MANITOBA	**Board Order 91//01**
THE PUBLIC UTILITIES BOARD ACT	**June 6, 2001**

Before: G. D. Forrest, Chairman
M. Girouard, Member
M. Santos, Member

AN APPLICATION BY CENTRA GAS MANITOBA INC. FOR AN ORDER SEEKING FINAL APPROVAL OF ACTUAL 1999 AND 2000 GAS COSTS, DISPOSITION OF CERTAIN GAS COST DEFERRAL ACCOUNT BALANCES AS OF MARCH 31, 2001, CONFIRMATION OF CERTAIN INTERIM ORDERS, APPROVAL OF SALES RATES TO BE EFFECTIVE FOR ALL GAS CONSUMED ON AND AFTER JUNE 1, 2001, AND OTHER MATTERS

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Executive Summary

Natural gas is a commodity subject to market fluctuations and natural gas prices respond to supply and demand forces in the unregulated market. The dramatic increase in natural gas prices over the last year results from current market conditions. Dramatic increases in natural gas prices are a North American phenomenon, in part caused by an upturn in North American demand.

Natural gas prices in Canada and the United States have increased dramatically over the past year. The price for Alberta spot gas at the border was approximately $3/gigajoule ("Gj") in January 2000. In January 2001 the price was over $13/Gj. In March 2001, the spot price was approximately $7.60/Gj. This dramatic increase in the commodity cost of gas has been responsible for most of the increase in sales rates requested by Centra Gas Manitoba Inc. ("Centra").

In this Order, The Public Utilities Board (the "Board") has approved the actual 1999 gas costs, the actual 2000 gas costs, excluding Primary Gas, and the disposition of all PGVA and gas cost deferral account balances (excluding the post May 1, 2000 Primary Gas PGVA account) as at March 31, 2001 (by way of a rate rider over the 11 month period from June 1, 2001 to April 30, 2002. The Board has directed Centra to file revised sales rates for Supplemental Gas, Transportation (to Centra) and Distribution (to customer) to include the forecast increase in non-primary gas costs for 2001/02, based on the twelve month forward price strip at March 1, 2001, for all gas consumed on or after June 1, 2001.

The Board approved the cost consequences of Centra's derivative hedging transactions for the 1998/1999 and 1999/2000 gas years. Although disappointed with Centra's limited hedging activities, the Board was of the view that the success of a derivative hedging program must be reviewed in the context of an entire gas year. The Board will review the 2000/2001 derivative hedging transactions at a future proceeding. The Board directed Centra to file revised Derivative Hedging Operating Procedures that included the specific circumstances under which future derivative hedging transactions will be placed, by no later than October 31, 2001.

The Board approved the cost consequences of the TransCanada Energy Ltd. ("TCE") contract. However, the Board expressed concern that Centra did not bargain for a regulatory approved condition precedent to protect Centra and Manitoba consumers. The evaluation of the relative success of the contract negotiations after the fact can only be speculative in nature. Although disappointed with many aspects of the renegotiated contract, the Board concluded that the renegotiated contract taken as a whole, was an improvement over the legacy contract.

The Board expressed disappointment with the length of time taken by Centra to respond to a Board directive to review the merits of outsourcing the management of Centra's gas supply assets. However, no compelling evidence was submitted at the hearing that clearly indicated that Centra could have achieved better results through outsourcing. Future direction of this issue largely depends on the results of a "Blank Page" analysis currently being undertaken by Centra. The Board has directed Centra to file this analysis by no later than November 1, 2001.

The Board also rendered decisions regarding amendments to the Terms and Conditions of Service for the removal of Buy/Sell Service and the Buy/Sell Summer Interruptible Delivery Option, the allocation of unaccounted for gas, demand levels, load factor, and confirmation of certain interim orders. Further details regarding these specific matters can be found in the body of the Order.

The approximate rate impacts of the decisions from this Order on the annual natural gas bills of various customer classes are expected to be approximately as follows:

Customer Class	**% Annual Bill Increase**
Small General Class ("SGC")	6.0 to 6.5
Large General Class ("LGC")	8.0 to 9.0
High Volume Firm ("HVF")	7.0 to 8.0
Mainline	4.5 to 7.0
Interruptible	17.0 to 18.5

In addition to this Application, the Board is currently considering a separate application by Centra for changes to sales rates relating to Primary Gas, pursuant to the quarterly Rate Setting Methodology approved by the Board in Order 55/00. The sales rate impacts of the Primary Gas application, as filed, are expected to be minimal.

Sommaire

Le gaz naturel est un produit sensible aux fluctuations du marché qu'entraînent les forces de l'offre et de la demande dans un marché non réglementé. La hausse phénoménale des prix du gaz naturel au cours de la dernière année découle des conditions du marché. Ces hausses importantes des prix du gaz naturel représentent un phénomène nord-américain qui sont causées, en partie du moins, par l'augmentation de la demande en Amérique du Nord.

Les prix du gaz naturel au Canada et aux États-Unis ont augmenté énormément au cours de la dernière année. Le prix du disponible albertain, près de la frontière, se situait approximativement à 3,00 $ le gigajoule en janvier 2000. En janvier 2001, le prix excédait 13,00 $ le gigajoule. En mars 2001, le prix du disponible était approximativement de 7,60 $ le gigajoule. Cette hausse spectaculaire des coûts du gaz est responsable en grande partie de la hausse des prix à la consommation demandée par Centra Gas Manitoba Inc. (« Centra »).

Dans ce décret, la Régie des services publics (la « Régie ») a approuvé les coûts actuels du gaz en 1999 et en 2000, excluant le gaz primaire et la disposition des soldes du compte PGVA et du compte de coût du gaz reporté (excluant le compte PGVA pour le gaz primaire après le 1er mai 2000) en date du 31 mars 2001 (par l'utilisation d'un supplément de tarif sur une période de 11 mois allant du 1er juin 2001 au 30 avril 2002. La Régie a ordonné à Centra de déposer ses tarifs de vente révisés pour le gaz d'appoint, les frais de transport (chez Centra) et de distribution (chez les clients) afin d'y inclure la hausse prévue des coûts du gaz non primaire pour 2001 et 2002, établie en fonction du créneau de prix des douze mois précédant au 1er mars 2001, pour tout le gaz consommé le ou après le 1er juin 2001.

La Régie a approuvé les conséquences reliées au coût des transactions de couverture dérivées de Centra pour les années de gaz 1998/1999 et 1999/2000. Bien que déçue des activités de couverture limitée de Centra, la Régie était d'avis que le succès d'un programme de couverture dérivée devait être examiné dans le contexte d'une année de gaz complète. La Régie examinera les transactions de couverture dérivées pour 2000/2001 lors d'une procédure à venir. La Régie a ordonné à Centra de produire des Procédures d'exploitation de couverture dérivées qui comportent les circonstances spécifiques en vertu desquelles les futures transactions de couverture dérivées seront effectuées, au plus tard le 31 octobre 2001.

La Régie a approuvé les répercussions sur les coûts du contrat de TransCanada Energy Ltd. (« TCE »). Cependant, la Régie a manifesté sa préoccupation à l'effet que Centra n'avait pas négocié une condition suspensive réglementaire destinée à protéger Centra et les consommateurs manitobains. L'évaluation du succès relatif des négociations du contrat après coup ne peut être que de caractère spéculatif. Bien que déçue par plusieurs aspects du contrat renégocié, la Régie a conclu que le contrat renégocié, dans son ensemble, constituait une amélioration par rapport au contrat hérité.

La Régie a exprimé sa déception concernant la période de temps qu'avait mis Centra pour répondre à une directive de la Régie d'examiner les avantages de l'impartition de l'administration des actifs de Centra. Cependant, aucune preuve péremptoire n'a été déposée devant l'audience indiquant que Centra aurait obtenu de meilleurs résultats par le biais de l'impartition. L'orientation future sur cette question dépend grandement des résultats d'une analyse « page blanche » présentement entreprise par Centra. La Régie a ordonné à Centra de déposer cette analyse au plus tard le 1^er^ novembre 2001.

La Régie a également rendu des décisions concernant les amendements apportés aux modalités de service pour le retrait du service Achat/Vente et l'option de livraison d'été interruptible Achat/Vente, l'allocation de pertes de gaz, les niveaux de demande, le facteur d'utilisation et la confirmation de certaines commandes intérimaires. Des détails supplémentaires concernant ces sujets spécifiques se retrouvent dans le corps du décret.

Les impacts des décisions de ce décret sur les factures de gaz naturel annuelles de différentes catégories de clients seront approximativement les suivants :

Catégorie de clients	% d'augmentation de la facture annuelle

Catégorie générale petit (« SGC »)	6,0 à 6,5
Catégorie générale grand (« LGC »)	8,0 à 9,0
Entreprise à grand volume (« HVF »)	7,0 à 8,0
Client ordinaire	4,5 à 7,0
Interruptible	17,0 à 18,5

En plus de cette requête, la Régie étudie présentement une requête distincte de Centra visant à la modification du tarif à la consommation du gaz primaire, en vertu de la méthodologie d'établissement des tarifs trimestrielle approuvée par la Régie dans le décret 55/00. Les impacts sur le prix à la consommation de la requête sur le gaz primaire, telle que déposée, devraient être minimes.

1.0 Appearances

R. Peters K. Kalinowsky	Counsel for The Manitoba Public Utilities Board (“the Board”)
J. Foran, Q.C. M. Murphy	Counsel for Centra Gas Manitoba Inc. (“Centra”)
B. Meronek, Q.C. K. Saxberg	Counsel for Consumers’ Association of Canada (Manitoba) Inc. and the Manitoba Society of Seniors Inc. (“CAC/MSOS”)
D. Brown	Counsel for Municipal Gas, A Division of Direct Energy Marketing Limited (“Municipal”)

2.0 Witnesses for Centra

G. Neufeld	Consultant (Former Manager, Gas Forecasts Department, Centra)
G. Meyer	Manager, Rates Department, Centra
H. Stephens	Manager, Gas Procurement Department, Centra
B. Sanderson	Senior Gas Cost Analyst, Gas Procurement Department, Centra
V. Warden	Chief Financial Officer, Vice President, Finance & Administration, Manitoba Hydro

3.0 Intervenors

Consumers' Association of Canada (Manitoba) Inc. and the Manitoba Society of Seniors Inc. ("CAC/MSOS")

Municipal Gas ("Municipal")

Simplot Canada Limited ("Simplot")

Communications, Energy and Paperworkers Union, Local 681 ("CEPU")

Gerdau MRM Steel ("MRM")

4.0 Witnesses for CAC/MSOS

A. Pringle	President, GSC Energy
G. Forget	Consultant
A. Ilnycky	President, Ilnycky Consulting
G. DeJulio	President, Gia M. DeJulio Consulting Inc.

5.0 Witness for Municipal Gas

K. Melnychuk	Manager, Manitoba Region, Municipal Gas

6.0 Application

The Application was filed by Centra Gas Manitoba Inc. (“Centra”) with The Public Utilities Board (“the Board”) on December 20, 2000 and subsequently revised. The Application requested the following:

1. Final approval of actual 1999 gas costs and the 1999 Purchased Gas Variance Account (“PGVA”), heating value and capacity management deferral accounts.

2. Final approval of actual 2000 gas costs, excluding Primary Gas.

3. Approval of the disposition of all PGVA and gas cost deferral accounts balances (excluding the post May 1, 2000 PGVA as at March 31, 2001, and net of forecast capacity management revenues for 2001/02 through rate riders.

4. Confirmation of the following interim Orders:

   (a) Order 115/00 for Primary Gas rates effective August 1, 2000
   (b) Order 142/00 for Primary Gas rates effective November 1, 2000
   (c) Orders 15/01 and 18/01 for Primary Gas rates effective February 1, 2001

5. Approval of sales rates for Supplemental Gas, Transportation (to Centra) and Distribution rates to include the forecast increase in non-primary gas costs for 2001/02 for all gas consumed on or after June 1, 2001.

6. Approval of amendments to the Terms and Conditions of Service for the removal of the Buy/Sell Service and the Summer Interruptible Delivery Option.

7. Approval of the gas cost consequences of the changes to Centra’s long-term gas supply contract with TransCanada Energy Ltd. (“TCE”).

A public hearing was held in Winnipeg at the Board offices on March 14 to 16, March 19 to 23, and April 3 and 4, 2001, and final argument was heard on April 5 and 6, 2001.

7.0 Gas Costs

7.1 Background

Centra last appeared before the Board regarding cost of gas issues, other than the cost of primary gas, in the spring of 1999. The Board approved Orders 118/99 and 126/99 dated June 29, 1999 and July 12, 1999, respectively for sales rates to be effective July 1, 1999. These rates included rate riders for the recovery of the 1998 PGVA, the 1998 Price Management results, other 1998 gas cost deferral accounts and the estimated 1999 capacity management revenues. The Board also directed that the deferral account balances for the Small General Class ("SGC") and Large General Class ("LGS") customer classes be recovered through rate riders on volumes consumed over the six month period from July 1, 1999 to December 31, 1999, and that the deferral account balances for the High Volume Firm ("HVF"), Mainline and Interruptible customer classes be recovered through rate riders on volumes consumed over the 21 month period from April 1, 2000 to December 31, 2001. Although the outstanding balances in the various gas cost deferral accounts allocated to the SGC and LGC classes were substantially recovered by December 31, 1999, the rate riders were continued after January 1, 2000 pursuant to Orders 200/99, 202/99 and 55/00. The Board considered that removing the existing rate riders at a time when the 1999 and 2000 PGVA balances were increasing substantially would result in unnecessary rate fluctuations.

7.2 1999 Gas Costs

Sales rates billed to consumers are based on forecast costs, including the forecast cost of gas. To the extent that the forecast cost of gas included in sales rates differs from actual cost of gas, the difference is accrued in the PGVA. The PGVA balance is subsequently recovered from or refunded to customers by way of a rate rider which is added to the base sales rate.

1999 sales rates were based on a forecast cost of gas of $220.31 million whereas the actual cost of gas for 1999 was $217.39 million. The components of the cost of gas, and the comparison between actual and forecast costs, are as follows:

Gas Cost Component	**1999 Actual Cost ($ million)**	**1999 Approved ($ million)**
Fixed Pipeline/Storage Demand	49.47	50.47
Supply:		
Variable Transportation	4.44	4.58
Western Canadian	138.31	134.60
Oklahoma	0.63	3.07
Storage Withdrawals & Exchanges	23.30	27.07
Delivered Service and Other	0.69	0.09
Other Miscellaneous Charges	0.55	0.43
Total	217.39	220.31

Most of the difference between forecast and actual amounts is attributed to the increased Western Canadian supply cost as a result of increases in both sales volumes and purchase price. Oklahoma supplies were used sparingly during 1999 because of the high price and due to the mild winter months. However, the decrease in costs associated with Oklahoma supplies was offset by an increase in costs associated with storage withdrawals.

7.3 1999 Capacity Management Revenue

When Centra does not need its contracted pipeline capacity to provide gas to customers, and if there is a demand for this capacity, Centra enters into capacity management transactions. The revenue from capacity management transactions is applied to reduce the net gas costs to customers.

Total net capacity management revenue for 1999 was $588,741, plus interest of $18,544 to March 31, 2001. Centra stated that revenue was lower than anticipated because of significant restructuring that has occurred in the marketplace. According to Centra, market forces had a negative effect on the types of capacity management transactions that were available and profitable. 1999 Capacity Management Revenue is included in the 1998 Gas Deferral account to reduce the amount that would otherwise be owing to Centra by customers.

7.4 1999 and Earlier PGVA Balances

The 1999 PGVA balances as of March 31, 2001 are as follows:

December 31, 1999 Balances Plus Carrying Costs to March 31, 2001

1999 PGVA (bundled)	$ 8,279,920
1998 Price Management Deferral	2,605,694
1998 Gas Deferrals (includes 1999 Capacity Management)	1,128,028
1999 Heating Value Deferral	(6,433)
Total 1999 PGVA Balance, March 31, 2001	$12,007,209

Centra was to apply carrying costs for the 1998 Price Management Deferral account at its weighted average cost of capital to December 31, 1999. Centra has calculated carrying costs on this account to March 31, 2001 using its weighted average cost of capital.

7.5 2000 Gas Costs

The forecast cost of gas for 2000 was $66.87 million, excluding Primary Gas, whereas the actual cost of gas for 2000 was $72.98 million. The components of the year 2000 cost of gas, and the comparison between actual and forecast gas costs, are as follows:

Gas Cost Component	2000 Actual Cost	2000 Approved

	($ million)	($ million)
Fixed Pipeline/Storage Demand	51.42	50.47
Variable Transportation	4.93	4.58
Non Primary Supply:		
Oklahoma	0.0	3.07
Storage Withdrawals & Exchanges	8.02	6.10
Delivered Service and Other	3.32	0.09
Other Miscellaneous Charges	5.29	2.56
Total	72.98	66.87

Most of the difference between forecast and actual amounts is attributed to the increased commodity cost and increased volumes in throughput due to colder than normal weather. Centra also elected to increase its daily demand levels for firm transportation ("FT") and short term storage ("STS") contracts by 1% effective November 1, 1999. In addition, tolls of TCPL and pipeline shippers have increased.

7.6 2000 Capacity Management

Total net revenue for 2000 was $3,734,383, including interest to March 31, 2001, compared to a forecast of $2.0 million for the year. Centra stated that because of a rising market price, there were more opportunities for the sale of Centra's TCE long-term supply that is set based on a monthly index. A higher demand for transportation of gas downstream of the Manitoba market facilitated diversions of TCPL transportation to Emerson and points in Eastern Canada.

7.7 2000 PGVA Balances

The PGVA balances reflect activity for a 15-month period because Centra changed its fiscal year end from December 31 to March 31.

The 2000 PGVA balances reflect 12 months actual results to December 31, 2000 and three months projected results to March 31, 2001, as follows:

December 31, 2000 Balances Plus Carrying Costs to March 31, 2001

Primary Gas to April 30, 2000	$11,364,836
2000 Supplemental Gas Cost	2,857,289
2000 Transportation to Centra Costs	353,422
2000 Distribution to Customer Costs	2,161,328
2000 Heating Value Margin Deferral	(516,476)
2000 Capacity Management Revenue	(3,734,383)
SGC & LGC Rate Riders Revenue	(4,965,003)
	$7,521,013

Stub Period PGVA Balances From January 1, 2001 to March 31, 2001

Supplemental Gas	8,238,756
Transportation to Centra	(9,478,201)
Distribution to Customer	2,144,910
Heating Value Margin Deferral	6,302
Capacity Management Revenue	(500,000)
	$ 411,767
Total 2000 PGVA Balance, March 31, 2001	$7,932,780

Beginning January 1, 2000, the PGV accounts were unbundled into four separate accounts: Primary Gas, Supplemental Gas, Transportation to Centra and Distribution to Customer. With the implementation of WTS Service on May 1, 2000, the Primary Gas PGVA balance at April 30, of $11,364,836, to be recovered from all customers through the distribution rate, was segregated from Primary Gas costs incurred after May 1, 2000. The Primary Gas PGVA after May 1, 2000 is disposed of quarterly through the Rate Setting Methodology ("RSM"), and is not a subject of this Application.

The Primary Gas PGVA captures the cost of Western Canadian Gas supplied for TCE purchases and spot purchases, and includes the cost of TCPL compressor fuel to transport the gas from the Alberta border to the Manitoba delivery points and the impact of any hedges placed on TCE supplies. Western Canadian supplies used to support unaccounted for gas ("UFG") requirements have been removed from this account and transferred to the Distribution PGVA.

The Supplemental Gas PGVA captures the cost of US purchases, Delivered Services and Supplemental Gas withdrawn from storage to meet Manitoba load requirements.

The Transportation to Centra PGVA includes the costs associated with the transportation of supplies on various Canadian and U.S. pipeline systems and costs for the leasing of US storage capacity.

The Distribution PGVA captures the cost of UFG of 1.074% on Centra's distribution network and charges on the Minell Pipeline.

The SGC and LGC rate rider revenue represents revenue collected from SGC and LGC customers through a rate rider included as part of the sales rate throughout 2000. This amount is being applied to reduce the 2000 PGVA balances otherwise owing to Centra by customers.

As part of the transition resulting from a change in Centra's fiscal year-end from December 31 to March 31, new deferral accounts were opened as of January 1, 2001 for Supplemental Gas, Transportation to Centra, Distribution to Customer, Heating Value Margin Deferral and Capacity Management. These accounts will accumulate the differences between actual gas costs and gas costs recovered through sales rates for the stub period from January 1, 2001 to March 31, 2001. New PGVAs have been opened to accumulate gas cost differences for a full year beginning April 1, 2001. The balances in these accounts will be reviewed by the Board at a subsequent hearing.

The majority of the Stub Period Supplemental PGVA balance of $8,238,756 is due to the increase in commodity cost of gas. However, a portion of the balance is due to increase volumes due to load growth with the balance representing a timing component.

The Stub Period Transportation PGVA has a credit balance of $9,478,201 owing to customers, primarily due to timing. Many of the costs are incurred throughout the year, while the majority of revenues are earned during the higher volume winter months.

Centra stated the majority of the Stub Period Distribution PGVA balance of $2,144,910 represents UFG caused by metering errors and physical gas loss.

The Heating Value Margin Deferral account reflects the difference in the actual heating value from the estimated heating value. Centra stated that it did not expect the balance in the account at March 31, 2001 to be material. However, a material balance could arise in the future. Therefore, Centra requested the account be kept open.

The stub period deferral account balances have been offset by an estimated $500,000 of capacity management revenue for this stub period.

7.8 2001/02 Projected Gas Costs – Non Primary

Centra forecasted non-primary gas costs for 2001/02, based on the 12 month forward strip price at March 1, 2001, as follows:

Non-Primary Gas Cost Component	Non-Primary Gas Costs Included in Existing Rates	Forecasted Non-Primary Gas Costs
Supplemental Gas	11,303,270	40,185,177
Transportation to Centra	58,471,375	65,286,803
Distribution to Customer	2,502,252	7,401,764
	$72,276,897	$112,873,744

Centra stated that the majority of the required increase from existing rates was due to the forecasted increase in the cost of the natural gas commodity. For example, the Alberta spot gas price increased from $2.53/Gigajoule (“Gj”) at January 4, 1999 to $3.03/Gj at January 4, 2000 and $12.90/Gj at January 2, 2001.

7.9 2001 Estimated Capacity Management Revenues

Centra expected that the annual total net revenues for 2001/2002 will be approximately $1.5 million even though the historical average is closer to $3 million. The 2001/02 cost of gas embedded in sales rates is therefore reduced by $1.5 million. Centra also stated that capacity management performance has been better than expected for the beginning of the year. Any difference between the estimated results and actual results will be accumulated in the PGVA.

7.10 Intervenor Positions

7.10.1 CAC/MSOS

CAC/MSOS stated that Centra's unutilized system capacity has long been identified as a concern. CAC/MSOS retained a representative of Duke Energy who appeared before the Board in 1998 to explain the various aspects of capacity management. In Order 79/98, the Board stated that a comprehensive North American presence was critical to take advantage of different prices and opportunities in the market place. CAC/MSOS is of the view that Hydro, as the owner of Centra, is reluctant to take full advantage of the potential revenues which could be generated by selling unutilized capacity until Hydro has explored future synergies for alternate energy sources.

CAC/MSOS contended that the 1999 capacity management revenue of $558,000, of which $62,000 was for capacity release, and 2000 capacity management revenue of $3.6 million, of which $1.9 million was for capacity release, were grossly inadequate, as is the forecast 2001 capacity management revenue of $1.5 million. These revenues represent a very small percentage of the potential value of Centra's unutilized capacity.

CAC/MSOS contended that opportunities for greater utilization were lost for 1999 and 2000, and will be lost for 2001 because of Centra's delay in evaluating outsourcing opportunities. CAC/MSOS recommended that if Centra cannot improve its capacity utilization, it should be held accountable and penalized.

CAC/MSOS suggested that Centra could have done better in managing its unutilized system capacity. Two CAC/MSOS witnesses testified that other LDCs in North America have done better in managing system capacity. CAC/MSOS recommended that the Board disallow $5 million in revenue requirement for each of 1999 and 2000, as a punitive measure. CAC/MSOS further recommended that the Board should set revenue benchmarks for each year that Centra would be expected to achieve. If Centra is unable to achieve these benchmark requirements, then Centra should outsource the management of its assets.

7.11 Board Findings

The major points at issue regarding the Board's review and approval of gas costs for 1999, 2000, and 2001 relate to Centra's derivative hedging activities and to the outsourcing of the management of Centra's gas supply assets including the release and resale of excess system capacity. Matters related to both derivative hedging activities and outsourcing the management of Centra's gas supply assets, including Board Findings, are discussed in more detail in subsequent sections of this Order.

The Board does not accept the recommendation of CAC/MSOS that Centra should be penalized $5 million for each of 1999 and 2000 as a punitive measure for failing to manage its unutilized capacity more effectively. While CAC/MSOS is disappointed in the results of this activity over the years under review, the Board heard no compelling evidence that clearly articulated any serious mismanagement on Centra's part that would support a punitive disallowance of the type recommended by CAC/MSOS. The Board also heard no specific evidence of any alternative plan that could have been implemented by Centra with more favourable results than actually realized by Centra.

The Board will approve the actual 1999 gas costs of $217.39 million. The Board will also approve the actual 2000 gas costs, excluding Primary Gas, of $72.98 million, and the disposition of all 1999 and 2000 PGVA and gas cost deferral account balances as at March 31, 2001, excluding the post May 1, 2000 Primary Gas PGVA, by way of a rate rider, subject to the carrying costs on the 1998 Price Management Deferral Account to be recorded at the short-term borrowing rate from January 1, 2000. The Board will direct Centra to file, for Board approval, revised sales rates for Supplemental Gas, Transportation (to Centra) and Distribution rates to include the forecast increase in non-primary gas costs for 2001/02 based on the 12 month forward price strips at March 1, 2001 for all gas consumed on and after June 1, 2001.

8.0 Derivative Hedging Activities

8.1 Background

In Order 79/98 dated June 19, 1998, the Board expressed the view that, "in a marketplace of indexed pricing for natural gas, where such prices may be extremely volatile, a well executed price management program will serve the interests of the ratepayers. To do otherwise would expose the ratepayers to the vagaries of the marketplace."

Derivative hedging is but one component in Centra's objective to reduce bill volatility. Under the Rate Management Policy ("RSM") approved in Order 55/00, Centra was to acquire natural gas for customers at the lowest possible cost having regard to security of supply and rate volatility. Centra defined the lowest cost achievable as the indexed market price of natural gas. Price caps and collars could be used to provide the necessary upward price protection considered appropriate, but derivative hedging would not be used in an attempt to beat the market. Centra stated that ultimately, customers must bear the risks of the natural gas market price volatility.

Through customer research and focus groups, Centra determined that the upper threshold of customer tolerance for bill volatility, not related to weather, was $60 annually. Although it was not explicit in Centra's Derivative Hedging Policy, Centra stated that it would base new sales rates on the current forward price curve and the proposed RSM. Then, using normalized volumes for Small General class customers, the average annual bill will be determined. Centra would calculate the probability of the price approaching or exceeding the $60 threshold that was acceptable to customers. If the probability of prices exceeding that threshold was greater than

5%, Centra would place derivative transactions, following approval by the Gas Supply Committee and the Executive Committee.

In Order 55/00 the Board reiterated that it had “spent substantial effort in two recent proceedings establishing guidelines for the future direction of price risk management for Centra.” The Board stated that Centra had not complied fully with the Board’s requirements. The Board, however, approved the Derivative Hedging Policy, subject to the inclusion and filing of strategies, objective, and circumstances under which derivative could be placed. The Board further stated that it was concerned about the level of skills and knowledge of the personnel within Centra responsible for placing and reviewing derivative hedging transactions. However, the Board viewed these responsibilities as that of management and expected Centra management to deal with them appropriately.

8.2 1999 Derivative Hedging Activities

As previously stated, customer research conducted by Centra indicated that bill volatility for an average residential customer of $60/year, which at that time equated to approximately $0.50/Gj, was acceptable. Since Centra determined that price volatility for 1999 could be constrained within that threshold, Centra did not place any derivatives for the first six months of the 1999 calendar year.

In June 1999, gas prices began to increase significantly. Concerned that prices would continue to increase, Centra placed a hedge on the remainder of the gas year volumes to attempt to dampen volatility to a level within the $0.50/Gj threshold. Quotations were obtained for both caps and costless collars. The cost for price caps was approximately $700,000, and a costless collar would have had an upper strike price of $3.05/Gj for Alberta Energy Company (“AECO”) and $3.17/Gj for Empress volumes with floors for both of $2.59/Gj. Centra placed collars for the remainder of the gas year, since it considered the premium for caps was too high. Centra achieved a positive result of $7,626 on their derivative hedging activities in 1999.

The average residential customers bill decreased by approximately $13.40 for the period from November 1, 1998 to October 31, 1999 because of a reduction in the commodity cost of gas. Therefore, the threshold was maintained.

8.3 2000 Derivative Hedging Activities

In October 1999 Centra decided to place costless collars with upper and lower strike prices of $3.67 to $4.55/Gj for December 1999 to January 2000. By the time Centra placed the transaction, November pricing was largely established and Centra was unable to hedge November volumes. Centra was unable to hedge its Empress volumes due to market conditions, and therefore only hedged 70% of its eligible volumes. After the December and January transactions, the market experienced a significant downward trend with settlement prices of $3.15 in December and $2.97 in January 2000. The negative mark-to-market for these months was $1.3 million and $1.7 million, respectively.

Centra stated that there was no price management plan in effect during the 1999/2000 gas year, since Centra was transitioning from the former plan to the new Rate Management Program.

Until Centra reviewed Order 55/00 in April 2000, Centra placed caps on a next to near month basis from February through May 2000. Initial collars were rejected since price caps predefined Centra’s cost. After receipt of Order 55/00, caps were placed on June through September volumes, using the $0.50/Gj out of the money approach, as a transitional measure to allow for implementation of the Rate Management Program. The $684,000 cost of the premiums for four months was considered reasonable in the circumstances.

Contrary to the advice of the Gas Supply Committee, the Executive Committee rejected a subsequent proposal to place a cap for October 2000 because the Executive Committee decided that the premium of approximately $500,000 was too high. If the cap had been placed, Centra customers would have paid approximately $4,200,000 less for their gas costs for October 2000.

Centra provided evidence at the hearing indicating that the increase in an average customer's bill of $56.37 for the period November 1, 1999 to October 31, 2000 was within the threshold of $60. However, in the minutes of the Gas Supply Committee, Centra indicated that it would measure the change for the period December 1, 1999 to November 30, 2000. Using this timeline, an average residential consumers bill would have increased $70.11, which is outside of the $60 threshold.

For all derivatives placed in 2000, the positive net market-to-market was $725,000. Centra urged the Board not to consider this positive result as a benchmark of the success of its derivative program. Rather the Board should consider whether Centra had met its customers' requirement that bill volatility be kept within the +/- $60 annual threshold.

8.4 2001 Derivative Hedging Activities

In the April and June 2000 meetings of the Gas Supply Management Committee, any decision to place derivatives was deferred until the Trans Canada Energy ("TCE") contract was finalized. Subsequently, it became apparent that the finalization of the TCE contract would be extended beyond the expected fall completion. As a consequence, Centra reconsidered options to place derivatives.

In late August 2000, the Gas Supply Management Committee turned to a methodology whereby Centra would calculate the updated primary gas rates for the upcoming gas year on or before September 15, 2000, and determine if there was a 5% or greater probability that increases in gas costs would cause bills to exceed the customer's tolerance level of $60. The analysis indicated that the $60 annual threshold could not be achieved primarily because of the substantial balance in the PGVA. Notwithstanding that Centra could not meet its benchmark, Centra considered placing caps at $0.40 and $0.50 out of the money. At $0.40, the price for a cap was $22 million or 10% of Centra's annual primary gas costs and at $0.50 the price would decrease to $21 million. The premium for $0.50 ranged from $0.46/Gj to $0.67/Gj.

The Gas Supply Management Committee then considered alternative options. At $1.00 out of the money, the cost of a cap was $15 million and at $1.25, the cost was $13 million. Quotations for these price caps were so high that Centra elected not to purchase any derivatives for the gas year, deciding instead to rely upon the Rate Management Program to dampen volatility. The Executive Committee concluded that the costs of the derivatives were greater than the benefits of the protection that those instruments could potentially provide.

Centra did obtain price quotes on collars for $0.40 and $0.50 upper strike prices. These transactions were not recommended because the strike price on the floor provided minimal opportunity to participate in any downward movement in prices. Centra stated that the negative experience with collars in December of 1999 and January 2000 led Centra to favour caps. Collars with upper strike prices of $1.00 and $1.25 were not evaluated by Centra.

If a costless collar had been purchased for the first quarter of the gas year, Centra would have paid approximately $25 million less for their gas costs for the first quarter of the gas year.

8.5 Derivative Hedging Policy - Operating Procedures and Terms of Reference of the Gas Supply Committee

In Order 19/00, the Board's directed Centra to update the Derivative Hedging Policy. Centra's response was delayed for almost a year. Centra submitted, however, that it had satisfied the

Board's requirement in Order 55/00 and that the objectives, strategies, and circumstances under which derivatives are to be placed are outlined in the documents if the Rate Management Policy, Derivative Hedging Policy, Operating Procedures, and Terms of Reference of the Gas Supply Management Committee are considered together. Changes to these documents were minor when compared to the documents the Board reviewed in leading to the decisions in Order 55/00.

Centra's Derivative Hedging Policy previously stated that derivatives would be place on warmest year volumes. This statement was changed to encompass actual volumes purchased under the TCE contract, which eliminates the risk of hedging volumes for which there are no underlying physical requirement. Centra testified that they would continue to hedge only minimum year volumes with counterparties other than TCE.

Centra stated its intent was to review the placement of derivatives on a quarterly basis. A decision would be made at the beginning of the new gas year to ensure the benchmark of $60 would be met for the twelve-month period. The forward gas strip and market activity would be monitored on an ongoing basis.

Under the Rate Management Program, derivatives would be used when appropriate to mitigate gas cost volatility. Centra testified that volatility includes changes in both directions. Centra stated that for the past year, prices had been consistently escalating and derivatives were never intended to control a constantly rising market. Centra's objective was to purchase gas at the lowest possible cost, meaning at the market-indexed price. Rate stability was to be obtained through the rate management program.

In making a decision whether or not to place derivatives, Centra stated that its gas procurement manager would present a report to the Gas Supply Management Committee. The Gas Supply Management Committee would then make a recommendation to the Executive Committee. The

Executive Committee, using judgment, would ensure the objective of mitigating gas cost volatility would be satisfied prior to approving or rejecting the placement of derivatives, subject to weighing the costs of the derivative against its value. The President and CEO is kept up to date on the derivative hedging by receiving the Daily Position Report when derivative positions are in place.

At its meeting on August 31, 2000, the Gas Supply Management Committee agreed that a twelve month rolling average, updated quarterly, should be used to measure the annual change in residential billing, even though a customer would not be able to perform such a calculation. The Gas Supply Management Committee also noted that customers could always purchase their gas from a broker if they wished to have a fixed price option.

Centra testified that the skill, education, and knowledge of its staff that placed derivatives was adequate, with some individuals attending courses and seminars, and reviewing extensive published literature. Furthermore, Centra was not considering outsourcing derivative hedging since it believes it has the requisite skills to execute the program in a cost efficient manner.

8.6 Intervenor Positions

8.6.1 Municipal's Position

Municipal stated that Centra's actions with respect to its derivative hedging program should be evaluated based on four criteria.

1. The standard of prudence and reasonableness as stated in Order 79/98.

2. Centra's objective to manage the risk of exposure to price volatility. Municipal pointed out that in the recent past, the Board had not disallowed "negative" price management results related to market volatility. Municipal suggested that it was especially critical to adhere to

this principle because of the pattern of unprecedented market volatility over the two-year period currently being reviewed.

3. Results should be evaluated having regard for circumstances as they existed when the activities took place, as opposed to assessment of the results with the benefit of hindsight. Municipal suggested that to assess prudence, the Board should put itself in the shoes of Centra at the time that various decisions were made with respect to price management activities.

4. Centra's stated objectives contained in its price management policies approved by the Board in Order 55/00, which contain an element of discretion and judgment.

Municipal stated that consumers benefited from price management activities through lower gas costs in 1999 and 2000. In addition, Municipal suggested the Board evaluate Centra's actions based on the annual tolerance band of $60 Centra had established. In Municipal's opinion, Centra met its objective in 1999, and came very close to meeting its objective in year 2000. In Municipal's view a mere ten dollars should not be a basis for the Board to find that Centra was imprudent.

In support of Municipal's statement that the gas market in North America has experienced increases in gas prices of an unprecedented nature, Municipal filed an exhibit that indicated the Alberta spot gas price increasing from $2.53/Gj in January 1999, to $3.03/Gj in January 2000, and $13.22/Gj in January 2001 . Municipal argued that in times of unpredictable price volatility, the rate management approach taken by Centra is reasonable and prudent for a regulated utility. However, it is the customer that must bear the ultimate risk of price volatility. If a customer wants to fix its gas price, then the services of a broker could be sought. It is not for Centra to engage in hedging to try and fix the gas prices for customers over a long period of time.

Municipal submitted that market volatility was not unique to Manitoba. Therefore to a certain extent, to assess the prudence of Centra, one had to take a look at what was happening elsewhere. Municipal noted that other LDCs with price management programs have requested similar rate increases between September 2000 and February 2001. Muncipal argued that such rate increases are a North American phenomenon, and not unique to Manitoba.

Municipal stated that the gas market in North America has experienced increases in gas prices of an unprecedented nature. In times of unpredictable price volatility, the rate management approach taken by Centra is reasonable and prudent for a regulated utility. However, it is the customer that must bear the ultimate risk of price volatility. If a customer wants to fix its gas price, then the services of a broker could be sought. It is not for Centra to engage in hedging to try and fix the gas prices for customers over a long period of time.

Municipal submitted that Centra acted in a manner consistent with the stated and approved objectives contained in its price management policy, and that a disallowance would only impact the taxpayers of Manitoba. Therefore, if the Board feels that changes should be made in the future to the manner in which Centra conducts its price management activities, then the Board should provide guidance.

8.6.2 CAC/MSOS' Position

CAC/MSOS argued that Municipal's reason for defending Centra was to prevent a potential disallowance that would also impact Municipal and its customers.

CAC/MSOS stated that Centra should not be evaluated on its mark-to market results but rather on the development and implementation of appropriate plans, controls, and strategies relative to derivative hedging. CAC/MSOS also submitted that if the Board was not convinced that Centra's derivative hedging was appropriate, a disallowance of some sort is appropriate, with no concern regarding the impact on the shareholders of Centra who are also the taxpayers of Manitoba.

CAC/MSOS did not specifically object to Centra's derivative hedging activities during 1999. However, CAC/MSOS stated that Centra did not have a clear and defined strategy with respect to the use of derivatives, and interim strategies changed repeatedly throughout 2000.

CAC/MSOS stated that the cost/Gj is an appropriate way to determine results. It appeared as though the Executive Committee was simply looking at the absolute price of the cap, and arbitrarily determining if it was too expensive, rather than considering other factors. The decision made by the Executive Committee not to approve the cap for October fundamentally altered Centra's approach. CAC/MSOS argued that this action demonstrates that the judgment on whether to place a hedge stems from the Executive Committee and not the Gas Supply Committee. CAC/MSOS stated that the members of the Executive Committee are all new to the gas industry and the practice of placing derivatives. None of them have any formal training in the placement of derivatives, and their experience is related to the electric operations, and not gas. CAC/MSOS submitted that the Executive Committee should have responsibility for approval of overall strategies, but the Gas Supply Committee should be in charge of the operational decisions.

CAC/MSOS stated that the Derivative Hedging program has been "mismanaged" by Centra for years, that there have been no lessons learned, that trading has gone historically from dynamic to sporadic to limp, and that consumers expect and deserve much more. CAC/MSOS argued that Centra's actions have neither reduced volatility nor lowered gas costs.

CAC/MSOS questioned Centra's statement that derivatives will increase costs in the long run given the 1999 and 2000 results. CAC/MSOS stated that Centra looked at the results during December 1999 and January 2000 and realized that losses were being incurred. As a result, Centra shifted away from the fundamental aspects of its program and started to concentrate on the results on a month-by-month basis. December and January were much too early in the gas year to begin categorizing the hedging program as a failure because of some lost opportunity costs.

There were no gas supply committee meetings between June 26, 2000 and August 23, 2000 despite the fact that gas prices continued to rise to unprecedented levels. The main justification Centra offered for not taking action in June or earlier, with respect to the new gas year, is that a protocol had been established during the testimony at the rate management hearing and that protocol required Centra to wait until September before placing derivatives for the next year. CAC/MSOS questioned why this express criteria was blindly followed while the major aspects of the strategy were not. CAC/MSOS added that the TCE contract negotiations should not have played a role in the decision to delay hedging for the new gas year.

CAC/MSOS disagreed with Centra's statement that collars have a cost if the floor is breached. CAC/MSOS noted that Centra did not even evaluate disaster insurance in the form of a costless collar with an upper strike price of $1.25 in August 2000.

CAC/MSOS adopted the evidence of Ashmead Pringle, and requested that $15 million be disallowed, being approximately two thirds of the $25 million positive mark-to-market for the first quarter of 2001 which CAC/MSOS maintains was not realized as a result of Centra's inactions with respect to placing a collar. In addition, CAC/MSOS stated that only minor edits were made to the Derivative Hedging Policy and that the combination of the documents submitted does not contain any discussion of strategies and objectives and does not meet the Board's directive.

8.6.3 Ashmead Pringle's Position

Mr. Ashmead Pringle provided evidence on behalf of CAC/MSOS. Mr. Pringle stated that a cap should be the first choice of Centra as upside protection is achieved, but Centra can still participate in all downside price movement. However, when the cost of a cap is too high, the use of a collar is a good compromise and is commonly used in the natural gas industry.

Mr. Pringle advised that a collar provides certainty regarding price ranges and reduces risk. If the price drops below the floor, as it did in December of 1999 and January 2000, that is not necessarily a bad thing because the objective is to reduce volatility, rather than to produce a positive mark-to-market.

Mr. Pringle concluded that The Gas Supply Committee minutes reveal Centra was imprudent from a risk management perspective for several reasons. Staff training in derivative use did not take place. The plan to modify the derivative policy was put off repeatedly. The Gas Supply Committee did not meet every month, even during time of very volatile prices. Centra did not seem to have the in-house ability to analyse the options market in order to determine the cost of various strategies. As the market became increasingly volatile, Centra changed the rules regarding the measurement of consumers' bill volatility, and decided that derivatives were not useful; rather, reliance should be placed on the smoothing mechanism. In Mr. Pringle's view, Centra failed to protect customers from extreme price shocks by rationalizing that customers who want protection can buy gas from a broker at a fixed price instead of from Centra.

Mr. Pringle stated that when Order 55/00 was issued in April 2000, Centra should have been projecting gas costs into the 2000/2001 gas year. As spring turned to summer, Centra did not conduct any hedging for the coming gas year. Applying the most forgiving interpretation of events, by August 31, 2000, at the latest, Centra should have place collars for the 2001/2001 gas year. Mr. Pringle noted that he had not performed an independent analysis of the consequences of this inaction, but Centra had indicated that a positive mark-to-market in the amount of $25 million would have resulted.

Mr. Pringle stated that the result of Centra's inactions exposed customers to substantially higher gas costs which could have been avoided by the development of, adherence to and reasonable exercise of, an appropriate derivative hedging policy. In Mr. Pringle's opinion, the ratepayers should not be required to bear the burden of the costs incurred because of Centra's fundamental failure to protect the consumers' interests. In his estimation, the consequences of Centra's departure from the stated hedging policy represents, at the very least, a cost to the ratepayers of approximately $15 million.

8.7 Board Findings

As stated in previous Orders, the Board considers a well-executed Derivative Hedging Program to be in the interest of the ratepayers by reducing exposure to the vagaries of the marketplace. However, the customers will ultimately carry the actual risk of volatility in the marketplace.

8.7.1 1999 Derivative Hedging Activities

The Board considers the use of the $60 annual threshold, which equalled approximately $0.50/Gj at the time it was determined, to be a reasonable test for the placement of derivative transactions for the period from November 1, 1998 to October 31, 1999. The Board recognizes that SGC customer bills were kept within that threshold. Given Centra's adherence to the process to contain rate volatility as contained in Order 55/00, the Board will approve gas cost consequences of the derivative hedging transactions for 1999.

8.7.2 2000 Derivative Hedging Activities

For the gas year November 1, 1999 to October 31, 2000, the Board believes that the use of the $60 annual threshold remained the appropriate test of circumstances for the placement of derivative transactions. During this period the Board is aware that Centra was able to maintain SGC customer bills within this tolerance level. The Board will approve the gas cost consequences of the derivative transactions for 2000. Notwithstanding this approval the Board is troubled by many of Centra's responses and inaction during the latter part of this gas year.

The Board heard evidence that suggests that the process used to evaluate transactions during this period was seriously flawed. The Executive Committee did not perform the correct analysis to approve the transactions during the year. The Executive Committee overruled a Gas Supply Committee recommendation to hedge October volumes. The Executive Committee's decision appears to have been primarily driven by the absolute costs of the cap. The decision to "save" approximately $500,000 related to the cost of the cap may have increased gas costs by over $4 million. The Board is of the view that an absolute dollar cost should not be used in isolation to determine whether or not a cap should be placed. The Board is also concerned that the ultimate decision to place derivatives was made by the Executive Committee which does not appear to have the depth of expertise to evaluate these transactions. It is the Board's view that it would be more effective to have the Executive Committee approve policies and procedures under which the Gas Supply Committee should take action. The Gas Supply Committee should then be evaluated based on their effective execution of the approved polices and procedures in the prevailing circumstances. The Board previously requested that such circumstances and strategies be incorporated in Centra's policies and procedures. To date, this directive has not materialized.

The Board remains of the view that Centra should not be evaluated using mark-to-market results in isolation. Therefore, negative market-to-market losses sustained during December 1999 and January 2000 should not have negatively influenced the decision to place collars in the later portion of the year. The Board is of the view that collars remain a valuable tool when mitigating volatility and may be useful when caps are cost prohibitive.

The Board is sympathetic with many of the arguments put forward by CAC/MSOS and its witnesses. However, in the final analyses, the Board was not able to conclude that any reasonable person would have done otherwise than what Centra did, given the highly unusual market conditions and other factors.

8.7.3 2001 Derivative Hedging Activities

The gas year beginning November 1, 2000 has been marked by extreme volatility in natural gas prices. The Board is of the view that in situations of extreme upward volatility such as these, the use of the formulaic approach on a stand-alone basis is not appropriate, and some use of judgment must be included into the process. While specific circumstances for the placement of derivatives should be set out in the policies and procedures, management judgment should be used to modify these rules if necessary. In a situation where the management of Centra has used its judgment, Centra should be charged with the responsibility of providing the appropriate documentation to justify its actions or inactions.

While derivatives were not placed for the period of November 1, 2000 to January 31, 2001, the Board is of the view that no one could have predicted the further extreme increase in the price of natural gas during this time, given that the price of natural gas was already at an all time high. The Board is of the view that a reasonable person in this circumstance may have come to Centra's conclusion to not place derivatives.

Notwithstanding the comments above, the Board is of the view that the success of a derivative hedging program cannot be judged based on the results of one quarter. The Board will review the actions of Centra during the first quarter in the context of the entire 2000/2001 gas year at a future proceeding.

8.7.4 Derivative Hedging Policy, Operating Procedures and Terms of Reference of the Gas Supply Committee

The Board spent substantial effort in three recent proceedings establishing guidelines for the future direction of derivative hedging for Centra. In Order 55/00 the Board stated that it would approve the Derivative Hedging Policy subject to the inclusion of the strategies, objectives and circumstances under which derivatives can be placed as they were explained in that hearing. The Board also stated that it wanted to ensure that Centra would not downplay its responsibility to shed risk in placing derivatives on behalf of its customers. The Board is of the view that Centra has not complied with these directives.

Therefore, the Board will again direct Centra to clearly set out the circumstances under which derivatives will be placed in its Derivative Hedging Operating Procedures. The circumstances should be specific in order to create clear goals, define when discretion will be required and by whom, and permit the decisions to enter or not enter a transaction to be scrutinized and justified at a later date. The revised Derivative Hedging Operating Procedures including the specific circumstances under which derivative transactions will be place should be filed with the Board by no later than October 31, 2001.

The Board remains concerned about the skills, knowledge and workload of the various personnel charged with placing and reviewing derivative transactions. Therefore, the Board will direct Centra to develop and formalize a training program that will enhance the skills of the Gas Supply

Committee and the expertise of those employees charged with placing and reviewing derivative transactions. This plan should be developed and executed as quickly as possible, and reported to the Board by no later than October 31, 2001.The Board would encourage Centra to examine alternate ways to meet customer tolerance levels. Such alternatives could include entering into fixed price contracts for a portion of Centra's gas supply.

With respect to eligible hedging volumes, the Board is of the view that Centra should place derivatives for warmest year volumes, unless the instruments are placed under the provisions of the TCE contract. In this regard, actual volumes may be used because TCE carries the risk associated with volumes.

9.0 Rate Impacts

Centra requested that the existing non-primary gas rate riders for SGC, LGC, HVF, Mainline, Interruptible, and Special Contract Customer classes be replaced by revised rate riders developed to recover all gas cost deferral account balances, excluding Primary Gas from May 1, 2000, over the 11-month period of June 1, 2001 to April 30, 2002. The Primary Gas rate rider is updated as part of the quarterly Rate Management Process and is not part of this application.

The Board has directed Centra to file revised rate schedules and customer impact information which reflects the decisions of this Order. However, the approximate rate impacts on the annual natural gas bills, by customer class, as a result of the forecasted increase in non-Primary Gas cost, based on the 12-month forward strips at March 1, 2001, as well as the revised rate rider to recover all gas cost deferral balances at March 31, 2001 over the 11- month period ended April 30, 2002, are estimated to be as follows:

Customer Class	Annual Bill Impact (%)
Small General Class	6.0 to 6.5
Large General Class	8.0 to 9.0
High Volume Firm	7.0 to 8.0
Mainline	4.5 to 7.0
Interruptible	17.0 to 18.5

10.0 Confirmation of Interim Orders

10.1 Background

In Order 55/00 dated April 17, 2000, the Board approved a Rate Setting Methodology ("RSM") where the Primary Gas cost component of Centra's sales rate is adjusted at the beginning of every gas quarter to reflect:

(a) 50% of the difference between the updated 12-month forward price for natural gas, weighted for the cost of gas in storage, and the Primary Gas Rate set in the previous quarter; and

(b) a rate rider to dispose of the estimated accumulated PGVA balance over the next 12 months of forecast volume.

The RSM Process approved by the Board requires Centra to file its application during the first week of the month prior to the commencement of each gas quarter (February 1, May 1, August 1, and November 1) and to provide public notice during the second week of that month. The Board could either conduct a "paper hearing" or an oral public hearing in respect of the application, and was requested to approve the sales rates prior to the commencement of the gas quarter.

Pursuant to the RSM, the Board has approved three interim Orders related to Primary Gas costs as follows:

- Order 115/00 related to the Interim Primary Gas cost rates effective August 1, 2000
- Order 142/00 related to Interim Primary Gas cost rates effective November 1, 2000
- Orders 15/01 and 18/01 related to Interim Primary Gas cost rates effective February 1, 2001.

As part of this application, Centra requested confirmation from the Board of these interim Orders.

10.2 Intervenors' Positions

No Intervenors took any position with respect to confirmation or otherwise of these Board Orders.

10.3 Board Findings

The Board will confirm interim Orders 115/00 and 142/00. Interim Orders 15/01 and 18/01 for Primary Gas rates effective February 1, 2001 will be considered for confirmation by the Board at a later date.

11.0 Other Board Directives

11.1 Background

The Board's decisions resulting from various applications since 1998 have included a number of specific directives to Centra. In the current Application, Centra filed reports dealing with Board directives related to gas supply outsourcing, load factor, an assessment of the value of

Interruptible customers, Buy/Sell Summer Interruptible Delivery Option and determination of demand levels. Centra also filed a copy of the renegotiated contract with TCE.

11.2 TCE Contract

Centra finalized its renegotiated contract for long-term gas supply with TCE on October 31, 2000. This contract terminated various agreements which were signed in 1989, and had been amended from time-to-time, (collectively the Legacy Agreement). The new contract is comprised of four distinct agreements (Amending Letter, First Term Agreement, Second Term Agreement, and Third Term Agreement) that outline the terms and conditions for the next four years. The new contract became effective on November 1, 2000, and will expire on October 31, 2004. This represents an extension of the original contract by one year.

The new contract replaces the 30% Empress index component of the pricing formula with the AECO index plus the AECO/Empress basis differential. According to Centra, this change addresses difficulties experienced in acquiring quotations for derivatives based on an Empress index price, and will also allow Centra to place derivatives on additional volumes in the future. The balance of the pricing formula is based on the AECO index plus NOVA tolls. Centra acknowledged that at the time of the negotiations, the basis differential was much smaller than the corresponding NOVA tolls. However, TCE was willing to permit Centra to move to the use of a 100% AECO index only if Centra would agree to assume responsibility for the related NOVA transportation and pay the related tolls and Unutilized Demand Charges ("UDC") charges.

The previous contract term factor of 2% is reduced to 1.5% for the 2000/2001 gas year, decreases to 1% for the period November 1, 2001 to October 31, 2002, and decreases to 0.5% for the period November 1, 2002 to October 31, 2003. The term factor is completely eliminated commencing November 1, 2003.

The Amending Letter also provides for the termination of the legacy Transportation Operation Agreement effective November 1, 2000, which eliminates a potential complication if Centra elects to outsource its asset management in the future.

The new contract provides for TCE to be the sole supplier of Centra's system gas requirements including Operating Demand Volumes and Swing Service, and provides the right of first refusal to TCE on Delivered Services. Centra maintains the ability to contract with other suppliers for Delivered Service and other counterparties for derivative transactions.

Centra stated that allowing TCE the exclusive right to provide Swing Service brings several benefits, including:

- Favourable pricing compared with that obtained in the past;
- Additional security of supply as TCE will have a firm delivery obligation;
- The ability to change nominations on an intra-day basis allowing Centra a means to reduce pipeline balancing fees; and
- The pricing mechanism for this service provides Centra with a reasonably balanced portfolio of basis risk on its Western Canadian purchases.

Centra stated that TCE has the right of first refusal to provide all price structures (i.e., derivatives) on either a fixed volume or actual volume basis, at Centra's sole discretion. Centra stated that this feature eliminates the requirement for derivatives to be placed on minimum year volumes. Additionally, this will allow Centra to ensure that TCE quotations are equal to or better than those provided by other counterparties.

The contract also reduces by 50% the penalty associated with the failure to meet the 85% annual load factor. As well, for the period of November 1, 2003 to October 31, 2004, Centra will have a 100% Take or Pay Obligation under its Base Load Service. Centra will determine the daily quantity for this service, and adjust the take levels quarterly to reflect direct purchase activity.

Centra submitted that the one-year contract extension places it essentially where it would be for Base Load Service if the contract was to terminate on the original date, but adds the benefits which Centra feels it has negotiated in the new contract.

Centra believes there are benefits to Manitoba consumers resulting from the renegotiated contracts. Centra urged the Board to consider the circumstances surrounding the negotiations, and not to "cherry pick" isolated contract clauses in evaluating the success of the negotiations. Centra's position is that it had certain obligations under the existing contracts, and that it was not prepared to enter into further long-term arrangements with TCE. Centra contended that these factors put it at a disadvantage, compared to a circumstance where it was negotiating a completely new agreement.

Centra submitted that the term factor saving estimated at $8.6 million over the three remaining years of the Legacy Agreement was valid, because that was the additional amount which would be paid had Centra not renegotiated. Centra also pointed out that none of the Intervenors' witnesses could provide any evidence that other Canadian LDC's contracts with TCE had lower term factors. Centra contended that the renegotiated agreement contained a term factor that was the lowest in Canada, when compared on an equitable basis.

Centra suggested that if agreement was not reached with TCE on a new contract, the alternative was the retention of the legacy contract and the implementation of an arbitration process to resolve disputes. Centra considered that, in light of the provision in the legacy contract, arbitration was a process which Centra could have lost, given the equivalent or higher term factors paid by other LDCs. As well, the term factor for the current gas year could have been greater for all of Centra's TCE supply,

Centra submitted that, when all the advantages it had negotiated were considered, the request by TCE for an extension to the Legacy Agreement for one year was reasonable, and Centra's agreement to the request was prudent.

Centra reminded the Board of Centra's role on the TCPL Tolls Task Force, and Centra's opposition to the Task Force agreement in principle for a two-year toll increase. This agreement has the potential of increasing TCPL tolls to Manitoba consumers by an additional 10%. Centra is currently reviewing its options prior to advancing its position in this regard, including requesting a hearing before the National Energy Board ("NEB"). Centra has since filed a copy of the Memorandum of Understanding of the TCPL Task force with the Board for information.

11.2.1 Intervenor Positions

CAC/MSOS

CAC/MSOS contended that Centra had failed to satisfy the burden of proof in respect of the reasonableness and prudence of its negotiations with TCE, noting that neither the Board nor Intervenors had any input during the negotiation stage. This Application by Centra is the first opportunity for the Board and other interested parties to hear independent and expert testimony concerning the reasonableness of the terms and conditions of the renegotiated agreements.

CAC/MSOS summarized Centra's view on gains and concessions flowing from the renegotiated agreements. CAC/MSOS saw no advantages to Manitoba consumers as a result of Centra's negotiations with TCE. It was also CAC/MSOS' opinion that TCE gains included increased supply volumes, including Delivered Service if it were competitively priced; hedging opportunities if priced competitively, one year extension to the contract term; retention of the pricing index, and standard form of agreement. CAC/MSOS also suggested that an added advantage to TCE was not having to negotiate agreements annually.

CAC/MSOS suggested that the appropriate measure of success of Centra's negotiations with TCE was its objective to achieve the lowest possible gas cost for consumers. CAC/MSOS contended that the term factor had never conferred any significant benefit to the consumer. The term factor had been relatively stable since 1996. CAC/MSOS suggested that Centra knew the price of gas would not significantly decrease and that by agreeing to a percentage based term factor, the Manitoba consumer was financially harmed. CAC/MSOS estimated this amount to be $600,000 for November and December 1999, and could be $4.3 million above market value of gas for the term of the renegotiated agreement.

CAC/MSOS submitted that the term factor was nothing more than a marketing fee payable to TCE, and should attract a value of between $0.005 and $0.02/Gj. At worst, CAC/MSOS suggested that a percentage based term factor should have been capped at a certain dollar value, and failure by TCE to agree to such concessions should have been a deal breaker. It was the view of CAC/MSOS that Centra obtained a reduced percentage term factor, but at an increased cost to Manitoba consumers, and that the absolute dollar cost is what matters to consumers. CAC/MSOS submitted that an arbitrator would have agreed with the position advanced by CAC/MSOS that TCE and its producers were costing consumers, not only in high commodity prices, but also in additional premiums through the term factor.

CAC/MSOS had no objection to TCE providing Centra with Swing Service, but suggested that TCE should have given a greater concession. They were of the view that Centra's ability to hedge actual volumes, with the switch to AECO index, is a win-win situation for both parties.

The reduction in the load factor penalty was not really a concession by TCE, as it had never been imposed in the past.

CAC/MSOS expressed a major concern with the renegotiated pricing index. By agreeing to the 70% AECO plus Nova toll for Base Load Service, CAC/MSOS suggested that Manitoba Consumers are paying $0.12/Gj above a market value for gas on 70% of the volume, given that the Empress AECO basis differential is currently trading at $0.03/Gj, and the Nova Toll is $0.1486/Gj. CAC/MSOS contended that Centra did not renegotiate a satisfactory pricing mechanism, but in addition extended an unfavourable term for an additional year. CAC/MSOS suggested that this resulted in increased costs of approximately $670,000 for November and December 2000, and could be significantly more for the contract term.

In summary, CAC/MSOS submitted that Centra gave TCE all its system supply volumes for one more year, at pricing options potentially more beneficial to TCE. Centra retained the status quo for the AECO plus NOVA tolls price structure, which it could have negotiated with others. In return Centra obtained a reduced load factor which cost Manitoba consumers more and the Nova toll structure also increased Manitoba consumers' costs.

CAC/MSOS contended that Centra had made a business decision that the contracts would not be contingent upon Board approval, and thus took that choice out of the hands of the Board. The only choice remaining for the Board was to disallow the excessive term factor cost for 2000 of $670,000, and excessive Nova tolls of $1.25 million. Additionally, CAC/MSOS recommended that the Board put Centra on notice that in the future similar disallowances would be the order of the day, unless Centra could demonstrate that the markets have changed such that Centra's cost over market price have been reduced or eliminated, or Centra has renegotiated a better deal.

CAC/MSOS suggested that Centra has a renegotiation clause in the Legacy agreements which it can still exercise this year, and may have similar renegotiation ability under the renegotiated agreements. However, the choice with respect to further negotiation should remain with Centra. CAC/MSOS acknowledged that the Board cannot and should not order Centra to renegotiate.

Evidence of Gia DeJulio

Ms. DeJulio provided evidence on behalf of CAC/MSOS, and stated that Centra has found benefits for its end use customers in a few of the provisions of the renegotiated contracts, namely the termination of the 1989 "legacy" contract, including its complex arbitration provisions, and the terms of Swing Load Service. However, there are many other contract provisions.
Ms. DeJulio cautioned the Board to fully evaluate based on the limited or non-existent value of those provisions. These include the Term Factor, the determination of the transportation from AECO to Empress, the Option Price Adjustment, the Third Term Agreement and the elimination of the TOA. Ms. DeJulio added that the reduction in the load factor penalty is a "red herring" with limited value.

Evidence of Andrew Ilnycky

Mr. Ilnycky provided evidence on behalf of CAC/MSOS and stated that TCE has indicated its desire to phase out the long-term supply pool by 2006. The extension of Centra's contract by one year does not help position Centra for ultimate purchases from other suppliers. Mr. Ilnycky also noted that the term factor was too generous given the dilution of the force majeure and gas supply obligations in the new contract. The renegotiation occurred at a time when there was an expectation of escalating prices. A fixed rate would have assured a reduction in the obligation. Further, the term factor should have been phased out prior to the natural termination of the contract of October 31, 2001.

Mr. Ilnycky stated that exclusivity takes away from the advantages of the market. The continuation of the previous program would have achieved certain benefits including the ability to cultivate alternate suppliers, and avoid the supply premium of $0.005/Gj. He stated that there was no assurance that Centra was obtaining a lower price as a result of the exclusivity.

Evidence of Gerard Forget

Mr. Forget provided evidence on behalf of CAC/MSOS and stated that consumers are at risk with respect to supply security given that Centra does not contract for their total peak demand requirement. He stated that it would have been preferable to have a larger portion of the contract determined using the Empress/AECO Index as the NOVA tolls are considerably higher.

11.2.2 Board Findings

The Board was requested to approve the cost of gas consequences flowing from the new contracts with TCE, but was not requested to specifically approve the contracts.

Several revised contract terms and conditions will impact the cost of gas. These include term factor; pricing indices; extension in contract term by one year to October 31, 2004; TCE exclusivity for Centra's annual supply requirements and pricing structures, and load factor penalty. The Board considers other matters such as standard form and contract language to be a matter best described as "win/win" circumstances for TCE and for Centra.

The Board recognizes that Centra was bound by the terms and conditions of the existing Legacy Agreement, and the reasonableness and prudence of the results of Centra's contract negotiations should be considered keeping this fact in mind. The Board agrees with Centra that the contracts should be viewed in total, and cannot be evaluated based on the merits of any one clause taken on its own.

Neither the Board nor the Intervenors were party to the negotiations, nor should they have been. The reality is that the perceived success of Centra's negotiations can only be speculative. The Board's concern in this Application is solely the resulting cost consequences flowing from the contracts. In accordance with the provisions of the Legacy Agreement, if a satisfactory result could not be negotiated with respect to pricing mechanisms and term factor, the matter would be given over to arbitration.

It is within this context that the Board makes its observations and decisions in this matter. The evidence is that most contracts between Canadian LDCs and TCE contain term factors, and that the term factors, expressed as a percentage, are greater than that negotiated by Centra. Absent negotiations, the term factor would have remained at 2%. Thus, the gradual reduction and eventual elimination of the term factor is a benefit to Manitoba consumers. Should the price of gas continue at current levels, the savings over the remaining three-year terms of contract, while modest in terms of annual gas costs over the same period, will be approximately $8.6 million. This fact was not disputed. It is the unprecedented increases in gas market prices that will lead to increased absolute dollars for the term factor, as it will for the commodity portion of a consumer's bill.

The Board is of the view that the merits of the negotiated pricing mechanism, 70% of the volumes priced at AECO index plus Nova Tolls, and 30% at AECO plus AECO/Empress basis differential, will only be able to be evaluated in the future. Such an evaluation must also consider the financial impacts of Centra's new ability to place derivatives on all volumes purchased under contract, rather than minimum volumes as was previously the case. The Board has some concern about the impact on the practical competitiveness of the pricing structure, given TCE's right of first refusal to all offers, but recognizes that competitive prices have been received and accepted from other counterparties in the recent past.

The Board has similar concerns about TCE being the "sole supplier" for all of Centra's Western Canadian gas, although Centra has the right to purchase Delivered Service should other suppliers provided it received more favourable quotations. The Board considers the pricing structure for Swing Service, which is to be obtained on an as required basis, to be reasonable. While any reduction in a potential penalty should be of a benefit to Centra and its consumers, the Board notes that such a penalty has never been invoked.

The Board agrees with Centra and CAC/MSOS that any commentary on the advantages or disadvantages of the extension of the term of the TCE contract by one year is pure speculation. It provides Centra with assured supply from Western Canada for an additional year, at a formulated pricing structure for a commodity to be purchased three years hence.

The Board is also concerned that Centra did not obtain a regulatory approval condition precedent to protect itself and Manitoba consumers, comparable to the condition precedent by TCE to protect its suppliers.

While having these concerns, the Board concludes that, taken as a whole, the renegotiated contract is an improvement over the legacy contract. The Board will therefore approve the gas cost consequences flowing from the renegotiated TCE contracts for the 2001/02-gas year, commencing November 1, 2001. The Board encourages Centra to continue to monitor the market and to take appropriate action to protect Manitoba consumers in future negotiations.

11.3 Outsourcing Management of Gas Supply Assets

In response to Orders 79/98 and 19/00, Centra prepared a report related to outsourcing the management of its Gas Supply Assets, including the release and resale of excess capacity. In November 1999, Centra retained the services of Ziff Energy Group ("Ziff") to provide an independent review of Centra's gas portfolio management. Ziff requested proposals from a number of firms to determine the degree of interest and potential for outsourcing this function. A copy of the Ziff report was filed with the Board on July 5, 2000. The Ziff analysis did not consider any future requirements of Manitoba Hydro with respect to potential synergies between the electric and natural gas energy commodities.

Ziff identified and asked for expressions of interest from eleven energy service providers. Seven of the firms requested proposal terms of reference and made submissions to Ziff. Subsequent to a review of the submissions, Ziff recommended that Centra negotiate further terms and conditions with two firms, Enron Canada Corporation ("Enron") and TransCanada Gas Services ("TCGS"). Ziff also identified the submission by Engage Energy as being the third best of those received. Although Ziff had requested a proposal from Sempra Energy ("Sempra"), communication difficulties unintentionally eliminated Sempra from the process. However, Centra elected to allow Sempra to participate in the process.

Ziff indicated that some benefits might be achieved through outsourcing, but cautioned that Centra will still be required to maintain an internal level of expertise in this area.

Centra heard detailed presentations from the three companies in the spring of 2000. Centra summarized these submissions as follows:

- Enron offered a potential benefit of up to a maximum of $15 million over a three-year term. However, the offer was subject to additional due diligence by Enron, and Enron would not conduct such a review until an outsourcing agreement was signed.

- TCGS was willing to guarantee capacity management revenues of $1 million per year for three years and proposed a sliding scale for sharing revenues in excess of that amount. The proposal would replace the current capacity management program and could potentially reduce revenues that Centra was already achieving.

- Sempra proposed that any benefits would be best be achieved by a partnership arrangement and provided a variety of profit-sharing mechanisms.

In addition to using the Ziff report, Centra researched other industry sources and filed a paper prepared by DMR Consulting Group ("DMR"). The DMR publication outlines best practices from energy and other industries, and strongly advocates against outsourcing. Centra provided the following excerpt from that paper:

> "There are hidden drawbacks to transferring business-critical proprietary supply-and-demand information to the outsiders. Energy trading partners do not share the benefits of prudent trading with an energy service provider. They can, in fact, leverage the utility's considerable asset base to generate substantial profits, which are not shared with the client. All this can be detrimental to an energy service provider's long-term profitability. The most significant long-term cost of outsourcing is that the energy service provider's management does not get the needed education and fails to build crucial in-house skills. When full deregulation is ushered in, the firm will find itself in a very vulnerable position, facing lower margins and a higher risk profile."

Centra concluded that the most appropriate course of action was not to outsource the management of gas supply assets. Centra cited the following seven reasons for that conclusion:

1. Centra eliminated Enron because it required an outsourcing agreement to be signed prior to making any commitment relating to potential revenues.

2. TCGS was eliminated because of a potential conflict of priorities, in that focusing of maximizing capacity revenues might conflict with Centra's fundamental goal to serve the market in the most cost-effective manner.

3. Sempra was not in a position to manage the full portfolio alone, though it appeared to be the most promising alternative with respect to a flexible partnership arrangement.

4. At certain times during the summer of 2000, none of the parties could accommodate the substantial amount of gas and capacity Centra had available for release, and outsourcing capacity management would have reduced revenues realized by Centra.

5. By not outsourcing, Centra would maintain the flexibility to adapt to industry changes and pursue synergies with the electrical operations.

6. Sharing business-critical proprietary information with outsiders who can use the information to gain a competitive advantage is avoided.

7. Internal strategic expertise can be retained and further developed.

In closing argument, Centra reiterated that the revenues offered in the form of guarantees by both Enron and TCGS were significantly less than those which Centra was able to generate on its own. Centra's average annual revenues over the past few years are of the order of $3 million, while Enron guaranteed $1.3 million and TCGS $1 million. Centra also submitted that Sempra offered no guarantee and was not in a position to manage the portfolio.

Centra stated that the proposal process was done on a competitive basis, and that further negotiations were not likely to result in a better proposal. Parties were originally expected to put forward their best proposals, which reflected their interest in providing the services.

Centra also suggested that the recommendation that Centra outsource a portion of it asset management ignored the realities of the issues associated with gas supply and portfolio management in Manitoba related to weather and unavailability of local storage. Centra also submitted that it was unrealistic to expect unutilized demand charges to be zero, and suggested that all parties were in general agreement with this. The concept of retaining a consultant is also unrealistic, in Centra's view, as the consultant would only duplicate what Centra is already doing and would not be in a position to improve on Centra efforts.

Centra pointed out that even the witness for CAC/MSOS provided several cautions with respect to outsourcing, including loss of internal skills, duplication of skills, possible conflicts and revenue sharing disputes, accountability and security of supply issues. Centra indicated that it shared those concerns.

In summary, Centra submitted that it had undertaken an extensive review, pursuant to the Board's directive, and that none of the proposals received from third parties would provide benefits to ratepayers over and above those which Centra is already realizing. In view of the risks and concerns involved, Centra concluded that the decision not to outsource was appropriate, and that the issue of outsourcing has been resolved for the present.

11.3.1 Intervenor Positions

CAC/MSOS

CAC/MSOS submitted that the history of capacity management, supply portfolio review and the related matter of outsourcing were a "litany of inaction, half measures, broken promises", and "a product that doesn't stand the test of scrutiny." CAC/MSOS observed that Centra has taken two years to get the report on outsourcing before the Board, and that the report submitted was apparently incorrect. CAC/MSOS expressed the view that Duke Energy, a major player in the field, were not even made aware of Centra's proposals, but suggested that Ziff, not Centra, was at fault in that case.

CAC/MSOS questioned why Ziff had apparently not assessed Sempra's submission, but commented that, despite the report shortcomings, Ziff still made some positive recommendations with respect to Enron and TCGS, and several other respondents to the proposal call. CAC/MSOS questioned why only Enron and TGCS were requested to make presentations, along with Sempra, which was at the request of Centra, and why the "drop dead" date for action in the submissions received had expired before anything was done with the Ziff report. CAC/MSOS questioned the reasons cited by Centra for eliminating the three offers and declining to further negotiate with interested parties. CAC/MSOS submitted that the DMR report recommendation not to outsource is irrelevant, as it relates to an American study about the electrical industry dealing with energy trading.

CAC/MSOS suggested that the real reason for not outsourcing is that Hydro wished to retain the gas supply assets until all possible energy source synergies are explored. Further, CAC/MSOS submitted that the amount of potential revenue, which Hydro indicated would be necessary before it would consider outsourcing, was in fact now available in the form of unutilized demand charges. CAC/MSOS also suggested that the mindset at Hydro in respect of this matter was that "nobody can do better."

CAC/MSOS contended that lack of sufficient and experienced staff to adequately deal with gas supply asset management, and lost opportunities to generate additional revenue, resulted in increased gas costs to Manitoba consumers.

In conclusion, CAC/MSOS submitted that the choice to outsource or to retain the gas supply asset management function is Centra's and should not rest with the Board. To force one party to do something it does not want to do will only result in failure. However, if Hydro wishes to retain idle assets until it decides how to deal with them, this should not be at the expense of the ratepayer. CAC/MSOS recommended that the Board reduce revenue requirement by $5 million in 1999 and $5 million in 2000 to account for lost opportunities in this area, and to establish a benchmark for measuring capacity management successes in the future.

Evidence of Gia DeJulio

Ms. DeJulio questioned the prudence of Centra's decision not to outsource its capacity management function. She submitted that any one of the marketers identified by Centra would offer immense value to the ratepayers, greater than that which Centra could achieve on its own.

Evidence of Andrew Ilnycky

Mr. Ilnycky stated that success of the Capacity Management Program should be measured by the extent to which costs were avoided or eliminated in relation to total UDC. He added that it is not sufficient to hide behind geography and weather factors to avoid continuous improvement, and the quotes obtained by Ziff can be used as a benchmark. Mr. Ilnycky highlighted that there is interest among potential supply pool managers to outsource. In his view, Centra's customers have been and continue to be deprived of the benefit of improved capacity management. A blank page analysis is long overdue, and is an appropriate approach to the opportunities for improvement.

Mr. Ilnycky noted that an intermediate step to outsourcing may be to engage an independent gas marketing management firm to work on site with Centra's supply group in developing strategies and manage the fixed obligations with a specific objective of minimizing UDC.

Mr. Ilnycky also stated that "If Centra is to adopt an outsourcing program for capacity management, then careful consideration must be given to addressing several concerns. It is important to recognize that management of supply and dispatch are the essence of Centra's gas distribution activities. Mr. Ilnycky itemized those concerns as follows:

(a) Since management of supply and dispatch are central to Centra's gas distribution activities, outsourcing of this function could result in the loss of a critical skill set that will be difficult to replace if the outsourcing were to be terminated.

(b) Management of the Outsourcing Agreement and results monitoring will require Centra to be knowledgeable in the function and thus Centra will need to retain sufficient supply skills in house to interface between the supply and delivery functions.

(c) The entity providing the outsourcing activity may have, or may develop over time, objectives that conflict with those of Centra and the consumers on its system. These could result in considerable management time diverted to the outsourcing and in monitoring the actions of the service provider. Therefore, care must be taken in setting up the arrangement to avoid and resolve conflict.

(d) Gains captured from reducing UDC will not all flow to Centra's customers; this will be tolerable if the results are favourable, but could still lead to significant disagreements with the service provider. Thus it would be important to agree in advance on reward-sharing with the service provider.

(e) Accountability for results and supply reliability to the consumers and before The Public Utilities Board will need to be clarified."

Evidence of Gerald Forget

On the topic of outsourcing, Mr. Forget stated that Centra would have to contract with more than six parties in one year to have a successful Capacity Management Program. Marketers like ENRON and Sempra are better positioned to produce value from Unutilized Demand Charges. They already have a bigger portfolio to draw from and they trade will more players more often. He recommended that Centra outsource a portion of its portfolio. Centra will gain experience and continue its Capacity Management program with the outsourcing as a benchmark. He added that Centra did not provide sufficient evidence to support its conclusion that the most appropriate course of action is not to outsource its gas management function. He suggested that Centra's ANR summer capacity could be reassigned to meet increased summer co-generation demand for natural gas.

11.3.2 Board Findings

Centra has entered into contractual arrangements for the purchase of gas, transportation of gas to the Manitoba market and for the transportation of gas to storage facilities. These contractual arrangements include obligations for Centra to pay certain fixed costs, regardless of whether any gas is being transported to Manitoba or to storage.

The Capacity Management Program of Centra attempts to capture value from the unutilized portion of Centra's fixed cost obligations. In addition to the resale of unutilized capacity, Centra also engages in gas loans and exchanges provided such transactions are profitable. The purpose of the Capacity Management Program is to realize revenues that will reduce the gas costs for Manitobans. A Capacity Management Program can be conducted internally by the utility, outsourced to a service provider or, as a hybrid, conducted internally by the utility with assistance from an external service provider. The Board notes the consistent evidence from several witnesses that even if the program is outsourced, Centra needs internal expertise to assist and evaluate the performance of the external service provider.

Centra has conducted its Capacity Management Program internally and was first requested, by this Board, in 1998, to investigate outsourcing this Program. It is disappointing that Centra's response to the Board's 1998 request has taken until this hearing to be publicly reviewed. Centra's response was primarily to engage a consultant to assess the potential for outsourcing this Program. While the consultant identified possible benefits to Manitoba consumers by outsourcing the Program, Centra's actions and inactions made it clear that Centra did not favour outsourcing the management of the gas supply assets.

Centra's internal Capacity Management Program realized approximately $0.6 million in 1999 and $3.5 million in 2000. Against these results, offers for outsourcing by external service providers were received, including an offer of $15 million over three years. Centra dismissed the offers, without further negotiations which should have been explored if Centra was serious about maximizing revenues to reduce gas costs of Manitoba consumers.

Expert evidence in this hearing has identified approximately $20 million of unutilized demand charges in each of the years 1999 and 2000. It is these demand charges that Centra must pay pursuant to its contractual arrangements, even if no gas is flowing to Manitoba or to storage. It is these demand charges which can be partially or perhaps fully offset by a Capacity Management Program. The Board recognizes that revenues will fluctuate from year to year dependent on such factors as weather, and the supply and demand forces at play in the North American marketplace.

No witness was able to quantify with certainty and precision, the amount of additional revenue that would have been received had the Capacity Management Program been outsourced. The

Board will not arbitrarily select an amount for disallowance as a punitive response to Centra's actions and inactions.

The Board considers the objective of the Capacity Management Program, whether managed in-house by Centra – or outsourced, is to minimize the unutilized demand charges paid by consumers, and maximize the use of all fixed-cost assets for the benefit of the Manitoba consumer. While geography and climate are factors that impact this Program, the Board expects Centra to seek continuous improvement by capitalizing on the opportunities that deregulation has created for Centra to minimize the costs paid by Manitoba consumers.

The future question of outsourcing asset management must now be considered with the results of the "Blank Page" analysis which Centra is conducting to determine its optimum gas supply portfolio. Such an analysis should identify excess capacity, storage and transportation which would be available to generate incremental revenue when not required to serve Centra's Manitoba gas customers. The issues identified by Messrs. Ilnycky and Forget should also be addressed in the "Blank Page" analyses.

The Board expects Centra to include in its analysis the details and particulars of any external service provider's interests in managing Centra's assets.

Additionally, the Board expects Centra to include in its analysis, a review and quantification of the synergies possible between natural gas and hydro electricity, together with Centra's plan in respect of such synergies.

11.4 Load Factor

Centra was directed to review the most appropriate and economic gas supply portfolio in conjunction with the report on outsourcing the management of the gas supply assets, and report to the Board by June 30, 2000. The report was to define a load factor based on the current Manitoba supply characteristics that would provide the best value to Manitoba consumers.

In response to this request, Centra prepared and filed a Load Factor Report with the Board on July 5, 2000. The report was based on the portfolio review that was filed with the Board in 1997, and analyzed the cost effectiveness of moving the TCPL load factor from 80% to 100%. Based on the analysis contained in that report, a load factor of 80% was determined to be appropriate for achieving the lowest overall cost of serving the Manitoba market.

During the hearing process, and pursuant to a December 2000 Board request, Centra stated that it would be performing a "Blank Page" portfolio analysis in this regard. This analysis would assume that Centra is unencumbered by any long-term arrangements, including TCE contracts, and ANR storage arrangements. Centra indicated that this report would be concluded and filed with the Board in late 2001.

11.4.1 Intervenor Positions

CAC/MSOS submitted that it was only after many years of prompting by the Board that Centra conducted a portfolio review, and that even then it was conducted improperly. The model utilized by Centra had built in constraints related to TCPL and ANR contracts, which according to CAC/MSOS, gave predictable results. CAC/MSOS contended that Centra's intent to conduct the "Blank Page" analysis proved that the prior report was flawed. CAC/MSOS also expressed concern that any changes in the supply portfolio, including the matter of outsourcing Centra's gas supply assets, may take two to three years to accomplish.

11.4.2 Board Findings

The Board had requested that Centra conduct further analysis after the Board reviewed Centra's Load Factor report, which was submitted in December 2001. In particular, the Board was concerned that the commodity prices, pricing mechanisms, tolls, and system load growth since 1996 used in the 1997 analysis were outdated. Additionally, the reported cost of $0.04/Gj necessary to achieve a 100% load factor was not supported. All of these factors, combined with the rapid multiplicity of changes in the natural gas industry led the Board to request a further report in this matter.

The Board shares the concerns expressed by CAC/MSOS about the elapsed time since the Board initially request a review of Centra's gas supply portfolio. The Board is aware of the substantial and significant changes which Centra has undergone prior to and pursuant to the acquisition of its shares by Manitoba Hydro, but is concerned that there may have been lost opportunities for Centra to either reduce gas supply costs or to increase capacity management and other asset management revenues.

The Board will direct Centra to complete the "Blank Page" Analysis, and to submit a report to the Board by no later than November 1, 2001. The Board will review that report at the next GRA. The Board will require that there be no constraints to the analyses conducted, and that any consultants retained to assist Centra in this matter will be available as witnesses when the report is considered by the Board.

11.5 Value of Interruptible Customers and the Buy/Sell Summer Interruptible Delivery Option

In Order 118/99, the Board directed Centra to investigate and determine if the Interruptible customer class represented a greater value to Centra and other customer classes than was previously determined, and file a report with the Board. Centra currently has 61 Interruptible customers.

Centra engaged Navigant Consulting Inc. to undertake a review of the supply and delivery aspects of Interruptible service. The study indicates that Centra's rates for Interruptible service reasonably reflect the value these customers bring to firm customers. In making this assessment, Centra determined that the savings in costs necessary to provide firm service to its existing Interruptible customer was approximately $1.6 million on an annualized revenue requirement basis. The Interruptible customer class saves approximately $1.4 million annually compared to the rates these customers would pay for Firm service. Although Centra conceded that this comparison is somewhat coincidental, it demonstrated that the discounted rates enjoyed by the Interruptible class are reasonable, and that the Interruptible rates do not impose a burden on other ratepayers. Centra also concluded that if the Interruptible service was eliminated, there would essentially be no changes in rates to the Firm Service classes, other than Simplot, because that class enjoys a relatively high load factor. Centra submitted that the cost allocation methodology originally accepted by the Board in 1996 accurately reflected the value of the Interruptible customer, and therefore no changes were recommended.

During the study, Navigant met with Centra's Interruptible customers and concluded that there is disagreement on the fundamental justification for and operational requirements of Interruptible service between Centra and its customers. The major concerns of the customers are:

- Desire for fewer interruptions and more notice of interruption;
- Lower prices due to additional flexibility provided to the system;
- Lower prices because of their necessary and expensive investment in alternate fuel capability; and
- Lower prices because of the contributions they make to the Province.

In this regard Navigant recommended that:

- Extensive costs incurred by customers to provide alternate fuel capacity not be reflected in Centra's rates; and
- Additional subclasses of Interruptible service should not be introduced.

In closing argument Centra stated that it had not contemplated identification of all benefits or costs to the system if the Interruptible customers were to leave the system entirely. Centra submitted that such an analysis would be outside the scope of the study as directed by the Board in Order 118/99. Centra further contended that such an analysis would not be a valid measure of the appropriateness of Centra's Interruptible rate. Centra is of the view that it does not pay to have customers on the system. Rates are determined based on the fair share of costs imposed on the system by each customer class. Thus, Centra contended that measuring a customer's value by determining what would happen if they left the system was not valid.

11.5.1 Intervenor Positions

No Intervenors at this hearing took a position in on these matters.

11.5.2 Board Findings

In Order 118/99, as a result of a request from Interruptible customers, the Board directed Centra to conduct a study to "fully investigate the current gas purchase environment, and the nature of the gas supply portfolio to determine if the Interruptible class represents a greater value to Centra and the other customer classes than was determined in 1996, when the current cost allocation methodology was accepted by the Board." The Board notes Centra's position that the Navigant Report, which was intended to determine whether the lower rates for Interruptible service reflect all the avoided costs of serving the customers on an Interruptible basis, satisfied the Board's requirements. Centra indicated that the report did not contemplate identification of all benefits or costs to the system if these customers were to leave the system entirely.

However, the Board is not satisfied that the report filed in these proceedings met the Board's requirements. The Board will direct Centra to conduct a further analysis, which will determine the value that the Interruptible customers, as a class, confer on the system. This analysis will include a summary of the nature of the costs and revenues attributable to this customer class, based on the most current complete data, and the impact on gas supply portfolio and gas costs as a result of Centra's ability to curtail Interruptible customers.

11.6 Buy/Sell Summer Interruptible Delivery Option

Navigant reviewed Centra's existing Interruptible service to system and Buy/Sell customers. System Interruptible customers are required to provide a supply of Primary Gas for the system every day of the year. However, under this option, Buy/Sell Interruptible customers are allowed to deliver their entire annual requirements in the summer months, relieving them of their obligation to provide firm supply in the winter.

In offering each of these services, the intention was to provide those customers that wanted to avail themselves of the direct purchase option the opportunity to provide Western Canadian Supplies at the same load factor and profile that gas is purchased and transported for system customers. The provision of the Summer Interruptible Delivery Option providing Interruptible customers the opportunity to supply their gas at a different load factor or profile creates an inequity between system customers and direct purchase customers utilizing the Summer Interruptible Delivery Option.

The Summer Interruptible Option is presently utilized by six Interruptible customers. If this option were to be utilized by all Interruptible customers, increased injection of gas during the summer months from the additional Interruptible customers could cause Centra to experience difficulties in meeting its annual take requirements for its own supplies. This would lower Centra's overall load factor and could jeopardize its ability to meet its contractual obligation under existing supply contracts. Further, the gas received by Centra in the winter months would be reduced, leading to more frequent curtailments of Interruptible loads.

Therefore, Centra requested that the Summer Interruptible Option be terminated by March 31, 2001 and Centra's service offerings be eliminated as of November 1, 2001.

11.6.1 Intervenor Positions

No Intervenors took a position in on these matters.

11.6.2 Board Findings

In 1999, Centra stated that it would amend its Terms and Conditions of Service, without seeking Board approval to eliminate this service offering on November 1, 1999. Centra later amended its position and proposed to grandfather this offering to the seven Interruptible customers then receiving the service, but would withdraw the offer of service from all other Interruptible customers.

In Order 19/00, the Board was of the view that Centra's proposal would be unduly discriminatory and provide preferential treatment to certain customers, and ordered that any customer opting for Buy/Sell arrangements should have this delivery option available. The Board also accepted that the elimination of the service could have a significant short-term impact on customers who were using the service. The Board also ordered Centra to conduct a study respecting the value of Interruptible customers to Centra's system and operations before ruling on any further changes in this matter.

As articulated in the Navigant Report, the Board is satisfied that this service offering creates an inequity between system and Buy/Sell Interruptible customers by allowing different supply load factors to customers within a single customer class. The Board accepts that expanding this service to all Interruptible customers could result in lowering Centra's overall load factor, jeopardizing Centra's ability to meet its long term contract obligations, and could also result in more frequent curtailment of supply to this customer class. The Board will therefore order that the Buy/Sell Summer Interruptible Delivery Option be eliminated, effective November 1, 2001 as requested by Centra.

11.7 Demand Levels

In Order 118/99, the Board directed Centra to prepare a report to address the different methods used for determining the demand levels for Firm and Interruptible Customers.

In response, Centra prepared a report explaining the two different methods used to calculate the demand billing levels for its three customer classes with a demand billing component. Centra indicated that the different methods do not result in inequitable billing. All Interruptible and Mainline customers have telemetry instruments installed on their premises which allow Centra to assess a monthly demand charge based on their actual peak-day consumption. Centra is currently in the process of installing the telemetry instruments on the premises of the HVF customers which would also allow assessment of a monthly demand charge on the same basis, rather than the current determination based on average daily use during their peak winter month. The installations were expected to be completed by February 2001. However, one customer remains to be converted. Once all metering is in place, Centra will change its methodology for the HVF class to be consistent with the other classes.

In the report, Centra indicated that there would be no impact on the HVF customer class as a whole as a result of a change in the method of determining the appropriate demand levels. However, because both the billing units and the unit rate would change, there may be some impacts on customer within the HVF Class. Centra also indicated that there would be no change in the present system until approval is received for the change at the next general rate application.

11.7.1 Intervenor Positions

None of the Intervenors at the hearing took a position on this matter.

11.7.2 Board Findings

The Board is of the view that the methodology used to measure demand levels should be consistent for all customer classes. This should allow for a better understanding of the demand component of the rate structure by the customers, and will result in equal treatment for all classes affected by demand charges. The Board will not require any change in the present methodology until the issue has been fully canvassed at the next GRA. The Board will expect Centra to be prepared to address this issue, and to have detailed information on all customer impacts resulting from this proposed change.

12.0 Unaccounted For Gas ("UFG") Allocation to Simplot

12.1 Simplot's Position

Centra defined UFG as consisting of actual physical gas lost in the distribution system and any metering errors.

Simplot opposed the proposed allocation of the cost of UFG by Centra, contending that the proposal was contrary to cost-based rates and would constitute rate shock for Simplot. Simplot quoted Centra officials as having stated that Centra "strives for cost-based rates" which "try to fairly and accurately allocate the costs to the correct customer class."

The Simplot plant is located approximately 20 kilometres south of Centra's TCPL take-off point and is served by a series of looped transmission mains. Simplot apparently purchases the vast majority of its gas from a supplier other than Centra. Simplot had understood, in error, that its consumption of gas relative to Centra's TCPL receipts on all transmission lines serving Simplot was metered and known by Centra. Simplot expressed disappointments that it was only near the end of this hearing when it discovered that such was not the case. Simplot further submitted that while this matter was important to Simplot, Centra apparently did not share that view.

Although Centra had indicated that it would take a lot of work, Simplot requested that the effort be undertaken to enable Centra's allocation to more accurately and precisely calculate Simplot's responsibility for its share of UFG costs. Simplot took the position that 15% of the entire system's UFG, representing 0.7% of Simplot's total consumption, cannot be lost on the 20 kilometres of transmission line for the TCPL take-off point. If this were the case, Simplot suggested that a major safety problem related to escaping gas existed. Simplot further suggested that meter error alone could not justify the allocation. Centra had stated that meters of the type used at the TCPL take-off and at Simplot's plant are corrected regularly. As such, the allowed metering error, if in excess of 2% or 3% would result in a retroactive correction, and any error is corrected to zero on an on-going basis. Therefore, any metering errors would be negated over the long-term.

Simplot also pointed out that its cost for UFG would increase from $280,000 to $995,000 per year, if Centra's application was approved. Simplot contended that the increase in Simplot's annual consumption was a factor but was not a significant component of the cost increase.

Simplot submitted that such an increase constituted rate shock, and requested the Board to order Centra to conduct the work necessary to measure Simplot's actual UFG which should then be its allocated cost. As well, Simplot requested the Board to direct that the increase in cost to Simplot be held in a deferral account and the balance be disposed of subsequent to the completion of the work.

Simplot did not oppose the rate increases as long as it paid only its fair share of the rate increase. However, Simplot believes that increase in the allocation percentage assigned to Simplot for UFG of 13%, an increase of 2%, is unreasonable. Mr. Riad requested that the Board consider whether the rate of 0.07% UFG losses allocated to Simplot over an uninterrupted 20 km pipeline is equitable, whether that rate is normal, and whether is it feasible to obtain better and more specific estimates of UFG losses in the pipeline supplying Simplot.

12.2 Centra's Position

Centra submitted that UFG is the difference between the amount of gas it receives and the amount it bills its customers. The majority of the gas is not physically lost, but is a result of accuracy limitations of measuring devices on the meters. Centra stated that metering tolerances and regulations related to on-going meter recall and testing are established by Measurement

Canada, and are adhered to by Centra. UFG costs are allocated to customer classes based on respective customer class consumptions and are not specifically calculated for each customer.

Centra submitted that because the gas cannot be accounted for, Centra was unable to provide specific data as to points on the system where the gas is lost, and it is thus an allocation process. Centra contended that volumetric method of allocating UFG costs results in Simplot, as well as other customers, receiving a fair and proportionate share. Centra pointed out that the $712,000 cost increase to Simplot consists of $529,000 for increases in gas commodity costs, and $183,000 for increased consumption. Centra concluded that the cost allocation methodology is appropriate and Simplot is bearing only its fair share of the UFG costs.

12.3 Board Findings

The Board acknowledges Simplot's significant increase of approximately $713,000, to an amount of $955,633 as a result of the allocation of Centra's UFG. The Board notes however that Centra attributes $183,000 to an increase in Simplot's annual consumption and $529,000 to the increase in the commodity cost of gas. The Board notes that since the last allocation of non-Primary gas costs Simplot's consumption from 1998 (actual) to 2000/01 (estimated) has increased approximately 81%, from approximately 268,249,000 cubic metres to 485,480,000 cubic metres. In 1998 Simplot's consumption represented less than 15% of Centra's annual throughput volumes and this is estimated to increase to 21.6% for 2000/01.

The Board also wishes to point out that Centra's UFG is estimated to be 1.074%, which is well within the meter error tolerance of +/-2% established by Measurement Canada, and amongst the lowest UFG levels experienced by Centra within recent years. The cost allocation methodology previously approved by the Board allocates UFG costs on a customer class basis rather than on an individual customer basis, with allocations based on annual throughput volumes, having consideration to daily load curves to determine relative firm and Interruptible demands. The methodology treats Centra's system on a province-wide basis, and does not consider location or distance from the TCPL system as being a factor in the allocation. The Board is also aware that it is neither fair, cost effective or practical to meter individual customers' premises to determine UFG. Under such a methodology, a customer near a TCPL take-off would have an unfair advantage over a customer located at the far reaches of Centra's system.

The Board is of the view that Centra's allocation of UFG to Simplot is consistent with an approved methodology and represents a fair an equitable treatment of all customer classes. While the Board sympathizes with Simplot additional financial impact, the Board considers that the unprecedented increase in natural gas commodity costs since 1998 has also significantly impacted UFG costs for the other customer classes. Additionally, the increase in Simplot's volumes is a major factor in the absolute dollar increase for Simplot's share of the UFG. The Board will therefore approve the allocation of UFG as applied for by Centra. The Board would encourage discussion between Centra and Simplot to determine whether other solutions or alternatives can be pursued to ensure that Simplot's share of UFG is accurately and fairly allocated.

13.0 Cost Allocation

13.1 Background

A cost allocation study estimates the cost to provide a service to a specific customer or classes of customers, with a goal of establishing rates for various customer classes that are fair, equitable, and not unduly discriminatory. Centra considers that rates are fair and equitable when they recover the costs incurred to provide that service. Centra submits that rates can be different for different classes of customers and, provided that there is a reasonable and rational basis for the difference, can still be considered as not being unduly discriminatory.

The cost allocation methodology in this case was applied only to cost of gas matters. However, because all four basic rate elements contain gas costs, all rate elements will require a change. As this application explicitly excludes the Primary Gas Cost element, the Supplemental Gas, Transportation to Centra, and Distribution to Customer rate elements require change. Generally, the Transportation to Centra rate reflects Transportation and Storage tolls and tariffs, while the Distribution to Centra rate reflects UFG costs.

Centra's cost allocation methodology was last approved by the Board in Order 107/96, dated October 17, 1996. The only difference from the previously approved methodology is the reclassification of compressor fuel costs as a component of Primary Gas, rather than being included in the Transportation to Centra rate. Centra stated that the original treatment when rates were first unbundled was incorrect, and that the change in the design to the Primary Gas Rate is reflected in the current application. Additionally, Centra requested approval of a refinement which allocates supplemental gas costs between firm and Interruptible customers based on daily use load curves for summer months rather than on a monthly volumetric basis.

13.2 Intervenor's Position

Other than Simplot's objection to Centra's allocation of UFG costs discussed previously no other Intervenors advanced any position in regard to cost allocation.

13.3 Board Findings

The Board will accept the cost allocation of non-Primary Gas costs and related deferral account balances as requested by Centra in the Mach 23, 2001 revision. The Board accepts that the reclassification of compressor fuel as a component of the cost of Primary Gas rather than of the cost of Transportation to Centra is logical and is consistent with the principles underpinning the Western Transportation Service. Compressor fuel related to Primary should be the responsibility of the supplier of Primary Gas, be it Centra or an ABM. The Board notes that there is a corresponding reduction in the Transportation to Centra rate.

The Board also considers the use of load curves during the winter months to allocate daily consumptions between the firm and Interruptible customer classes to be more accurate and equitable than the use on monthly volumes because of weather. The Board will therefore approve this refinement, as requested.

14.0 Presenters' Positions

14.1 General

The Board received approximately 10 letters from individuals in Manitoba voicing their opposition to the recent increases in the cost of gas. These included a letter dated March 12, 2001 from Charlotte Marks, letters dated March 15, 2000 from Joan Curran, Sandra Horyski, Douglas Cavers, Stacey Webster, Sharon Abrenica, a letter dated March 16, 2000 from Janeen Pastucha, a letter dated March 19 from John Woloski, a letter dated March 20 from Alberta Hajes, and a letter dated March 24 from Jeri and Murray Payette.

The Board received approximately 600 coupons from the City of Brandon which state "Dear Public Utilities Board members, we've had it with gas price increases. We get gouged at the pumps and hit at home. We want you to stand up for us and say no to the latest rate hike application." In addition to this correspondence, the following presentations were made at the public hearing.

14.2 Ms. Sandra Horyski

Ms. Horyski opposed the rate increase proposed by Centra. She is both shocked and horrified at the spiralling and out of control energy cost. She stated that she would be campaigning the Federal Government for assistance.

14.3 Mr. Al Cerilli

Mr. Cerilli, President of the Manitoba Association of the Union Retirees, opposed the rate increases proposed by Centra. The multiple increases in natural gas rates over the past year have created great hardship among Manitobans. He commended Hydro and Centra for internally reviewing methods of relief to Manitobans, to reduce the cost of natural gas and hydro.

However, wages have not kept up with the increases in energy costs. If Canadians are to see a long-term relief in costs for energy, Canadian and provincial Members of the Parliament and Legislative Assemblies mush deal with this one gas, oil and hydro industry as a whole. He added that he would make presentations to the Federal and Provincial members of Parliament and Legislatures.

14.4 Social Planning Council of Winnipeg

Mr. Harold Dyck and Ms. Ogaranko, on behalf of the Social Planning Council of Winnipeg, opposed the rate increase proposed by Centra.

14.5 Ms. Marlene Vergata

Ms. Vergata opposed the rate increases proposed by Centra. She noted her budgeted natural gas bill has increased three times in one year. As a volunteer, she is aware of elderly people who must choose between gas bills, prescriptions, and groceries. It is time for the governments to help people.

14.6 Mr. M. Pozzoboni

Mr. Pozzoboni was opposed to the rate increase proposed by Centra. He stated that the efficiency loans offered by Centra and Hydro do little for homeowners in areas with low property values.

14.7 Ms. Joan Curran

Ms. Curran was opposed to the rate increase proposed by Centra. She stated that she is on a fixed disability income and there is little money left to pay dental bills, repair bills or other expenses once utility bills have been paid. She requested that the Board not let Centra profit while the public is suffering.

14.8 Ms. Sharon Abrenica

Ms. Abrenica opposed the rate increase proposed by Centra. She stated that not only are consumers natural gas bill increasing, the price for products and services are increasing to include the rate increase.

15.0 It Is Therefore Ordered That:

1. The actual 1999 gas costs of $217.39 million, BE AND ARE HEREBY APPROVED AS FINAL.

2. The actual 2000 gas costs, excluding Primary Gas, of $72.98 million, BE AND ARE HEREBY APPROVED AS FINAL.

3. The disposition of all 1999 and 2000 PGVA gas cost deferral accounts balances as at March 31, 2001 totalling $19,939,989 (excluding the post May 1, 2000 Primary Gas PGVA and net of forecast capacity management revenues for 2001/02) through rate riders over the 11-month period from June 1, 2001 to April 30, 2002, BE AND ARE HEREBY APPROVED, subject to calculating carrying costs on the 1998 Price Management Deferral account at Centra's short-term borrowing rate from January 1, 2000.

4. Order 115/00 for Primary Gas rates effective August 1, 2000, and Order 142/00 for Primary Gas rates effective November 1, 2000, BE AND ARE HEREBY CONFIRMED. Orders 15/01 and 18/01 for Primary Gas rates effective February 1, 2001 will be considered for confirmation at a later date.

5. Amendments to the Terms and Conditions of Service for the removal of the Buy/Sell Summer Interruptible Delivery Option effective November 1, 2001, BE AND ARE HEREBY APPROVED.

6. Amendments to the Terms and Conditions of Service for the removal of the Buy/Sell Service effective November 1, 2001, BE AND ARE HEREBY APPROVED, subject to the Board's decisions set out in Order 78/01

7. The gas cost consequences of the changes to Centra's long-term gas supply contract with TransCanada Energy Ltd., BE AND ARE HEREBY APPROVED.

8. Centra complete the "Blank Page" portfolio analyses and submit a report to the Board by no later than November 1, 2001.

9. Centra conduct additional analyses regarding the value of Interruptible customers, as a class, on the system including a summary of the nature of the costs and revenues attributable to the customer class, and the impact on gas costs as a result of Centra's ability to curtail Interruptible customers and report to the Board by no later than November 1, 2001.

10. Centra file with the Board a copy of a formalized training program for derivative hedging activities by no later than October 31, 2001.

11. Centra file a revised copy of the derivative hedging operating procedures that includes the specific circumstances under which derivative hedging transactions will be placed by no later than October 31, 2001.

12. Centra file, for Board approval, a revised schedule of sales rates, to be effective for all gas consumed on or after June 1, 2001 that reflect the above decisions. Sales rates for Supplemental Gas, Transportation (to Centra) and Distribution rates are to include the forecast increase in non-primary gas costs for 2001/02, based on a 12-month forward price strip at March 1, 2001.

Centra should also file the supporting information relative to rate impacts on customers.

The Public Utilities Board

Chairman

Acting Secretary

THE PUBLIC UTILITIES BOARD

"G. D. Forrest"
Chairman

"Hollis Singh"
Acting Secretary

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Acting Secretary