost associated with the remaining assets.

### 7.2.2 Views of the Board

Given the Board's decision to deny the two most significant Applications of the four presented to it, the Board agrees with AGN that the deferred income taxes should be retained until such time as all the properties are sold. The Board considers that customers will continue to benefit from the availability of deferred income taxes in relation to those assets retained by AGN

## 7.3 Title Defects and Environmental Liabilities

In the Viking Application, the sales agreement between AGN and Burlington contained an adjustment clause for title defects and environmental liabilities. The agreement contemplated that these adjustments could be as large as $73.5 million. Although not of the same magnitude, all the agreements for sale in the other Applications contained similar provisions with respect to title defects and environmental liabilities.

### 7.3.1 Positions of Parties

In the NCC's view, the properties have been subject to the management and control of AGN for some time and uncertainties regarding titles should be minimal. However, in the event that these title defects impact customers, due process would require an opportunity to establish whether or not these defects occurred because of past errors or omissions on the part of management. If it was determined that the defects were the result of error or poor management, the NCC submitted that any reduction in proceeds should be directly attributable to the portion of proceeds allocated to AGN. It should not be automatically assumed that customers would share a portion of the costs associated with title defects.

AGN acknowledged in testimony that certain price adjustments could occur because of possible title defects and environmental liabilities. However, AGN was reluctant to speculate on the actual amount of these defects because they were the subject of ongoing negotiations with purchasers and would not be known until the sales closed.

#### 7.3.2 Views of the Board

At this time, the Board is not prepared to determine whether it is appropriate to deduct adjustments for title defects or environmental liabilities from the proceeds so as to affect the amount to be allocated to customers. These liabilities are presently unknown. Until these amounts are ascertained and their prudence can be established and approved by the Board, the Board directs AGN not to deduct the value of the title defects or environmental liabilities from the proceeds.

### 7.4 Negative Salvage

"Negative salvage" represents the costs recovered through the unit of production depreciation method to pay for future abandonment costs associated with the P&NG assets.

#### 7.4.1 Positions of Parties

In the Applications, AGN proposed to exclude the negative salvage from the NBV that would be used when determining the value of the sale to customers. Specifically, AGN stated that it would retain negative salvage to offset future environmental liabilities.

The NCC was opposed to this approach because, typically, annual depreciation includes an amount that includes the forecast of net salvage derived from a formal depreciation analysis. Negative salvage, the NCC argued, should be returned to customers, adjusted to the appropriate income tax credit.

#### 7.4.2 Views of the Board

The Board accepts as reasonable that the negative salvage collected by AGN as depreciation has been collected to pay for the costs of abandonment of any retained facilities, including any associated environmental liabilities. The Board considers that it is appropriate for AGN to retain these amounts for the purposes for which they have been collected. The Board considers that customers will ultimately benefit by AGN's ability to draw on these funds to satisfy any liabilities associated with abandoned facilities not sold in the two approved Applications. The question of net salvage can be addressed again should AGN present further applications for disposition of the P&NG assets that have not been approved by the Board.

Therefore, the Board has included in the NBV of the assets the value of negative salvage identified for the Westlock and Lloydminster Applications.

## 8 REFILING

Throughout the Decision the Board has noted a need to refile information for the Westlock and Lloydminster Applications that will:

1. reconcile the NBVs used by AGN in the Applications and those presented by the NCC based on information provided by AGN in response to information requests;
2. restate the rate base values showing the retained negative salvage; and
3. provide a final statement of proceeds from the approved sales to be used by the North Core Committee in its negotiations regarding distribution of the customers' share of the proceeds.

The Board directs AGN to refile the above noted information within 30 days after the completion of the transactions or the date of this Decision, which ever is later.

With respect to the title defects and environmental liabilities, AGN can file with the Board to establish the validity of the adjustments, if required.

## 9 BOARD ORDER

Having regard to the evidence and argument presented and having regard to our own knowledge and findings in this Decision, the Board hereby orders that:

1. The denial of the Viking and Beaverhill Applications (Application Nos. 2001017 and 2001030) in Decision 2001-46 is confirmed.

2. The approval of the Westlock and Lloydminster Applications (Application Nos. 2001020 and 2001070) in Decision 2001-46 is confirmed, subject to the refiling by AGN of its calculations of the net proceeds available for allocation and the allocation of the net proceeds between shareholders and customers in the Westlock and Lloydminster Applications as directed in Section 8 of this Decision.

Dated in Calgary, Alberta on July 31, 2001.

**ALBERTA ENERGY AND UTILITIES BOARD**

*(Original signed by)*

B. F. Bietz, Ph.D.
Presiding Member

*(Original signed by)*

B. T. McManus, Q.C.
Member

*(Original signed by)*

T. McGee
Member

# APPENDIX 1

## THOSE WHO APPEARED AT THE HEARING

## (AND ABBREVIATIONS USED)

| Principals | Witnesses |
|---|---|
| ATCO Gas – North (AGN)<br>L.E. Smith, Q.C. | J. F. Engler<br>D.A. Wilson<br>G. M. Engbloom, P.Eng. |
| Customers Representatives of the North Core Committee (NCC)<br>J.A. Bryan, Q.C., | His Worship Mayor W. Smith<br>E. M Higgins<br>R. H. Brekko<br>N. Stewart<br>W. Haessel, Ph.D.<br>F. Sayer<br>R. T. Liddle, P.Eng. |
| Aboriginal Communities * and Saddle Lake First Nation (Aboriginal Communities)<br>R. C. Secord<br>J. Graves, P.Eng. | |
| Burlington Resources Canada Energy Ltd. (Burlington)<br>C. K. Yates | |
| City of Calgary (Calgary)<br>J. A. Wachowich | |
| Canadian Forest Products Limited *, Vanderwall Contractors (1971) Ltd., Spruceland Millworks Inc., and Zavisha Saw Mills Ltd. (Canfor)<br>L. L. Manning | |
| City of Edmonton (Edmonton) *<br>M. Sherk | |
| Consumers Coalition of Alberta (CCA) *<br>J. A. Wachowich | |

Enron Canada Corp. (Enron)
H. R. Huber

EPCOR Energy Services (Alberta) Inc. (EESAI)
H. D. Williamson, Q.C.

Federation of Alberta Gas Co-ops and Gas Alberta Inc.
(FGA) *
T. D. Marriott
G. Cooke

Municipal Intervenors (MI) *
J. A. Bryan, Q.C.
C. R. McCreary

Public Institutional Consumers Association (PICA) *
R. Retnanandan

Top Grade Solutions Inc.
W. Ferguson

University of Alberta *
P. A. Smith, Q.C.

G. Wolosinka
G. Wolosinka

Alberta Energy and Utilities Board:
A. E. Domes, Counsel
J. L. Hocking, Counsel
D. R. Weir, C.A.
C. Burt

*** Members of NCC**

# APPENDIX 2

## ALLOCATION OF PROCEEDS

| | | Westlock ($000) | Lloydminster ($000) |
|---|---|---|---|
| 1 | Original Cost | 15,613 | 2,169 |
| 2 | Current Dollar Index[1] | NA | 1.658 |
| 3 | Gross Proceeds | 15,400 | 3,800 |
| 4 | Cost of disposition | 286 | 69 |
| 5 | Petroleum rights | 35 | 42 |
| 6 | Storage inventory | NA | 93 |
| 7 | Price adjustment | 2,700 | 0 |
| 8 | Net Proceeds[2] | 12,379 | 3,596 |
| 9 | NBV (net of salvage) | 7,553 | 1,085 |
| 10 | NBV of retired production assets | 780 | NA |
| 11 | To Shareholders[3] | 8,333 | 1,085 |
| 12 | Available for Allocation[4] | 4,046 | 2,511 |
| 13 | Accumulated Depreciation | 8,060 | 1,084 |
| 14 | To Customers[5] | 4,046 | 1,084 |
| 15 | Remainder to be shared[6] | 0 | 1,427 |
| 16 | Share to Shareholders[7] | 0 | 714 |
| 17 | Share to Customers[8] | 0 | 713 |
| 18 | **Total to Customers[9]** | **4,046** | **1,797** |
| 19 | **Total to Shareholders[10]** | **8,368** | **1,934** |

[1] Current Dollar Index (2) equals Original Cost (1) divided by Net Proceeds (8)
[2] Net Proceeds (8) equals lines 3-4-5-6-7
[3] To Shareholders (11) equals lines 9+10
[4] Available for Allocation (12) equals lines 8-11
[5] To Customers (14) equals the lesser of lines 12 or 13
[6] Remainder to be shared (15) equals lines 12-14
[7] Share to Shareholders (16) equals (NBV x Current Dollar Index (2))-NBV
[8] Share to Customers (17) equals (Accumulated Depreciation (13) x Current Dollar Index (2))-line 13
[9] Total to Customers (18) equals lines 14+17
[10] Total to Shareholders (19) equals lines 5+6+11+16

# APPENDIX 3

## CALCULATION OF NO-HARM THRESHOLD FOR VIKING

| | A | B | C | D | E | F | G | H | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | (B+C+D+E) | | (F+G) | | (A*J) | (K-H) |
| | Natural Gas Production (TJ) | Operating Costs ($000) | Abandonment Costs ($000) | ATCO Asset Related Costs ($000) | ATCO Administration & Overhead ($000) | Cost of Service ($000) | Royalty & Mineral Tax ($000) | Cost to Customer ($000) | AECO C Market Price ($/GJ) | Sales Revenue ($000) | Value to Customer ($000) |
| 2001 | 22748 | 5137 | 0 | 8938 | 3200 | 17274 | 36535 | 53809 | 6.56 | 149299 | 95490 |
| 2002 | 33845 | 6894 | 63 | 13105 | 3264 | 23326 | 43869 | 67195 | 4.96 | 167937 | 100742 |
| 2003 | 29209 | 6608 | 96 | 11400 | 3329 | 21433 | 33103 | 54536 | 4.39 | 128189 | 73653 |
| 2004 | 25656 | 6344 | 158 | 10014 | 3396 | 19912 | 25005 | 44917 | 3.87 | 99200 | 54283 |
| 2005 | 22390 | 6019 | 250 | 8769 | 3464 | 18501 | 20144 | 38645 | 3.68 | 82395 | 43750 |
| 2006 | 19630 | 5706 | 283 | 7696 | 3533 | 17218 | 17341 | 34559 | 3.75 | 73703 | 39144 |
| 2007 | 17399 | 5446 | 196 | 6787 | 3604 | 16032 | 15000 | 31033 | 3.83 | 66612 | 35579 |
| 2008 | 15237 | 5145 | 177 | 5941 | 3676 | 14938 | 12892 | 27830 | 3.95 | 60143 | 32313 |
| 2009 | 13402 | 4869 | 162 | 5214 | 3749 | 13993 | 10993 | 24987 | 4.01 | 53803 | 28816 |
| 2010 | 11928 | 4667 | 122 | 4605 | 3824 | 13218 | 9158 | 22376 | 4.07 | 48564 | 26188 |
| 2011 | 10598 | 4467 | 147 | 4056 | 3901 | 12570 | 8242 | 20812 | 4.19 | 44363 | 23551 |
| 2012 | 9390 | 4267 | 0 | 3557 | 3979 | 11802 | 6974 | 18776 | 4.24 | 39841 | 21065 |
| 2013 | 8342 | 4067 | 45 | 3119 | 4058 | 11289 | 6091 | 17380 | 4.36 | 36338 | 18958 |
| 2014 | 7239 | 3867 | 46 | 2701 | 4140 | 10752 | 5047 | 15800 | 4.41 | 31934 | 16134 |
| 2015 | 6375 | 3667 | 66 | 2356 | 4222 | 10310 | 4334 | 14644 | 4.50 | 28658 | 14014 |
| Remaining Reserves | 39460 | | | | | | | | | | 52258 |
| **No-Harm Threshold** | (Sum of the individual values in column L after discounting) | | | | | | | | | | **$460,339** |

**Parameters:**

**(Differences may occur due to rounding)**

*Discount Rate:* 8% with mid-year discounting

*Production Level:* Per Information Request BR-NCC.12, Table 1a, "Natural Gas Production", column

*Royalty:* Per Information Request BR-NCC.12, Table 1a, "Royalty & Mineral Tax", column

*Cost of Service:* Per Information Request BR-NCC.12, Table 1a, Sum of "Operating Costs", "Abandonment Costs", "ATCO Asset Related Costs" and "ATCO Administration & Overhead", columns

*Price of Gas:* McDaniels January 1, 2001 price forecast in NCC Evidence, March 9, 2001, section 2B, Table 9, "AECO C Market Price $/GJ", column

*Remaining Reserves:* Per Information Request BR-NCC.12, Table 1a, Value of "Rem.". See Decision Section 5.2.2.2 for valuation

# APPENDIX 4

## CALCULATION OF NO-HARM THRESHOLD FOR WESTLOCK

| | A | B | C | D<br>(B+C) | E | F<br>(E-D) | G<br>(A*F) |
|---|---|---|---|---|---|---|---|
| | Production<br>(TJ) | Cost of Service<br>($/GJ) | Royalties<br>($/GJ) | Cost to Customer<br>($/GJ) | Market Price of Gas<br>($/GJ) | Differential<br>($/GJ) | Savings to Customer<br>($000) |
| 2001 | 1116 | 2.24 | 1.80 | 4.04 | 6.56 | 2.52 | 2,811 |
| 2002 | 949 | 2.48 | 1.30 | 3.78 | 4.96 | 1.18 | 1,120 |
| 2003 | 806 | 3.15 | 1.11 | 4.26 | 4.39 | 0.13 | 105 |
| 2004 | 685 | 3.08 | 0.93 | 4.01 | 3.87 | (0.14) | (96) |
| 2005 | 582 | 3.43 | 0.86 | 4.29 | 3.68 | (0.61) | (354) |
| 2006 | 495 | 3.85 | 0.84 | 4.69 | 3.75 | (0.94) | (467) |
| 2007 | 421 | 4.32 | 0.83 | 5.15 | 3.83 | (1.32) | (556) |
| 2008 | 358 | 4.87 | 0.81 | 5.68 | 3.95 | (1.73) | (620) |
| 2009 | 304 | 5.52 | 0.79 | 6.31 | 4.01 | (2.30) | (699) |
| 2010 | 259 | 6.25 | 0.78 | 7.03 | 4.07 | (2.96) | (767) |
| Remaining Reserves | 7625 | | | | | | 0 |
| **No-Harm Threshold** (Sum of the individual values in column L after discounting) | | | | | | | **$1,742** |

**Parameters:** **(Differences may occur due to rounding)**

*Discount Rate:* 8% with mid-year discounting

*Production Level:* Per AGN Application Dated January 25, 2001, Appendix A, Schedule Titled "Non-Operated Properties Production Analysis (Includes retirement of remaining production rate base)", "Utility Production", column

*Royalty:* Per Information request BR-ATCOGAS-W.7 Attachment 2 of 2, "Royalties", column

*Cost of Service:* Per Information request BR-ATCOGAS-W.7 Attachment 2 of 2, "Estimated Cost of Service", column

*Price of Gas:* McDaniels January 1, 2001 price forecast in NCC Evidence, March 9, 2001, section 2B, Table 9, "AECO C Market Price $/GJ", column

*Remaining Reserves:* No value assigned. (Break-even approach, see Decision Section 5.2.2.2)

# APPENDIX 5

## CALCULATION OF NO-HARM THRESHOLD FOR BEAVERHILL

| | A | B | C | D | E | F | G | H | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | (B+C+D+E) | | (F+G) | | (A*J) | (K-H) |
| | Natural gas Production (TJ) | Operating Costs ($000) | Abandonment Costs ($000) | ATCO Asset Related Costs ($000) | ATCO Administration & Overhead ($000) | Cost of Service ($000) | Royalty & Mineral Tax ($000) | Cost to Customer ($000) | AECO C Market Price ($/GJ) | Sales Revenue ($000) | Value to Customer ($000) |
| 2001 | 3226 | 900 | 0 | 1980 | 400 | 3280 | 6115 | 9395 | 6.56 | 21173 | 11778 |
| 2002 | 3178 | 904 | 0 | 2011 | 408 | 3323 | 4612 | 7935 | 4.96 | 15767 | 7832 |
| 2003 | 2776 | 873 | 16 | 1739 | 416 | 3044 | 3397 | 6441 | 4.39 | 12182 | 5741 |
| 2004 | 2427 | 855 | 8 | 1502 | 424 | 2789 | 2513 | 5302 | 3.87 | 9383 | 4081 |
| 2005 | 2123 | 822 | 22 | 1295 | 433 | 2572 | 2018 | 4590 | 3.68 | 7814 | 3224 |
| 2006 | 1860 | 810 | 0 | 1115 | 442 | 2367 | 1714 | 4081 | 3.75 | 6983 | 2902 |
| 2007 | 1627 | 789 | 0 | 957 | 450 | 2196 | 1467 | 3663 | 3.83 | 6230 | 2567 |
| 2008 | 1414 | 769 | 23 | 816 | 459 | 2067 | 1258 | 3325 | 3.95 | 5582 | 2257 |
| 2009 | 1237 | 748 | 0 | 695 | 469 | 1912 | 1092 | 3004 | 4.01 | 4966 | 1962 |
| 2010 | 1088 | 746 | 0 | 591 | 478 | 1815 | 931 | 2746 | 4.07 | 4429 | 1684 |
| 2011 | 910 | 671 | 8 | 487 | 488 | 1653 | 735 | 2388 | 4.19 | 3811 | 1424 |
| 2012 | 768 | 596 | 3 | 400 | 497 | 1496 | 593 | 2089 | 4.24 | 3257 | 1168 |
| 2013 | 651 | 521 | 18 | 329 | 507 | 1375 | 496 | 1871 | 4.36 | 2838 | 967 |
| 2014 | 556 | 446 | 3 | 270 | 517 | 1235 | 405 | 1640 | 4.41 | 2455 | 815 |
| 2015 | 478 | 371 | 4 | 220 | 528 | 1122 | 340 | 1462 | 4.50 | 2149 | 688 |
| Remaining Reserves | 1136 | | | | | | | | | | 1350 |
| **No-Harm Threshold** | (Sum of the individual values in column L after discounting) | | | | | | | | | | **$37,409** |

**Parameters:** **(Differences may occur due to rounding)**

*Discount Rate:* 8% with mid-year discounting
*Production Level:* Per Information Request BR-NCC.12, Table 3a, "Natural Gas Production", column
*Royalty:* Per Information Request BR-NCC.12, Table 3a, "Royalty & Mineral Tax", column
*Cost of Service:* Per Information Request BR-NCC.12, Table 3a, Sum of "Operating Costs", "Abandonment Costs", "ATCO Asset Related Costs" and "ATCO Administration & Overhead ", columns
*Price of Gas:* McDaniels January 1, 2001 price forecast in NCC Evidence, March 9, 2001, section 2B, Table 9, "AECO C Market Price $/GJ", column
*Remaining Reserves:* Per Information Request BR-NCC.12, Table 3a, Value of "Rem.". See Decision Section 5.2.2.2 for valuation

# APPENDIX 6

## CALCULATION OF NO-HARM THRESHOLD FOR LLOYDMINSTER

| | A | B | C | D | E | F | G | H | J | K | L |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | (B+C+D+E) | | (F+G) | | (A*J) | (K-H) |
| | Natural gas Production (TJ) | Operating Costs ($000) | Abandonment Costs ($000) | ATCO Asset Related Costs ($000) | ATCO Administration & Overhead ($000) | Cost of Service ($000) | Royalty & Mineral Tax ($000) | Cost to Customer ($000) | AECO C Market Price ($/GJ) | Sales Revenue ($000) | Value to Customer ($000) |
| 2001 | 80 | 55 | 0 | 208 | 100 | 363 | 125 | 489 | 6.56 | 526 | 37 |
| 2002 | 440 | 327 | 0 | 483 | 102 | 912 | 496 | 1408 | 4.96 | 2182 | 774 |
| 2003 | 386 | 317 | 0 | 410 | 104 | 831 | 358 | 1189 | 4.39 | 1694 | 505 |
| 2004 | 328 | 306 | 0 | 339 | 106 | 751 | 242 | 992 | 3.87 | 1268 | 276 |
| 2005 | 265 | 280 | 44 | 271 | 108 | 703 | 166 | 869 | 3.68 | 976 | 107 |
| 2006 | 217 | 242 | 0 | 217 | 110 | 569 | 133 | 703 | 3.75 | 814 | 111 |
| 2007 | 179 | 228 | 23 | 175 | 113 | 539 | 113 | 651 | 3.83 | 686 | 35 |
| 2008 | 150 | 219 | 0 | 141 | 115 | 474 | 99 | 573 | 3.95 | 591 | 18 |
| 2009 | 128 | 215 | 0 | 113 | 117 | 446 | 85 | 531 | 4.01 | 512 | (18) |
| 2010 | 108 | 191 | 0 | 90 | 120 | 400 | 74 | 474 | 4.07 | 440 | (34) |
| 2011 | 86 | 175 | 0 | 67 | 122 | 363 | 58 | 421 | 4.19 | 362 | (59) |
| 2012 | 71 | 139 | 33 | 49 | 124 | 345 | 45 | 390 | 4.24 | 300 | (90) |
| 2013 | 14 | 67 | 200 | 9 | 127 | 403 | 8 | 411 | 4.36 | 60 | (351) |
| 2014 | 0 | 0 | 0 | 0 | 129 | 129 | 0 | 129 | 4.41 | 0 | (129) |
| 2015 | 0 | 0 | 0 | 0 | 132 | 132 | 0 | 132 | 4.50 | 0 | (132) |
| Remaining Reserves | 0 | | | | | | | | | | 0 |
| **No-Harm Threshold** | (Sum of the individual values in column L after discounting) | | | | | | | | | | **$1,220** |

**Parameters:** **(Differences may occur due to rounding)**

*Discount Rate:* 8% with mid-year discounting
*Production Level:* Per Information Request BR-NCC.12, Table 4a, "Natural Gas Production", column
*Royalty:* Per Information Request BR-NCC.12, Table 4a, "Royalty & Mineral Tax", column
*Cost of Service:* Per Information Request BR-NCC.12, Table 4a, Sum of "Operating Costs", "Abandonment Costs", "ATCO Asset Related Costs" and "ATCO Administration & Overhead", columns
*Price of Gas:* McDaniels January 1, 2001 price forecast in NCC Evidence, March 9, 2001, section 2B, Table 9, "AECO C Market Price $/GJ", column
*Remaining Reserves:* Per Information Request BR-NCC.12, Table 4a, Value of "Rem.". See Decision Section 5.2.2.2 for valuation

# APPENDIX 7

## DECISION 2001-46

## ATCO GAS – NORTH
## A DIVISION OF ATCO GAS AND PIPELINES LTD. SALE OF CERTAIN PETROLEUM AND NATURAL GAS RIGHTS, PRODUCTION AND GATHERING ASSETS, STORAGE ASSETS AND INVENTORY

ALBERTA ENERGY AND UTILITIES BOARD

**Calgary, Alberta**

**ATCO GAS – NORTH**
**A DIVISION OF ATCO GAS AND PIPELINES LTD.**
**SALE OF CERTAIN PETROLEUM AND NATURAL GAS RIGHTS, PRODUCTION AND GATHERING ASSETS, STORAGE ASSETS AND INVENTORY**

**Decision 2001-46**
**Application Nos. 2001017, 2001020, 2001030 & 2001070**
**File No. 6405-14, 6405-15, 6405-16 and 6405-18**

# 1 INTRODUCTION

By letters dated January 22, 2001, January 25, 2001, February 2, 2001 and March 6, 2001, respectively, ATCO Gas – North[1] (AGN), a division of ATCO Gas and Pipelines Ltd., submitted applications (collectively, the Applications) to the Alberta Energy and Utilities Board (Board) for approval of the following:

- Application No. 2001017 - Sale of certain petroleum and natural gas rights and production and gathering assets in the Viking Kinsella Field to Burlington Resources Canada Energy Ltd. (Viking Application)

- Application No. 2001020 - Sale of certain petroleum and natural gas rights and production and gathering assets in the Westlock, Peace River Arch, Phoenix and other fields not operated by AGN to Trioco Resources Inc. (Westlock Application)

- Application No. 2001030 - Sale of certain petroleum and natural gas rights and production and gathering assets in the Beaverhill Lake and Fort Saskatchewan fields to NCE Petrofund Corp. and NCE Energy Corporation (Beaverhill Application).

- Application No. 2001070 - Sale of certain petroleum and natural gas rights and production and gathering assets, storage assets and inventory in the Lloydminster field to AltaGas (Sask.) Inc. and AltaGas Services Inc. (Lloydminster Application)

Based on the information provided by AGN in the Applications, a summary of the properties encompassed by each Application and the proceeds associated with each sale is provided in Appendix A to this Decision. The Board notes that this summary is only provided in order to give some context to this Decision and does not reflect the views of other parties to the proceedings.

AGN's request for approval of the Applications for the sale of its petroleum and natural gas assets (collectively, the P&NG assets) was made pursuant to section 25.1 of the *Gas Utilities Act*, which provides, inter alia, that no owner of a gas utility may dispose of its property without the approval of the Board unless it is in the ordinary course of the owner's business.

[1] ATCO Gas – North was previously a division of Northwestern Utilities Limited. Effective January 1, 2001 Northwestern Utilities Limited was wound up into ATCO Gas and Pipelines Ltd.

AGN indicated that it set a target of using approximately fifteen per cent of company owned production (COP) in its aggregate sales portfolio. AGN stated that generally the P&NG assets were used for operational, rather than price, considerations. However, AGN submitted that its P&NG assets were no longer required for those purposes as the natural gas market place had changed in nature and was sufficiently liquid to allow it to meet all of its utility obligations without the need for COP. AGN believed that its decision to offer the properties for sale would allow it to capture the recently increased value of all of the gas reserves in the ground.

## 2 NOTICE AND THE HEARING

The Board published Notices of Hearing for the Viking, Westlock and Beaverhill Applications in daily newspapers having a general circulation in AGN's service areas. Notice of Hearing for the Viking Application was also published in the *Viking Weekly*. The Board also served the Notices on intervenors and interested parties registered on the mailing list of AGN's last gas cost recovery rate application.

Because of time constraints with respect to the hearing schedule, the Board served a Notice for Objections in respect of hearing the Lloydminster Application in conjunction with the other three Applications. That Notice was served on the interested parties already served with the Notice of Hearing for the other Applications. The Board received no objections to the inclusion of the Lloydminster Application in the hearing of the other three Applications. Therefore, the Applications were heard concurrently.

Interested parties representing consumers presented evidence and arguments at the hearing opposing the Applications. These parties considered that approval of the Applications would not be in the public interest as there would be insufficient proceeds to keep the customers harmless. They also considered that, given today's natural gas price levels, COP should be increased above that proposed by AGN.

The Applications were considered by the Board at a public hearing in Edmonton, Alberta lasting six days, commencing on April 5, 2001, before a Division of the Board consisting of B. F. Bietz, Ph.D., B. T. McManus, Q.C. and T. McGee.

## 3 AGN'S POSITION ON TIMELY RELEASE OF THE BOARD'S DECISION

AGN noted that three of the agreements for sale of the P&NG assets contemplated by the Applications contained price adjustment clauses that diminish the sale proceeds with any delay in the closing dates. AGN indicated that if the disposition of the proceeds was controversial it was requesting approval of the sale prior to the approval of the disposition of the proceeds.

## 4 BOARD FINDINGS

The Board has carefully considered the evidence and argument presented by all parties, including the arguments concerning the public interest, the Board's jurisdiction, and the applicable legal principles. The Board notes that AGN is prepared to accept the risk associated with any conditions that the Board may attach, including any ultimate disposition of proceeds to customers with respect to the Applications that are approved.

The Board notes AGN's concern with the need for an early decision and is prepared to issue this Decision with reasons and conditions to follow. A detailed report setting out the reasons for the Board's decision in relation to the Applications will be issued as soon as possible.

## 5 ORDER

IT IS HEREBY ORDERED THAT:

1. The Application for the sale of certain petroleum and natural gas rights and production and gathering assets in the Viking Kinsella Field to Burlington Resources Canada Energy Ltd. is denied;

2. The Application for the sale of certain petroleum and natural gas rights and production and gathering assets in the Westlock, Peace River Arch, Phoenix and other fields not operated by ATCO Gas – North to Trioco Resources Inc. is approved;

3. The Application for the sale of certain petroleum and natural gas rights and production and gathering assets in the Beaverhill Lake and Fort Saskatchewan fields to NCE Petrofund Corp. and NCE Energy Corporation is denied; and

4. The Application for the sale of certain petroleum and natural gas rights and production and gathering assets, storage assets and inventory in the Lloydminster field to AltaGas (Sask.) Inc. and AltaGas Services Inc. is approved.

DATED at Calgary, Alberta on May 29, 2001.

**ALBERTA ENERGY AND UTILITIES BOARD**

(Original signed "B. F. Bietz")

B. F. Bietz, Ph.D.
Presiding Member

(Original signed "B. T. McManus")

B. T. McManus, Q.C.
Member

(Original signed "T. McGee")

T. McGee
Member

# APPENDIX 1

## SUMMARY OF THE APPLICATIONS

**Application No. 2001017 (Viking Application):**

The proposed agreement for sale included AGN's interest in the Viking Kinsella area in:

- the Viking rights and associated infrastructure, which comprises a land base in excess of 314,000 acres of predominately 100% working interest in the Viking zone and
- all remaining non-Viking zones, the majority of lands of which include petroleum and natural gas (P&NG) rights surface to basement but with varying interval ownership.

AGN provided the following financial information ($000s) with respect to the proposed sale:

| | |
|---|---|
| Gross proceeds | 490,000 |
| Cost of disposition | (5,414) |
| Proceeds associated with seismic | (1,500) |
| Proceeds for petroleum rights | (7,670) |
| Net proceeds | 475,416 |

**Application No. 2001020 (Westlock Application):**

AGN provided a list of the gas fields concerned in the proposed sale with its application. With respect to these properties AGN noted the following:

- all are non-operated and cost control is limited,
- all are considered to be non-core,
- production represents about 7% of its total annual production, and
- over the period 1996 – 2000, average growth in capital expenditures exceeded 50%.

AGN provided the following financial information ($000s) with respect to the proposed sale:

| | |
|---|---|
| Gross proceeds | 15,400 |
| Cost of disposition | (286) |
| Proceeds for petroleum rights | (35) |
| Net proceeds | 15,079 |

**Application No. 2001030 (Beaverhill Application):**

For the Beaverhill Lake area, the agreement for sale includes AGN's:

- 95.548% gas Unit working interest,
- 100% working interest in P&NG rights, surface to basement, in approximately 11,400 acres, and
- 100% working interest in natural gas rights, surface to basement, in approximately 2,560 acres outside the Unit boundaries.

For the Fort Saskatchewan area, the agreement for sale includes AGN's:

- 100% working interest in 12 producing wells and 4 suspended wells,
- 75% % working interest in 1 producing well, and
- 88% % working interest in 1 producing well.

AGN advised that production from those properties represents approximately 15% of its total annual COP and that they are core production properties.

AGN provided the following financial information ($000s) with respect to the proposed sale:

| | |
|---|---|
| Gross proceeds | 37,000 |
| Cost of disposition | (265) |
| Proceeds for petroleum rights | (37) |
| Net proceeds | 36,698 |

**Application No. 2001070 (Lloydminster Application):**

AGN advised that it had discontinued production from the Lloydminster wells and use of the storage facility in 1996 but that the wells were not abandoned as some remaining reserves were recoverable. However, it noted that recovery would involve additional capital investment. AGN considered that the proposed sale would allow it to maximize the value of those assets.

AGN provided the following financial information ($000s) with respect to the proposed sale:

| | |
|---|---|
| Gross proceeds | 3,800 |
| Cost of disposition | (69) |
| Proceeds for petroleum rights and storage inventory | (135) |
| Net proceeds | 3,596 |