MANITOBA	**Board Order 118/03**
THE PUBLIC UTILITIES BOARD ACT	**July 29, 2003**

Before: G. D. Forrest, Chair
L. Evans, Member
M. Girouard, Member

A GENERAL RATE APPLICATION BY CENTRA GAS MANITOBA INC. FOR AN ORDER APPROVING SUPPLEMENTAL GAS, TRANSPORTATION TO CENTRA AND DISTRIBUTION TO CUSTOMER SALES RATES TO BE EFFECTIVE APRIL 1, 2003 FOR ALL GAS CONSUMED ON AND AFTER AUGUST 1, 2003, AND OTHER MATTERS

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Executive Summary

Application

Centra Gas Manitoba Inc. ("Centra") applied to The Public Utilities Board ("the Board") for approval of Rate Base, Rate of Return and sales rates based on a 2003/04 future Test Year, for supplemental gas, transportation to Centra and distribution to customers sales rates to be effective April 1, 2003 for all gas consumed on or after August 1, 2003. Centra also sought approval of a number of other matters. A public hearing was held from May 20 to June 5, 2003 and final submissions were heard on June 10 and June 11, 2003. This is Centra's first General Rate Application ("GRA") since the acquisition of Centra by Manitoba Hydro ("Hydro") on July 31, 1999.

Plant In Service

Centra's net plant in service has increased from $273.1 million approved in 1998 to $344.6 million requested for the 2003/04 Test Year. The majority of the additions to plant relate to rural expansion, system load growth and distribution system upgrades. Except for approximately $1 million in expenditures related to two system extension projects and the incremental costs related to extending gas service to the inactive CanAgra plant in Ste. Agathe, which expenditures the Board has directed are to remain in Construction Work-in-Progress ("CWIP") until final disposition by the Board at a future date, the Board has approved all net additions to plant as additions to Rate Base. The Board has also approved changes to depreciation rates as a result of an updated depreciation study, as well as changes to depreciation methodologies.

Gas Costs

The Board has approved 2002/03 gas costs, based on the June 3, 2003 update, noting that in large part, non-primary gas costs are dictated by market forces and nationally and internationally regulated transportation and storage tariffs. The Board also approved the recovery of $5.6 million in deferral account balances, based on the June 3, 2003 update, to be recovered by way of a rate rider over a 12-month period commencing August 1, 2003.

The Board approved the 2003/04 forecasted non-primary gas costs of $90.3 million in Revenue Requirement, based on the April 9, 2003 forward price strip. In addition to the forecast commodity costs, estimates are based on terms and conditions and pricing structures contained in Centra's supply contract, its various existing transportation and storage arrangements and tolls. Differences between estimated and actual 2003/04 costs will accumulate in the appropriate deferral accounts commencing April 1, 2003.

Cost of Operations

The Board has accepted the forecasted cost of operations of $49.3 million for 2003/04 noting that because of synergistic benefits resulting from Centra's acquisition by Hydro, cost of operations has increased only marginally from the $48.7 million previously approved by the Board in Order 79/98.

Income Taxes

The Board approved Centra's request to vary Order 208/02 and to amortize the remaining balance of the one-time tax liability of $46 million based on a 30-year amortization period. The tax liability that originally totalled $58.5 million was the result of Centra becoming a non-taxable entity at the time of the acquisition of Centra by Hydro in July 1999. The Board also directed that Centra remove the unamortized balance of the one-time tax liability of $46 million from Rate Base, and treat this amount as a deferral account which will attract carrying costs at the approved overall rate of return.

Synergy Benefit Transfer

The Board approved a synergy benefit transfer of $3 million from Centra to Hydro be included in Revenue Requirement to partially offset the costs incurred by Hydro related to the acquisition and integration of Centra. The Board viewed this transfer as a transitional matter and expects Hydro to realize additional savings from the acquisition in the future so as to eliminate the need for any synergy benefit transfer amount by the time of the next GRA.

Rate of Return

In 1995 the Board established a formula to be used to calculate a reasonable Return on Equity for Centra. The Board accepted the continuation of the proposed formula. However the Board denied Centra's request to modify the capital structure used in the Rate of Return calculation. The Board has approved a Return on Equity of 9.56% and directed Centra to file a revised calculation of overall Rate of Return based on actual capitalization, expected to be in the range of 7.96%.

Other Matters

The Board confirmed as final Board Orders 79/02, 84/02, 135/02, 136/02, 188/02, and 11/03. The Board also accepted Centra's proposal to introduce two new customer classes being the Co-operative Class and Power Station Class.

The Board also directed Centra to establish a more regular schedule for periodic rate reviews, not exceeding three years between hearings, even if no rate changes are required. This timeframe will improve the efficiency, effectiveness and timeliness of the regulatory process.

Revenue Requirement, Rates and Customer Bill Impacts

The Board directed Centra to file an updated schedule of Rate Base, Rate of Return, Revenue Requirement, rates and customer rate impacts, reflecting all the decisions set out in this Order. The resulting rates and customer bill rate impacts will be dealt in a subsequent Order of the Board.

Résumé

Demandes à la Régie

Centra Gas (« Centra ») a soumis une demande à la Régie des services publics (la « Régie ») pour que soient approuvés sa tarification de base, son taux de rendement et ses prix à la consommation basés sur l'exercice de référence à venir 2003-2004 pour le gaz de réserve, les frais de transport vers Centra et la distribution aux clients, devant prendre effet le 1er avril 2003 pour le gaz consommé à partir du 1er août 2003. Centra a également demandé des approbations dans un certain nombre d'autres domaines. Une audience publique a eu lieu du 20 mai au 5 juin 2003 et les conclusions finales ont été entendues les 10 et 11 juin 2003. Il s'agissait de la première demande d'approbation générale des tarifs de Centra depuis son acquisition par Hydro Manitoba (« Hydro ») le 31 juillet 1999.

Installations en activité

La valeur nette des installations en activité de Centra a augmenté, passant de 273,1 millions de dollars approuvés en 1998 à 344,6 millions de dollars demandés pour l'exercice de référence 2003-2004. La plupart des dépenses en capital sont liées à l'expansion en milieu rural, à l'augmentation de la charge du réseau et à l'amélioration du réseau de distribution. La Régie a approuvé l'ajout des dépenses en capital nettes au calcul de sa tarification de base, à l'exception d'environ 1 million de dollars attribuable à deux projets d'agrandissement du réseau et aux coûts marginaux liés à l'extension des services de gaz à l'installation inactive CanAgra de Sainte-Agathe. À la demande de la Régie, et jusqu'à ce qu'une décision finale soit prise par elle à une date ultérieure, ces dernières dépenses doivent demeurer dans les travaux de construction en cours. La Régie a aussi approuvé certaines modifications aux taux d'amortissement à la suite d'une étude récente de l'amortissement, de même que des changements aux méthodes d'amortissement.

Coûts du gaz

La Régie a approuvé les coûts du gaz de 2002-2003 basés sur la mise à jour du 3 juin 2003 et a noté que, pour une large part, les coûts du gaz non primaire ont été établis en fonction des forces du marché et des réglementations nationales et internationales en matière de tarifs de transport et d'entreposage. La Régie a également approuvé le recouvrement de 5,6 millions de dollars en soldes reportés, basé sur la mise à jour du 3 juin 2003, au moyen d'un supplément de tarif couvrant une période de douze mois commençant le 1er août 2003.

La Régie a approuvé les coûts du gaz non primaire prévus pour 2003-2004 de 90,3 millions de dollars dans les besoins de revenus, établis en fonction du créneau

de prix du 9 avril 2003. En plus des coûts prévus pour le service du gaz, les estimations sont basées sur les conditions et les structures de prix contenues dans le contrat d'approvisionnement de Centra, sur les dispositions actuelles pour le transport et l'entreposage, et sur le coût des redevances. L'écart entre les coûts réels et estimés de 2003-2004 sera comptabilisé dans les comptes de report appropriés à partir du 1er avril 2003.

Coûts de fonctionnement

La Régie a approuvé des coûts de fonctionnement prévus de 49,3 millions de dollars pour 2003-2004 et a noté qu'en raison des bénéfices de synergie résultant de l'acquisition de Centra par Hydro, les coûts de fonctionnement ont augmenté de façon marginale seulement par rapport aux 48,7 millions de dollars approuvés par la Régie dans l'ordonnance 79/98.

Impôt sur le bénéfice

La Régie a approuvé la demande de Centra de modifier l'ordonnance 208/02 en vue depermettre l'amortissement sur une période de 30 ans du solde résiduel de 46 millions de dollars de l'assujettissement à l'impôt (coût ponctuel). Le solde d'origine, qui s'élevait à 58,5 millions de dollars, résultait de ce que Centra est devenue un organisme non assujetti à l'impôt au moment de son acquisition par Hydro en juillet 1999. La Régie a aussi ordonné à Centra de retirer le solde non amorti de l'assujettissement à l'impôt de 46 millions de dollars de sa tarification de base, et de comptabiliser ce montant dans un compte de report dont les frais de détention équivaudront au taux de rendement général approuvé.

Transfert des bénéfices de synergie

La Régie a approuvé un transfert de bénéfices de synergie de l'ordre de 3 millions de dollars de Centra à Hydro afin de les inclure dans les besoins de revenus et ainsi compenser en partie les coûts occasionnés à Hydro lors de l'acquisition et de l'intégration de Centra. La Régie a considéré ce transfert comme étant une mesure transitoire et s'attend à ce que cette acquisition permette à Hydro de réaliser des économies supplémentaires suffisantes pour éliminer tout besoin d'effectuer de nouveaux transferts de ce type d'ici à la prochaine demande d'approbation générale des tarifs.

Taux de rendement

En 1995, la Régie a établi une formule pour le calcul d'un taux de rendement des capitaux propres raisonnables pour Centra. La Régie a accepté que Centra continue d'utiliser la formule proposée. Par contre, la Régie a rejeté la demande de Centra de modifier la structure de capital utilisée dans le calcul du taux de rendement. La Régie a approuvé un taux de rendement des capitaux propres de 9,56 % et a ordonné à Centra de présenter un calcul révisé du taux de rendement général basé sur le capital réel, qui devrait se situer à environ 7,96 %.

Divers

La Régie a confirmé le caractère final des ordonnances 79/02, 84/02, 135/02, 136/02, 188/02 et 11/03. La Régie a également accepté la proposition de Centra de créer deux nouvelles catégories de clients, soit les catégories Coopérative et Centrale.

La Régie a aussi ordonné à Centra d'établir un horaire de révision périodique des tarifs plus régulier et n'excédant pas trois ans entre les audiences, même s'il n'est pas requis de modifier les tarifs. Cette exigence améliorera l'efficacité, l'efficience et la rapidité du processus réglementaire.

Impacts sur les besoins de revenus, les tarifs et la facture du consommateur

La Régie a ordonné à Centra de présenter un tableau complémentaire à jour de sa tarification de base, de son taux de rendement sur les capitaux propres, des besoins de revenus, et de l'impact sur les tarifs et la facture du consommateur de toutes les décisions mentionnées dans cette ordonnance. La Régie traitera des impacts sur les tarifs et sur la facture du consommateur dans une nouvelle ordonnance promulguée par elle.

1.0 Appearances

R. F. Peters K. L. Kalinowsky	Counsel for The Public Utilities Board ("the Board")
J. E. Foran, Q.C. M. Murphy	Counsel for Centra Gas Manitoba Inc. ("Centra")
B. J. Meronek, Q.C. K. Saxberg	Counsel for the Consumers' Association of Canada (Manitoba) and the Manitoba Society of Seniors ("CAC/MSOS")
D. Brown K. Melnychuk	Counsel for Direct Energy Marketing Ltd./Municipal Gas Representing Direct Energy Marketing Ltd./Municipal Gas

2.0 Witnesses for Centra

A. Aziz	Manager, Gas Distribution, Planning and Design
K. Derksen	Senior Analyst of Gas Rates
W. Derksen	Manager, Management Accounting and Budgeting
D. Rainkie	Manager, Regulatory Affairs
B. Sanderson	Senior Gas Cost Analyst, Gas Supply, Pricing and Administration
T. Simard	Principal, RiskAdvisory Services
H. Stephens	Manager, Gas Supply, Transportation and Storage Department
L. Stewart	Manager, Gas Supply, Pricing and Administration
V. Warden	Vice-President, Finance & Administration, and Chief Financial Officer
R. Wiens	Divisional Manager, Rates and Regulatory Affairs

3.0 Witnesses for CAC/MSOS

J. Todd	President, Econalysis Consulting Services, Inc.
J. Stephens	Principal and Managing Consultant, Stephens Consulting Ltd.
M. G. Matwichuk	Partner, Steven Johnson, Chartered Accountants

4.0 Intervenors

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

Direct Energy Marketing Ltd./Municipal Gas ("Municipal")

Communications Energy & Paper Workers Union Local 681 ("CEPU")

CEPU did not provide evidence, participate in cross examination or submit closing arguments.

5.0 Background

The Board last considered a Centra General Rate Application ("GRA") for the 1998 Test Year. The Board issued Order 79/98, dated June 19, 1998 that approved, amongst other things, the following:

- 1998 Test Year Rate Base of $280.1 million.
- Return on Equity of 9.912%, calculated in accordance with a formula previously approved by the Board.
- Overall Rate of Return of 8.893% based on Centra's actual capital structure.
- Revenue Requirement, exclusive of cost of gas, of $113.8 million, including cost of operations of $48.7 million and an income tax component of $12.0 million.

Subsequently, the Board issued Orders 103/98 and 104/98, dated August 7 and August 10, 1998, respectively that dealt with Centra's filings pursuant to Order 79/98.

Order 103/98 directed Centra to defer the impact of the change in the accounting treatment of contributions in aid of construction related to rural expansion for the Small General Class ("SGC") pending resolution of the cost allocation issue surrounding this matter. Subsequently, in Order 118/99, dated June 29, 1999, the Board instructed Centra to alter its cost allocation of rural expansion costs at the next GRA to ensure that all existing customer classes were saved harmless by rural expansion expenditures.

The Rate Schedules approved by the Board in Order 104/98 consisted only of Delivery and Sales Rates, Delivery Only Rates and T-Service Rates. In Order 15/98, dated February 11, 1998, the Board instructed Centra to unbundle sales rates to include Primary Gas, Supplemental Gas, Transportation to Centra and Distribution to Customer components that were to be shown separately on the gas bills. Unbundled rates have been used by Centra since 1999.

This Application is Centra's first GRA since the acquisition of Centra by Manitoba Hydro ("Hydro") on July 31, 1999. The Board held two hearings and issued orders related to the acquisition process. The most recent in this respect was Order 208/02 dated December 8, 2002, which included a number of directives related to accounting for certain aspects of the acquisition. Centra's GRA was filed on December 9, 2002 and therefore initially did not reflect any of the directives contained in Order 208/02.

6.0 Application

Centra filed its GRA based on a 2003/04 Test Year on December 9, 2002. The application included non-primary gas cost forecasts based on an August 1, 2002 forward market price. Centra filed an update to the application on March 11, 2003 that used a January 20, 2003 forward market price as the basis of non-primary gas cost forecasts for 2003/04. On April 16, 2003 Centra filed a further amendment to the original GRA that reflected its interpretation of Order 208/02. In Order 208/02, the Board directed that Centra use a shortened amortization period for the one-time tax payment required because of the acquisition of Centra's shares by Hydro. Centra requested the Board to reconsider this directive and to allow Centra to use a 30-year amortization period.

On May 1, 2003, Centra filed a final update for the cost of non-primary gas, using the April 9, 2003 forward market price. This Order considers the April 9, 2003 forecasts for 2003/04 gas costs, and the May 1, 2003 amended application which reflects most of the Board directives from Order 208/02.

Centra's GRA requests Board approval for the following matters:

1. Sales rates for the sale and/or transportation of natural gas in respect of Supplemental Gas, Transportation to Centra and Distribution to Customer costs effective April 1, 2003 with respect to all gas consumed on and after August 1, 2003.

2. Final approval of gas costs from April 1, 2002 to March 31, 2003 that the Board had previously approved on an interim basis.

3. Approval and disposition of March 31, 2003 balances of the various Purchased Gas Variance Accounts ("PGVA"), and other gas deferral accounts, excluding the Primary Gas PGVA.

4. Disposition of the SGC revenue accrual related to the acceleration of the amortization of contributions in aid of construction, pursuant to Order 79/98.

5. Final approval of the Supplemental Gas, Transportation to Centra and Distribution to Customer sales rates, effective August 1, 2002, that had been given interim Board approval in Order 135/02.

6. Final approval of interim Ex Parte Orders 79/02, 84/02, 136/02, 188/02, and 11/03 related to the quarterly approval of Primary Gas Sales Rates for May 1, August 1, November 1, 2002, and February 1, 2003.

7. Final approval of interim Ex Parte Orders 134/02 and 79/03 related to an amendment to the existing franchise agreement and a feasibility test for extending gas service within the Rural Municipality of Rockwood, and a feasibility test for extending gas service within the Rural Municipality of Woodlands, respectively.

8. New depreciation rates to be effective April 1, 2002.

9. Changes in the methodology of calculating depreciation expense.

10. Amendment to the Service Disconnection and Reconnection Policies and Procedures with respect to the requirement for face-to-face contact.

11. Approval of long-term inter-company loans from Hydro to Centra to finance acquisition taxes, other capital requirements, and to refinance a portion of Centra's cumulative short-term debt.

12. Connection fees for three larger volume customers within the Interlake area of Manitoba.

13. Approval of changes to Centra's Terms and Conditions of Service.

14. Approval of a fee for the retrieval of customer information.

15. Removal of legal action fees for small claims from Centra's Schedule of Miscellaneous Charges for Service.

A public hearing was held in Winnipeg from May 20 to June 5, 2003 and final submissions were heard on June 10 and June 11, 2003.

7.0 Rate Base

7.1 General

Centra's Rate Base at December 31, 1998 approved in Order 79/98 was $280.1 million. Centra's fiscal year end changed from December 31 to March 31, effective in 2000. Centra's requested Rate Base in this application is $409.4 million. The component changes in Rate Base are as follows:

($ millions)	1998 Approved	2003/04 Forecast	Change
Gas Plant in Service	$ 405.5	$525.1	$119.6
Accumulated Depreciation	(129.8)	(180.0)	(50.2)
Disallowed Assets	(2.6)	(0.4)	2.2
Net Plant	$273.1	$344.7	$71.5
Contributions in aid of construction	(27.1)	(57.2)	(30.1)
Working Capital	34.1	75.9	41.8
One time tax payment		46.0	46.0
Average Rate Base	$280.1	$409.4	$129.2

7.2 Gas Plant in Service

7.2.1 Capital Project Justification Process

In the 1998 GRA, Centra utilized a priority approach in planning its capital program. Projects related to enhancing system integrity and safety and ensuring compliance with existing codes and standards were deemed to be essential and to have the highest priority. Projects, such as required plant relocations deemed to be necessary were assigned to the second priority group. All other projects related to rural expansions, system load growth, IT expenditures and most other General Plant expenditures were designated as justifiable. The Board required such projects to be supported by cost/benefit studies or other justification means.

Centra has adopted a Capital Expenditure Forecast ("CEF") approach to defining its capital program, consisting of Major and Domestic Items. Major Items represent significant initiatives, such as rural expansion projects, and are internally approved through a Capital Project Justification ("CPJ") process. Major Items, once identified, are reviewed at the Department, Division and Business unit levels before submission to the Executive Committee ("EC") for approval. Complex projects may be subject to review by the Planning Review Committee prior to submission to the EC. The EC scrutinizes the CPJs to confirm the requirement, based on criteria of system reliability, safety, efficiency, customer service and impact on profitability. Additionally, the EC reviews and determines overall priorities to ensure that funding levels remain within the approved CEF. Centra submits that this process is essentially the equivalent of the previous classification system.

Domestic Items are those items that are relatively routine in recurring business activities and are designated as being blanket or non-blanket. Domestic Item blanket forecasts are based on past year activities for routine upgrades and replacements, as well as forecasts for future system load growth, for an annual "blanket" expenditure. As projects become better defined, specific work packages are authorized by management and charged against the annual blanket sum. Blanket domestic items include projects such as distribution mains, services and meter and regulator installations. Non-blanket items are usually non-recurring projects in nature, costs generally range from $100,000 to $2 million in total, and the project can span more than one year.

7.2.2 Tendering Process

Centra tenders for supply of materials and certain labour for capital projects. To conform with Hydro, Centra's tendering process has changed from that used in prior years. Generally, the current process involves preparation of several copies of all tender documents and publishing of Centra's intent to call for tenders. Previously, Centra pre-qualified potential contractors and only these were asked to bid on the projects. Recently, Centra has tendered for specific work packages for three years, with built-in price escalation mechanisms for the last two years of the contract.

Subsequent to receipt of the contractor's bids, all bids are opened in a public forum. The work is awarded on consideration of contractor experience, available capacity, and local content. In the previous system bids were not opened in public.

7.2.3 Plant Additions

The following table summarizes Centra's major plant additions since 1998, including forecasted additions for 2003/04, for various plant categories, by major project.

Capital Projects (in $millions)	1998 Approved	1998 Historical	1999/00 Historical	2000/01 Historical	2001/02 Historical	2002/03 BridgeYear	2003/04 Test Year	Total
System Load Growth	9.6	10.6	11.4	8.5	6.7	9.1	9.0	55.3
Rural Expansion		4.0	5.6	7.3	0.5	0.8	0.3	18.5
Other System Upgrades	1.8	1.3	1.7	1.5	1.5	4.1	1.8	11.9
Selkirk Generating Station						10.3		10.3
System Capacity Upgrades				4.4		0.5	2.6	7.5
Riser Rehabilitation				0.5	1.6	2.0	2.0	6.1
Brandon Combustion Turbine						4.9		4.9
Regulator Station Upgrades		0.4	0.7	0.5	0.1	1.8	1.2	4.7
Adjustment CWIP						4.0		4.0
Plant Additions < $100,000	1.0	0.9	1.4	0.9				3.2
LGS Relief Vent Piping Upgrade					0.4	0.9	1.0	2.3
Simplot Potato Plant						1.4		1.4
RSU	0.8	0.7	0.2	0.1	0.2	0.1	0.1	1.4
Dresser Replacements		0.2	0.3	0.1	0.1	0.4	0.4	1.5
Ste. Agathe Expansion						1.3		1.3
Integrity Assessment Projects							1.0	1.0
Southwest TP Line Repairs						0.9		0.9
Portage La Prairie Upgrade	0.9	0.8						0.8
Insufficient Ground Cover						0.4	0.2	0.6
Pipeline Relocations						0.3	0.3	0.6
Lockport Road Project						0.3	0.2	0.5
Westwood Condominiums Upgrade							0.3	0.3
Distribution Mains - Brandon		0.2						0.2
Replace Field RTU's	0.3				0.2			0.2
Assiniboine River Crossing			0.1					0.1
Pipeline Rd Main Replacement			0.1					0.1
Rural Expansion Phase I Service	0.4							-
Reinfeld Upgrade Project	0.1							-
General Plant:								
New CIS - Banner	0.2	0.1	5.7		5.0			10.8
DFIS			0.2	2.3	1.8			4.3
Transportation Equipment	1.2	1.1	0.5	0.4				2.0
Y2K Enhancements	0.8	0.5	1.0					1.5
SCADA	1.2	1.2	0.2					1.4
Other	1.4	0.3	0.5	1.7	1.0	-	-	3.5
Total	**19.7**	**22.3**	**29.6**	**28.2**	**19.1**	**43.5**	**20.4**	**163.1**

Plant additions by service category since 1998 are as follows:

(in $millions)	1998 Historical	1999/00 Historical	2000/01 Historical	2001/02 Historical	2002/03 Bridge Year	2003/04 Test Year	Total
Rural Expansion	4.0	5.6	7.3	0.5	2.1	0.3	19.8
System Load Growth	10.6	11.4	8.5	6.7	9.1	9.0	55.3
Distribution System Upgrades	3.5	3.1	7.2	4.1	28.3	11.1	57.3
CIS Banner	0.2	5.7	0.0	5.0	0.0	0.0	10.9
DFIS	0.0	0.2	2.3	1.8	0.0	0.0	4.3
Y2K	0.5	1.0	0.0	0.0	0.0	0.0	1.5
Other	3.5	2.6	2.9	1.0	4.0	0.0	14.0
Total Plant Additions	22.3	29.6	28.2	19.1	43.5	20.4	163.1

7.2.4 Major Plant Additions

System Load Growth

Centra spent $55.3 million for system load growth projects since 1998, representing approximately 34% of total capital expenditures during that period. System load growth capital expenditures represent the costs to attach additional customers to the distribution system within existing franchise areas and consist of costs for distribution mains, services, meters and regulators. Centra stated that 13,600 customers have been added since 1998, and 2,900 customer additions are forecasted in the 2003/04 Test Year.

Rural Expansion Projects

Centra spent $19.8 million for rural expansion projects since 1998 including $1.3 million in Ste. Agathe, discussed later in this order, which represents about 11% of all capital expenditures. These projects were all in areas of the Province where Centra had no previous existing franchise agreements. Therefore, public hearings were held and franchises were approved prior to the projects being initiated.

Expansion projects completed since 1998 included Rural Municipalities ("RM") of Hanover/LaBroquerie, Macdonald, North Cypress, Wallace, West Emerson, Kola, East Portage la Prairie, Rockwood, and Bifrost. Third party funding for these projects included contributions totalling $11.0 million from all three levels of governments as well as from individual customers. Required contributions were determined based on the Board approved feasibility tests.

System Capacity Upgrades

Projects required to upgrade capacity on the transmission and distribution pipeline systems are dictated by growth of new and existing customer loads or by existing constraints that could adversely impact the delivery of natural gas during periods of heavy or peak consumption. Expenditures in this category since 1998 amounted to $7.5 million, approximately 4.6% of the total capital program.

Other System Upgrades

Expenditures for system upgrades, required to ensure system integrity required for the safe and efficient delivery of natural gas accounted for $11.9 million and represent approximately 7% of total capital expenditures. Projects included in this group varied and are initiated after engineering assessments of computerized system integrity data and other field information. Required pipeline relocations are also included in this work category.

Riser Rehabilitation Program

Service riser assemblies may become stressed over time due to soil settlement around building foundations. This creates the possibility of failures and the uncontrolled escape of natural gas in proximity to habitable buildings, thus creating a hazard. In 1998, Centra embarked on a service riser engineering assessment of approximately 66,000 residential service riser assemblies that, due to age and configuration, Centra deemed as having the highest potential risk for failure. Centra currently has determined that as many as 20,000 such riser assemblies pose a high risk of failure. By 2003/04 approximately 4,500 riser assemblies will have been rehabilitated at a cost of $6.2 million. Centra estimates this program will be completed in 2007/08.

Regulator Station Upgrades

The Regulator Station Upgrades Program consists of the replacement of below grade stations to above grade and the enclosure of existing above grade stations. Below grade stations present flooding and freezing problems, compromise employee safety, and adversely impact equipment useful life. Where existing exposed stations are obsolete or nearing obsolescence, they are replaced with new equipment and housed above grade in buildings to extend the life of the stations. The cost of this program from 1998 including the forecast for 2003/04 is $4.7 million. The program is expected to require annual expenditures of approximately $500,000 over the next five years.

Regulator and LGS Relief Vent Piping Upgrades

Since 1998, Centra has spent $2.3 million for this program. The expenditures were necessary because replacement parts for certain types of regulators that are between 30 and 50 years old are no longer available. As well, all relief piping was upgraded to meet current standards and requirements.

Dresser Replacements

Centra continues to implement the replacement program for main Dresser compression couplings and Dresser end valves. Originally expected to be completed several years ago, additional coupling and valve problems have been found during routine inspections and are being replaced. It has been demonstrated in the past that these fittings are unsuitable for Manitoba’s soil conditions. This program enhances system safety by reducing the number of potential leaks. Centra forecasts that $1.4 million will be spent on this program, estimated to be completed in 2003/04.

Remote Sensing Units ("RSUs")

Centra spent approximately $1.4 million since 1998 for RSUs. The units are installed on customer premises and relay readings to Centra on a daily basis via the customer's telephone lines. These readings provide information with respect to corrosion protection levels and operating pressures, and allow the identification of problem areas that enhance the planning of a more effective protection program. Centra stated that this is an innovative program developed by Centra personnel and is a relatively low cost approach. Centra forecasts that the program will be completed in 2004/05.

Selkirk Generating Station

The installation of supply and service lines to Hydro's Selkirk Generating Station was undertaken in 2002/03, at a cost of $10.3 million. The actual costs were less than originally estimated, and subsequent to the carrying out of a feasibility test, Hydro paid a contribution of $12.5 million towards the project. During the hearing the Board was informed that a system malfunction required an expenditure of $190,000 to repair. Centra indicated that volume estimates used for the feasibility tests were conservative, and that Hydro's required contributions will be recalculated on three occasions over the course of the next 10 years and appropriate refunds, or additional payments, will be made. As a part of an integrated system, this plant will provide added capacity that will increase Hydro's system reliability, will assist in meeting peak requirements, and will allow increased export sales. As well, environmental concerns dictated the fuel type should be switched to natural gas from coal.

Brandon Combustion Turbine

In 2002/03 Centra installed natural gas mains and ancillary equipment to provide service to Hydro's Brandon Combustion Turbines at a cost of $4.9 million. As with the Selkirk Generating Station, this project will provide added capacity to Centra's overall system. The expenditure resulted from the decision to switch the fuel type to natural gas from coal. The results of the Board approved feasibility test indicated a required contribution of $5.1 million from Hydro, which Centra has received. As with the Selkirk Generating Station, refunds or additional contributions will occur as periodic reviews of actual results are made.

Centra indicated that although the project included future capacity for the Southwest expansion project completed in 1996, and for the Brandon Simplot Plant, Hydro was the only customer considered in the feasibility test to determine the required customer contributions.

Portage Simplot Potato Plant

Centra provided service to Simplot's potato processing plant located near Portage la Prairie at a cost of $1.4 million. Total contributions will be determined following a true-up calculation. Total contributions from Simplot are currently estimated to be $985,000.

Ste. Agathe Expansion

Centra requested that $1.3 million be reclassified from Construction Work-in-Progress ("CWIP") and added to Rate Base. The CWIP treatment had been previously ordered by the Board. Although the system is designed with excess transmission line capacity to serve the former CanAgra canola crushing plant, facilities to serve the plant have never been installed. The CanAgra plant remains in the hands of a receiver and there is no current plan to extend gas service to the plant. Centra submitted that the related expenditures were prudent, and were made as a result of Centra's commitment to provide gas service to the residents of Ste. Agathe.

Distribution Facilities Information System ("DFIS")

The Board approved the DFIS project and estimated expenditures for Phase I of the project in Order 79/98. DFIS was to result in one set of plans that could be read electronically by all departments requiring the information so as to allow for improved employee and public safety, improved gas supply planning, and operational efficiency. Estimated expenditures at that time were $3.4 million. Total project costs included in Rate Base are $4.3 million. Centra attributed most of the additional costs charged to the results from Centra's new fully loaded activity based accounting methodology.

Southwest Transmission Line

This transmission line experienced several corrosion leaks and, consequently, Centra undertook an investigation to identify and repair all corrosion and coating damages. Centra indicated that the life expectancy of the pipeline has not been adversely affected because of these features. Costs for the repair of the pipeline, including a third party risk assessment study, are currently projected to be $894,000, which Centra has requested be included in Rate Base. Centra filed a lawsuit against the contractor and inspection firm seeking to recover the costs, but no defence has yet been issued. Centra stated that should any funds be recovered from litigation, that amount would be treated as a contribution and credited to Rate Base in the future.

Hanover/LaBroquerie Transmission Line

Several defective welds on the steel transmission line were detected during a post inspection process after commissioning the transmission line in 1999. The installation contractor has since repaired these defects pursuant to the contract guarantee. However, further investigations revealed additional welds on the pipeline that do not meet the minimum standards required by the CSA Z662 Oil and Gas Pipeline Systems. Centra has retained a consultant to conduct a risk assessment of pipeline integrity risks. Total costs incurred by Centra to date, including the cost of the risk assessment and repair, are approximately $160,000. These expenditures have been included in 2003/04 Rate Base as a component of System Integrity Assessment Projects. As with the Southwest Transmission Line, Centra has filed a claim against the contractor and welding inspection firm. To date no statement of defence has been filed. Any funds recovered from the litigation will be credited to Rate Base in the future.

System Integrity Assessment Projects

Centra is embarking on a multi-faceted System Integrity Assessment Project and is requesting approval of $1.0 million in 2003/04 Rate Base related to a variety of distribution main projects, including further investigation of the Southwest Transmission Line, the Hanover/LaBroquerie Transmission main, polyethylene butt fusions and steel weld assessments, and other miscellaneous studies and remediation works.

General Plant Additions

General plant expenditures are items such as computer software and hardware, vehicles, tools, equipment, heavy work equipment, communications equipment and other miscellaneous items used in support of construction, operations and maintenance activities. Effective April 1, 2002, Hydro began to purchase general plant items designated as common assets. Therefore, general plant items are no longer being added to Centra's Rate Base. However, Centra is being charged for the portion of common assets purchased by Hydro on behalf of Centra, estimated at $904,000 for 2003/04, to be included in Centra's Revenue Requirement.

The majority of general plant expenditures since 1998 have been related to Information Technology ("IT") which is discussed in another section of this Order. General plant expenditures from 1998 to March 31, 2002 amounted to $23.5 million and represent 14% of the capital expenditures. Of the $23.5 million, approximately $21.1 million is for IT and other computer projects. Another major expenditure was $2.0 million for transportation equipment. Transportation equipment replacements up to March 31, 2002 are dictated by Centra's policies that had previously been reviewed and accepted by the Board.

Construction Work In Progress

Centra is requesting that $4.0 million related to several projects be approved as an addition to Rate Base because that amount was inadvertently left in Construction Work in Progress ("CWIP") in 2001/02, even though the assets were being used at that time. The majority of the projects, approximately $3.4 million, were related to main installations required for customer growth and distribution system upgrades with associated overheads. Smaller projects were for DFIS, computer aided drafting, mains, services, regulator and meter installation costs.

Centra is also requesting approval to recover the SGC revenue accrual deferral in the amount of $2.9 million to the end of 2002/03 by reducing the appropriate amount of contributions rather than collecting it from additional SGC rates. The deferral, related to the impact of rural expansion on customer classes, was approved by the Board in Order 79/98.

7.2.5 Banner Customer Information System ("CIS")

Centra adopted the Banner CIS in October 1999 through a licensing agreement with Enlogix, a company related to Westcoast Energy Inc. This licensing agreement was subsequently terminated. In 2000, after the acquisition of Centra by Hydro, a project team was established to conduct an analysis of establishing one corporate wide CIS for both Hydro and Centra. Based on the results of an economic and qualitative analysis, the project team recommended that Centra purchase a license for the Banner CIS from Enlogix. Acting on the project team's recommendation, Centra purchased a software license for $5.2 million and established a data centre on Hydro owned hardware to operate the gas billing system.

On an overall basis Centra incurred approximately $10.8 million in capital costs including the software license related to the Banner CIS software, citing that an additional $300,000 in training costs would be sought to be recovered at a future GRA. Centra also has budgeted $1.9 million for future hardware replacement and indicated that it is currently in the process of converting former Winnipeg Hydro customers, and expects the process to be completed by May 2004. Although it is anticipated that Banner CIS will be used to service both gas and electric customers in the future, the decision to convert Hydro customers has not yet been made.

Centra indicated that once the full conversion was completed, Banner CIS would be treated as a common asset and the costs incurred by Centra in acquiring the Banner CIS license would be apportioned between Centra and Hydro.

7.2.6 Information Technology Expenditures and Planning

Centra stated that no gas specific IT capital projects are planned for 2003/04. Centra indicated that Hydro has budgeted $20 million in capital expenditures for IT for 2003/04 of which Centra would be allocated a portion of the depreciation on the assets it utilizes through the integrated cost allocation methodology. Centra stated that it does not prepare a separate IT budget since IT is managed at the corporate level on an integrated basis between the gas and electric utilities and indicated the preparation of a separate IT budget for Centra would be of limited use.

Centra indicated that Hydro is currently in the process of developing IT benchmarking metrics to evaluate the level of IT spending undertaken by Hydro.

7.2.7 Intervenor Positions

Gas Plant in Service

CAC/MSOS was the only Intervenor to challenge aspects of Centra's application to allow inclusions of plant additions in Rate Base.

CAC/MSOS submitted that the Board should disallow the Revenue Requirement related to the expenditure for Centra's system expansion to service the Ste. Agathe CanAgra canola crushing plant. CAC/MSOS contended that the Order related to this project had directed Centra to place all direct and indirect costs into CWIP until that plant had achieved projected Phase I annual volumes, or until Centra could otherwise demonstrate the prudence of these expenditures to the Board. The required fifth-year revenue to cost ratio could not be achieved without the plant consuming Phase I volumes, and to date, the plant is not operating. CAC/MSOS stated that Centra should bear the consequences of the decision. CAC/MSOS suggested that CanAgra's financial difficulties were well known at the time of installation, and the Board had expressed concern that Centra had not conducted a full and adequate due diligence process before deciding to proceed. CAC/MSOS estimated that the annual Revenue Requirement related to the capital expenditure of $1.293 million would be $108,000, and submitted that the $1.293 million amount be disallowed from Rate Base.

CAC/MSOS further requested the Board to disallow the expenditure of $190,000 that was required to correct a regulator station failure related to the commissioning caused by the operation of the Selkirk Generating Station. CAC/MSOS submitted that this was as a result of an error in communication between Centra and Hydro, and the cost should not be borne by the ratepayer.

CAC/MSOS also requested the Board to disallow $890,000 included in 2003/04 Rate Base on a forecast basis for repair of defects on the transmission line to serve the Southwest expansion project. CAC/MSOS contended that Centra had a responsibility either to make sure the work was done correctly through inspections itself, or to hire somebody competent to do so. Failure to do this resulted in a cost that, in the view of CAC/MSOS, was unnecessary. Although Centra has filed a statement of claim, CAC/MSOS considers the chances of recovering any funds to be remote. As an alternative, CAC/MSOS suggested that the amount could be placed into CWIP and if the courts determine there was no negligence, the costs could be placed in Rate Base at that time. If any funds are recovered, these would be netted against CWIP and there would be no increase in Rate Base. If the CWIP alternative is chosen, CAC/MSOS recommended that interest be at the short-term rate.

CAC/MSOS also requested the Board to disallow an inclusion of $160,500 in Rate Base with respect to the Hanover/LaBroquerie Transmission pipeline. This is the amount that Centra is attempting to recover from the installation contractor, and is part of the cost of rectifying defective welds on the pipeline. CAC/MSOS suggested that if the amount were not disallowed from Rate Base now, then it should not be included until such time as is determined that there was no negligence.

Information Technology

CAC/MSOS adopted the position of Mr. Stephens who provided evidence related to IT expenditures. Mr. Stephens concluded that on an overall basis, Hydro's IT costs were reasonable, but that he could not assess Centra's costs because of a lack of information. Mr. Stephens stated that Centra's costs per customer should approximate that of Hydro. If Centra's costs were higher, this would increase Hydro's average cost, when in the industry, electric utilities' costs are generally greater than gas utilities' costs.

Mr. Stephens made the following four recommendations:

- The Board should require Centra to file an IT strategic plan that is separate from the Hydro corporate strategic plan at least every two years.

- The Board should require Centra to annually file the IT budget (O&M plus hardware depreciation plus software amortization) and provide key metrics including the annual growth in IT budget and the IT budget per end user.
- The Board should ensure that the Hydro/Centra IT allocations result in a Centra IT budget that is approximately $8,500 per end user and not higher than that for Hydro for both 2002/03 and 2003/04.
- The Board should require Centra to annually file a table of Customer Service (contact centre, meter reading, billing, payment processing, collections and related IT services) costs per customer and include a comparison of these costs to top performing utilities.

7.2.8 Board Findings

Gas Plant in Service

Since the last approved Rate Base is based on a 1998 Test Year, this application contains six years of Rate Base components including plant additions, plant deletions, contributions in aid of construction, depreciation and working capital allowance changes. The Board is required to review and decide on the prudence of all these components to properly discharge its obligations. The task is made more onerous and time consuming than it would otherwise have been because of the long passage of time since the last GRA filing.

The Board notes that Centra has attached approximately 13,600 SGC and small commercial customers from 1998 to 2002/03, and anticipates extending service to another 2,900 in 2003/04. These customers were located within existing and new franchise agreements. The Board notes that a significant portion of the capital expenditures for new expansion projects were funded by the three levels of government. Contributions were also received from customers by way of connection fees or up front payments in existing and new franchise areas. Contribution levels were determined as a result of the application of the Board approved feasibility test. The Board has reviewed the feasibility test results submitted to date, and is satisfied that the net expenditures on an overall and per customer basis are reasonable and will allow the inclusion of these net expenditures into Rate Base, as requested by Centra. The Board further notes that

Centra is required to file true-up calculations for all rural expansion projects for review by the Board and other contributing agencies. Depending on the results of the review, Rate Base may be further impacted if the recalculation indicates that the actual level of contribution to eligible costs paid by the governments has exceeded the level of contribution required.

The Board notes that although Centra's estimated expenditures related to the provision of service to the Brandon and Selkirk Generating Stations and to the Simplot Plant in Portage la Prairie are approximately $16.6 million, the customer contributions were, on an overall basis for the Brandon and Selkirk Projects, greater than the estimated costs. Therefore, there will be no net additions to Rate Base in respect of those two projects. As well, with the contribution from Simplot estimated to be $985,000, that project will result in a net addition to Rate Base of approximately $465,000. The Board notes that the actual costs for Brandon and Selkirk Generating Stations are less than those included in the feasibility test, and will expect that actual net impacts be reflected in future applications.

During the hearing the Board was informed that a system malfunction related to the Selkirk Generating Station required an expenditure of $190,000 to repair. In the Board's view this occurrence could have been avoided had Centra personnel taken the proper steps in regards to system start-up. The Board will allow this expenditure in Rate Base but urges Centra to be diligent in complying with safe operating procedures in the future.

With respect to the Ste. Agathe project, the Board will not allow the inclusion in Rate Base at this time of any incremental portion of Centra's system that was designed and installed to serve the CanAgra Plant, since that amount does not currently meet the test of used, useful and prudently acquired. The Board will expect Centra to determine these incremental costs and to reduce Rate Base by the corresponding amount, by reclassifying that amount as CWIP. Since Centra indicated it was still possible, the Board suggests Centra approach the former owners of the utility in an attempt to recover the incremental costs.

The Board considers that more diligent supervision of the Southwest Transmission Line and the Hanover/LaBroquerie projects may have prevented the circumstances related to post construction problems now being experienced. The Board will require that all costs related to identification and corrective action related to these projects be placed into CWIP. The Board notes that legal action has been initiated in both cases, though apparently not rigorously pursued. Neither a statement of defence has been filed, nor any defendants noted in default. These projects are to be the subject of true-up calculations pursuant to the various funding agreements. The Board will make a final decision in these matters pending finalization of the legal action and review of the true-up calculations.

The Board considers that the approximate $4.0 million that remained in CWIP related to 2002/03 projects was an inadvertent error, in some part due to pre and post Hydro/Centra acquisition activities, and will therefore be allowed in Rate Base. The Board will also approve Centra's requested treatment related to the SGC revenue accrual deferral by reducing that amount of contribution. In the Board's view it conforms with the Board's intent as initially outlined in Order 79/98.

One of the Board's primary concerns is that appropriate programs be initiated and constructed to ensure that Centra's total system is in conformance with current codes and regulations, continues to be safe for use, and enhances operational efficiency and response time related to unusual occurrences, such as pipeline damages. The Board has considered the many projects related to these matters, and will approve the expenditures as requested by Centra.

The Board is encouraged by Centra's initiatives related to the Riser Rehabilitation Program but cautions Centra to properly prioritize the program and to provide the Board with more detailed estimates of the total project costs in the next GRA. In the Board's view failure to continue with this program could compromise public safety.

The Board also notes that, while Centra had purchased some 1,500 RSUs to monitor cathodic protection and operating pressure levels in 1997, not all units have been installed. The Board encourages Centra to continue with the annual program until all necessary units have been installed so that the full benefits of the monitoring program are realized.

The Board considers that expenditures related to system integrity, capacity upgrades and other miscellaneous projects, many less than $100,000 in value, to be either essential or necessary. The Board will, except for system integrity expenditures related to the Southwest Transmission and Hanover/La Broquerie projects discussed above, allow the inclusion of the related expenditures in Rate Base.

Capital Justification Process

In the past, the Board has required Centra to prioritize and place all of its capital projects into three categories being Essential, Necessary and Justifiable, with specific criteria applicable to each category. The Board recognizes that with the acquisition of Centra by Hydro, certain processes and procedures have changed and may continue to undergo further changes in the future. One of these is the change in the manner of budgeting and justifying capital projects using Hydro's Capital Justification Process.

The Board will require Centra to assign priorities of Essential, Necessary and Justifiable to all capital projects. The Board will continue to require Centra to provide cost/benefit analyses for projects considered to be Justifiable, as the basis for justifying these projects.

The Board notes that the feasibility test used by Centra for assessing the economic viability and justifying expansion projects contains parameters that may no longer be appropriate. The Board encourages Centra to review this matter, as it has indicated it will, and to propose required changes as soon as time allows.

Tendering Process

Centra's procedures for tendering capital projects has changed to conform to Hydro's tendering system. The Board understands that this is a public process and accepts that this change is reasonable. The Board, however, is concerned about the low number of bidders responding to Centra's tenders. The Board encourages Centra to review contractor availability and to stage its construction program so as to attract the most bids from qualified contractors for each of its projects, and initiate any other changes to improve the tendering system to ensure competitive and qualified bids are submitted.

Banner CIS

The Board will approve the current expenditures as filed for the repatriation of the Banner CIS. The Board notes that Winnipeg Hydro customers are currently being converted to the Banner CIS and the potential future conversion of Hydro to a common billing system. The Board expects that as a result of these initiatives there may be cost reductions to Centra in the future. The Board further notes that the Banner CIS, if used as a common billing system, would be considered as a common asset. Accordingly the capital costs incurred by Centra in the repatriation and conversion should be shared on an equitable basis between the electric and gas utilities in the future.

Information Technology

The Board notes that from an IT standpoint, Centra is functionally integrated with Hydro and that for efficiencies to be realized, total IT expenditures are coordinated by Hydro. It is the Board's view that budgeting activities should be conducted on a corporate wide basis. It is therefore impractical for Centra to have a separate IT budget for operations and capital projects. The Board notes that Hydro is currently in the process of developing IT metrics to assist the organization in evaluating its future IT spending based on sound metrics. The Board will expect Centra to file these metrics at the next GRA.

7.3 Working Capital Allowance

Centra is requesting a working capital allowance component of Rate Base of $75.9 million for the 2003/04 Test Year, compared to $34.1 million approved for 1998, an increase of $41.8 million. Working capital allowance includes such items as cash requirements for inventories and accounts receivable, offset by certain accounts such as accounts payable, and is determined through the application of a lead/lag study.

Working Capital Allowance **($ millions)**

	2003/04 Test Year	1998 Test Year	Increase (Decrease)
Materials inventory	$ -	$1.2	$(1.2)
Gas storage inventory	57.1	22.3	34.8
Total inventory	57.1	23.5	33.6
Security deposits	(1.1)	(1.1)	-
Finance contracts	-	4.3	(4.3)
Cash requirements	19.9	7.4	12.5
Total Working Capital Allowance	$75.9	$34.1	$41.8

The significant increase in the working capital allowance component of Rate Base is primarily attributable to an increase in cash requirements for storage gas inventory as a result of the large increases in the gas commodity cost and the results of the lead/lag study conducted for the 2003/04 Test Year.

A lead/lag study is an approved methodology used to calculate a reasonable estimate of the cash requirement component of working capital for regulatory purposes. The updated study indicated an increase in the number of days in collections, lags and payment leads, contributing to an overall increase in cash requirement.

Some changes to the lead/lag study include an extension of the budget plan for three months, change in the payment date for purchased gas lead, and the elimination of income taxes due to the change in Centra's tax status.

7.3.1 Intervenor Positions

CAC/MSOS noted that the updated lead lag study indicated an increase in the amount of time from billing to payment from 19.5 days to 32.9 days.

CAC/MSOS expressed concerned about the increase in working capital allowances arrived at by using this methodology. CAC/MSOS did concede that it was in no position to contest the methodology and would address the matter in more detail in a future hearing.

7.3.2 Board Findings

The Board notes the significant increase in the working capital allowance component of rate base, as a result of the large increases in gas commodity costs, which is passed on to customers without mark-up. The Board will accept Centra's calculation of working capital allowance as updated to be included in Rate Base, subject to further adjustment for decisions made elsewhere in this Order that impact the working capital allowance.

The Board accepts that the updated lead/lag study is reasonable and appropriately reflects changes in Centra's ownership and the adoption of new operating procedures.

8.0 Cost of Gas

8.1 2002/03 Cost of Gas

In Order 135/02, the Board approved forecasted 2002/03 non-primary gas costs of $80.5 million. Effective customers and volumes were estimated using Centra's methodology that used historic data to project annualized consumption. Centra also assumed a 1.83% factor for Unaccounted For Gas ("UFG") to determine the annual volumes it would be required to purchase. Centra stated that actual 2002/03 gas costs reflected actual sales and purchase volumes, U.S. exchange rates, and tolls and tariffs as these became effective throughout the course of the fiscal period.

Centra's application indicates final 2002/03 non-primary gas costs of $88.3 million. The following table compares forecast total 2002/03 gas costs with the May 1, 2003 update and with actual results. Although the final 2002/03 gas costs were filed on June 3, 2003, as Centra Exhibit #40, Centra did not re-run the cost allocation methodology for these costs.

($ millions)	**2002/03 Forecast**	**2002/03 May Forecast**	**2002/03 Final Costs**
Fixed	$ 54.7	$ 54.5	$ 54.3
Variable Transportation	9.7	9.0	9.4
Supplemental Supply	15.5	16.3	18.7
Delivered Service	0.1	2.2	3.1
Alternate Service	0	3.3	2.3
Balancing Fees	0.5	0.5	0.5
	80.5	85.8	88.3
Primary Supply	256.1	286.8	286.3
Hedging	0.8	(15.5)	(15.3)
Total Costs	$337.4	$357.1	$359.3

8.1.1 Intervenor Positions

No Intervenor submitted comments on this matter.

8.1.2 Board Findings

The Board notes that the non-primary gas costs are higher than the $80.5 million forecast over a year ago by approximately $7.8 million. Of the $7.8 million, the commodity cost for supplemental gas, that is dictated by actual market prices, increased by $3.2 million. Delivered service which is dependent on weather, increased by $3.0 million, and is reflective of the much colder than normal late winter weather. Alternate service that is available to interruptible customers in lieu of curtailment, at cost, increased by $2.3 million. Fixed costs and variable transportation costs, including supplement gas storage charges, decreased by approximately $0.6 million. The Board will approve as final 2002/03 gas costs including the results from the derivative hedging activities submitted by Centra in the June 3, 2003 update.

8.2 Gas Cost Deferral Account Balances at March 31, 2003

Differences between forecast 2002/03 and actual 2002/03 gas costs accumulate in various deferral accounts from April 1, 2002 to March 31, 2003. In addition to deferral account balances for the 2002/03 gas costs, the residual balances related to accounts accumulated prior to April 1, 2002 were carried over into the 2002/03 balances. Centra is proposing to carry over the differences between the May 1, 2003 forecast and the actual results for 2002/03 gas costs into the appropriate 2003/04 deferral accounts. Centra proposed to set rates based on the May 1, 2003 updates and to accumulate the difference between that update and final costs in the 2003/04 PGVA and other related gas cost deferral accounts. Under Centra's proposal, recovery of any difference would not commence until the 2003/04 gas costs and deferral account balances are finalized approximately one year from now.

The following table summarizes the forecast deferral account balances owing to Centra (or owing to customers) as at July 31, 2003. Centra is requesting that existing rate riders continue until July 31, 2003 and the new rate riders to recover the estimated July 31, 2003 balances be implemented on August 1, 2003.

Account	**May 1 Estimated Balance**	**June 3 Updated Balance**
Prior to July 31, 2002	$(7.43)	$(7.42)
2000/01 Capital tax	0.63	0.63
2001/02 Capital tax	0.23	0.23
2002/03 Balances		
Supplemental gas	9.33	12.66
Transportation	(2.37)	(3.04)
Distribution	1.14	1.10
Heat value margin	(0.67)	(0.69)
2003/04 capacity management revenue	(3.00)	(3.00)
Total at March 31, 2003	(2.14)	0.47
Carrying costs to July 31, 2003	0.06	0.09
Existing rate rider amortization to July 31, 2003	4.20	5.04
Total July 31, 2003 balance	$2.12	$5.60

An existing rate rider that was initiated August 1, 2001 to recover approximately $104.0 million over 24 months is to be removed after July 31, 2003. Centra estimates that the residual in this account balance will be approximately $1.9 million owing to Centra. This matter will be dealt with by the Board in conjunction with the August 1, 2003 Primary Gas Rate Application.

Centra has requested the recovery of Capital Tax and carrying charges of $633,062 for 2000/01 and $231,225 for 2001/02. The additional Capital Tax was attributable to additional debt incurred by Centra to finance gas purchases, which resulted in a build up of the PGVA to over

$120.2 million in 2000/01 and $44.5 million in 2001/02 due to unexpected increase in natural gas prices in those years.

Centra's capacity management program remains unchanged from that employed over the last number of years. It is designed to mitigate the gas costs related to supply, storage and transportation assets used to serve the Manitoba market. Centra's first priority is to ensure that the requirements of the customers are satisfied before any capacity management transactions are considered. This, and the fact that there are a number of variables outside the control of Centra, influence the revenue generated. In 2002/03, capacity management revenues were $5.4 million. Centra is forecasting revenues of $3.0 million for 2003/04 and this amount forms a part of the 2002/03 deferral accounts. Centra stated that the $5.4 million was the second highest revenue generated by the program since its inception, and the $3.0 million included in 2003/04 Revenue Requirement is a more appropriate amount based on past experience.

8.2.1 Intervenor Positions

CAC/MSOS opposed Centra's request to create a Capital Tax deferral account in the amount of $880,000 for the following reasons:

- Centra was using a judgmental derivatives strategy. That decision resulted in Centra not placing derivatives for certain months that resulted in gas costs that were much higher than they would have been had the derivatives been placed.
- Centra shouldn't be allowed to collect in this retroactive manner since Centra chose to abandon its 2001 GRA. CAC/MSOS' position is that when a utility waits five years for a GRA, there are going to be numerous examples of pluses and minuses with respect to the collection for various items.

CAC/MSOS also recommended the Board direct Centra to include $5.4 million in forecast capacity management revenues for 2003/04, since that amount was realized in 2002/03. CAC/MSOS submitted that this would give Centra incentive to maximize such revenues. If revenues of $5.4 million were not realized, the difference would be captured in a deferral account for future disposition. CAC/MSOS was hopeful that the issue of unutilized capacity charges would be addressed in the forthcoming Blank Page Analysis Report.

8.2.2 Board Findings

The Board will require Centra to recalculate rate riders required to recover July 31, 2003 deferral account balances of $5.6 million, including the capital tax deferral accounts, as submitted in the June 3, 2003 update. The Board remains of the view that, as these costs are known, the recovery using forecast normalized volumes is appropriate and necessary.

The Board notes the significant run up in the cost of gas and PGVA balances during 2000/01 and 2001/02 and that Centra purchases gas on a flow through basis at cost. The build up in the PGVA at that time was unprecedented given the very high natural gas prices, resulting in Centra incurring higher than normal debt to finance gas purchases. Accordingly the Board will allow in this instance only, the recovery of the capital tax and related carrying cost for 2000/01 and 2001/02 as applied for by Centra. The Board further notes that the cost of gas mechanism which now allows for the full recovery of the build up in the PGVA quarterly through a rate rider should ensure the PGVA does not build up to levels experienced in 2000/01 and 2001/02. Accordingly the Board believes that capital tax should not be impacted to any great extent in the future because of PGVA balances. Therefore, the Board expects that, except for the one-time recovery of capital tax balances discussed above, deferral accounts for future capital tax differences will not be required.

The Board will also approve Centra's forecast 2003/04 capacity management revenue of $3.0 million. The Board notes that this amount has been included over the past several years and represents a reasonable estimate of revenues realized. On the other hand, the $5.4 million is the second highest revenue ever realized from this program, and may not be representative of the 2003/04 forecasted amount.

8.3 2003/04 Forecast Customers and Volumes

Centra's forecasts for 2003/04 SGC and LGC gas requirements utilize actual number of customers and volumes for the 2001/02 year, and the use of regression analysis that relates customer growth to change in real domestic product for 2002/03 and 2003/04. Average use forecasts, using 2001/02 as the base, were also projected by regression analysis and conservation effects related to greater use of higher efficiency gas burning appliances, for both heat loss and non-weather sensitive load. In addition to the introduction of the regression analysis to predict customers and average use, Centra also refined the existing method by employing the monthly average use and customer estimates, as opposed to using the average annual use and average annual customers. System supply load forecasts were determined by estimating and removing WTS volumes from total loads to determine system supply volumes. These are the only changes from the method used by Centra for the 2002/03 cost of gas forecasts.

Forecasts for larger volume customer classes were forecast by using three years of historic monthly sales information and reviewing company specific information as necessary to analyze significant consumption variances.

After estimating sales volumes, Centra added an UFG factor of 0.952% to arrive at is forecast purchase volume requirements. The UFG factor has been updated to reflect the three-year average ended in September 2002. This approach, in the Board's view, is reasonable.

The following table illustrates Centra's forecasts for number of customers based on the revised methodology, and shows the changes from 2001/02 actual results.

Customer Class	2001/02 Actual	2003/04 Projected	Estimated Increase
SGC – Residential	223,936	227,480	3,544
SGC – Commercial	15,275	15,907	632
LGC	8,443	8,651	208
HVF	90	96	6
Mainline	8	10	2
Co-op	0	1	1
Power Station	0	2	2
Special Contract	1	1	0
Interruptible	62	56	(6)
Total	247,815	252,204	4,389

The following table illustrates Centra's forecasts for normalized purchase volumes, expressed in thousands of cubic metres, based on the revised methodology, and shows the changes from 2001/02 actual results.

Customer Class	2001/02 Actual	2003/04 Projected	Estimated Increase
SGC- Residential	676,912	683,196	6,284
SGC – Commercial	87,918	91,933	4,015
LGC	528,741	541,522	12,781
HVF	117,120	153,205	36,085
Mainline	95,981	222,714	126,733
Co-op	0	0	0
Power Station	0	0	0
Special Contract	426,226	461,559	35,333
Interruptible	161,402	145,829	(15,573)
Total	2,094,300	2,299,958	205,658

Centra also estimated WTS customers, average use and volumes for 2003/04 to arrive at its system supply requirements.

8.3.1 Intervenor Positions

No Intervenors took a position on this matter.

8.3.2 Board Findings

The Board accepts Centra's use of regression analyses for forecasting annual customer growth and sales volumes. The Board will expect Centra to track the effectiveness of the forecasts by providing a comparison of the estimated values with actual results in future GRAs.

8.4 2003/04 Gas Cost Forecast

Centra's estimate for 2003/04 non-primary cost of gas is $90.3 million based on the April 9, 2003 forward price strip for commodity costs. This consists of $55.0 million in fixed costs, $12.7 million in variable transportation costs, $21.2 million in supplemental supply costs, $0.7 million for delivered service and $0.7 million in other costs. In addition to the forecast commodity costs, estimates are based on terms and conditions and pricing structures contained in Centra's supply contract with Nexen, its various existing transportation and storage arrangements and current NEB and FERC tolls. Differences between estimated and actual 2003/04 costs will accumulate in the appropriate deferral accounts commencing April 1, 2003.

8.4.1 Intervenor Positions

CAC/MSOS recommended that Centra continue in its efforts to reduce load-balancing charges expected to amount to $465,420 for 2002/03. CAC/MSOS requested the Board to require Centra to reduce the charges to be included in the forecast cost of gas for 2003/04 by about $250,000, noting that if actual results were different, the deferral account would capture this difference.

8.4.2 Board Findings

The Board continues to rely on the most current futures commodity market information to establish sales rates for natural gas. To this end, the Board requested Centra to file an updated forward price strip after the hearing that would provide an indication of more recent gas price trends. Centra filed this material on June 26, 2003. Centra's updated application utilized gas cost forecasts based on an April 9, 2003 strip that averaged $6.578 per Gj. In the June 26, 2003 communication, Centra submitted the following data respecting forecast average gas costs based on several price strip-closing dates:

Date	**Unit Cost $/Gj**
April 9, 2003	$6.578
June 9, 2003	7.208
June 18, 2003	6.539
June 24, 2003	6.753

The Board is aware of the current high degree of volatility in the futures market, as evidenced by the above data. The prices cited above are for gas supply out of Western Canada, related to Primary Gas, and can only serve as an indicator of pricing trends for supplemental gas, which constitute a small percentage of Centra's overall gas commodity costs. Costs of other non-primary components are transportation tolls as established by the NEB and storage and related transportation charges and tolls regulated by FERC. These charges are those currently in effect, and are not significantly impacted by commodity futures forecast gas prices.

Any differences between non-primary gas costs embedded in August 1, 2003 rates and actual 2003/04 gas costs will accumulate in the 2003/04 deferral accounts commencing April 1, 2003 and will be dealt with by the Board at the next cost of gas proceeding. Therefore, given the demonstrated volatility in gas prices, the materiality of any change in supplemental gas unit prices, and the existence of the deferral accounts, the Board will approve rates that include forecast 2003/04 non-primary costs of gas based on Centra's May 1, 2003 update filing utilizing an April 9, 2003 forward price strip.

8.5 Gas Supply Management and Portfolio

8.5.1 Centra's Long-Term Gas Supply and Transportation Contracts

In August 2002, Centra was requested to agree to the assignment of Centra's long-term supply contract with Mirant Canada Inc. ("Mirant) to Nexen Marketing ("Nexen"), a division of Nexen Canada Limited. Pursuant to the precedent contract, Centra could not withhold agreement unless it had reasonable grounds to do so. After conducting an internal due diligence review, Centra concluded that Nexen was a substantive company and has a high financial rating.

Centra stated that Nexen has fulfilled its contractual obligations to date in a fully satisfactory manner. Centra further indicated that there were no outstanding obligations or contingent liabilities owing from Mirant, nor were there any owing from Centra. None of the terms and conditions included in the Mirant contract were altered as a result of this assignment.

There are no changes to Centra's management of its daily gas supply operations, other than the assignment of the Nexen contact. The portfolio mix to meet the design peak day is unchanged from that estimated last year.

8.5.2 Gas Supply Portfolio Analysis

International Gas Consulting ("IGC") submitted a draft report on May 26, 2003 reviewing the optimization of Centra's overall gas supply portfolio. This review also referred to as the Blank Page Analysis, was ordered by the Board in 1995, and was to determine the optimum portfolio mix having no regard to any existing supply or storage contract or any transportation arrangements.

At the time of the hearing, Centra had not yet reviewed the report and proposed that the report not be filed with the Board until it was considered by Centra's Board of Directors in August 2003. Centra submitted that it would serve no useful purpose to file the draft report without Centra having adopted its position. Centra proposed that the matter be dealt with at the next application for an adjustment to its non-primary gas rates or at some other time as the Board may direct.

Centra assured the Board that the proposed timetable would not negatively impact Centra's ability to service its customers after October 31, 2004. Centra stated that in addition to the supply contracts that are to expire on October 31, 2004, existing TCPL transportation arrangements will also expire on that date. Centra's exiting storage and related transportation arrangements continue until 2011.

8.5.3 Intervenor Positions

With respect to gas supply delivery terms and conditions, Municipal stated that currently, customers, except for the SGC customers, are entitled to Transportation Service offering, and all customer classes are eligible for WTS. Municipal stated that the WTS offering contains several operational limitations. Centra establishes the maximum daily quantity, controls daily nominations, frequency of enrolment of WTS customers and the reduction of daily nominations of direct purchase gas. While Agents, Brokers and Marketers ("ABMs") are able to bid to supply supplemental gas to Centra, ABMs cannot negotiate for supplemental supply on behalf of the ABM's customers.

Municipal pointed out that within 18 months, Centra would be required to renegotiate or obtain its new gas supply and transportation arrangements with TCPL, and review and perhaps implement recommendations arising out of the Blank Page Analysis. Municipal urged the Board to require Centra to consult with ABMs prior to making any decisions on those matters. Municipal contended that this was vital to ensure a competitive market and level playing field.

Municipal expressed a degree of frustration concerning the extent of past communications with Centra on ABM related matters. In summary, Municipal recommended that the Board direct Centra to file the Blank Page Analysis once the technical review had been completed, before it is considered by Centra's Internal Task Force. Additionally, Municipal suggested that Centra be directed to consult with the ABMs before recommendations are made by Centra. Further, in reviewing the prudence of the gas supply portfolio, the Board ought to consider the impacts on the competitive market, prejudices contained in the terms and conditions of gas supply, impact on open access, and consideration of ABMs suggested delivery options as factors.

Municipal also recommended the Board advise Centra that if Centra failed to consult with interested parties in this matter, the Board would consider penalizing Centra by reducing its allowed Return on Equity in the next rate proceeding.

CAC/MSOS recounted the history of the Blank Page Report issue, and stated that the report is long overdue. CAC/MSOS submitted that the review of the report should be conducted in a public forum to which all interested parties have apparently agreed. CAC/MSOS stated that the sooner the report was put into the public domain, the better for all concerned. CAC/MSOS suggested that the proper time to release the report would be when it was submitted to the Executive Committee. CAC/MSOS submitted a proposed timetable for the process, commencing with Centra's filing of the report on July 14, 2003 and a public hearing to commence as soon as possible after the filing. The timetable allowed for a round of information requests and responses, filing of Intervenor Evidence and information requests of the Intervenors.

8.5.4 Board Findings

The Board recognizes that under the terms and conditions of the original long-term gas supply contract with TransCanada Gas Services subsequently assigned to Mirant. Centra is obliged to agree to a transfer of the contract unless it can demonstrate that doing so would be detrimental to

Centra. The Board considers that Nexen enjoys favourable financial circumstances and has not violated any terms of the contract to date. The Board finds Centra's actions in this regard to be prudent and reasonable.

The Board has considered the position put forward by Municipal Gas in respect of terms and conditions related to WTS, issues of open access to the system in the future and the matter of the Blank Page Analysis. The Board urges Centra to involve all stakeholders in the upcoming review of all aspects of Centra's gas supply, including commodity, storage and transportation arrangements. The Board encourages the development of a competitive gas supply market in Manitoba, and all parties should consider this factor in their deliberations. The Board also recognizes that Centra must, first and foremost, satisfy itself that all Manitoba consumers have access to an appropriate and efficient overall gas supply portfolio. As the supplier of last resort, Centra must have the flexibility in its various arrangements to ensure a competitive market while fulfilling its obligations.

The Board shares the frustrations of the Intervenors with respect to the delay in the preparation and filing of the long awaited Blank Page Analysis. The Board is anxious to review the report and notes that all parties have agreed that this review be conducted in a public forum as soon as possible. The Board notes that Centra anticipates the report to be filed with Centra's Board in August 2003. The Board sees little benefit in ordering Centra to file the report prior to review and approval by Centra's Board of Directors. The Board understands that this review will take place in August, and that the report will be filed with the Board by no later than August 31, 2003. The Board will expect the filing to include the consultants report and recommendations, and a summary of changes proposed to those recommendations by Centra. The Board will review the report in a public forum. The Board will expect Centra to file a proposed timetable for the review when it files the report in August.

8.6 Derivative Hedging

8.6.1 Overall Strategy and Policy

Centra's derivative hedging policy for primary gas and related operating principles and procedures have been amended. Two significant changes to the policy are:

1. The objective of the policy is to mitigate gas price volatility to customers.
2. To increase the hedge coverage from 50% to 90% of warmest year volumes.

Centra's Derivative Hedging Policy for Primary Gas states that "Centra will mitigate natural gas price volatility to customers through the use of derivative products restricted to price swaps, call options, and cashless collars. At a minimum, Centra will have hedges in place for 90% of eligible (i.e., warmest year) volumes for the future nine months. Prior to the end of each quarter, Centra will hedge a minimum of 90% of eligible volumes for the fourth quarter forward, that being months 10, 11, and 12."

In accordance with the revised derivative hedging policy, the circumstances under which derivatives will be placed are as follows:

1. Volatility will be mitigated through the use of a mechanistic hedging implementation strategy that is not subject to any discretion associated with current price levels or directional market views;
2. The timing of the hedge transaction and the magnitude of the hedge are automated; and
3. The instruments that may be used are restricted to swaps, caps, and collars.

Centra's objective is to mitigate price volatility to customers by the use of cashless collars with the cap set at $0.50 out of the money. Competitive market quotes are obtained from different counterparties to obtain the floor with the lowest strike price that can be achieved in combination with the $0.50 ceiling. All counterparties are A-rated financial institutions approved by the Minister of Finance.

8.6.2 Mechanistic vs. Judgmental Oversight of Policy Execution

The mechanistic hedging approach involves an automatic implementation strategy that is not subject to any discretion associated with market views. The decisions around the timing of the hedge transaction, the magnitude of the hedge and the type of instrument to be used are all automated. The strategy is not influenced by current market price levels or by directional market views. The judgmental hedging implementation strategy, on the other hand, allows for the inclusion of market directional views in the decision-making process.

The change in policy to a mechanistic approach recognizes that Centra does not have the resources to accurately predict market price movements as price volatility is attributable to a wide variety of factors. Since December 2001 Centra has essentially used a mechanistic approach and has hedged 90% of all eligible volumes.

8.6.3 RiskAdvisory Report

RiskAdvisory was retained by Centra to conduct an external assessment of the staff involved in all aspects of the Centra Derivative Hedging Program for Primary Gas. In his report, Mr. Simard stated that the mechanistic approach is appropriate for organizations with the following characteristics:

- The objective of the risk management activity is to lower volatility. The objective is not to lower costs;
- The organization does not believe it has a competitive advantage with respect to outforecasting future market prices. This suggests that there is a belief that current forward market prices represent the best estimate available of future spot market prices;
- The organization is risk adverse with respect to the actual results of the hedging program.

On the other hand, the judgmental approach is appropriate for organizations with the following characteristics:

- The hedging program has dual objectives to lower both volatility and costs;
- The organization believes it has a competitive advantage with respect to forecasting future prices;
- The organization is willing to take risk with respect to the actual results of the hedging program being markedly different from the expected results of the hedging program;
- The organization is willing to make significant oversight of the market view-driven implementation.

The staff assessment performed by RiskAdvisory reached the following conclusions:

- If Centra follows a mechanistic hedge implementation approach with inclusion of a directional market view component, all of the groups that come into contact with the risk management program currently have the requisite skill sets to perform their functions.
- In most areas, Centra and Hydro do not possess the requisite skills to implement and monitor a judgmental risk management program that permits discretion in the establishment of hedge positions based on market price views. There is no indication that any group within Centra possesses a competitive informational advantage or trading expertise to outperform the mechanistic approach over the long-run.
- RiskAdvisory believes that maintaining the existing set of skills and the adoption of a mechanistic approach is the most appropriate strategy for Centra's Derivative Hedging Program for Primary Gas. It is unrealistic to assume that a regulated utility can or should possess the expensive and base skills required to ensure out performance over the long run through the exercise of directional market views. The sole objective of mitigating ratepayer volatility can be achieved through the mechanistic approach without resorting to subjective and risky market views.

8.6.4 Hedging Results/Costs of Program

Centra has placed derivatives throughout the 2002/03 gas year and into the 2003/04 gas year. Since January 2002 all derivatives placed have been cashless collars and throughout this period, 90% of all eligible volumes have been hedged, representing just over 60% of all gas volumes.

Schedule 8.2.0, filed at the hearing, set out the individual derivative transactions and the results, and indicated the extreme market volatility, with settlement prices ranging from $2.62/Gj to $9.60/Gj within a 12-month period. As a result of hedging activities, gas costs for the 2002/03 gas year are $15.5 million lower than they would have been.

Since the June 2003 gas month Centra has continued to place derivatives, but these subsequent price results have not yet been reviewed by the Board in this hearing, since they remain unfinalized.

Centra stated it will be conducting new market research this fall. The research will be used to reassess customers' risk tolerance and the appropriateness of the out of the money band. Once the research has been completed Centra will develop performance measures on how the program has met customers expectations with respect to bill volatility.

Centra submitted that Mr. Simard's evidence be given significant consideration by the Board. Mr. Simard strongly disagreed with CAC/MSOS that Centra's Derivative Hedging Policy should be put on hold until the updated customer research is completed. Mr. Simard expressed his view that such an approach would place Centra in an untenable position and that Centra should be allowed to proceed with the best data currently available.

8.6.5 Intervenor Positions

CAC/MSOS cannot endorse Centra's new mechanistic strategy because there was no evidence presented at the hearing to demonstrate that the formula selected is the most appropriate one to restrain bill volatility within customer tolerance levels. Centra must update its market research to determine current customer tolerances, and then establish the formula.

CAC/MSOS stated that Centra should not take a judgmental approach when executing derivative transactions. CAC/MSOS stated the mechanistic approach is less adaptive to changing conditions and opportunities and discretion and judgment cannot completely be eliminated from the program. CAC/MSOS noted that if Centra utilized a formula, it should retain the skills and knowledge to recognize when discretion will be necessary. According to CAC/MSOS, Centra is under-funding training for derivatives hedging activities. CAC/MSOS also suggested that the Board consider allowing Centra to provide different pricing options to customers.

8.6.6 Board Findings

The Board will approve the results from Centra's derivative hedging transactions that settled during 20002/03. The Board is of the view that Centra complied with policies and procedures in placing derivative transactions.

The Board accepts the findings in the RiskAdvisory Report and is of the view that a mechanistic approach is an appropriate hedging strategy, given the risk management skills within Centra. The Board however remains concerned, and recommends that Centra remain diligent in ensuring the appropriate resources with the required skills are retained within Centra.

The Board considers the objective of mitigating price volatility to be acceptable and appropriate for a utility in the current market of ever changing and fluctuating gas prices. Futhermore, the ability of a utility to outperform the market and thereby lower gas costs, is remote and fraught with risk. Such a risk is unacceptable for the ratepayers, and likely also for Centra.

The Board notes Centra will be updating its market research on customers' expectations related to bill volatility. The results of that research may require a change in the hedging strategy and performance measures on which the program results can be evaluated. Accordingly the Board will expect Centra to file any required update to its hedging policy incorporating the new research at the next annual Cost of Gas hearing.

The Board heard evidence on the lack of liquidity within the market that may hinder the effective execution of the hedging policy. Mr. Simard proposed that judgment should be exercised within the mechanistic approach to address liquidity concerns. The Board further notes that Centra may encounter liquidity problems because of the large volumes transacted on Centra's chosen dates. Accordingly the Board urges Centra to apply judgment related to assessing the liquidity in the market and if Centra determines that there is concern about the liquidity in the marketplace, consider transacting in tranches.

The Board will approve the Hedging Policies and Procedures as filed. The Board will expect Centra to file any changes that may be required to address liquidity concerns and any information from the updated market research, as soon as practical.

9.0 Cost of Operations

9.1 Application

Centra's application included cost of operations of $49.3 million, compared to $48.6 million last approved in 1998, as follows:

Cost of Operations by Business Unit
(In $ Millions)

	1998 *Approved*	**1999/00 Actual (15 mos.)**	**2000/01 Actual**	**2001/02 Historical**	**2002/03 Bridge Year**	**2003/04 Test Year**
Pre 2001 Accounting						
Operations	20.1	$ 24.9	$ 15.4	$ -	$ -	$ -
Finance & Gas Supply	3.4	3.7	2.2	-	-	-
Customer Accounting & IS &T	12.4	18.0	10.5	-	-	-
Business Relations	4.5	6.2	3.0	-	-	-
Human Resources & Administration	11.2	14.0	7.9	-	-	-
Legal & Executive	2.8	4.8	0.3	-	-	-
Post 2001 Accounting				-	-	-
Integrated Operations:(New)	-	-	13.1			
President & CEO	-	-	-	1.2	1.0	1.0
Finance & Administration	-	-	-	11.8	9.6	8.9
Transmission & Distribution	-	-	-	5.4	5.8	6.0
Power Supply	-	-	-	0.1	0.2	0.2
Customer Service & Marketing	-	-	-	38.0	37.3	38.2
Corporate Allocations & Adjustments	-	-	-	1.3	1.2	1.4
Program View - Cost of Operations	54.4	71.7	52.4	57.8	55.1	55.7
Adjustments	(5.8)	(4.8)	(2.1)			
Depreciation, Interest, Taxes	-	-	-	(6.9)	(6.1)	(6.4)
Cost of Operations Centra	48.6	66.9	50.3	50.9	48.9	49.3
Synergy Transfer	-	-	(6.3)	(5.1)	(4.6)	-
Cost of Operations	$ 48.6	$ 66.9	$ 44.0	$ 45.8	$ 44.4	$ 49.3

Centra's operations have been integrated into Hydro's business units of President and CEO, Finance and Administration, Power Supply, Transmission and Distribution, and Customer Service and Marketing. To establish an overall target for its Cost of Operations, Hydro takes into account economic conditions, changing business requirements, and items impacting the current year such as wage settlements, accounting changes, and productivity improvements. The overall target is then apportioned into targets for each of the business units and then for the gas and electric utilities.

9.2 Allocation of Costs Between Utilities

To take advantage of all possible synergies, Hydro has integrated the gas and electric operations by adopting an integrated accounting methodology. The allocation process provides a fair and equitable allocation to each of the gas and electric operations, meets the business needs, both internal and external, of each utility, and is consistent for both gas and electric operations. The resultant methodology is based on full absorption costing principles.

Because of the significant changes of Centra's accounting system since the last GRA, Centra is unable to present certain components of its cost of operations in the same format as previous GRAs. The Board examined the accounting system that allocates individual costs between Centra and its parent, Hydro, as set out in Order 208/02, in which the methodology was approved.

As evidenced in the above table, Centra's cost of operating prior to and subsequent to the new accounting method are not comparable. Centra is now accounting for costs by function and business unit.

Activity charges form the basis for cost allocation to the gas and electric utilities. Activity charges are based on the time spent performing capital, operating and administrative, and supportive functions within the company and are calculated by multiplying hours spent by activity rates that are designed to cover groups of like costs within specific resource centres. Primary costs incurred specifically by Centra for its gas operations are allocated exclusively to Centra. Administrative and general overhead costs that cannot be specifically connected with either gas or electric operations are treated as common overhead. The following table provides the breakdown of the cost of operations:

Operating Costs **($millions)**	**2001/02**	**2002/03**	**2003/04**
Activity Charges by Business Unit			
President and CEO	0.2	0.2	0.2
Finance and Administration	4.5	5.3	4.8
Transmission and Distribution	3.1	3.4	3.7
Power Supply	0.1	0.1	0.1
Customer Service and Marketing	24.5	25.1	25.4
Total Activity Charges	32.4	34.1	34.2
Primary costs	13.0	9.9	10.1
Overhead	11.1	9.9	10.0
Corporate allocations and adjustments	1.3	1.2	1.4
Total Program Costs	57.8	55.1	55.7
Depreciation, interest and taxes	(6.9)	(6.1)	(6.4)
Synergy transfer	(5.1)	(4.6)	-
Cost of Operations	$45.8	$44.4	$49.3

9.3 Intervenor Positions

CAC/MSOS' view, as supported by Mr. Matwichuk's evidence, is that Centra's baseline and synergy estimates are overstated. CAC/MSOS stated that the Board must look at actual costs incurred to run the gas company in order to determine if the forecast for the test year is reasonable. However, CAC/MSOS believes the Board will have difficulty with that endeavour due to Centra's change in cost allocation methodology.

Mr. Matwichuk calculated cost of operations by taking the 1998 approved balance and adjusting for inflation and efficiencies. Mr. Matwichuk's calculation derived a balance of $52.1 million. This amount was also used to calculate Centra's synergy benefit/transfer as discussed in a later section.

Mr. Todd, on behalf of CAC/MSOS, suggested that the Board cannot assess the reasonableness of Centra's operating costs without looking at the total operating costs of the combined Hydro and Centra entity. Mr. Todd suggested that in the future, a revised regulatory process may be appropriate that would include a phase to review the total costs of the combined entity, and a separate phase to then review the allocation of those costs between the gas and electric utilities. Mr. Todd's proposal of suggested changes to the regulatory models are discussed in Section 20 of this Order.

CAC/MSOS noted that an important operating cost benchmark that regulators have used in the past has been cost per customer. Mr. Matwichuk's evidence noted that Centra was able to keep its average cost per customer relatively flat from 1993 to 1998, near the $200 per customer level. Mr. Matwichuk noted that while total cost of operations may increase over the years, the average cost per customer can remain flat. CAC/MSOS reviewed the average cost per customer of approximately $200 from 1995 to 1998. It noted when one added the synergy transfer amount of $7.1 million to the cost of operations of $49.3 million, Centra's cost per customer for the 2003/04 Test Year is $221.86, which is out of line with Centra's historical trends.

CAC/MSOS stated that the cost of operations of $49.3 million was only reasonable if there was no synergy benefit transfer. CAC/MSOS therefore suggested that no synergy benefit transfer be allowed and the Revenue Requirement be reduced by the synergy transfer amount of $7.1 million.

9.4 Board Findings

Mr. Todd's arguments regarding a review of operating costs and suggested changes to the regulatory model are discussed in Section 20 of this Order.

The Board does not fully accept the arguments put forward by Mr. Matwichuk regarding benchmarking and cost per customer requirements. The Board believes that operating costs components vary considerably by utility and as a result, inter-utility cost per customer measurements and comparisons must be used with a great deal of caution.

The Board will approve Centra's cost of operations of $49.3 million for 2003/04. The Board is satisfied that the accounting cost allocation methodology provides a fair allocation of operating and capital costs to Centra. The change in accounting requires a leap of faith in that there is a lack of comparability between how costs were presented in 1998 versus the current application. However, the Board's concern is tempered by the fact that on an overall basis, the projected 2003/04 cost of operations is not significantly higher than that approved in 1998, which is partly attributable to planned synergies subsequent to the acquisition of Centra by Hydro.

The Board notes that the $49.3 million in cost of operations for 2003/04 will represent a baseline from which future applications will be measured, which will allow the Board to review cost of operations by activity and function on a comparative basis.

10.0 Other Expenses

10.1 Amortization Expense

Amortization expense for 2003/04 Test Year is $3.5 million, which is an increase of $0.7 million over the 1998 approved amount of $2.8 million. The 2003/04 Test Year amount includes amortization of deferred charges, many related to past regulatory hearings.

Deferred charges are normally amortized over periods of one to five years and include the costs and the carrying costs associated with various public hearings, special studies, decommissioning of plant assets and bad debt deferral accounts.

Included in the amortization expense were costs incurred by Centra for the Western Transportation Service and Agency Billing and Collection Service, including fees paid to Navigant Consultants Inc. ("Navigant"). Navigant provided services for project management and the development and assistance with the preparation of Centra's application, the information request process, the stakeholder process, testifying at the hearing, and working with Centra to implement the services after receipt of the Board's Order. Centra stated the whole process from development to implementation spanned a year and a half. Centra credits the success of the stakeholder process and the short duration of the hearing to the excellent work that Navigant performed. Centra submitted that these costs are appropriate and should be allowed.

10.2 Depreciation Rates, Methodology and Expense

Total depreciation expense is forecasted to be approximately $15.2 million for the 2003/04 Test Year, which is an increase of $2.1 million over the 1998 approved amount of $13.1 million. Increases in depreciation expense reflect the impacts of increased capital investment, partially offset by a reduction in depreciation rates resulting from the depreciation study which was completed in August 2002.

The Board last approved depreciation rates in 1995 based on an update to a 1989 depreciation study. Centra's application requests approval of new depreciation rates, based on an updated depreciation study, to be effective April 1, 2002 when the new rates were adopted by Centra. The application is also seeking approval to change the depreciation calculation methodology such that all depreciation expense is calculated based on the previous month-end balances of plant assets in service. Finally, Centra is requesting that amortization accounting be used for certain plant asset categories, including office furniture and equipment, computer equipment, transportation equipment, tools and work equipment, and other general equipment. Centra believes this is appropriate because it will allow for more efficient plant accounting procedures, while at the same time providing for items which are individually inexpensive and difficult to track, and for which retirement orders are often not prepared.

The following table summarizes the financial impacts of adopting the proposed depreciation rates, based on March 2001 year-end plant balances.

Category **($000s)**	**Previous Depreciation**	**Proposed Depreciation**	**Change in Depreciation**
Intangible	$ 13.3	$ 13.3	$ 0.0
Transmission	1,122.6	925.3	(197.3)
Distribution	10,278.3	7,855.9	(2,422.4)
General	2,816.3	3,016.0	199.7
	$14,230.5	$11,810.5	$(2,420.0)

10.3 Municipal and Other Taxes

Centra's application for the 2003/04 Test Year includes $15.8 million to be included in Revenue Requirement for Municipal and Other Taxes, compared to $14.4 million in the 1998 Approved Year. This includes Municipal Taxes, Taxes on Common Assets, Corporation Capital Tax, and Business Tax.

Municipal and Other Taxes applied for in 2003/04 compared to 1998 allowed as follows:

	1998 Approved	**2003/04 Test Year**
Municipal taxes	$13.0	$13.5
Taxes on common assets	-	(0.1)
Corporation capital tax	1.3	2.3
Business tax	0.1	0.1
Total ($ millions)	$14.4	$15.8

Centra continues to pay Municipal Taxes in the same manner as was in place prior to the acquisition by Hydro. Unlike Hydro, Centra does not pay these property based tax amounts in the form of Grants in Lieu of Tax. Centra is estimating a 4% increase in property tax in 2003/04 compared to the prior year. Since 1998, Municipal Taxes have increased by an average of 2.8% annually.

Centra continues to be taxable under the Corporations Capital Tax Act after its acquisition by Hydro and continues to determine that amount of tax payable in accordance with the Act. The increase in capital tax since 1998 is due to the increased debt and equity in the company.

10.4 Intervenor Positions

CAC/MSOS stated that amortization in the amount of $363,800 should be disallowed in its entirety as it relates to fees charged by Navigant for the hearing held in October 1999. CAC/MSOS stated these costs cannot be justified on a prudent basis as having been reasonably expended. According to CAC/MSOS, Navigant's fees totalled $1,245,400. CAC/MSOS stated that there is no way to gauge the work performed by Navigant. There is no documentation, contracts or quotes to assess the prudency of these expenditures. CAC/MSOS stated that this is an example of run away costs of a consultant not asked for a quote.

10.5 Board Findings

The Board will approve the Amortization Expense, Depreciation Expense and Municipal and Other Taxes for 2003/04 as filed, subject to other required adjustments resulting from this Order.

The Board will also approve the new depreciation rates in effect since April 1, 2002 and the changes in depreciation methodology as applied for. In the future, the Board would prefer such proposals for changes in depreciation rates and similar matters to be requested on a prospective basis, so as to not require a retroactive application.

The Board does not agree with the argument put forward by CAC/MSOS regarding the disallowance of the Navigant fees. However, the Board strongly encourages Centra to be more diligent in ensuring that proper documentation is in place for future major contracts and that those contracts are carefully monitored.

11.0 Income Taxes

11.1 History

As a result of the acquisition of Centra by Hydro in July 1999, Centra is no longer subject to either federal or provincial income taxes. Under the Income Tax Act of Canada, the conversion of Centra to a non-taxable entity resulted in a deemed disposition of all assets. This deemed disposition resulted in a one-time income tax liability of $58.25 million. At the acquisition hearing Hydro had indicated that it would apply the full amount of income taxes currently in sales rates of approximately $11 million against the one-time tax liability and carrying costs to extinguish the obligation within approximately seven to eight years.

In early 2001 the Province released Centra of any obligation to pay the provincial tax otherwise payable. As a result, Centra began to amortize the one-time income tax liability over a 30-year period, on the same basis as other acquisition expenses.

The Board heard the evidence of Centra on this matter at the Integration update hearing and, in Order 208/02, directed Centra to apply the full amount currently included in sales rates for income taxes of approximately $11 million each year, to fully extinguish the one-time tax related debt and carrying costs as quickly as possible.

11.2 Request to Vary Order 208/02

In a letter to the Board dated December 31, 2002, Centra made a request to vary the above decision in Order 208/02. Centra stated "The requirement to charge customers $11 million per year in hypothetical taxes in order to pay down debt associated with the transfer tax of $58 million, if implemented in isolation, would cause additional increases to customer rates and negate a policy decision explicitly taken by Centra's Board of Directors, consistent with a policy decision of government not to extract equivalent income taxes from Centra." Furthermore, the 30-year amortization period was deemed by Centra to be more appropriate, because it was on a consistent basis as the period used to amortize other acquisition costs of Centra. On this basis, Centra requested the Board to reconsider its directive to allow the 30-year amortization period for acquisition taxes.

11.3 Inclusion in Rate Base

Centra has included the one-time tax payment, net of accumulated amortization, in Rate Base in the amount of $46.0 million for the 2003/04 Test Year. Centra believes the one-time tax liability should be included in Rate Base because it was a payment made as a result of the utility's change to a non-taxable status. This created a long-term benefit to the customers of Centra, as rates are lowered by the income taxes that are on longer required to be paid.

While this payment is a result of the acquisition, it has not been transferred to Hydro because Centra was required to make the payment. As well, Centra customers will realize the benefits of the non-taxable status. Therefore Centra believes that its customers should bear the associated cost. Centra further stated that if the amount was not included in Rate Base, but rather in a deferral account, it should attract carrying costs at the overall rate of return rather than the short-term rate, as is the case with the Propane Storage Tank deferral account, since the liability is being financed with long-term debt.

11.4 Intervenor Positions

Mr. Matwichuk, on behalf of CAC/MSOS, took exception to Centra's proposal and suggested that the amount should be treated in a manner similar to other deferral accounts. Furthermore Centra should be allowed carrying costs at a rate less than that of the overall rate of return.

CAC/MSOS stated that the one-time tax payment does not fall under the definition in Section 112 of The Public Utilities Board Act, and therefore is not a Rate Base asset. CAC/MSOS argued that even if a benefit were being conferred upon the ratepayer, that benefit does not accrue in full until the liability is paid off in full. CAC/MSOS argued that an income tax arrangement can never be construed as an asset for the purposes of earning an overall rate of return. It is an obligation payable at law which must be recouped from the ratepayer.

CAC/MSOS stated that the only issue is whether the one-time tax treatment should be paid off at a short-term or a long-term interest rate. CAC/MSOS noted the payment was not a short-term item and that long-term debt was dedicated for the purposes of making the payment, therefore it was appropriate that the long-term interest rate of 7.42% be charged for the purposes of the amortization period in paying down the liability. CAC/MSOS stated that this treatment would equal the amount that Centra is required to pay.

11.5 Board Findings

The Board will approve Centra's request to vary Order 208/02, and will allow for the amortization of the unamortized portion of the one-time tax liability over a 30-year amortization period. To do otherwise would have a significant upward impact on customer rates in the shorter term. However the Board is of view that the one-time tax liability should not be included in Rate Base. The Board is not convinced that the one-time tax liability is consistent with the pure definition of a Rate Base asset. Accordingly the Board will deny the inclusion of the unamortized balance of the one-time tax liability of $46 million in Rate Base. The unamortized balance of the one-time tax liability is to be included in a deferral account and attract carrying costs at the approved overall rate of return.

12.0 Synergy Benefit Transfer

12.1 Application

Centra requested a $7.1 million synergy benefit transfer be included in Revenue Requirement. Centra stated that this amount is necessary as a result of Order 208/02 in which the Board stated that the costs and benefits of the acquisition of Centra by Hydro should rest with the shareholders of Hydro. The Board directed Hydro, for regulatory purposes, to account for the acquisition and integration costs in the books and records of Hydro as opposed to Centra.

Centra originally applied for a total Cost of Operations expense of $46.1 million. In response to an interrogatory, Centra refiled tables and schedules to reflect the directives as set out in Order 208/02, but stated it was not seeking to amend their original application. Centra stated that pursuant to the directives in Order 208/02, the Cost of Operations was $56.4 million as a result of eliminating synergy savings of $10.3 million. This synergy savings amount was derived by taking the projected 2003/04 synergy saving of $15.3 million less the $5 million in synergy savings disallowed by the Board in Order 208/02.

Centra did amend its application on April 16, 2003, revising Cost of Operations to $49.3 million. This was derived from Centra's integrated cost allocation methodology and included a separate synergy benefit transfer of $7.1 million to be included in Revenue Requirement. Centra's requested synergy benefit transfer of $7.1 million was determined as follows:

Integration savings as presented at the Integration Hearing	$15.3
Less: Disallowed integration savings as ordered in Order 208/02 (including inflation)	(5.0)
Less: Synergies transferred from Hydro	(3.2)
Synergy Benefit Transfer	$7.1

Centra filed a schedule of costs incurred by Hydro resulting from compliance with Order 208/02, indicating that a cost of $20.9 million would be incurred annually over the next 30 years and that

Centra's equity component of Return on Rate Base, plus the $7.1 million synergy benefit transfer amount would adequately compensate Hydro for the costs resulting from the acquisition and integration of Centra.

12.2 Intervenor Positions

CAC/MSOS opposed Centra's proposal to include an annual synergy benefit payment of $7.1 million to Hydro. CAC/MSOS noted that Centra's plan, if approved, would result in Centra ratepayers paying more than $210 million to Hydro over the course of the next 30 years. CAC/MSOS stated the no-harm principle provides that the ratepayers of a utility that have been purchased by another should be at least no worse off as a result of the acquisition.

CAC/MSOS submitted that at the acquisition hearing, the Board and Intervenors were told that Centra only needed to realize $6 million in synergies from the acquisition to break even. Therefore it was not appropriate for Centra to transfer $7.1 million each year to pay Hydro for the acquisition, if the no-harm break-even point is only $6 million.

CAC/MSOS contended that the Board must decide what amount of eligible synergies have been or will be achieved in the test year. CAC/MSOS noted that at the Integration Hearing, Centra stated that as of September 1, 2001, $13.2 million in annualized synergies had been achieved, of which Order 208/02 excluded approximately $5.0 million, reducing the synergy savings to $8.7 million.

CAC/MSOS further noted that Centra had restated the synergy savings to be $10.3 million, a number arrived at by subtracting the $5.0 million in disallowed synergies from its most recent forecast of synergy savings for 2003/04 of $15.3 million. CAC/MSOS suggested that Centra has not provided any evidence that synergies had grown by $2.1 million from the $13.2 million level scrutinized at the Integration Hearing to $15.1 million.

CAC/MSOS stated that of the $8.7 million in synergies, not more than $2 million had been allocated to Centra, citing the evidence of Mr. Todd that any cost savings associated with combining operations would be reflected in lower activity rates and therefore the synergies are embedded in activity rates which are being allocated on a proportional basis between Hydro and Centra. Mr. Todd further stated that if both companies are equally efficient at the time of merger, then the distribution of synergies will depend on relative size of the companies. CAC/MSOS submitted that there was no evidence advanced in the hearing, or at the Integration Hearing, with respect as to the relative efficiencies or inefficiencies of Hydro or Centra. Accordingly, synergies should be allocated based on the relative size of the companies. As a result, not more than $2.0 million of synergies can be attributed to Centra operations based on the relative size of the two utilities.

12.3 Board Findings

The Board believes the no-harm principle is paramount, and that both Centra and Hydro ratepayers should, to the extent possible, be held harmless as a result of the decision by Hydro to acquire Centra. The Board also recognizes that since Hydro initiated the transaction, it should bear some risk relative to the transaction, particularly since Hydro's size relative to Centra makes it better able to manage any negative cost implications resulting from the acquisition.

At the acquisition hearing, the Board heard evidence that Hydro paid $519 million to acquire Centra. The purchase price includes $65 million for goodwill and $56 million for the write up of net assets to fair market value. The purchase price of $519 million was financed by assuming liabilities of $277 million, and incurring additional debt of $242 million.

Centra has stated that the annual payment required to amortize the additional debt of $242 million plus net eligible acquisition and integration costs of approximately $12 million is $20.9 million, based on a 30-year amortization at the long-term debt rate of 7.24%. Centra's evidence suggests that Hydro must recover at least $20.9 million annually in order that Hydro's ratepayers are held harmless as a result of the acquisition of Centra.

The Board notes that Centra's return on equity, which accrues to Hydro on an annual basis, will be in the range of $14 million to $16 million. In addition, the Board has heard that synergies realized by Hydro as a result of the acquisition, exceed $3.2 million. Therefore, Hydro will, at a minimum, realize annual benefits in the range of $17 million to $19 million. The Board further notes that this amount does not include additional synergy benefits that may be realized by Hydro as the integration process continues. As well, the annual Hydro costs of $20.9 million include a component related to purchased goodwill and the write up of net assets to fair market value which, arguably, should not be paid for by Centra ratepayers, but rather paid for by Hydro. The $20.9 million annual payment also includes a component related to approximately $4 million of acquisition and integration costs which the Board has not yet reviewed. The Board therefore has difficulty reconciling the evidence presented at the hearing with Centra's request to include, as a component of Revenue Requirement, a synergy benefit transfer to Hydro in the amount of $7.1 million.

The Board believes the difference between the $20.9 million annual payment incurred by Hydro and the approximate $17 million of annual benefits to be realized by Hydro, as a result of Hydro's acquisition of Centra, represents a reasonable amount to include in Centra's Revenue Requirement. Therefore, the Board will allow a synergy benefit transfer of $3 million to be included in Revenue Requirement for the 2003/04 Test Year. The Board views this allowance as a temporary measure to partially offset the acquisition costs incurred by Hydro and to help ensure that Hydro ratepayers are held harmless.

The Board expects that over the next two to three years, Hydro and Centra will realize further synergies as operations become more integrated, sufficient to offset all acquisition and integration costs incurred by Hydro, and eliminate the requirement for a synergy benefit transfer in the future. For example, Hydro will realize future savings in the area of customer service with potential savings realized in the adoption of a common billing system and customer service center. These additional benefits will help ensure that customers of both utilities are held harmless. The Board expects that the need for a synergy benefit transfer will be eliminated by no later than March 31, 2005 and if possible earlier.

In approving a temporary synergy benefit transfer of $3 million, the Board notes the total operating cost of Centra approved in this Order, including the synergy benefit transfer, is reasonable when compared to the cost of operations approved by the Board in 1998, after adjusting for inflation.

13.0 Return on Rate Base

13.1 Application

Centra requested approval of the following related to the Rate of Return:

1. Continuation of the Return on Equity ("ROE") formula that was approved in Order 49/95 for the purpose of setting the 2003/04 allowed ROE.

2. Capitalization for rate setting purposes that is equal to Rate Base.

3. A notional capital structure of 60% debt and 40% equity.

4. An ROE of 9.56%, based on the Board approved ROE formula, compared to 9.91% approved in Order 79/98.

5. An overall Rate of Return of 8.28%, compared to 8.89% approval in Order 79/98.

Centra stated the ROE has been calculated using the formula approach adopted by the Board in Order 49/95 and reaffirmed in Order 79/98. The formula adjusts the 1995 allowed ROE of 12.12% to plus or minus 80% of the change in the Long Canada Bond Yield Forecast in the test year. The Long-term Canada Bond yield is calculated as the average of the 3 month and 12 month – ten year Canada bond yield obtained from the November Consensus Forecast report, adjusted for the average of the 10 and 30 year Long Canada Bond spread in the last six trading days in November.

The Board approved the use of the current ROE formula subject to the forecast Long Canada Bond yield falling within a range of plus or minus 2% of the 1994 forecast yield of 8%. The Board also approved and reserved the right to require a full ROE hearing as a result of unusual or significant changes in the economy, the capital markets or Centra's underlying business or financial risk. The Long Canada Bond yield as determined in the formula was 5.92%, slightly below the range approved by the Board.

13.2 Continuation of the Formula

Centra stated that the risk premium imbedded in the approved ROE formula is acceptable, since the financial risks faced by Centra are basically unchanged and are fairly stable. Centra also noted that the formula used is similar to that set by the National Energy Board, Ontario Energy Board and the British Columbia Utilities Commission. Centra contended that the continued use of the formula will result in substantial savings in regulatory time and ultimate costs to consumers, as a hearing on Rate of Return and Cost of Capital would not be required.

13.3 Capital Structure

Centra repeated its request made at the 1997 and 1998 GRA for the use of a notional capital structure versus the actual capital structure to determine overall Rate of Return as follows:

1. The total capitalization used to calculate the overall Rate of Return would be equal to the requested Rate Base.

2. A notional capital structure, where equity would be deemed to be 40% of the total capitalization noted above.

3. The amount of long-term debt would be calculated based on the 13-month average of outstanding debt issues for 2004.

4. The amount of short-term debt would be determined by subtracting the amount of Equity and long-term debt from the total capitalization.

Centra stated that adopting a notional capital structure with 40% equity and 60% debt is consistent with the approved ROE formula. Increasing the debt component in the capital structure results in greater fixed payments and higher financial risk, which requires a higher rate of return to compensate for the increased risk. In moving to a notional capital structure, there would be no requirement to revisit the debt to equity ratio or the ROE formula.

In using total capital structure equal to rate base in determining the overall Rate of Return, Centra is attempting to determine Return on Rate Base, and the average financing cost of Rate Base, not the average financing costs of the company. Centra stated that the inclusion of non-rate base assets that attract short-term financing rates, in the determination of rate of return artificially lowers the overall Rate of Return. This would deny Centra the opportunity to earn a reasonable Rate of Return.

13.4 Cost of Capital

Centra indicated that the cost of equity has been calculated in accordance with the Board approved formula, which has resulted in a ROE of 9.56%. The cost of long-term debt for 2003/04 is 7.42% based on the calculation of the 13 month average embedded cost of debt calculation. The long-term debt cost was 9.154% for 1998. The reduction is attributed to the early redemption of Centra's previous debt issues, and refinancing of certain long-term debt by Centra's parent at more favourable rates.

The cost of short-term debt is forecast to be 4.95% for 2003/04. The rate is based on a short-term interest rate forecast of 4.0% plus the Provincial Guarantee Fee of .95%. The 1998 approved cost of short-term debt was 4.916%.

13.5 Overall Rate of Return

Centra's applied for overall Rate of Return is as follows:

	Capital Structure ($ millions)	**Weight**	**Cost Rate**	**Weighted Cost of Capital**
Long-term debt	$245.6	60%	7.42%	4.45%
Short-term debt	-	-	4.95%	-
Equity	163.8	40%	9.56%	3.82%
Total	$409.4	100%		8.28%

13.6 Intervenor Positions

CAC/MSOS stressed the importance of the Board being consistent in applying directives in Orders 8/97 and 79/98, which required actual capital structure to be used in calculating cost of capital. CAC/MSOS stated that Centra has not brought forth any new arguments to support the requested change to a notional capital structure.

CAC/MSOS submitted that Centra's use of a notional capital structure of 60:40 as opposed to an actual capital structure of 63:37 results in a difference of $1.63 million, which CAC/MSOS is requesting be reduced from Revenue Requirement.

CAC/MSOS stated that if Centra were a stand-alone private company it might be reasonable to equate the measure of risk with the amount of equity. As Centra is now essentially integrated into Hydro, the risk of Centra would not be perceived as being any greater.

13.7 Board Findings

The Board considers that the use of the current formula for the determination of the ROE should continue and should remain unchanged at this time. The Board will approve an ROE of 9.56%, as prescribed by the existing formula.

The Board notes that Centra had previously requested similar changes to capital structure to determine the Overall Rate of Return in the past two GRA's. In Order 8/97 and in Order 79/98, the Board denied Centra's requests for this change. The Board has heard no new evidence to convince the Board that a change is warranted in the capital structure used to determine the weighting of capital components for purposes of the Rate of Return calculation. The Board will therefore deny Centra's request to change the capital structure from actual to notional and that capitalization is equal to Rate Base for purposes of the Rate of Return calculation.

The Board will require Centra to file a revised Overall Rate of Return calculation in compliance with the directives prescribed in this Order.

14.0 Other Income

14.1 Application

Other income consists of various miscellaneous income items including late payment charges, administration charges to brokers and rental income from conversion burners. Other income for the 2003/04 Test Year is forecasted to be $2.23 million, which is marginally higher than the 1998 approved amount of $2.19 million.

14.2 Intervenor Positions

CAC/MSOS requests a Revenue Requirement reduction of $416,000, based on a calculation performed by Mr. Matwichuk that increases late payment charges because of higher gas costs. The calculation was based on the increase from 1997 to 2003/04 inclusive using the late payment charge as a ratio of the cost of gas.

14.3 Board Findings

The Board will approve other income for 2003/04 of $2.2 million as filed. The Board does not accept the recommended revenue reduction proposed by CAC/MSOS related to late payment charges.

The Board is of the view that Mr. Matwichuk's evidence and calculations were not balanced in that they considered only a trend average for the growth in late payment revenues with no coordination of an offset for bad debt expense.

15.0 Revenue Requirement Summary

Centra has applied for a Revenue Requirement (excluding Primary Gas Increase) of $503.8 million, compared to $451.1 million last approved in 1998, as follows:

	1998 Approved	2003/04 Test Year	Increase
Revenue requirement			
Cost of Gas	337.4	401.4	64.0
Cost of Operations	48.7	49.3	0.6
Amortization Expense	2.8	3.5	0.7
Depreciation Expense	13.1	15.2	2.1
Municipal And Other Taxes	14.4	15.8	1.4
Synergy Transfer	-	7.1	7.1
Income Taxes	12.0	1.8	(10.2)
Return on Rate Base	24.9	34.8	9.9
Other Income	(2.2)	(2.2)	-
Revenue Requirement from Gas Rates	451.1	526.7	75.6
Primary Gas Increase		(22.9)	(22.9)
Revenue Requirement (Excluding Primary Gas Increase)		503.8	52.7
Revenue at Existing Rates		489.3	
Revenue Deficiency		14.5	

15.1 Board Findings

The Board will direct Centra to file for approval a revised calculation of Revenue Requirement so that new rates may be effective August 1, 2003.

16.0 Cost Allocation

Centra's cost allocation methodology is a three-step process that assigns all Revenue Requirement components into one of six functional areas: Production, Pipeline, Storage, Transportation, Distribution, and Onsite. Step two classifies all of the functionalized costs as being either energy, customer or demand related. The final step then allocates the functionally classified cost to each of Centra's eight customer classes. Energy costs are allocated based on relative annual or seasonal class consumptions. Customer costs are based on the relative number of annual bills for each class, weighted to recognize differences in costs for significantly different types and size of customer classes. Demand related costs are allocated to customer classes based on one of several peak and average demand allocators. Centra indicated that the cost allocation methodology is consistent with that last approved by the Board in Order 107/96 and that used in the 2002/03 cost of gas hearing.

Centra cited several events that have transpired since the 1998 GRA which have impacted on the implementation of the approved methodology. The unbundling of rates into four discrete components of Primary Gas, Supplemental Gas, Transportation to Centra, and Distribution to Customer requires that cost be unbundled in a similar fashion. As well, Centra has incorporated changes in the allocation of investment costs, expenses and customer contributions associated with major expansion projects in new franchise areas, as previously directed by the Board. Centra is also proposing the addition of a Co-operative Customer Class and a Power Station Class that impact the cost allocation study.

Additionally, Centra has adopted Hydro's accounting system and employs a new Customer Information System. These systems generate more accurate information with respect to gas procurement and accounting costs, and service and meter investment and other functions resulting in a refinement to the cost allocation factors. Centra is now able to more precisely determine and directly assign onsite costs to the appropriate customer classes.

Centra has changed the allocation of gas procurement and accounting costs. Previously gas procurement costs were allocated by the peak and average method, and gas accounting costs were functionalized entirely to Transportation. In this GRA, Centra is proposing to allocate both types of costs in proportion to total gas costs. Centra is of the view that these costs are more sensitive to volumes consumed than to demands place on the system and thus are more appropriate to allocate in proportion to total gas costs.

Based on the May 1, 2003 cost of gas update the following table shows the results of the unbundling of gas costs into Primary and Supplemental components and the allocation to the Revenue Requirement to each customer class, including Primary Gas.

Cost of Gas Component **($ thousands)**	**Allocated Cost**
Primary Gas	$289,794
Supplemental Gas – Firm Supply	18,606
Supplemental Gas – Interruptible Supply	3,107
Total	$311,507

Revenue Requirement Allocation Results:

Customer Class	**Total Allocated Costs**
Small General Class	$125,522
Large General Class	47,005
High Volume Firm Class	9,272
Mainline Class	3,044
Co-operative Class	19
Power Station Class	1,029
Special Contract Class	1,881
Interruptible Class	4,557
Total Allocated Costs	$503,836

16.1 Intervenor Positions

Municipal addressed the matter of allocation of gas procurement costs, disagreeing with Centra's allocation of these costs. In Municipal's view, primary and supplemental gas costs should include non-gas, costs (overheads and accounting) incurred to support those services, and that an appropriate level of overhead should be assigned to primary gas. Municipal's cost of gas to its customers include Municipal's overheads, and if a level playing field is to be maintained, then Centra must assure that all appropriate overheads related to primary gas are included in the Primary Gas Rate. These costs should not be included as a portion of Transportation and Distribution costs. Transportation and distribution costs are paid for by system and ABM customers. Municipal suggested that it is counter intuitive that less than 25% of overhead costs are actually allocated to Primary and Supplemental gas, and 75% to Transportation and Distribution.

Municipal contended that Centra had not satisfactorily proved the validity of the allocation of these costs, citing several apparent discrepancies in amounts from different schedules in the application. Further Municipal was of the view that the basis of the assignment and allocation of these costs was suspect. Municipal submitted that the proper guide to just and reasonable allocation of gas procurement costs should be the use of ratios of primary gas, supplemental gas and transportation costs. In Municipal's estimation these were 77% for primary gas, 5% for supplemental gas, and 15% for transportation.

16.2 Board Findings

The Board notes that there have been no substantive changes to the cost allocation methodology approved by the Board in 1996. Four events have transpired since the last GRA that have impacted on the implementation of the methodology. The unbundling of sales rates that necessitated a further unbundling of costs was previously ordered by the Board. The specific treatment of costs related to rural expansion projects was also previously ordered by the Board.

The Board considers Centra to have fully complied with the Board's directives in these matters. The Board also accepts that the adoption of Hydro's accounting system and the use of a new CIS has provided more accurate information and allowed for a more precise assignment of certain costs to the various customer classes. As discussed, in Section 17.0 of this Order, the Board will approve the creation of two new customer classes being the Co-operative Customer Class and the Power Station Customer Class. It follows that these new classes impact on all other classes in respect of the allocation of costs. The Board finds that the treatment of allocation of costs to these classes is consistent with that accorded to the other classes and finds that the methodology is reasonable.

The Board notes Municipal's view that there has been an incorrect allocation or assignment of Gas Procurement and Gas Accounting costs. The Board views the change in the allocation of these cost to a percentage of total gas costs, as opposed to the use of a peak and average factor, to be more responsive to cost causation and to be reasonable. The Board also notes that the only evidence on the record in respect of the assignment and allocation of various components of the pool of these costs was provided by Centra in response to one of the undertakings. The Board is not prepared to accept the fact that a proper allocation of these costs is a mathematical calculation using the respective annual values of primary, supplemental, transportation and distribution related gas costs. The Board will approve Centra's treatment of these costs, but will require Centra to more precisely track such costs in the future.

17.0 Rate Classes and Rate Design

Centra is proposing to introduce two new customer classes: the Co-operative Class and the Power Station Class. The Co-operative Class is designed to accommodate the North Cypress Energy Co-op ("North Cypress") that had been previously served under the LGS Class. Centra had proposed an Inter-Utility Rate for North Cypress in the 2002/03 cost of gas hearing. In Order 135/02, the Board directed Centra to further discuss the rate proposal with North Cypress. Centra complied with this request and is now proposing the Co-operative Class, with the agreement of North Cypress.

The rate design for this class recognizes that North Cypress is served from a dedicated high-pressure distribution main and on-site equipment. These considerations have resulted in a proposed three-part rate structure. The Basic Monthly Charge ("BMC") is designed to recover all of the onsite costs, and the demand charge is to recover 100% of the demand related costs. The variable commodity rate will recover the balance of the costs.

The proposed Power Station Class will consist of Hydro's two generating plants in Brandon and Selkirk. Natural gas service has been provided to these two plants since early 2002 under the Mainline Class Rates, because these were the approved existing rates most closely reflecting the plant's service requirements.

Centra submitted that the two plants belonged in a separate rate class because of the nature of the service requirements. These include the magnitude of onsite costs, load factors at 30%, the lowest on the system, and large annual volumes. Centra submitted therefore, that if they were to remain in the Mainline Class, the other Mainline customers would in fact be subsidizing the Power Station customers. Centra contended that it was reasonable to include both plants in one class, even though they differed in size. They both use large volumes of gas, when they use it, have similar characteristics and use patterns; both have low load factors and high onsite investment. Centra is also requesting approval of Terms and Conditions of Service for Power Stations as set out in the respective contracts between Centra and Hydro.

The rate structure and contract conditions contemplate a three-part rate. The BMC, demand charge and a variable commodity charge are designed to fully recover all costs allocated to this new class. The contracts also contain a minimum gross margin guarantee respecting minimum annual revenue, and a guaranteed minimum ratcheted demand level. The contracts, that have a 10-year term, also provide for three true-up calculations to assess contributions in aid of construction which include refund provisions should the calculations prove such are necessary. Centra's position is that there will be little if any, possibility of additional contribution requirements as the feasibility test used very conservative assumptions, contributions already received are greater than capital project costs, and minimum revenue guarantees contained in the contracts.

Centra's rate structures is designed to fully recover from each customer class all of the costs allocated to that customer class. That is, all customer classes have a revenue to cost ratio of 1.0, subject to rounding. The SGC and LGC customer classes have a two-part rate: a BMC and a variable commodity rate. All other classes have a three part rated: a BMC, a Demand Rate and a variable commodity rate.

Centra is also requesting that the billing demand level for the HVF Class be changed to be determined in the same way as is currently done for the other classes. The level would be determined as the highest daily demand during the winter months, ratcheted to the highest level from the previous winter. Because of limited meters, Centra was unable to determine the peak daily demands for all HVF customers until this year. Centra had previously used the maximum winter month daily average as the determinant. This change will be revenue neutral for the HVF Class, but individual customers within the class will be impacted to differing degrees, estimated to be plus or minus 5% on an annual bill basis. The change cannot become effective until after the 2003/04 winter when peak daily demands for all customers have been established.

Centra is also requesting that the percentage of allocated demand costs to be recovered from the HVF and Interruptible Customer Classes be increased from 50% to 65%. Currently 50% of the demand costs are recovered through the variable commodity charge for these two classes. Centra is of the view that this change will allow for a more stable recovery of the fixed costs, and encourage a more efficient use of the system. Additionally, it will move the HVF and Interruptible customers closer to a 100% recovery of demand costs through demand rates, as is the case for all other customers having a three-part rate, and not subject to Special Contract provisions. The adjustments would be revenue neutral for the customer class as a whole, while individual customer impacts within the class could range from plus 5% to minus 5%.

In all other respects Centra's rate design remains unchanged from that previously utilized.

17.1 Intervenor Positions

CAC/MSOS expressed no concern with the economics of the Brandon and Selkirk projects as new feasibility tests were to be conducted in conjunction with the true-up clauses contained in the contracts for both Power Station Class Customers, and would be submitted to the Board and Intervenors. However, CAC/MSOS spoke to three issues with respect to the proposed Power Station Rate Class and Rates. CAC/MSOS stated that the term of the contracts is less than the expected life of the projects. Thus CAC/MSOS requested the Board to ensure that the minimum guarantees in the contracts were extended on an evergreening of the contracts or in any new contracts subsequently negotiated.

Additionally, although Centra does not expect that the future feasibility tests will show that additional contributions will be required, CAC/MSOS recommended that a clause be inserted in the contracts to provide for collection of additional required customer contributions.

CAC/MSOS agreed with Centra's proposed Rate Structure for the Power Station Class, subject to a future review if necessary, to assess if the rates are recovering costs in the most efficient manner.

17.2 Board Findings

The Board will accept Centra's proposal to introduce two new customer classes. The Co-operative Class was first suggested by the Board and addressed by Centra in 2002. The Board instructed Centra to conduct further discussion with North Cypress to agree to a rate. The Board notes that North Cypress has agreed to Centra's proposal. The Board considers the three part rate structure proposed by Centra to be consistent with its stated rate philosophies in that it is designed to recover all allocated costs from that customer.

The Board will also approve Centra's proposed Power Station Class. The Board notes that this customer class is akin to the Special Contract Class, in that the class has a rate as approved by the Board and each of the two customers have entered into a contract with Centra outlining the Terms and Conditions of Service. As with the Co-operative Class, the Board considers the rate structure and rates to be reasonable and appropriate. The Board acknowledges that the contract provide for a minimum revenue guarantees, but only for the respective contract terms. The Board will require that any changes in terms and conditions, or extensions to the term of contract will be filed with the Board for review and, if necessary, approval. The Board also expects that the minimum guarantee will continue for any extended contract terms.

The Board also notes that specific dates are contemplated for true-up calculations that will determine if customer contributions remain appropriate. The Board notes that the contracts contain clauses requiring a refund of contributions if a refund is necessary pursuant to the true-up calculations, but no clause is included requiring additional contributions should they be required. The Board will require that wording to rectify this matter be incorporated into the contracts.

The Board will accept Centra's proposed change to determine demand levels for the HVF Class, as this change will result in all classes being treated in the same manner. As well, the Board will accept the move to recover 65% rather than 50% of all demand related costs through the demand rate for the HVF and Interruptible Classes. The Board encourages Centra to continue with this initiative until 100% of the demand costs are recovered by the demand rate, but being mindful of the individual customer impacts, so that all classes will be treated consistently.

18.0 Base Rates, Billed Rates and Rate Impacts

Centra's Base Rates are designed to recover all approved Revenue Requirement for the future test year period, in this case, except for primary gas, the Revenue Requirement for 2003/04. Current Base Rates include Primary Gas Rates that were changed on May 1, 2003. These Primary Gas Rates will again change on August 1, 2003, and are the subject of a separate application to the Board.

Centra's billed rates include the Base Rates and all Rate Riders related to the disposition of various deferral account balances. Current billed rates include rate riders for the disposition of March 31, 2002 balances of the PGVA and other non-primary gas cost deferral accounts. The proposed billed rates will include the elimination of existing rate riders and imposition of new rate rivers to recover the March 31, 2003 PGVA and other gas cost deferral accounts, except for Primary Gas.

Additionally, the proposed billed rates will include carrying costs on the March 31, 2003 balances until July 31, 2003. As rates are not to change until August 1, the existing rates will continue to generate revenues for Centra related to the March 31, 2002 account balances from April 1, 2003 to July 31, 2003. Further, Centra has requested a "rate delay" rider designed to recover increased revenues from April 1, 2003 to July 31, 2004 when the new rates become effective.

18.1 Intervenor Positions

Intervenor positions respecting cost of service items that may impact base rates and as-billed rates are located throughout this Order.

18.2 Board Findings

Rates are impacted by all Board decisions that require changes to the 2003/04 Revenue Requirement and deferral account balances. Because there are a number of such changes within this Order, actual rate impacts in respect of Base Rates and Billed Rates cannot be calculated until the effects of these changes have been determined by Centra. The Board will comment on rate impacts in a future order of the Board.

The Co-operative Class consisting of one customer had previously been included in the LGS Class. The indicated rate impacts are calculated using the annual revenues that would have been generated had the customer remained in the LGS Class. As such the impact is not driven solely by costs, but also reflects the movement to a new class. In a similar fashion, the Power Stations customers were initially included in the HVF Class, because the Power Stations most closely resembled the operational characteristics and eligibility criteria for the HVF Class. Therefore, the indicated annual revenue impacts also reflect the movement to a new class.

The one customer in Special Contract Class has undergone a plant expansion since the rates were last approved. Therefore a significant amount of the annual revenue impact is due to greater annual consumption, an increased peak load and cost of dedicated facilities. Additionally, calculations of customer impacts for other classes (except Power Stations) reflect changes in all costs, while the impact shown for the Special Customer Class only reflect increases in non-gas costs, as the Special Contract customer does not purchase gas from Centra.

The Board recognizes that parties expressed frustration with Centra's absence from public review since 1998. As previously mentioned, the Board's job was made more onerous due to the long passage of time between the last GRA held in 1998. Therefore, the Board will require Centra establish a more regular schedule, not exceeding three years, for periodic rate reviews. This regular schedule should improve the efficiency, effectiveness and timeliness of the regulatory process, even if no rate changes are requested.

19.0 Interim Order Approvals

19.1 Primary Gas Interim Orders

Centra is seeking confirmation of Orders approving Primary Gas sales rates effective May 1, August 1, November 1, 2002 and February 1, and May 1, 2003. These Primary Gas rates were all approved on an interim basis by the Board every quarter throughout the gas year, in accordance with the previously Board approved methodology. The methodology also requires that all interim Primary Gas Rates be subject to an annual review.

19.2 Franchise Extension Interim Orders

Centra is also seeking final Board approval of interim Ex Parte Orders 134/02 and 79/03 related to system expansions. Order 134/02 required amendments to Centra's existing franchise agreements and approval of the feasibility test within the RM of Rockwood. Order 79/03 requested interim approval of a feasibility test to provide gas service to one customer within the RM of Woodlands.

19.3 Board Findings

The Board will approve as final, Orders 79/02, 84/02, 135/02, 136/02, 188/02, and 11/03.

The Board has previously reviewed the applications for expansion and approval of feasibility tests. The Board granted interim approval to facilitate construction in a timely fashion in order to satisfy customers' requirements. The Board is satisfied that all directives in these Orders, including the change in the required customer contribution, has been met, and will therefore approve Orders 134/02 and 79/03 as final. The Board notes that Centra is required to provide "true-up" calculations by December 31, 2007 for Order 134/02 and December 31, 2008 for Order 79/03, and expects that the proper documents will be filed by these dates.

20.0 Other Matters

20.1 Service Disconnection and Reconnection Policy and Procedures

Centra is requesting certain amendments to the face-to-face requirements of its Service Disconnection and Reconnection Policy and Procedures approved in Order 107/94. Centra's current policy requires Centra to notify all disconnected customers in writing and by making face-to-face contact with the customer.

Centra states that over the past several months there have been a number of incidents of threatened or potential violence by customers whose service has been, or will be, disconnected. As a result of this risk to Centra's employees, Centra is requesting an amendment to the Service Disconnection and Reconnection Policy and Procedures that would enable employees to maintain personal contact with customers through a telephone call as an alternative to the requirement for face-to-face contact. Centra is not proposing to eliminate face-to-face contact in the vast majority of cases where there are no issues of threatened or potential violence. Centra will also continue to monitor the circumstances of the residents to ensure customer safety. Centra submitted that the amendments will not alter the onus on the Company to assess whether there are safety concerns.

Centra is also proposing several other minor amendments be made at this time.

20.1.1 Intervenor Positions

CAC/MSOS does not support the proposed amendments to the face-to-face contact, because it may change the onus on Centra to satisfy itself that there are no safety concerns at the locked out household. The essence of CAC/MSOS' concern is the change in the policy from Centra being required to ensure that the individuals at the home fully understand the consequences, to having only to reasonably believe that those individuals fully understand the consequences of disconnection.

CAC/MSOS stated that if the Company simply wants the flexibility to deal with certain high-risk customers, and/or repeat offenders, who are notorious to Centra, and who pose a threat to employees, amendments could be re-drafted to facilitate the same. This would not alter the requirement to make the face-to-face contact with other customers, or home dwellers, to ensure that the best information is available, to make sure that there are no safety concerns.

20.1.2 Board Findings

The primary amendment proposed by Centra at this time is that all references to "face-to-face contact" be replaced by "personal contact." "Personal contact" is defined to include a face-to-face discussion, a telephone call or a registered letter sent to the customer. The Board, however, considers the existing face-to-face contact is needed to meet the requirements of Section 104 of The Public Utilities Board Act. However, the Board does recognize that certain customers, because of threatened potential violence, present a safety concern for Centra's employees.

In order to address the issue of the safety of Centra employees, the Board is prepared to deal with this matter in a manner similar to those customers who intentionally avoid the utility causing a failure to meet the face-to-face requirements. The Board will therefore continue to require "face-to-face" contact with customers except in those cases where customers are intentionally avoiding the utility or where a customer, in the opinion of the utility, poses a potential threat to the staff of the utility. In these two circumstances the utility will report to the Board in a manner similar to that outlined in Step 4 of the Policy (intentional avoidance) which allows Centra to seek relief from the requirement for face-to-face contact. The Board will approve an amendment to the face-to-face requirements of the Policy, on the basis that face-to-face contact will be the rule, and telephone contact will be the exception. The Board notes from Centra's testimony that there are only a few such individuals where face-to-face contact is not advisable due to safety concerns. The Board will require Centra to revise the wording of the Policy and submit the proposed amendments to the Board for approval. The revised Policy should also incorporate the various amendments that have been approved in prior correspondence by the Board, in addition to the other minor revisions requested by Centra.

20.2 Miscellaneous Fees and Service Re-Installation Policy

Reconnection Fees

Centra is requesting approval for a change to its Reconnection Fees as stated in its Terms and Conditions of Service.

Proposed Reconnection Fees:

During regular business hours	\$50 (plus GST)
Outside of regular business hours	\$65 (plus GST)

These fees are dependent on when the reconnection is to occur, whether it be inside or outside of regular business hours. The previous reconnection fees were \$50 (plus GST) unless the request was outside of regular business hours and in a location where 24 hour staff were not available, the fee being \$65 (plus GST).

Customer Requests for Information

Centra is also requesting to include a charge of \$55 per hour for retrieval of customer information in circumstances where the request for information would require greater than 30 minutes of staff time in order to respond to the request. This fee is similar to the practice, which Hydro has used for several years.

Centra stated the intent is not to limit the customer access to current account information, which is readily available, but rather to ensure that customers who request significant amounts of information recognize the costs that are incurred.

Legal Action Fees for Small Claims

Centra is requesting the removal of legal action fees for small claims from its Schedule of Miscellaneous Charges for Service. Centra stated it will continue to attempt to collect costs as awarded by the Courts from parities it obtains a judgment.

Reinstallation Policy

Centra is also seeking to amend the service re-installation policy stated in the Terms and Conditions of Service to read, "In the event that the meter and regulating equipment are removed and replaced on the same premises with five years of removal, the Company may charge a fee for resetting the meter and regulator." Centra has proposed the increase to five years from one year. This policy would be consistent with Hydro's re-installation policy.

20.2.1 Intervenor Positions

No Intervenors took a position on changes to the miscellaneous fees and Reinstallation Policy.

20.2.2 Board Findings

The Board will approve the requested fee changes for reconnection fees, customer requests for information, removal of legal action fees for small claims and changes to the Reinstallation Policy.

20.3 Interlake Connection Fees

On December 12, 2002 Centra asked for Board approval of connection fees for three specific commercial customers within the Interlake area. In Order 95/00, the Board approved a connection fee schedule for all customers with loads of 2,099 cubic feet per hour or less. Customers with greater demands were to have connection fees determined on a case-by-case basis. Centra stated that the fees were determined as being the largest of the fee for the next closest approved amount, that being $6,500; fee equal to estimated cost of service; or the estimated two-year cost savings relative to the fuel currently being used by the customers. Centra submitted that all three customers' fees were based on the estimated two-year energy cost saving.

Centra submitted that these customers represent 16% of the total Interlake expansion project load, but only 0.2% of the customers, with actual service costs being very nearly the $6,500 fee applicable to the next highest category. Thus, a fee based solely on cost of service would not take into account these significant design and cost impacts relative to other customers. Additionally, these customers would have a shorter payback than other customers in this expansion area and thus should contribute more to the project funding. If the fee were based on the cost of providing service the payback period for conversion for these customers would be three to four months, while payback periods for other residential or small commercial customers payback periods would be several years.

The requested fee for one customer was reduced after that customer informed Centra that the estimated load would be significantly less than anticipated because of market circumstances.

The following table summarizes the requested connection fees:

Customer	Load (Cfh)	Volume (Mcf)	Service Cost	Connection Fee
#1	4,184	8,822	$6,292	$56,542.94
#2	4,327	7,408	6,544	31,504.94
#3 Original	10,600	8,688	7,363	44,151.12
#3 Revised	10,600	4,370	7,363	24,456.21

20.3.1 Intervenor Positions

CAC/MSOS stated that their understanding was that the requested connection fees were based on the value of service concept as opposed to cost based rates. CAC/MSOS is of the view that while the value of service concept may have merit, any change in the principle of cost based rates should not be done on an ad hoc basis. CAC/MSOS requested that the matter should be a discrete issue to be dealt with by the Board at a future hearing, if Centra requested that the principle of cost based rates be changed.

20.3.2 Board Findings

The Board is concerned that the approach taken by Centra in determining the connection fees for the three customers is based on the value of service rather than the cost of service concept. This is evidenced by the renegotiation of one customer's fee due to a significant reduction in that customer's estimated product output, and therefore its gas consumption. The Board also has considered Centra's submission related to the pay-back periods for these three large commercial customers relative to the residential and small commercial customers, and to the relative loads imposed by these customers on the overall system. The Board recognizes that the three customers have agreed to the amount of connection fees proposed by Centra. The Board will therefore reluctantly approve these three specific connection fees as requested by Centra.

The Board will, however, require Centra to file its overall connection fee determination policy for Board approval, if connection fees are to be determined considering factors other than cost causation.

20.4 Centra/Hydro Energy Services ("CHES")

Centra Hydro Energy Services ("CHES") was originally formulated in 1998 as a joint venture between Hydro and Centra to provide joint meter reading services to the two utilities initially for Brandon and Winnipeg. Centra was also providing CHES with payroll and benefit administration services on a fully allocated cost basis. At the time the partnership was set up, loans were advanced by each of Hydro and Centra. With this funding, the joint venture was able to acquire the necessary assets to carry out its objectives. In accordance with the initial agreement, CHES has made repayments, including principal and interest, against its joint venture loans. These payments have continued and CHES will have fully repaid the outstanding amounts by 2005.

In Order 79/98 the Board ruled that CHES was a regulated utility under Section 1 of The Public Utilities Board Act, and its rates for service required Board approval. Centra filed a rate schedule reflecting rates to be charged CHES for gas meter reads. The Board has not approved these rates.

Upon the acquisition of Centra by Hydro, CHES became a fully owned subsidiary of Hydro with the transfer of the joint assets of CHES at $144,400. Under contract with Hydro, CHES continues to provide meter-reading services based on a fee schedule per meter to both the gas and electric utilities. The fee schedule indicated that the rates per meter for reading Centra meters were higher than that for Hydro meters. For instance, for a regular meter read in the City of Winnipeg, Hydro pays CHES $0.60 while Centra pays CHES $0.88. Centra attributed these higher fees to the large number of indoor gas meters, which require additional effort to obtain a reading than an outdoor meter. Furthermore, differences in self-read charges stem from negotiations at the time CHES was formed. Hydro negotiated that the terms of their existing outsourced meter reading contract, under which they paid only for readings received, would continue with CHES. Centra agreed to pay in accordance with the number of self-read cards left at customers' premises. Listed as a primary cost, meter reading services from CHES cost Centra $1.8 million in 2003/04.

20.4.1 Intervenor Positions

CAC/MSOS submitted that CHES had not obtained Board approval for the rates currently being charged to Centra or the contract with Hydro. CAC/MSOS stated that the rates being charged to Centra and Hydro were not legally valid, since Board approval of the rates had not been obtained. Accordingly CAC/MSOS stated that there should be an application and review of the rates charged by CHES.

CAC/MSOS stated that the meter reading component of the costs have increased from $1.6 million in 2001/02 to $1.8 million in 2003/04. CAC/MSOS stated that it is not clear to what degree the change is a function of more meters being read on a year-over-year basis, nor can it be determined on a per unit basis the extent to which the charges exceed CHES' costs.

CAC/MSOS further stated that it is unclear whether synergies are occurring to lower the costs. Additionally, the CHES financial statements for 2002 indicated retained earnings of approximately of $151,000, which represents profit. It is the view of CAC/MSOS that only direct costs should be borne by Centra.

CAC/MSOS recommended that Board approve the rates being charged on an interim basis, in whole or in part, until such time as the rates are reviewed by and approved by the Board. However, the costs should not be approved on an interim basis in their entirety since it is abundantly clear that there has been an overcharge of at least $150,000, which should not go into rates.

20.4.2 Board Findings

The Board has not approved the contract between Hydro and CHES, or the rates charged by CHES for services provided to Hydro or to Centra. In Order 79/98 the Board determined CHES was a public utility within the meaning of The Public Utilities Board Act. The Board will initiate a separate process to require CHES to file an application for approval of rates charged to Hydro and Centra and to review the contractual arrangements between affiliated companies.

20.5 Electronic Filings

20.5.1 Intervenor Positions

CAC/MSOS requested the Board consider Centra, at all future hearings to submit its application in electronic form, as well as hard copy, in an effort to improve the hearing process, all with the laudable goal of increasing efficiency and reducing costs.

20.5.2 Centra's Position

Centra stated it was not is not opposed to electronic filings in principle, as long as it is done on a reasonable basis over a period of time. Centra believes that it would be premature to direct that the next Application be filed electronically. It would be preferable to try this approach from the commencement of a more manageable proceeding and see how it develops.

20.5.3 Board Findings

The Board acknowledges that as technology advances, there will be a natural evolution of the regulatory process towards more extensive electronic filings. However, the adoption of a full electronic filing at the time would be an extremely costly and difficult process. The Board shares the view of Centra that the approach towards electronic filings should be undertaken on a more manageable proceeding to assess the benefits of such an approach from a regulatory process standpoint, and only with the prior consultation and approval of the Board.

20.6 Review of Utility's Regulatory Costs

20.6.1 Intervenor Positions

CAC/MSOS took issue with the fact that the only Interventors' costs get scrutinized on an actual rather than on a forecast basis. CAC/MSOS suggest the Board consider the following:

1. Either the Intervenors' costs be included on a forecast basis, as is the case with every other component of the hearing process and incorporated into the application and treated the same way as all other costs; or

2. The Board does not approved any external costs in a specific hearing until they are all reviewed by the Board.

3. The cost submissions of the Intervenors would follow forthwith after the hearing, so that the Board in its deliberations on the final decision in terms of Revenue Requirement can incorporate all regulatory costs.

4. This can come at the same time as an award as to costs, using the same criteria that the Board presently uses in terms of contribution to process. In other words the Board does not have to make a decision on the main issues before it renders a decision as to costs.

CAC/MSOS believes that by reconstituting the process in the manner describe above, there will be a fair and equitable playing field and the Intervenors will not have to continually bear the brunt of having to justify their costs ex post facto, without the Board considering the relative contribution and reasonableness of all other costs in the process.

20.6.2 Centra's Position

Centra stated CAC/MSOS' proposal for the Board to review and approve Centra's internal and external regulatory costs at the same time as Intervenor costs is not warranted. Centra further stated the current method is appropriate in that the review and disposition of Centra's regulatory costs occur at the same time and in the context of a GRA noting that the reason that Intervenor costs are awarded after the end of a hearing is that the Intervenors want to be reimbursed for their costs in a timely fashion. Centra noted that if its regulatory costs are reviewed at the same time as the Intervenors' cost, such a review would not result in the disposition of these costs in rates after a hearing as Centra recovers these costs in its non-gas Revenue Requirement at a GRA.

Centra further stated that the proposal would be less efficient in that it would require more time by the Board, Board staff, the Applicant and Intervenors.

20.6.3 Board Findings

The Board is of the view that the current process is appropriate and changes proposed by CAC/MSOS are not warranted. The Board further notes that Intervenors are free to question at any time the applicants' regulatory costs. The Board's current rule of practice require Intervenors to bring forward a budget of its costs at the outset of a hearing with its application for Intervenor status.

20.7 Future Regulation

20.7.1 Intervenor Positions

CAC/MSOS adopted the evidence of its witness, Mr. Todd, who stated the integration of Hydro and Centra has created challenges for the traditional regulatory models, and the current regulatory methodology does not work for two integrated companies. Mr. Todd stated that it was necessary to look at how the regulatory model could be adapted in the future in order to more effectively and efficiently regulate Centra and Hydro.

Mr. Todd further stated the approach being used by Hydro implicitly starts with the assumption that all the costs it wishes to recover are reasonable. Mr. Todd questioned how the Board could judge whether an activity charge is appropriate without looking at the underlying costs first, stating that the Board is charged with the duty to make a determination that costs are just and reasonable. To do that it has to first make a determination, the costs being assigned out to customers, being embedded in rates, are prudent.

Mr. Todd suggests the establishment of a three-phased process, where the first phase looks at the total cost of the company to scrutinize them, and determine whether the global costs, are prudently incurred, just, and reasonable.

The second phase would then take those global costs, and assign them between the two companies either based on a cost allocation methodology, which is analogous to the process used to assigned cost to customer classes within the company or work with the companies' activity-based approach, and make it sufficiently transparent, that the Board could examine the method of allocating the share of the costs to the utilities.

The third step would be the traditional cost allocation, or cost of service study, which would take those costs within each company, and assign them out to customer classes.

If the Board could not evaluate the prudency of expenditures on a line-by-line basis, Mr. Todd suggested the Board adopt a streamlined regulatory process such as Performance Based Regulation ("PBR"). The regulatory process would involve periodic cost reviews, rather than annual cost reviews. Implementing this process would require setting up an explicit methodology that addresses the appropriate way to escalate costs from year to year, considering factors such as inflation and productivity targets.

20.7.2 Centra's Position

Centra did not agree with Mr. Todd's proposals to change the regulatory process to a three-phase process, with the first phase being a determination of the global Hydro/Centra Gas Revenue Requirement. Stating that Mr. Todd's proposal fails to recognize that Hydro's cost allocation methodology is specifically designed to allocate costs to different functions and different lines of business. Centra stated the Board in Order 208/02, specifically stated that the cost allocation methodology employed by Hydro results in a fair and equitable allocation of costs. It is therefore unnecessary to examine the whole to determine the prudence or reasonableness of a part.

Centra further noted that the total costs of the Corporation were reviewed at the recent Status Update and Integration Hearing and Hydro's electricity rates were set in Order 7/03. This

Hearing follows on that process and will allow Centra's gas rates to be set for the 2003/04 Test Year. Centra stated it is confident that the information before the Board is adequate for rate setting purposes.

Centra further stated the implementation of CAC/MSOS's proposal will result in an increase in the number of Hearings and the associated costs and is further complicated by the different jurisdiction, which the Board has over Hydro and Centra. In regards to PBR, Centra stated Mr. Todd has admitted during cross-examination that the implementation of PBR and a price cap scheme are lengthy processes. Centra stated the Board must address the fundamental question of whether a PBR scheme is appropriate for this jurisdiction.

20.7.3 Board Findings

The Board does not accept Mr. Todd's recommendation for the establishment of a new regulatory framework. In addition to this Centra GRA, the Board has recently held an integration hearing and status update hearing for Hydro, which also examined the expenses of the utilities. Through these several processes the Board is satisfied it has sufficient information to rule on these matters and does not believe it is necessary to analyze cost of operations on a global basis. On a going forward basis, an examination of cost allocation may be required, and comparisons of costs should allow the Board to discharge its responsibility. The Board further is of the view at this time, that the PBR framework, proposed as an alternative by Mr. Todd, is not appropriate given the prohibitive up-front time and regulatory costs involved in establishing such a regulatory framework. Furthermore, as established during the hearing process, Mr. Todd was primarily concerned with the Cost of Operations being improperly determined on an overall level and then allocated between Centra and Hydro. The Board notes the Cost of Operations at $50 million is one-tenth of Centra's overall Revenue Requirement. The Board is confident it can discharge its statutory obligations under the current regulatory framework.

20.8 Long-Term Debt

Centra received $157 million in long-term advances from Hydro including approximately $15 million in redemption premiums when it refinanced Centra higher cost debt at a lower rate. The Board approved these advances in Order 135/02

Centra is currently seeking approval of an additional $105 million in for two long-term advances received from Hydro as follows:

- A $75 million long-term advance made by Hydro in February 2000, to finance the one-time acquisition taxes and associated other capital requirements of Centra. The advance has a fixed coupon rate of 6.29% and matures on February 22, 2010.
- A $30 million long-term advance issued from Hydro in October 2002 used to re-finance a portion of cumulative short-term advances. The advance has a coupon rate of 4.35% and matures on October 29, 2007. Hydro can extend the advance for an additional 25 years at a coupon rate of 6.20%.

Centra has forecasted for 2003/04 to have $259 million in long-term advances from Hydro.

20.8.1 Intervenor Positions

No Intervenor took a position on this matter.

20.8.2 Board Findings

The Board will approve the long-term advances from Hydro of $75 million and $30 million because the lower interest rates are beneficial to ratepayers.

21.0 It Is Therefore Ordered That:

1. Net plant additions to Rate Base, as requested by Centra, BE AND ARE HEREBY APPROVED subject to the following items:

    - Incremental costs related to system expansion installed to serve the CanAgra Plant in Ste. Agathe be reclassified to Construction Work-in-Progress until such time as the expenditures can be supported as used, useful and prudently acquired.

    - $1,050,000 in costs related to the identification and corrective actions related to the Southwest Transmission Line and the Hanover/LaBroquerie projects be reclassified to Construction Work-in-Progress until such time as the legal proceedings and true-up calculations are completed.

2. Centra assign priorities of Essential, Necessary and Justifiable to all capital projects and utilize a cost/benefit analyses for projects considered to be Justifiable, as the basis for justifying these projects.

3. Working capital allowance in Rate Base, as requested by Centra, BE AND IS HEREBY APPROVED subject to further adjustment for decisions made elsewhere in this Order that impact working capital allowance.

4. The 2002/03 gas costs including the results from the derivative hedging activities, as filed in the June 3, 2003 update, BE AND ARE HEREBY APPROVED.

5. Centra’s request to recover the capital tax deferral accounts balances at July 31, 2003 for 2000/01 and 2001/02 by way of a 12-month Rate Rider, BE AND IS HEREBY APPROVED.

6. Centra’s request to recover all other deferral account balances as of July 31, 2003, excluding the Primary Gas PGVA, as filed in the June 3, 2003 update by way of a 12-month Rate Rider, BE AND IS HEREBY APPROVED.

7. The 2003/04 forecasted gas cost, excluding Primary Gas, based on the May 1, 2003 update utilizing an April 9, 2003 forward price strip, BE AND IS HEREBY APPROVED.

8. Centra file the Blank Page Analysis with the Board by no later than August 31, 2003, including the consultant's report and recommendations, and any changes proposed to those recommendations by Centra.

9. The revised Derivative Hedging Policies and Procedures as filed, BE AND ARE HEREBY APPROVED.

10. Cost of operations of $49.3 million for 2003/04, BE AND IS HEREBY APPROVED.

11. Amortization expense, Depreciation expense, and Municipal and other taxes as filed BE AND ARE HEREBY APPROVED, subject to other required adjustments resulting from this Order.

12. Centra's request to revise depreciation rates to be effective April 1, 2002 and changes in depreciation methodology, BE AND ARE HEREBY APPROVED.

13. Centra's request to vary Order 208/02, allowing for the amortization of the one-time tax liability over a 30-year period, BE AND IS HEREBY APPROVED.

14. Centra's request to include the unamortized balance of the one-time tax liability of $46 million in Rate Base, BE AND IS HEREBY DENIED. The unamortized balance of the one-time tax liability is to be included in a deferral account that attracts carrying costs at the approved overall rate of return.

15. Centra's request for a synergy benefit transfer of $7.1 million to be included in Revenue Requirement, BE AND IS HEREBY DENIED.

16. A synergy benefit transfer of $3 million to be included in Revenue Requirement, BE AND IS HEREBY APPROVED.

17. Continuation of the Return on Equity Formula resulting in a ROE of 9.56% for the 2003/04 Test Year, BE AND IS HEREBY APPROVED.

18. Centra's requests to adjust capitalization for Rate of Return purposes so that capitalization is equal to Rate Base, and to utilize a notional capital structure of 40% equity and 60% debt, BE AND ARE HEREBY DENIED.

19. Other income of $ 2.2 million for 2003/04, BE AND IS HEREBY APPROVED

20. Centra's request to introduce the Co-operative Customer Class and Power Station Customer Class, BE AND IS HEREBY APPROVED.

21. Centra revise the wording of the contracts in respect of the Selkirk Generating Station and the Brandon Combustion Turbine to include a clause requiring the payment of additional customer contributions if required pursuant to the true-up calculations.

22. Centra's requested changes to the method to determine demand levels for the HVF Class, and the move to recover 65% of all demand related costs through demand rates for the HVF and Interruptible Classes, BE AND ARE HEREBY APPROVED.

23. Centra establish a more regular schedule for periodic general rate reviews, not exceeding three years between general rate applications.

24. Interim Orders 79/02, 84/02, 135/02, 136/02, 188/02, and 11/03, BE AND ARE HEREBY CONFIRMED AS FINAL.

25. The amendment to the existing franchise agreement and a feasibility test for extending gas service within the Rural Municipality of Rockwood approved on an interim basis in Order 134/02, BE AND ARE HEREBY CONFIRMED AS FINAL.

26. The feasibility test for extending gas service within the Rural Municipality of Woodlands approved on an interim basis in Order 79/03, BE AND IS HEREBY CONFIRMED AS FINAL.

27. Centra revise, and submit for Board approval, the Service Disconnection and Reconnection Policy and Procedures to permit telephone contact with customers instead of face-to-face contact, in the relative few cases where there is threatened or potential violence by the customer.

28. The requested fees for reconnection of $50 for regular business hours and $65 for outside business hours plus applicable taxes, for the retrieval of customer information, removal of legal action fees for small claims, and the proposed changes to the Reinstallation Policy, BE AND ARE HEREBY APPROVED.

29. The three specific Interlake connection fees as requested by Centra, BE AND ARE HEREBY APPROVED. The Board will, however, require Centra to file its overall connection fee determination policy for Board approval, if connection fees are determined considering factors other than cost causation.

30. The Inter-Company long-term advances of $75 million and $30 million, BE AND ARE HEREBY APPROVED

31. Centra immediately file for approval a revised calculation of Rate Base, Rate of Return, Revenue Requirement, Cost of Service, Rates and customer bill impacts that reflect all of the directives of this Order, as well as the directives in Order 119/03 regarding Primary Gas, which is issued concurrently with this Order so that new rates may be approved to be effective April 1, 2003 for all gas consumed on and after August 1, 2003.

The Public Utilities Board

Chairman

Acting Secretary

THE PUBLIC UTILITIES BOARD

"G. D. Forrest"
Chairman

"Hollis Singh"
Acting Secretary

Certified a true copy of
Board Order 118/03 issued by
The Public Utilities Board

Acting Secretary