ANNUAL REPORT

2003

THE PUBLIC UTILITIES BOARD

April 6, 2004

The Honourable Gregory F. Selinger
Minister of Finance
103 Legislative Building
Winnipeg, Manitoba
R3C 0V8

Dear Minister Selinger:

Pursuant to the provisions of Section 109(1) of The Public Utilities Board Act, I am pleased to submit to you the Forty-fourth Annual Report of the Board, pertaining to calendar year 2003.

The utilities regulated by the Board provide vital services to virtually every Manitoba resident and business; the combined revenues of the utilities exceed $3 billion.

I acknowledge Board Staff, Advisors and my fellow Members for their ongoing dedication to the work of the Board. Assisted by the cooperative efforts of the regulated utilities and the interveners representing ratepayer interests at the Board's public hearings, the Board reviews service rates and other matters within its jurisdiction from the perspective of the public interest.

On behalf of the Board, I particularly want to recognize the service of Mr. Gerry Forrest, who retired as Board Chairman on February 6, 2004. Mr. Forrest provided long and distinguishable service to Manitoba, both at the Board (1991 to 2004) and, prior to that, in the Civil Service. We wish him well in his future endeavours.

Sincerely,

Graham F.J. Lane, C.A.
Chairman

TABLE OF CONTENTS

PAGE NUMBER

RESPONSIBILITIES

The Public Utilities Board (the Board) is an independent quasi-judicial body operating pursuant to The Public Utilities Board Act. The Act was enacted in 1959, though the Board has regulated similar services under other legislation since 1912.

During the year under review, the Board was responsible for the regulation of public utilities as defined under *The Public Utilities Board Act*; namely:

Centra Gas Manitoba Inc. (wholly owned by Manitoba Hydro), Stittco Utilities Man Ltd., Gladstone, Austin Natural Gas Co-op Ltd. (now wholly owned by Centra Gas Manitoba Inc.), Swan Valley Gas Corporation, and most water and sewer utilities in the Province.

Pursuant to *The Crown Corporations and Public Review and Accountability Act,* the Board regulates the premiums charged by Manitoba Public Insurance for compulsory auto insurance and related premiums charged on drivers' licences, and Manitoba Hydro's rates for the sale of power.

Other enactments assigning regulatory or adjudicative responsibilities to the Board are:

The Greater Winnipeg Gas Distribution Act
The Gas Allocation Act
The Prearranged Funeral Services Act
The Cemeteries Act
The City of Winnipeg Act (passenger carrier agreements)
The Manitoba Water Services Board Act (Appeals)
The Highways Protection Act (Appeals)

Also, the Board is responsible for the administration of The Gas Pipe Line Act, and authorizes construction and operation of all gas pipe lines in Manitoba. The Board's concern in these matters is safety.

The utilities regulated by the Board had aggregate 2003 revenues in excess of $3 billion, and serve and affect virtually every Manitoba resident and business.

BOARD MEMBERS AND STAFF

Members of the Board:

Graham F. J. Lane, C.A., Chairman*
Robert A. Mayer, Q.C., Vice-Chair
Denyse T. Côté
The Honourable Dr. Leonard Evans
Monica Girouard, C.G.A.
Eric Jorgensen
Dr. Kathi Avery Kinew
Susan Proven, P.H.Ec.
Mario J. Santos, LL.B.

*appointed March 8, 2004

Staff Members:

Officers:

Gerald O. Barron, F.C.G.A, Executive Director and Secretary
Hollis Singh, Associate Secretary

Administrative Staff:

Jo-Donna Williamson, Office Manager
Debra Feuer, Secretary to the Chairman
Brenda Bresch, Administrative Secretary

The Chairman is a full-time appointment and the other Board members are part-time. All Board members are appointed by the Lieutenant Governor in Council.

Board members comprise the membership of panels that hear and subsequently decide upon rate applications and other matters brought before the Board. Board members, staff and advisors are governed by conflict of interest guidelines, to ensure those appearing before the Board obtain unbiased and independent judgments.

The Board relies upon expert advisors from the fields of accounting, actuarial science, engineering and law.

SUMMARY OF BOARD ACTIVITIES

BOARD MEETINGS AND HEARINGS

Board Meetings (primarily decision-making panels)	23
Pre-Hearing Conference Days	2
Public Hearing Days	38
Appeal Hearings:	
Disconnection of Service	7
The Highways Protection Act	6
Natural Gas Brokers	9

Public hearings of the Board are advertised in advance, and attended by representatives of the regulated utilities, interveners and the general public. Organizations, groups and, occasionally, individuals apply to the Board to serve as interveners in utility rate application hearings. Interveners represent the interests of utility rate classes and customers, and present analyses and arguments pertaining to the issues before the Board. Interveners are charged with the responsibility of assisting the Board in its effort to gain a good understanding of the issues before it. The Board may direct the utilities regulated by it to meet the costs incurred by interveners, depending upon the Board's views of the value of the interventions. In awarding costs to interveners, the Board relies upon criteria set out in its draft Rules of Order, along with its judgement with respect to value.

ORDERS ISSUED

During calendar 2003, the Board issued 189 Orders:

Regulated Industry Orders:

Water and Sewer Utilities	63
Manitoba Hydro	65
Natural Gas and Propane Utilities	23
Service Disconnection & Reconnection	7
Manitoba Public Insurance Corporation	6
Highways Protection Act	8
The Cemeteries Act	5
Natural Gas Broker Appeals by ratepayers	11
The Gas Pipe Line Act	1

Note: Copies of the decisions of The Public Utilities Board of Manitoba are available from the Board's office upon request.

FINANCIAL INFORMATION

Revenue and expenses related to Board operations and Board decisions are recorded in the accounts of the Consolidated Fund and of the utilities regulated by the Board. The Board incurs costs to its own account, and directs the utilities to pay the costs of its advisors and of interveners to its hearings

Levies, Direct and Indirect ($000)

General Board Levies on Manitoba Hydro with respect to:		
a) electricity; and	$ 347	
b) gas operations	782	
		$1,129
Costs of Board Advisors, paid by Manitoba Hydro:		
a) electricity; and	1,006	
b) gas operations	727	
		1,733
Costs of Interveners, paid by Manitoba Hydro:		
a) electricity; and	245	
b) gas operations	370	
		615
Aggregate Board levies on Manitoba Hydro consolidated		3,477
Levies on Manitoba Public Insurance Corporation (MPI), with respect to:		
General Board Levies on MPI	337	
Costs of Board Advisors, paid by MPI	433	
Costs of Interveners, paid by MPI	54	
Aggregate Board levies on MPI		824
Levies on:		
Stittco Utilities Man Ltd.		11
Swan Valley Gas Corporation		3
Fees related to cemetery and funeral related activities		25
Other fees		1
		$4,348

Expenditures, Direct and Indirect ($000)

Direct costs of the Board:

Rate regulation and safety related costs	$356	
Salaries and Per Diems	463	
General overheads (rent, technology, utilities, etc.) 257	$1,076	
Board Advisor Costs, billed to regulated utilities	2,180	
Intervener costs billed to regulated utilities		669
Aggregate costs related to Board operations and directions		$3,925

Order No. 38/89 established how the Board recovers its expenditures relating to proceedings before the Board. Order No. 2/94 together with Order-in-Council 142/1994 provide for the Board to recover costs from the major regulated industries including Manitoba Public Insurance, Manitoba Hydro, Centra Gas Manitoba Inc. and Stittco Utilities Man Ltd.

INTERVENER FUNDING

Pursuant to The Public Utilities Board Act and Board Order No. 163/87, the Board may award costs to parties making an intervention in matters before the Board.

These costs are paid directly by the applicant entity.

Details of awards in the calendar year 2003 are as follows:

	Applied for	Granted
Manitoba Public Insurance		
2003 Insurance Rates		
CAC/MSOS[1]	$ 43,458.64	$ 43,458.64
CMMG[3]	$ 10,461.39	$ 10,461.39
Centra Gas Manitoba Inc.		
Primary Gas Sales Rates Effective February 1/03		
CAC/MSOS	$ 3,660.76	$ 3,660.76
Primary Gas Sales Rate Effective May 1, 2003		
CAC/MSOS	$ 3,186.26	$ 3,186.26
2003/04 GRA		
CAC/MSOS	$362,910.96	$362,910.96
Manitoba Hydro		
Integration Activities as a Result of the Acquisition of Centra		
CCEP[3]	$121,781.79	$ 80,461.73
Status Update Filing		
CAC/MSOS	$165,025.68	$165,025.68

[1]Consumers' Association of Canada (Manitoba) Inc./Manitoba Society of Seniors
[2]Coalition of Manitoba Motorcycle Groups Inc.
[3]Canadian Centre for Energy Policy Inc.
Note: other intervenors did not seek an award of costs.

SUMMARIES OF SIGNIFICANT BOARD DECISIONS

2003

NATURAL GAS DISTRIBUTION

The primary supplier of natural gas in Manitoba is Manitoba Hydro, through its wholly owned subsidiary Centra Gas Manitoba Inc. Natural gas is delivered by Hydro throughout the southern portion of the Province, to approximately 100 communities using approximately 8,200 kilometres of pipelines. Hydro forecasts delivering approximately 2.3 billion cubic metres of natural gas through its system annually. Hydro's stated mission is "To provide for the continuance of a supply of energy adequate for the needs of the province, to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-of-use of energy, and to market energy services, within and outside the province." (Manitoba Hydro, Annual Report, 2003)

CENTRA GAS MANITOBA INC.

AN APPLICATION BY CENTRA GAS MANITOBA INC. FOR AN INTERIM ORDER APPROVING PRIMARY GAS SALES RATES TO BE EFFECTIVE FOR ALL GAS CONSUMED ON AND AFTER FEBRUARY 1, 2003 – Order No. 11/03 – January 30, 2003

On December 12, 2002, Centra Gas Manitoba Inc. ("Centra") applied to The Public Utilities Board (the "Board") for approval of interim Primary Gas sales rates and a rate rider to dispose of the estimated January 31, 2003 Primary Gas PGVA to be effective February 1, 2003 and to remain in effect until a further Order of the Board, pursuant to Order 99/01. The requested rates were determined using the November 29, 2002 close forward price strip.

The previously approved Purchase Gas Deferral Account (PGDA) rate rider of $0.0363 per cubic metre was continued in the February 2003 rates.

Centra filed an updated forward price strip with the Board on January 22, 2003 with supporting documentation and a Schedule of Rates to reflect the updates. The price strip for the period from February 1, 2003 to January 31, 2004, based on closing prices at January 20, 2003 without incorporating revised hedging impacts, was $6.684 per Gj compared to the $5.447 per Gj contained in the December 12, 2002 application. This was an increase of approximately 23%, reflective of increases in the commodity market for natural gas.

As a result of hedging transactions based on the updated price strips and placing additional hedges on January 15, 2003, the revised gas costs are shown below:

Date	April 18/02	May 29/02	July 17/02	Oct. 16/02	Jan. 15/03
Type	Collar	Collar	Collar	Collar	Collar
Months	Feb./03-Apr./03	Feb./03 – Apr./03	May/03 – July/03	Aug./03 – Oct./03	Nov./03 – Jan./04
Volumes	4,760,000	3,800,000	7,080,000	7,570,000	8,700,000
Transaction Cost	$0	$0	$0	$0	$0
System Hedge	($4,946,930)	($4,181,640)	($6,927,150)	($4,699,500)	$0
Buy/Sell Hedge	($231,279)	($195,916)	($235,924)	($178,517)	$0
Total Impacts	($5,178,209)	($4,377,556)	($7,163,074)	($4,878,017)	$0
Cumulative Impact	($5,178,209)	($9,555,765)	($16,718,839)	($21,596,856)	($21,596,856)

Centra estimated that the impact of the above transactions would be a decrease of $0.487 per Gj. This to result in a Primary Gas base rate of $0.2264 per cubic metre, compared to the $0.2019 per cubic metre included in the December filing, and the $0.1939 per cubic metre in the existing base rate.

Centra's unit rate riders for the Primary Gas PGVA and PGDA remained unchanged from the December 12 application. Thus, the applied for February 1, 2003 billed Primary Gas Rate using the updated application was $0.2577 per cubic metre, compared to $0.2332 included in the December application and $0.2239 per cubic metre in current rates.

The revised changes to annual natural gas bills of different customer classes that result when the January 20, 2003 forward price curves were incorporated into the rates and reflected in the Table entitled *"Annualized as Billed Customer Impacts"*:

Annualized as Billed Customer Impacts

Customer Class	Bill Increase
Small General Service	8.9% to 9.8%
Large General Service	9.3% to 11.7%
High Volume Firm	11.3% to 12.4%
Mainline	12.1% to 13.4%
Interruptible	12.6% to 13.6%

The 12-month forecast as at January 20, 2003 close was $6.197 per Gj, a 16.2% increase in price. Because of Centra's forecasted positive price management impacts, and lower priced storage gas, the weighted commodity price requested by Centra was $5.860 per Gj, an increase of 9%. After applying supply overhead and compressor fuel costs, and considering Primary Gas PGVA and PGDA rate riders, the impact for the typical residential consumer was an increase of 9.1% or approximately $108 per year.

The Board approved Centra's February 1, 2003 proposed Schedule of Rates.

The following table illustrates the volatility of gas prices, and the impact on rates. Because factors other than commodity prices, such as the cost of gas in storage and price-hedging, are involved, the impact on rates is not directly related to the gas supply market place.

Date	Commodity Cost	Average Annual Bill for Residential Customers	% Change in Bill
December 1999	$3.003/Gj	$856	Base
August 1, 2000	$5.187/Gj	$993	16.1%
November 1, 2000	$5.894/Gj	$1,123	12.6%
February 1, 2001	$9.251/Gj	$1,381	23.0%
August 1, 2001	$4.614/Gj	$1,233	(10.7%)
November 1, 2001	$4.168/Gj	$1,147	(6.9%)
February 1, 2002	$4.028/Gj	$1,124	(2.0%)
May 1, 2002	$5.094/Gj	$1,237	10.0%
August 1, 2002	$4.759/Gj	$1,146	(7.4%)
November 1, 2002	$5.024/Gj	$1,194	4.2%
February 1, 2003	$5.860/Gj	$1,302	9.1%

AN ORDER ADDRESSING MOTIONS BY CENTRA GAS MANITOBA INC. AND BY THE CONSUMERS' ASSOCIATION OF CANADA (MANITOBA) INC. AND THE MANITOBA SOCIETY OF SENIORS IN RESPECT OF THE CENTRA GAS MANITOBA INC. GENERAL RATE APPLICATION FOR THE 2003/04 FISCAL YEAR – Order No. 55/03 – April 4, 2003

Centra filed a General Rate Application (GRA) with the Board seeking, amongst other things, approval of new sales rates for supplemental gas, transportation (to Centra), and distribution to customers. The proposed rates were to be effective April 1, 2003, with respect to all natural gas consumed on and

after August 1, 2003.

The Consumers' Association of Canada (Manitoba) Inc. and the Manitoba Society of Seniors ("CAC/MSOS") applied for and were granted intervenor status The Board issued procedural Order 9/03, dated January 22, 2003, providing a timetable for the orderly exchange of information and evidence among the parties. Both Centra and CAC/MSOS filed Motions with the Board.

Centra sought a Board Order to strike the evidence of John D. Todd, filed in the above noted Application, and a decision by the Board to decline to admit evidence in respect of "Comments on the Future Regulatory Methodology" and related matters at the hearing of the above noted Application.

CAC/MSOS opposed Centra's Motion and maintained its evidence was relevant to matters before the Board, and should not be struck.

CAC/MSOS sought an Order a) compelling Centra to provide answers and produce certain documents, b) compelling Centra to produce any interim report(s) prepared in connection with the Blank Page Analysis and, c) direction that the Board will admit evidence in respect of future regulation and related matters at the hearing of the above noted Application.

Centra opposed CAC/MSOS' requests for information, opining that the information was not being relevant to the GRA. Centra also maintained that CAC/MSOS's requested report did not belong to Centra, but was prepared by Manitoba Hydro for its Minister and was not intended for public review. The respective motions of both Centra and CAC/MSOS were denied by the Board.

AN APPLICATION BY CENTRA GAS MANITOBA INC. FOR AN INTERIM ORDER APPROVING PRIMARY GAS SALES RATES TO BE EFFECTIVE FOR ALL GAS CONSUMED ON AND AFTER MAY 1, 2003 – Order No. 73/03 – May 1, 2003

On March 19, 2003, Centra applied to the Board for approval of interim Primary Gas sales rates, and a rate rider to dispose of the estimated April 30, 2003 Primary Gas PGVA. Centra sought that these rates be effective May 1, 2003 and remain in effect until a further Order of the Board, pursuant to Order 99/01. The requested rates were determined using the March 7, 2003 close forward price strip. The previously approved PGDA rate rider of $0.0363 per cubic metre was to be continued in the May 1, 2003 rates.

Centra filed an updated forward price strip with the Board on April 22, 2003 with supporting documentation and a Schedule of Rates to reflect the updates. The price strip for the period from May 1, 2003 to April 30, 2004, was based on closing prices at April 9, 2003 without incorporating revised hedging impacts, and was for $6.617 per Gj compared to the $7.462 per Gj contained in the March 19, 2003 application; this reflective of then- recent decreases in the commodity market for natural gas.

Centra revised the gas costs from those reported in the initial application as a result of its hedging transactions (based on the updated price strips) and its placing of additional hedges on January 15, 2003, as shown below.

Date	July 17, 2002	October 16, 2002	January, 2003
Type	Collar	Collar	Collar
Months	May 03 – July 03	Aug. 03 – Oct. 03	Nov. 03 – Jan. 04
Volumes	7,080,000	7,570,000	8,700,000
Transaction Cost	$0	$0	$0
System Hedge	($8,128,030)	($6,363,320)	$0
Buy/Sell Hedge	($275,475)	($238,322)	$0
Total Impacts	($8,403,505)	($6,601,642)	$0
Cumulative Impact	($8,403,505)	($15,005,147)	($15,005,147)

Centra revised the estimated impact of the above transactions, estimated to be a decrease of $0.338 per Gj.

Using the 100% inclusion rate, and fuel, overhead and storage gas costs would result in a Primary Gas base rate of $0.2290 per cubic metre, compared to the $0.2418 per cubic metre included in the March filing and the $0.2264 per cubic metre in the existing base rate.

Centra's unit rate riders for the Primary Gas PGVA and PGDA remained unchanged from the March 19 application. Thus, the applied for May 1, 2003 billed Primary Gas Rate using the updated application was $0.2648 per cubic metre, compared to $0.2776 included in the March application and $0.2577 per cubic metre in the then-current rates.

The following table details the revised changes to annual natural gas bills of different customer classes that resulted when the April 9, 2003 forward price curves were incorporated into the rates.

Annualized as Billed Customer Impacts

Customer Class	Bill Increase
SGS	1.7% to 1.8%
LGS	1.7% to 2.1%
HVF	2.1% to 2.3%
Mainline	2.2% to 2.4%
Interruptible	2.3% to 2.5%

The Board was of the view that the request by Centra properly reflected the current commodity market price and market circumstances and therefore approved Centra's May 1, 2003 Schedule of Rates.

AN APPLICATION FOR AN INTERIM EX PARTE ORDER OF THE BOARD APPROVING A FINANCIAL FEASIBILITY TEST FOR THE EXTENSION OF NATURAL GAS SERVICE TO ONE CUSTOMER LOCATED WITHIN THE RURAL MUNICIPALITY OF WOODLANDS – Order No. 79/03 – May 13, 2003

On April 29, 2003 Centra applied to the Board for interim ex-parte approval of a financial feasibility test for expansion of Centra's distribution system to serve one customer within the Woodlands franchise area, on its own behalf and on behalf of Woodlands.

The phase one estimated annual consumption of 12,011 cubic metres was based on the equipment-input method. Phase two consumption was estimated to be 1,725 cubic metres, based on the square footage of the proposed facility Centra states that there are no other potential customers along the route of the proposed main extension.

Centra proposed to provide service to the customer by tapping into Centra's existing 60.3-mm polyethylene distribution pipe. A new 60.3-mm polyethylene pipe was to be installed for a distance of approximately 1,050 metres in a south-easterly direction, connected to the customer's facilities as required.

Centra estimated capital costs for the project to be $18,323, to be spent in the first year.

The feasibility test results indicated a positive 30-year NPV of $76, and the R/C ratio did not fall below 1.0 after the fifth year. Centra was to complete a "true-up" calculation at the end of the fifth year to determine if any refund of the customer contribution is to be required. The results flowing from the feasibility test indicated that the R/C ratio in year five of the project was 1.0, meeting the 30-year NPV test criteria. Additionally, the customer's contribution of $13,828 as determined by the feasibility test had already been collected by Centra.

The Board was satisfied, on a prima facie basis, that revenue, cost estimates and required customer contributions were reasonable, and that the Board's expansion criteria had been properly met; the Board approved Centra's application.

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 – Order No. 118/03 - July 29, 2003

Centra applied to the Board for approval of Rate Base, Rate of Return and sales rates based on a 2003/04 future Test Year. This for supplemental gas, transportation to Centra and distribution to customers sales rates, and 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. This was Centra's first GRA since the acquisition of Centra by Manitoba Hydro ("Hydro") on July 31, 1999.

Plant In Service

Centra's net plant in service had 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 related 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 directed to remain in Construction Work-in-Progress ("CWIP") until final disposition by the Board at a future date, the Board approved all net additions to plant as additions to Rate Base. The Board also approved a) changes to depreciation rates as a result of an updated depreciation study, and b) changes to depreciation methodologies.

Gas Costs

The Board approved 2002/03 gas costs, based on the June 3, 2003 update, noting that in large part, non-primary gas costs were 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 were 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 were to accumulate in the appropriate deferral accounts commencing April 1, 2003.

Cost of Operations

The Board accepted Cenra's forecast 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 to amortize the remaining balance of the one-time tax liability of $46 million, based on a 30-year amortization period. An income 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 directed Centra to remove the unamortized balance of the one-time tax liability of $46 million from its Rate Base, and treat this amount as a deferral account to 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, this 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 expected Hydro to realize additional savings from the acquisition in the future to eliminate the need for any synergy benefit transfer amount at the time of the next GRA.

Rate of Return

In 1995 the Board established a formula 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 approved a Return on Equity of

9.56%, directing 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 accepted Centra's proposal to introduce two new customer classes: the Co-operative Class and the Power Station Class.

The Board also directed Centra to establish a more regular schedule for periodic rate reviews, and not to exceed three years between hearings even if no rate changes is to be sought. In the Board's view, 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, all to reflect the decisions set out in the Order. The resulting rates and customer bill rate impacts are to be dealt with in a subsequent Order of the Board.

AN APPLICATION BY CENTRA GAS MANITOBA INC. FOR AN INTERIM ORDER APPROVING PRIMARY GAS SALES RATES TO BE EFFECTIVE FOR ALL GAS CONSUMED ON AND AFTER AUGUST 1, 2003 - Order No. 119/03 - July 29, 2003

On June 25, 2003, Centra applied to the Board for approval of interim Primary Gas sales rates and a rate rider to dispose of the estimated July 31, 2003 Primary Gas PGVA to be effective August 1, 2003, pursuant to Order 99/01. The requested rates were determined using the June 9, 2003 forward price strip. The previously approved PGDA rate rider of $0.0363 per cubic metre was to be discontinued effective August 1, 2003. Centra forecast that the residual balance of the PGDA at July 31, 2003 would be $1,920,854, and that this balance would form part of the Primary Gas PGVA at August 1, 2003.

In the GRA, Centra applied for approval of the establishment of a Capital Tax Deferral Account related to the PGDA balance of $878,008 for 2001/02 and 2002/03. Centra also requested that the balance, net of the transfer to the Distribution PGVA, of $874,139, be included as part of the Primary Gas PGVA.

Pursuant to Board requirements, Centra filed an update to its initial application on July 23, 2003, utilizing the July 16, 2003 forward price strip.

The requested rates reflected all cost of gas aspects of the gas supply contractual arrangements with Nexen Marketing ("Nexen"). The Term Factor, pursuant to the Nexen Contract was 0.5% from November 1, 2002 to October 31, 2003, and was to be eliminated effective November 1, 2003. The Nova AECO to Empress toll reflected the most recent forecast for this 12-month period from August 1, 2003 to July 31, 2004. The AECO/Empress basis differential was that approved by the National Energy Board effective January 31, 2003. The Primary Gas Rate Rider was calculated on forecast 12-month system and Buy/Sell volumes up to October 31, 2003. The July 23 revision included minor changes to the AECO/Empress basis differential to reflect current tolls.

As well, commencing on October 16, 2002, Centra placed price hedges on three separate occasions in the form of costless collars on volumes of approximately 24.78 million Gj. Centra's purpose for conducting hedge transactions was to provide some measure of protection for consumers for natural gas commodity price volatility. Effective October 31, 2003, Buy/Sell arrangements were to be eliminated, there were no hedging impacts on Buy/Sell volumes after that date. Subsequent to the June 25 application, Centra conducted hedging transactions on July 8 and July 9, 2003. The details of these two transactions, as well as the most recent results of the previous transactions were included in Centra's July 25 update.

The mark-to-market results forecast in Centra's June 25 application, as updated on July 23, were:

July 22 Update

Date	Oct. 16, 2002	Jan. 15, 2003	April 16, 2003	July 8, 2003	July 9, 2003
Type	Collar	Collar	Collar	Collar	Collar
Months	Aug. 03-Oct. 03	Nov. 03–Jan. 04	Feb. 04-April 04	Mar. 04-July 04	Mar. 04-July 04
Volumes	7,570,000	8,700,000	8,510,000	3,770,000	3,770,000
Transaction Cost	$0	$0	$0	$0	$0
System Hedge	($104,218)	$1,345,225	$3,627,800	$396,813	$490,113
Buy/Sell Hedge	($3,418)	$0	$0	$0	$0
Total Impacts	($107,636)	$1,345,225	$3,627,800	$396,813	$490,113
Cumulative Impact	($107,636)	$1,237,589	$4,865,389	$5,262,202	$5,752,315

The following table summarizes the various cost components used by Centra to determine Primary Gas Base Rates and Primary Gas billed Rates relative to the June 25, 2003 application and the July 23, 2003 application update, and compares the forecast to the costs used to determine the May 1, 2003 Primary Gas Base and Billed Rates.

Component	May 1, 2003	June 25 Application	July 23 Update
Date of Strip	April 9, 2003	June 9, 2003	July 16, 2003
12 Month Price	$6.617/Gj	$7.337/Gj	$6.092/Gj
Hedge Impacts	($15,055,147)	($18,287,248)	$5,752,315
Unit Hedge Impact	($0.3380/Gj)	($0.4540/Gj)	$0.1430/Gj
Western Supply Price	$6.279/Gj	$6.883/Gj	$6.235/Gj
Storage Gas Price	$4.127/Gj	$4.127/Gj	$4.127/Gj
Weighted Gas Cost	$5.928/Gj	$6.389/Gj	$5.857/Gj
Weighted Gas Cost	$0.2241/cm	$0.2415/cm	$0.2214/cm
Base Primary Rate	$0.2290/cm	$0.2478/cm	$0.2268/cm
PGVA Amount	($706,577)	($7,059,777)	($7,059,777)
PGVA Rider	$0.0005/cm	($0.0055/cm)	($0.0055/cm)
PDGA Rider	$0.0360/cm	$0.0000	$0.0000
Total Billed Rate	$0.2658/cm	$0.2423/cm	$0.2213/cm

The Board allowed the treatment of the PGDA as requested by Centra, and allowed Centra's requests with respect to the Capital Tax Deferral Account and the collection of the balance in this account through the Primary Gas PGVA mechanism. The Board opined that the request by the Centra properly reflected the current commodity market price, and approved the Application.

Although the annual natural gas bills for all different customer classes would have decreased because of the August 1, 2003 Primary Gas Billed Sales Rate, and the removal of the PGDA Rate Rider, the Board expected that the August 1, 2003 rates for Supplemental Gas, Transportation and

Distribution would increase.

The August 1, 2003 average annual bill and percent change in the bill would be shown in a future Order of the Board.

CENTRA GAS MANITOBA INC. APPLICATION FOR AN INTERIM EX-PARTE ORDER OF THE BOARD AUTHORIZING AND APPROVING AN AMENDMENT TO THE EXISTING FRANCHISE AGREEMENT BETWEEN CENTRA AND THE RURAL MUNICIPALITY OF ROCKWOOD - Order No. 120/03 - July 29, 2003

On July 23, 2003 Centra applied to the Board for interim ex-parte approval and authorization of an amendment to the existing franchise agreement between Centra and the Rural Municipality of Rockwood ("Rockwood") to enable the installation of a natural gas service for one residential customer within the expanded franchise area. Centra had a franchise agreement with Rockwood covering a portion of the Municipality. Centra was requested to extend natural gas service by a homeowner located in SE ¼ of Section 28, Township 16, Range 2 EPM, located adjacent to the existing distribution main serving the Town of Teulon. Centra requested a franchise for the entire quarter section, as the alternative was to apply for approval of franchises on a lot by lot basis, in Centra's view not practical.

The customer was to be served by the installation of a 26.7-mm service line and an appropriate meter set. There was no requirement for any other capital upgrade as a result of this service installation.

Pursuant to the requirements of Order 95/00, dated July 5, 2000, the customer had paid a $500 Residential Connection fee. Additionally, the customer had paid an Excess Footage Charge of $1,108.96 for 232 metres in accordance with Centra's Terms and Conditions of Service.

The Board agreed that franchise application on a lot-by-lot basis was not practical and that amending a franchise agreement to encompass a quarter section, even if to serve only one customer, was reasonable. The Board was satisfied that the Connections Fees and Excess Footage Charges were appropriate, and in accordance with existing requirements.

AN APPLICATION BY CENTRA GAS MANITOBA INC. FOR AN INTERIM EX PARTE ORDER OF THE BOARD: 1. AUTHORIZING AND APPROVING A FRANCHISE AGREEMENT BETWEEN CENTRA AND THE RURAL MUNICIPALITY OF HAMIOTA; 2. APPROVING THE FINANCIAL FEASIBILITY TEST FOR THE

EXPANSION OF NATURAL GAS TO SERVICE ONE COMMERCIAL CUSTOMER WITHIN THE EXPANDED FRANCHISE AREA – Order No. 121/03 – July 29, 2003

On July 3, 2003 Centra applied to the Board for interim ex parte approval and authorization of a franchise agreement between Centra and the Rural Municipality of Hamiota ("RM"), and interim ex parte approval of the financial feasibility test for expansion of Centra's distribution system to serve one commercial customer within the expanded franchise area.

Centra has a franchise agreement with the Town of Hamiota, which is located in the RM. Centra was requested to extend natural gas service to a commercial establishment located in NW ¼, Section 32, Township 13, Range 23 WPM. In order to service this customer a franchise was also required for NW ¼, Section 5, Township 14, Range 23 WPM.

Centra was requested to provide service by the fall of 2002, with an anticipated in-service date of August 2003. The estimated annual consumption was 17,336 cubic metres. Centra proposed to provide service to the customer by extending Centra's existing 60.3-mm transmission line supplying the Town of Hamiota. This line runs north south through the customer's property on Centra's easement. A pressure reducing farm tap was to be installed to the existing transmission pipeline to supply a 60.3 mm (NPS 2") polyethylene main extension, to be installed along the north side of the road allowance in SW ¼, Section 5, Township 14, Range 23 WPM. As this main extension is less than 10 km, it did not require environmental approval pursuant to *The Manitoba Environmental Act (Manitoba), Regulation 164/88, and there were* no additional capital costs required to provide service to the existing farm customer.

Estimated capital costs for the project were $23,882, including the installation of a farm tap, distribution line, and a service and meter set.

Centra submitted that the Board approved 30-year net present value ("NPV") test resulted in a required customer contribution of $18,773. With this contribution, the project would generate the required revenue to cost ("R/C") ratio of 1.0 by the fifth year, and did not fall below 1.0 for the duration of the project. Centra's capital contribution to this project was estimated to be $5,109. Centra had received a $10,000 contribution from the customer, and stated that the balance would be received upon Board approval of this application.

The Board was satisfied that this application was filed in a manner consistent with the Board's requirement to have system extension applications supported by the approved feasibility test.

The Board reviewed the system designs and capital costs and was satisfied that the system design was adequate and the costs were reasonable, as were other feasibility test costs and revenues. The Board approved the application on an interim ex-parte basis.

AN ORDER APPROVING CENTRA GAS MANITOBA INC.'S SALES RATES, PURSUANT TO BOARD ORDERS 118/03 AND 119/03 TO BE EFFECTIVE FOR ALL NATURAL GAS CONSUMED ON AND AFTER AUGUST 1, 2003 – Order No. 125/03 – August 6, 2003

The Board issued Order 118/03, dated July 29, 2003 related to Centra's GRA for the 2003/04 test year. Centra was directed to refile a series of schedules, including base and billed rate schedules to recover all costs other than

Primary Gas costs, to reflect Board decisions. Billed rates, other than for Primary Gas, were effective for all gas consumed on and after April 1, 2003 and were implemented on August 1, 2003. A rate rider was required to recover the incremental revenue for the cost components from April 1, 2003 to July 31, 2003.

In addition to the GRA, Centra submitted a separate application requesting a new Primary Gas Rate to be effective for all gas consumed on and after August 1, 2003. The Board reviewed this application and issued Order 119/03, also dated July 29, 2003, approving the Primary Gas Base Rate. Additionally, the Board approved the Primary Gas Billed Rate that consisted of the Base Rate as well as the impacts of recovering the July 31, 2003 PGVA balance over the ensuing 12 month period, and the scheduled removal of the Primary Gas Deferral Account ("PGDA") Rate Rider. The PGDA rate rider was implemented on August 1, 2001 and was to remain in effect for 24 months.

In Order 118/03, the Board instructed Centra to calculate and file the impact of the August 1, 2003 rates on all Customer Classes incorporating all Board decisions pursuant to Orders 118/03 and 119/03.

Applying the directives in Order 118/03 resulted in a reduction in rate base of $47,943,000.

In Order 118/03, the Board directed Centra to recalculate the Overall Rate of Return using actual capitalization at March 31, 2003 and forecast capitalization at March 31, 2004. This change decreased the overall return to 8.1% from the 8.28% originally requested.

The above resulted in a Revenue Requirement of $521,659,400.

Centra applied the cost allocation methodology and rate design approved by the Board in Order 118/03 to the revised Rate Base and Revenue Requirement filed on August 1, 2003.

The rate riders included recovery of March 31, 2003 (together with carrying costs to July 31, 2003) non-Primary Gas PGVA and other gas cost deferral account balances as filed by Centra on June 3, 2003 (Exhibit #40) in the amount of approximately $5.6 million. Of this amount, Centra had requested, and in Order 118/03 the Board approved, a transfer of $874,837 from this amount to the Primary Gas PGVA. Consequently the amount to be recovered over the ensuing 12 months through the non-Primary Gas rate rider is $4,729,826.

The Primary Gas rate rider, approved in Order 119/03 includes the effects of removing the PGDA rider, and the recovery of the July 31, 2003 Primary Gas PGVA balance over the ensuing 12 months. The Board also approved a Primary Gas Overhead amount of $1.48 per Gj in Order 118/03, which is included in the August 1, 2003 Primary Gas Rate.

Additionally, Centra recalculated the rate delay rider to recover foregone revenue of $56,307 because the revised GRA rates were not implemented until August 1, 2003. This Rate rider will be recovered in the Distribution rate for all customer classes, except for the Power Station and the Co-operative Customer Classes, where the rate rider is reflected in the Basic Monthly Charge.

The following Table indicates the range of billed rate impacts on annual customer bills for the various customer classes in respect of both the GRA filing pursuant to Order 118/03, and the August 1 Primary Gas Rate pursuant to Order 119/03.

Customer Class	Range of Annual Impacts
SGC	(5.8%) to (6.3%)
LGC	(6.1%) to (7.5%)
HVF	(5.2%) to (7.4%)
Co-op	(10.2%) to (11.3%)
Mainline	(5.6%) to (6.6%)
Special Contracts	106.3%
Power Stations	(57.8%)
Interruptible	0.7% to 1.1%

The typical residential customer's annual bill decreased by approximately 5.9% which equates to $77.

The Board reviewed all material filed by Centra on August 1, 2003, pursuant to the directives in Orders 118/03 and 119/03 and approved the rate schedules as submitted by Centra for rates to become effective for all gas consumed on and after August 1, 2003.

AN ORDER TO RESCIND VARIOUS BOARD ORDERS RELATING TO THE UNIFORM CLASSIFICATION OF ACCOUNTS FOR GAS UTILITIES – Order No. 140/03 – September 30, 2003

The Board issued Order 234/60 relating to the use of the Canadian Gas Association Uniform Classification of Accounts for Gas Distribution Companies.

Amendments and updates to Order 234/60 were included in Orders 16/61, 47/61 and 61/70 dated January 17, 1961, March 15, 1961 and June 8, 1970, respectively.

With advances in accounting technology, gas utilities have modernized their account classifications based on current regulatory and financial reporting needs. In addition, the Uniform Classification of Accounts for Gas Distribution Companies is no longer maintained by The Canadian Gas Association. The Board therefore determined that gas utilities under its jurisdiction should no longer be required to use the Uniform Classification of Accounts as previously directed.

APPLICATION BY CENTRA GAS MANITOBA INC. FOR AN INTERIM ORDER TO VARY THE PROCESS AND MINIMUM FILING REQUIREMENTS FOR THE RATE SETTING METHODOLOGY ESTABLISHED IN BOARD ORDERS 55/00, 115/00 AND 99/01 – Order No. 143/03 – October 3, 2003

Since 1999, Centra's sales rates have been "unbundled" such that customer bills now show separate rates for:

(i) Primary Gas
(ii) Supplementary Gas
(iii) Transportation to Centra
(iv) Distribution by Centra
(v) Basic Monthly Charges

Primary Gas rates are for natural gas received by Centra from Western Canadian sources at the Alberta border.

In Board Order 55/00, dated April 14, 2000, a Rate Setting Methodology ("RSM") was established to adjust Centra's Primary Gas rates quarterly, on November 1, February 1, May 1 and August 1 to reflect:

(a) 50% of the difference between the current 12 month forward price for Western Canadian supplies (weighted for the cost of gas in storage) and the cost of Primary Gas embedded in the current approved rates; plus

(b) the disposition of the balance in the Primary Gas Purchased Gas Variance Account ("PGVA") over a twelve month period.

The Board established Minimum Filing Requirements for the quarterly Primary Gas rate applications, including schedules and calculations to reflect 25%, 75% and 100% of the change in the forward price curve, in addition to the 50% adjustment factor in the approved RSM.

Subsequent decisions of the Board resulted in refinements and revisions to the RSM and process. In Board Order 115/00, dated July 31, 2000, Centra was requested to file an updated forward price strip ten days prior to the commencement of the gas quarter to provide the Board and all parties with more current information on gas prices. In Order 99/01, dated July 15, 2001, the Board determined that to be more responsive to market prices, the RSM be changed to have Primary Gas rates reflect 100% of the difference between the current 12 month forward price for Western Canadian supplies (weighted for the cost of gas in storage) and the cost of Primary Gas embedded in the approved sales rate.

Centra applied to vary the process, and Minimum Filing Requirements, for the RSM. Specifically Centra sought to avoid the filing of a quarterly Primary Gas rate application and then having to update the rate based on more current data shortly before the commencement of the gas quarter. To avoid confusion for customers, Centra requested approval to file its Primary Gas quarterly rate application during the month before the proposed implementation date. Centra's application would be based on forward price information calculated early in the month preceding the quarterly rate implementation date. There would be no updated forward price information calculated as there would be insufficient time to provide notice to customers should that information differ from the forward price information on which the quarterly rate application was initially based.

A second aspect of Centra's Application recognized that Primary Gas quarterly rates are now set using a 100% adjustment factor and therefore, Centra requested the elimination of the Minimum Filing Requirement of having to provide 25%, 50% and 75% adjustment scenarios.

In Order 55/00, and when initially establishing an RSM to determine Primary Gas rates, the Board indicated that since it was a new process, it would be implemented on a trial basis.

The present RSM process often results in differences between rates contained in Centra's initial application and the rates approved based on a subsequently filed updated price calculation. Because the public notice is based on Centra's initial application and the rates ultimately approved may be based on subsequently filed updated price calculations, this process may create confusion for natural gas customers.

In an attempt to avoid any such confusion, the Board varied the RSM process such that Centra is required to calculate the forward price for Western Canadian supplies (weighted for the cost of gas in storage) during the first week of the month preceding the new gas year quarter.

By performing that calculation early in the month preceding the commencement of the next gas year quarter, Centra will be able to file its application for new Primary Gas rates with the Board in sufficient time to permit public notice and at least one week for the public and intervenors to comment on the proposed rates.

In an effort to remain flexible, the Board did not fix a specific date for the calculation of the forward price of natural gas, or for the filing of its Primary Gas quarterly rate application. Rather, the Board expects Centra and all parties to efficiently implement the revision for the benefit of all gas consumers such that there is at least one week following public notice during which consumers and other stakeholders are given an opportunity to comment.

The Board discontinued the requirement for Centra to file supporting schedules and calculations to reflect 25%, 50% and 75% adjustments.

AN APPLICATION BY CENTRA GAS MANITOBA INC. FOR AN INTERIM EX PARTE ORDER APPROVING PRIMARY GAS SALES RATES TO BE EFFECTIVE FOR ALL GAS CONSUMED ON AND AFTER NOVEMBER 1, 2003 – Order No. 161/03 – October 30, 2003

On October 8, 2003, Centra applied to the Board for approval of interim Primary Gas sales rates and a rate rider to dispose of the estimated October 31, 2003 Primary Gas PGVA to be effective November 1, 2003, in accordance with the approved revised RSM process. The requested rates were determined using the October 1, 2003 forward price strip.

A public notice outlining this application, published in various newspapers commencing on October 18, 2003, invited interested parties to make comments respecting this application to the Board by October 29, 2003. The Board did not receive any comments regarding this application.

The following table summarizes the various cost components used by Centra to determine Primary Gas Base Rates and Billed Rates and compares the forecast to the costs used to determine the August 1, 2003 Rates.

Component	Existing Rates August 1, 2003	Requested Rates November 1, 2003
Date of Forward Price Strip	July 16, 2003	October 1, 2003
12 Month Forward Price	$6.0920/Gj	$5.5540/Gj
Estimated Price Management Impact ($/Gj)	$0.1430/Gj	$0.4140/Gj
Western Supply Price	$6.2350/Gj	$5.9680/Gj
Storage Gas Price	$4.1270/Gj	$6.1620/Gj
Weighted Gas Cost	$5.8570/Gj	$6.0030/Gj
Rates per cubic metre	$0.2214/m^3	$0.2269/m^3
Base Primary Rate	$0.2268/m^3	$0.2320/m^3
PGVA Rider ($/m^3)	($0.0055/m^3)	$0.0012/m^3
Total Billed Rate	$0.2213/m^3	$0.2332/m^3

A number of factors impact Primary Gas Rates. The western supply price of $5.9680/Gj reflected the current gas supply contract with Nexen Marketing, including the elimination of the 0.5% term factor effective November 1, 2003 that was applied during the previous year. Estimated negative mark-to-market price management results of $0.4140/Gj or $16.7 million have been included in the Primary Gas Rates. These estimated costs resulted from the placement of cashless collars on volumes of approximately 24.75 million Gj. The cost of gas in storage, projected to be $6.125/Gj, significantly increased from the previous quarter cost of $4.1270/Gj due to the total depletion of primary gas in storage as of March 31, 2003.

A PGVA balance is created when primary gas costs differ from the revenues provided by customers. The PGVA Rate Rider of $0.0012/m^3 reflected a PGVA balance of $1,561,738 owing to Centra.

The resulting total billed rate, effective November 1, 2003, was $0.2332/m^3, which compares to the billed rate for the previous quarter of $0.2213/m^3.

The following table illustrates the increases to annual natural gas bills of different customer classes as a result of this application. These impacts were based on the existing August 1, 2003 rates for Primary Gas, Supplemental Gas, Transportation and Distribution.

Annualized as Billed Customer Impacts

Customer Class	Range of Impacts
SGS	3.0% to 3.2%
LGS	3.1% to 3.9%
HVF	3.7% to 4.1%
Co-op	3.9% to 4.0%
Mainline	3.9% to 4.3%
Interruptible	3.9% to 4.2%

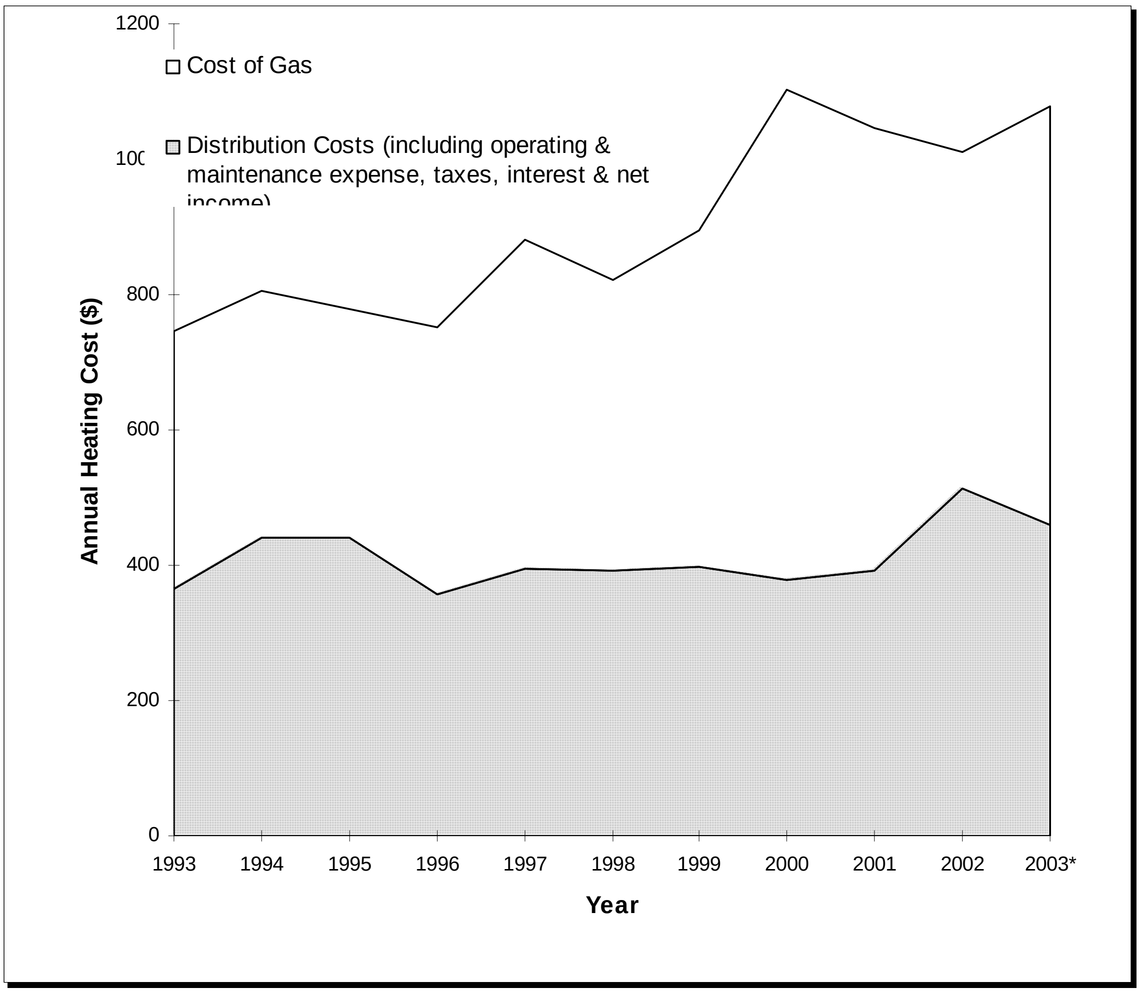
The average residential consumer would realize an increase in annual heating bills of approximately $36.

The Board was of the view that the request by Centra properly reflects the current commodity market price and circumstances, and the RSM and process previously approved by the Board. The Board approved Centra's November 1, 2003 Schedule of Rates.

The following table illustrates the volatility of the market place, and the impact on resulting rates. Because the RSM considers factors other than commodity prices such as the cost of gas in storage and price-hedging impacts, the volatility is somewhat dampened.

Date	Commodity Cost	Average Annual Bill	% Change in Commodity Cost	% Change Annual in Bill
December, 1999	$3.003/Gj	$840	Base	Base
August 1, 2000	$5.187/Gj	$975	72.7%	16.1%
November 1, 2000	$5.894/Gj	$1,098	13.6%	12.6%
February 1, 2001	$9.251/Gj	$1,350	57.0%	23.0%
August 1, 2001	$4.614/Gj	$1,204	(50.1%)	(10.7%)
November 1, 2001	$4.168/Gj	$1,121	(9.7%)	(6.9%)
February 1, 2002	$4.028/Gj	$1,099	(3.4%)	(2.0%)
May 1, 2002	$5.094/Gj	$1,209	26.5%	10.0%
August 1, 2002	$4.759/Gj	$1,120	(6.6%)	(7.4%)
November 1, 2002	$5.024/Gj	$1,167	5.6%	4.2%
February 1, 2003	$5.860/Gj	$1,273	16.6%	9.1%
May 1, 2003	$5.928/Gj	$1,295	1.2%	1.7%
August 1, 2003	$5.857/Gj	$1,213	(1.2%)	(6.3%)
November 1, 2003	$6.003/Gj	$1,250	2.5%	3.0%

FIGURE 1



*Estimated

ANNUAL HEATING COST OF AN AVERAGE RESIDENTIAL CUSTOMER USING BASE RATES (Annualized Basis) Centra Gas Manitoba Inc.

Based on usage of 3,711m^3/year

2003 costs are based on November 1, 2003 billed rates
2002 Costs included $120 for recovery of a purchased gas deferral account

GLADSTONE, AUSTIN NATURAL GAS CO-OP LTD.

In late 2003, Manitoba Hydro's Centra Gas Manitoba Inc. filed an application to acquire Gladstone, Austin Natural Gas Co-op Ltd., with benefits forecast to accrue to ratepayers in the area. The Board approved the sale in February 2004.

AN APPLICATION BY THE GLADSTONE, AUSTIN NATURAL GAS CO-OP LTD. FOR INTERIM EX PARTE APPROVAL OF AN INCREASE IN THE SALES RATE TO BE CHARGED FOR ALL GAS CONSUMED ON AND AFTER FEBRUARY 1, 2003 – Order No. 22/03 – February 19, 2003

On January 24, 2003, Campbell Ryder Engineering Ltd. ("CRE"), acting on behalf of the Co-op, filed an application with the Board to grant ex parte approval for an increase to the Commodity Sales Rate of $1.80/Gj, from $9.95/Gj to $11.75/Gj. The Co-op stated that the increase was required to meet an increase in the price of gas being purchased for re-sale from the $5.25/Gj imbedded in current sales rate to $6.679/Gj. Using the market strip close at January 23, 2003, the delivered gas cost was estimated to increase from the $6.60/Gj reflected in current sales rate to approximately $8.00/Gj over the 2002/03 gas year, from November 1, 2002 to October 31, 2003.

The actual PGVA balance at October 31, 2002 was $27,805 owing to the customers. The Co-op submitted that, without a change in rates, the PGVA from November 1, 2002 to October 31, 2003 would accumulate to a balance of approximately $80,500 owing to the Co-op. All else being equal, an increase in the Commodity Sales Rate of $1.80/Gj, effective February 1, 2003, was required to yield a PGVA balance of approximately zero at October 31, 2003. This change represented an increase of approximately 18% over the existing Commodity Sales Rate. The $1.80/Gj increase would recover the estimated 12 month increase in gas costs over the remaining nine months of the gas contract year.

The Co-op proposed advising its customers of the requested changes in rates by way of bill insert to be included with the February mailing. The bill insert would request that interested parties provide comments respecting this application to the Board by February 17, 2003.

The Board had previously expressed the view that sales rates should closely reflect market prices for natural gas, and that rate stability as well as intergenerational equity should also be considered in rate setting. The Board recognized that natural gas prices had increased dramatically since October 2002.

The Board noted that absent any increase in the sales rate, the estimated PGVA balance at October 31, 2003 would be approximately $80,000 owing to the Co-op. The Board considered that allowing the PGVA balance to build up to this level would not be appropriate, and was of the view that the requested rate increase appropriately reflected and balanced the three elements considered important by the Board (i.e. prevailing market prices, rate stability and intergenerational equity). The Board approved the Schedule of Rates applied for.

AN APPLICATION BY THE GLADSTONE, AUSTIN NATURAL GAS CO-OP LTD. FOR APPROVAL OF: 1. A DECREASE IN THE SALES RATE TO BE CHARGED FOR ALL GAS CONSUMED ON AND AFTER NOVEMBER 1, 2003. 2. A CHANGE IN THE RATE SETTING METHODOLOGY TO ALLOW FOR A CHANGE IN SALES RATES EVERY GAS-YEAR QUARTER – Order No. 163/03 – October 31, 2003

On September 30, 2003, CRE, on behalf of the Co-op, filed an application with the Board seeking ex-parte approval for a decrease in the Commodity Sales Rate. The anticipated decrease was $1.47/Gj based on the September 26, 2003 market strip and an estimated zero PGVA balance at October 31, 2004. On October 6, 2003 CRE filed an update to the application using the October 3, 2003 market strip and a zero October 31, 2004 PGVA balance.

The Co-op decided to continue its gas supply arrangement with PremStar for the supply of natural gas for a 12-month period commencing November 1, 2003. The Co-op submitted that entering a fixed price arrangement was not viable because of high market volatility, large premiums necessary to secure a fixed price contract, and a belief that the current market may be over priced. Additionally, the Co-op's small annual throughput failed to attract other vendors and favored the continuation of the existing arrangement. As well, PremStar's management of excess transportation capacity had resulted in a benefit of approximately $19,200 by the Co-op over the past year, and that benefit was expected to continue in the next year.

Based on the pricing mechanism contained in the PremStar Contract and the October 3, 2003 market strip, the Co-op requested a Commodity Sales Rate of $10.33/Gj which was a decrease of $1.42/Gj (12.2%) from the existing rate. The proposed Commodity Sales Rate embeds an estimated natural gas commodity price of $5.921/Gj, pursuant to the Contract with PremStar.

The estimated PGVA balance at October 31, 2003 was $23,344 owing to the customers. The anticipated net revenue from sales of excess transportation capacity was $16,500. The Commodity Sales Rate includes the average annual commodity price payable to PremStar, Transportation to City Gate, a PGVA balance refund and a component of downstream system delivery costs.

The 2003/04 forecast sales volume was 78,630 Gj, which is somewhat less than the 80,123 Gj now projected for 2002/03 and was based on a five year average and consideration of current circumstances. Lower sales volumes were anticipated because of the general state of the current agricultural economy, expectation of limited domestic market growth, and a return to normal sales volumes that were greater than normal in 2002/03.

In addition to the requested rate change for November 1, 2003, the Co-op requested that the Board approve a change in the method of establishing rates. Currently, the Co-op attempts to maintain annual rates, changing every November 1. Because of market volatility and the need to ensure that costs and recoveries are maintained within a reasonable balance, the Co-op requested that sales rates be changed every gas-year quarter (February 1, May 1, August 1 and November 1).

The proposed method is the same as that used by Centra Gas Manitoba Inc, in respect of Primary Gas rates. The method requires a forecast of gas costs and PGVA balance at the end of every quarter, and rates would reflect the forecast gas costs plus an amount to dispose of any PGVA balance over the next 12 months' annualized volumes. The disposal of the PGVA balance at the end of any quarter would be on a continuous or "rolling" 12-month volumes.

The Board continues to be of the view that sales rate should closely reflect market prices for natural gas, and that rate stability and intergenerational equity should also be considerations in rate setting. The Board also recognizes that natural gas prices have displayed a significant volatility over the past several years. As an example, the Board notes that the February 1, 2003 change in rates represented an increase in gas costs of approximately 25%, while this application was seeking rates that were 12% below the current rate.

The Board was of the view that gas sales forecast, diversion revenues, unit rates and fuel requirements were reasonable. The Board considered the requested Commodity Sales Rate appropriately reflected and balanced the three elements considered to be important by the Board: prevailing market prices, rate stability and intergenerational equity. The Board therefore approved the Schedule of Rates as applied for.

The Board also noted that the Co-op is proposing to adopt the RSM as outlined in Order 143/03, and will approve the proposal.

SWAN VALLEY GAS CORPORATION (SVGC)

SVGC receives its gas from SaskEnergy through the Many Island Pipeline. SVGC has continued with its marketing efforts to attach more customers; marketing activities include town hall meetings, trade show displays, meetings with local businesses, notices in local publications, and incentive coupon packages.

AN APPLICATION BY SWAN VALLEY GAS CORPORATION FOR AN ORDER OF THE BOARD APPROVING: 1. A CHANGE IN GAS PRICING METHODOLOGY; 2. REVISIONS TO THE SASKENERGY – SWAN VALLEY GAS CORPORATION CONTRACT DESCRIPTION OF THE GAS PRICING METHODOLOGY; 3. AN INCREASE IN THE GAS CONSUMPTION CHARGE FOR EACH SALES RATE CLASS – Order No. 90/03 – May 30, 2003

On April 11, 2003 Swan Valley Gas Corporation (SVGC) applied to the Board for interim ex parte approval for a change in the current gas pricing methodology. The proposal is to allow for TEP pricing based on prevailing market prices rather than using SaskEnergy's gas consumption charge as approved by the Saskatchewan regulator ("Saskatchewan"). Additionally, SVGC asked for approval to revise the gas supply contract with SaskEnergy to reflect these changes. The change would increase the gas consumption charge for each rate class by $1.062 per Gj to $6.441 per Gj, and would become effective June 1, 2003.

The Contract stipulates that SVGC would pay SaskEnergy for the commodity cost of gas at a rate as approved from time to time by Saskatchewan and a pro-rata share of downstream (from TEP) transportation and storage costs, based on SVGC's load factor. The difference between the Saskatchewan approved rate and actual gas costs is accumulated in SaskEnergy's PGVA. When disposition of the SaskEnergy Purchase Gas Variance Account ("PGVA") balance is approved, SVGC would be allocated its share and a rate rider would be imposed on SVGC customers to dispose of the PGVA balance.

Although Saskatchewan approved SaskEnergy's change to the commodity charge on two occasions in 2001, SVGC did not apply for any rate increases to reflect these changes. Current gas costs are greater than the presently approved commodity rate, and SaskEnergy's PGVA balance, owing to SVGC by its customers, was increasing. Existing sales rates reflect a commodity price of $5.379 per Gj, while current commodity prices are much higher and the market forecast was for prices to average over $6.25 per Gj for the balance of 2003 and into the winter of 2004. SVGC estimates that its share of the SaskEnergy PGVA deficit at May 31, 2003 would be $57,000, to be recovered from customers at a future date.

Under the proposed market-based pricing methodology SVGC would establish a commodity rate based on a forward AECO 12-month price strip daily index and would establish an annual rate using this strip. SVGC would not longer be responsible for any of SaskEnergy's PGVA balance, after May 31, 2003. In essence, the change would eliminate the need for SVGC to purchase natural gas and storage services to balance supply with demand from SaskEnergy's regulated supply. Instead, SVGC would purchase gas needed for its customers and its own internal operations based on the posted AECO daily price, plus the AECO to TEP differential as needed for its customers and its own internal operations.

SVGC submitted that until SaskEnergy commenced recovery of the PGVA balance and aligned its gas costs with current market prices, SVGC's new and developing customer base would send misleading price signals, and that a market based price would be preferable to the existing methodology.

SVGC requests that the fee for the procurement and management of gas supply be increased from $0.03 per Gj to $0.065 per Gj. The requested fee of $0.065 per Gj would yield an annual fee, for the 2003/04 forecast consumption of 46,915 Gj of $3,049.00, which is less than half of the original estimate. SVGC submitted that this fee was reasonable and was the lowest charged by SaskEnergy to any of its customers. The fee reflected factors such as risk to SaskEnergy, recovery of fixed costs, price charged by other marketers, daily volumes and provision of other non-standard services.

SVGC requested that the existing supply contract with SaskEnergy be revised to incorporate the above changes.

Because SVGC is not seeking any change to Basic Monthly Charge or the Delivery Charge, the annual bill impacts for the customer classes are as follows:

Rate Class	Existing Bill $	Proposed Bill $	Increase $	Increase %
Residential	925 – 1,528	1,006 – 1,692	82 – 164	8.9 – 10.7
Commercial	1,830 – 2,736	2,035 – 3,964	205 – 328	11.2 – 12.00
General Services	10,548 – 20,690	11,990 – 23,560	1,441 – 2,870	13.7 – 13.9
Institutional	25,160 – 41,720	28,850 – 47,870	3,690 – 6,150	14.7 – 14.7

SVGC submitted that the requested rates had the advantages of:

- Reflecting current forward market prices
- Mitigating the increase in the PGVA
- Reflecting established processes used by other Manitoba utilities
- Establishing SVGC as a more independent operation

On the other hand the requested rates result in higher customer impacts which could increase the risk of customers shedding or curtailing consumption.

The Board was aware the difficulties facing SVGC were due to fewer than anticipated customers consuming natural gas, resulting in lower than estimated throughput volumes.

The Board remained of the view that commodity rates should reflect the best estimate of market prices at any given point in time. Although the increases are significant, the Board considers that any alternative to market pricing would send false price signals to the consumers, and would erode the financial integrity of SVGC, which will not benefit any of the stakeholders.

The Board was of the view that the request to increase the management fee from $0.03 per Gj to $0.065 per Gj was reasonable in the circumstances. The Board therefore approved the request for a commodity charge of $6.441 per Gj and a management fee of $0.065 per Gj, effective for all gas consumed on and after June 1, 2003.

The Board had previously urged SVGC officials to address the matter of the ever-increasing PGVA balance and to come forward with an action plan in the very near future. In the Board's view this application addresses only a small component of the problem, in that the commodity related gas costs comprise only approximately 25% of the projected PGVA balance at May 31, 2004. The Board notes that there was a significant PGVA balance forecast for May 31, 2003 owing by the customers and that even with the requested rate increase the balance may grow to an estimated $417,262 by May 31, 2004. With the alternative proposed by SVGC, this balance would increase to $448, 043.

AN APPLICATION BY SWAN VALLEY GAS CORPORATION FOR A FINAL EX PARTE ORDER OF THE BOARD APPROVING A DECREASE IN THE BASIC MONTHLY CHARGE AND A CORRESPONDING INCREASE IN THE DELIVERY CHARGE FOR THE RESIDENTIAL CUSTOMER CLASS – Order No. 162/03 – October 31, 2003

On September 29, 2003, SVGC applied to the Board for a final ex parte Order approving a reduction in the BMC from $26.69 to $15.00, and an increase in the Delivery Charge from $0.031 per cubic metre to $0.078 per cubic metre. The Commodity Charge approved in Order 90/03 would not change.

In Order 93/00, the Board approved a Connection Fee of $877.40, including GST, for residential customers. Residential customers were entitled to receive a $300 incentive rebate if they converted to or installed natural gas space heat or a natural gas water heater within 12 months of service availability. Currently, 336 residential customers who had committed and paid for the service installation have chosen not to have a meter installed and thus have forfeited the $300 incentive rebate.
This significant short fall in customer attachments combined with a lower than estimated usage per customer attachment than that projected at the time of the franchise application has led to a greatly reduced annual throughput volume. At the time of the franchise application, the annual throughput volume was estimated to be 509,000 Gj for 2002, the actual consumption was 333,000 Gj, most of which was consumed by one large industrial customer.

SVGC suggests that the advantage natural gas had enjoyed over electricity in the year 2000 has been largely eroded because of large increases in gas costs combined with the fact that electricity rates in Manitoba have been frozen for the last six years.

Following door-to-door contact with those customers that opted to forfeit the incentive rebate, and at other information meetings convened by SVGC and local officials, the $26.69 BMC has been identified as a barrier to service for residential consumers. In the view of SVGC, customers are reluctant to hook up only one gas-burning appliance when the residential annual bill would be over $320, plus taxes.

SVGC has continued with its marketing efforts to attach more customers, and considered that the reduced BMC would send a strong positive price signal to potential customers, especially those who have forfeited their rebate. Marketing activities include town hall meetings, trade show displays, meetings with local businesses, notices in local publications, and incentive coupon packages in conjunction with local plumbing and heating contractors. The opinion of SVGC was that the revised pricing structure for only the Residential class will be sufficient, although conceding that there was a risk that commercial customers may request similar treatment. Additionally, SVGC realizes that there was an increased risk respecting intra-class cross-subsidization and a potential greater weather related financial risk.

SVGC requested that customers be notified of the proposed changes by direct mail out, given the relatively small number of customers served.

SVGC was seeking changes only to the BMC and the Delivery Charge for the Residential Customer Class. The Residential Class commodity Charge would not change.

Based on the average residential annual consumption, the Delivery charge would have to more than double from $0.032 to $0.078 per cubic metre. While the Residential Customer Class would be saved harmless as a whole, annual bill impacts on individual customers within the class would vary, depending on annual consumption, as shown below:

Consumption	Existing Bill $	Proposed Bill $	Change $
2,985 – BMC	320.28	180.00	(140.28)
2,985 – Delivery	92.54	232.82	140.28
2,985 – Commodity	931.32	931.32	0.00
Total	1,344.14	1,344.14	0.00
2,000 – BMC	320.28	180.00	(140.28)
2,000 – Delivery	62.00	156.00	94.00
2,000 – Commodity	624.00	624.00	0.00
Total	1,006.28	960.00	(46.28)
4,000 – BMC	320.28	180.00	(140.28)
4,000 – Delivery	124.00	312.00	188.00
4,000 – Commodity	1,248.00	1,248.00	0.00
Total	1,692.28	1,740.00	37.71

143 existing residential customers would be affected by this change in pricing structure. SVGC indicates that 122 would receive decreases from $2.00 to over $5.00 per month, while 21 would receive similar increases, depending on consumption. The largest decreases would be for those customers consuming the least amount of gas, while the largest consumption consumers would receive the largest increases.

The Board notes that with this proposal, the residential customer class as a whole will still be required to pay for the costs the class imposes on the system, within the context and parameters of cost allocation. While the Board recognizes that some greater degree of intra class inequity may result from this revised rate structure, the alternative would likely create an impossible position for all customers and the utility. The Board therefore approved the request to change the BMC charge to $15.00 and the Delivery Charge to $0.078 per cubic metre.

DIRECT PURCHASE OF NATURAL GAS

As of December 31, 2003 and for the natural gas year November 1, 2003 to October 31, 2004 the Board registered 11 companies for the brokerage of natural gas supplies to Manitobans.

The Board continued to monitor and supervise this direct purchase market. A number of enquiries were handled through-out the year.

Centra Gas Manitoba Inc. reported that, during the calendar year 2003, 11,880 direct purchase arrangements were submitted by Brokers. 999 customers were conversions from Buy/Sell and 10,881 were new WTS customers. 2612 applications were rejected because of inadequate information or because the customer was already under a direct purchase arrangement. As of December 31, 2003 natural gas was flowing for approximately 37,399 accounts under WTS direct purchase, as compared to 40,118 at December 31, 2002.

Customers who receive marketing information from Brokers offering a fixed price contract continue to contact the office. Staff generally advise customers about the rules applicable to Brokers and the markets for gas without commenting on the merits of the offer.

Staff handled about 900 enquires from customers about gas broker activity. This increase from 600 resulted from increased marketing activity from brokers marketing residential premises and the introduction of a second broker in the residential market. These enquiries dealt with door to door sales activity; adequacy of disclosure of information at the door, high pressure sales tactics and difficulty in contacting the Company. In addition, a number of customer-broker agreements had run their course and were up for either renewal or termination. Those customers who did not explicitly indicate to the Broker a desire to terminate had their contracts extended by a further 90 days at a new price as per the terms of their agreement. Customers complained to the Board suggesting that the renewal letters should be more explicit and that the practice should not be allowed. The Board reviewed this in early 2004 and agreed with the customer and so advised the broker to change the practice.

Customer Disputes

Pursuant to the Code of Conduct governing a Broker's conduct in Manitoba, a customer who is not satisfied with a Broker's attempts to resolve a dispute can refer the matter to the Board for resolution.

Ten such disputes were referred to the Board and hearings to consider whether the Code of Conduct was breached were held by the Board.

In four instances the Board ruled that the Code was breached and as a result the customers were returned to Centra's system supply. In six instances the Board found that the Code was not breached and the Broker continued to be the gas supplier.

PROPANE GAS DISTRIBUTION

STITTCO UTILITIES MAN LTD.

Stittco Utilities Man Ltd. (Stittco) provides propane by pipeline in the communities of Thompson, Snow Lake and Flin Flon. The pipeline activities are regulated by the Board with respect to rates under *The Public Utilities Board Act* and with respect to safety under *The Gas Pipe Line Act*. The following number of customers are served in each community:

	Domestic	Commercial
Thompson	904	135
Flin Flon	0	28*
Snow Lake	0	15

*3 inactive

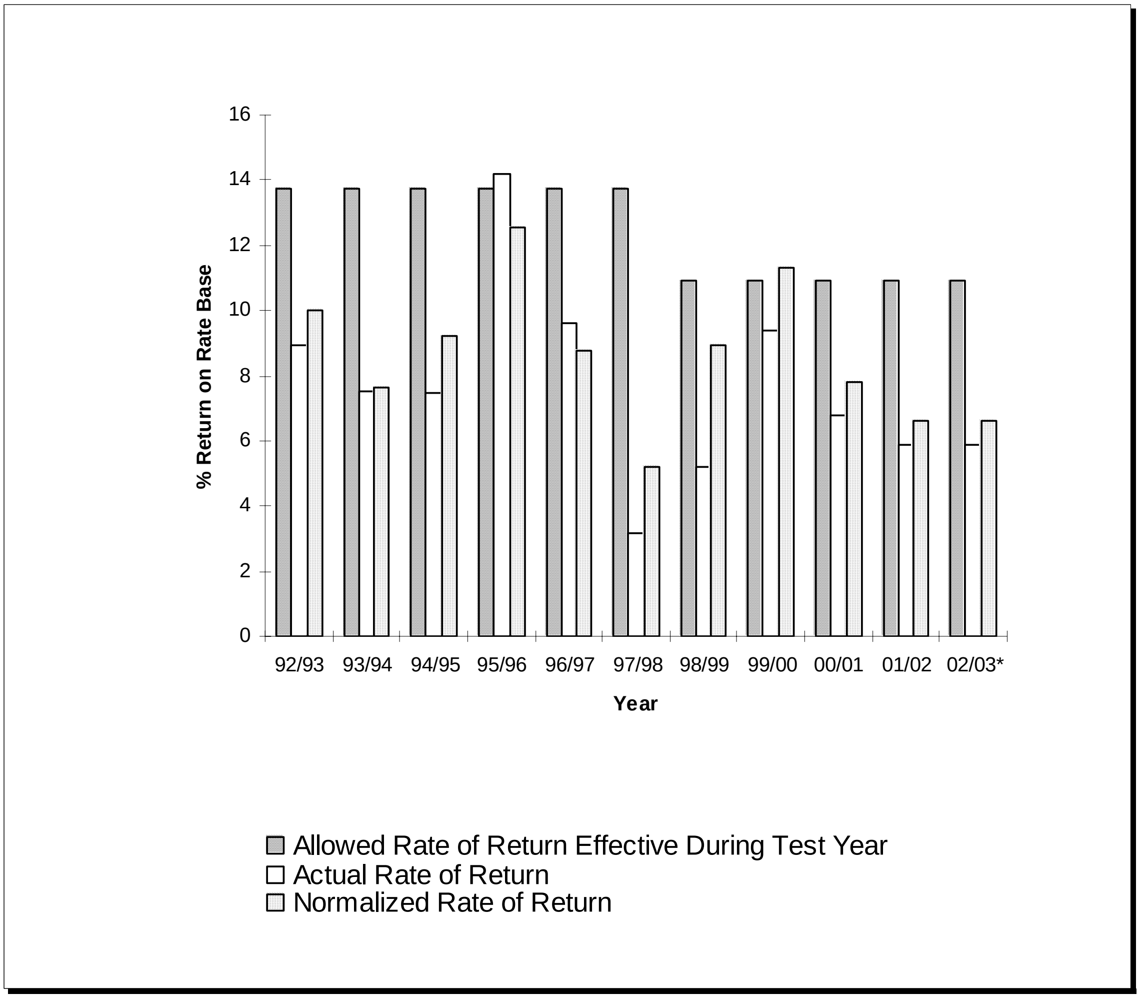
An affiliate of Stittco provides propane in bulk through non-pipeline facilities which are not regulated by the Board.

The Board issued Order No. 20/03 dated February 18, 2003 approving a change in rates for Stittco as a result of a change in market prices.

The Board approved the implementation of Rate Rider "A" in the amount of $97.03 per cubic metre, liquid ($0.3662 per cubic metre, vapour). Stittco stated that the average cost of propane for the 12-month period ending July 31, 2003 was now projected to be $282.03 per cubic metre liquid. The requested Rate Rider represented a 52.4% increase in the price of propane, and an increase of 26.2% over the average of the current sales rates.

The Board noted the significance of this price increase. As the increase reflected changes in the market price of propane which are beyond the control of Stittco, to allow these cost increases to flow through to the ratepayers with no mark-up was consistent with the adopted past practice for handling of such price changes.

FIGURE 2



*Estimated

OVERALL RATE OF RETURN ON RATE BASE

Stittco Utilities Man Ltd.

NOTE: Overall rate of return is the return earned or allowed to be earned by a utility calculated as a percentage of its Rate Base, i.e., investment in property, plant and equipment

NOTE: Normalized rate of return is that earned by the Company assuming normal weather.

SERVICE DISCONNECTION AND RECONNECTION
May – December 2003

Section 104(1) of The Public Utilities Board Act prohibits the disconnection of a residential gas customer's service for non-payment of arrears during the period October 1st to May 14th. The Board in Order No. 107/94 established the rules and procedures for the notice, monitoring and reporting responsibilities of the utility. As there is no requirement for service to be reconnected in the winter months and given the associated risks because of a lack of heat, the Board rigorously monitors the process and extensively liaise with the utility with regards to those customers who remain without gas service past September 30th.

Total disconnections of 6284 (see Table) for the period May 14th to September 30th, 2002 showed significant upward trend contrary to the steady declines which averaged 2760 over the past three years. This occurred as a result of the utility aggressively pursuing accounts in arrears and initiating disconnections promptly on May 14th. The growing number of customers with outstanding arrears is largely a result of the continuing high gas prices. It is also due in some instances to customers entering into fixed price agreements with Brokers when gas prices were at their peak. At this time accounts with arrears over 90 days are estimated to be about $5.6, $4.8 of which is residential. This compares to amounts of $5.2M and $4.3M last year.

Anecdotal evidence indicates that many of the customers disconnected continue to be single parents and the elderly, generally on fixed incomes. Temporary unemployment and individuals in the process of changing jobs and or awaiting benefits from unemployment insurance or workers compensation were affected.

During the period May 14th to September 30th customers about to be disconnected or who have been disconnected frequently contact the Board with inquiries as to their rights or for assistance in resolving disputes that they may have with the utility. To December 31, 2003 7 Board hearings were held.

The utility is required to file frequent reports on the number of customers disconnected as well as details as to the contact with the customer as well as information on the occupants - children, elderly, sick. These reports were duly submitted and audited by the Board.

Disconnected premises determined by the utility to be vacant based on the information collected over the summer requires contacts with the neighbours, real estate agents (if the building is listed), mortgage holder and owner. This category poses the greatest risk as an individual, not understanding the risk involved, could easily come to harm as the weather gets colder if the building is occupied.

The utility's report of September 12, 2003 indicated a total of 86 premises confirmed as vacant and a further 100 as potentially vacant. On November 3 a further report was submitted indicating a total of 87 premises confirmed as vacant.

The utility's report was satisfactory in that there was contact with the owners of the premises in most cases. These premises are largely located in the core of the City and often include rental properties. In the absence of contact with the owners, the utility based its conclusion on information collected from the City Health Department, neighbors and real estate agents.

As of December 31, 2003, 52 premises remain in the vacant category.

The Board's Rules require that the utility maintain certain information on its file about each disconnected customer. Face to face contact with the customer is required in order to obtain this information. Some customers deliberately avoid face to face contact with the utility and are placed in the category 'Intentional Avoidance". The utility report of September 12 listed a total of 126 such customers. The list was later reduced to 93.

The Board sent letters to each of those customers identified as intentionally avoiding the utility. A number of customers did contact the Board indicating that they were in touch with the utility but could not come to a payment arrangement. In 2 cases Board hearings were held.

The file of each customer is carefully reviewed to ferret out any information that would indicate if the customer is not capable of understanding the risk they are facing. In two instances the utility enlisted the aid of Social Service Agencies who visited and evaluated the situation at the person's home. The utility also had its staff visit some premises to try and establish contact. Many of these individuals eventually resolved the matter with the utility. As of December 31, 2003, 45 premises remained in this category of Intentional Avoidance.

The remaining disconnected files represent those disconnected customers who continue to occupy the premises and for whom the utility has all of the information on the files as required by the Board. In general the customers in this category are single parents, elderly individuals, those in between jobs and those awaiting payments from injury or unemployment insurance. The utility generally maintains contact with these customers. On September 12, 2003 there were 1,861 premises in this category. As of December 13, 2003 there were 296 premises in this category.

There are 21 accounts with incomplete information on file. These however raise no concerns as the customers (5) have indicated they do not want gas service, 13 accounts were referred to Residential Tenancies for non-payment by the landlord and 3 have alternate heat.

The utility continued to contact customers regularly throughout this process. The utility again made site visits to those customers which they felt were at the greatest risk.

STITTCO UTILITIES MAN LTD.

In 2003 Stittco Utilities Man Ltd. disconnected four commercial customers and reconnected one. The utility also disconnected a total of 27 residential accounts of which 18 were subsequently reconnected. The Board did not receive any complaints or inquiries from the customers of Stittco.

GLADSTONE, AUSTIN NATURAL GAS CO-OP

One commercial customer was disconnected. The account was settled and the customer has been reconnected. The Board did not receive any complaints from the customers of Gladstone Austin Natural Gas Co-op Ltd.

SWAN VALLEY GAS CORPORATION

No customers are disconnected. The Board did not receive any complaints from the customers of Swan Valley Gas Corporation.

Centra Gas Manitoba Inc.

Residential (May 14 – December 31)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Total Customers Disconnected	3346	3284	3924	3151	3650	4151	3177	2765	3389	6288
Total Customers Reconnected	3277	3158	3842	3065	3557	3922	2851	2418	3011	5867
Vacant, Alternative Heat, etc. and Disconnected	69	126	82	86	93	229	326	347	387	421

Residential - Currently occupied with no gas service - 316 homes

Commercial (January 1 – December 31)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Disconnected	458	512	457	459	443	372	306	421	305	603
Reconnected	430	487	439	448	418	212	257	333	250	439
Vacant, Alternative Heat, etc. and Disconnected	28	25	18	11	25	160	49	88	55	164

THE GAS PIPE LINE ACT

The Gas Pipe Line Act (the Act), administered by the Board, governs the public safety aspects of the distribution of natural gas by Centra Gas Manitoba Inc., Gladstone, Austin Natural Gas Co-op and Swan Valley Gas Corporation, of propane by Stittco Utilities Man Ltd. in Thompson, Snow Lake and Flin Flon, and of propane by Manitoba Housing Authority in Churchill.

The Board reviews pipeline owners adherence to safety standards as adopted by the Board and/or by Regulations to the Act. The Board approves plans of proposed construction and monitors compliance using audit procedures.

The Board is also involved in the investigation of pipeline damages, explosions and/or fires. Such investigations may lead to recommendations related to the utilities' practices or procedures and also, to recommendations for other agencies and stakeholders in order to prevent similar incidents in the future.

In 2003, there were 115 reported incidents of pipeline damage, of which 104 resulted in "blowing" gas. The major causes of such occurrences were related to third party excavations for which clearance was not sought from the utility. Others were caused by excavators not following safe excavation procedures and by improper line location provided by the utility. Parties continue to meet with excavators to make them aware of the Regulations.

The Board is represented on the Canadian Standards Association (CSA) Steering Committee, Technical Committee and Gas Advisory Council on Oil and Gas Pipeline Systems.

MANITOBA HYDRO

Manitoba Hydro is a provincial Crown Corporation providing electric energy to approximately 500,000 customers, residential and commercial, throughout Manitoba. Manitoba Hydro also exports electricity to over 50 electric utilities and marketers in the mid-western U.S., Ontario and Saskatchewan. Nearly all of Manitoba Hydro's electricity is generated from self-renewing waterpower. The Corporation estimates that about 30 billion kilowatt-hours are generated annually, with 98% produced from 14 hydroelectric generating stations on the Nelson, Winnipeg, Saskatchewan and Laurie rivers. Manitoba Hydro purchased Winnipeg Hydro from the City of Winnipeg as of September 2002.

Manitoba Hydro rates are approved by the Board under *The Crown Corporations and Public Review and Accountability Act, The Manitoba Hydro Act* and *The Public Utilities Board Act.*

A FILING BY MANITOBA HYDRO TO PROVIDE AN INFORMATION UPDATE REGARDING FINANCIAL RESULTS, FORECASTS, METHODOLOGIES, PROCESSES, AND OTHER MATTERS RELATING TO SALES RATES CHARGED BY MANITOBA HYDRO – Order No. 7/03 – February 3, 2003

The Manitoba Hydro-Electric Board ("Hydro") filed a status update with The Public Utilities Board ("the Board") on November 30, 2001. The purpose of the filing was to provide the Board and interested parties with an information update on Hydro, including its financial results, forecasts, methodologies, processes, and events that have transformed the electricity industry over the last few years. Hydro was not seeking any general rate changes, stating that for 2002/03, rates will have effectively been frozen for six years for residential customers and for eleven years for large industrial customers, except for the rate reductions to certain consumers as a result of province-wide implementation of Uniform Rates on November 1, 2001.

Hydro last requested a general rate increase in the fall of 1995, followed by a public hearing in early 1996. The Board's decisions from that hearing are set out in Order 51/96. In light of the long passage of time since Hydro's sales rates were last reviewed in a public forum, the Board determined that one of the purposes of this hearing would be to determine whether the existing sales rates continue to be just and reasonable and whether any changes to existing sales rates may be required.

On February 8, 2002, Hydro announced its intention to acquire the assets and business of Winnipeg Hydro, which had approximately 570 employees and served about 94,000 customers in the City of Winnipeg. The acquisition may have a significant impact on the future overall operations of Hydro.

Hydro believed holding rates constant was a more prudent course of action than offering rate reductions because of the robust export markets and favourable water conditions, which underpinned Hydro's strong financial performance, may not continue at present levels. Rates at or near their current levels were to assist Hydro in achieving its longer term financial objectives. Hydro also stated domestic rates were less than market prices in nearby interconnected markets. Current rates were, on average, the lowest of any utility in North America. Lower rates would encourage more domestic consumption, which would reduce revenues as profitable export sales. Hydro agreed, however, that lower rates could attract more energy intensive industry to the Province.

During the course of the public hearing, the Board examined a number of specific areas related to Hydro's operations including operating results and financial projections, financial targets and risk, capital expenditures, extra provincial revenues, payments to the Province of Manitoba, operating, administrative and finance expenses, transmission tariffs, load forecasts and overall revenue requirements. As a result of this review, the Board identified a number of areas of concern, and made a number of recommendations including:

- Hydro limit its capital expenditures not related to new major generation and transmission, where safety and reliability constraints allow, and focus on reducing long-term debt.
- Hydro pursue short-term financing options to expeditiously pay down the debt incurred for the special export profit payment to the Province of Manitoba.
- Hydro continue to monitor and control operating and administrative expenses.
- Hydro consider ways to diversify and supplement its hydraulic generation with an appropriate mix of other forms of energy.

In addition to the above recommendations, the Board directed Hydro to:

File an updated Integrated Financial Forecast reflecting the integration of Winnipeg Hydro and the in-service dates of all new generation within the eleven-year planning period;

File a detailed debt management strategy;

Undertake a study to quantify specific reserve provisions required to cover major risks and contingencies;

Undertake a study on the merits of implementing an inverted rate structure for all customer classes;

Undertake a study on the impact of decreasing the demand charge and increasing the tail block of the energy charge;

Undertake a study which considers time of use rates for General Service classes based on a seasonal, weekly, daily, and hourly basis;

Identify and specifically account for all export-related capital expenditures in its capital forecasts to ensure that export revenues are appropriately matched against the full cost of production;

Undertake a study on the methods and impacts with respect to the classification of generation costs in the Cost of Service Study;

Re-examine the current level of Demand Side Management programs and pricing strategies to encourage conservation, develop a program with more aggressive targets, and report to the Board;

Consider the use of wind power in remote diesel electric communities and file a report with the Board; and

A considerable amount of time at the hearing was directed towards a review of the various cost of service studies filed by Hydro, and in particular, the proposed changes in methodology from the methodologies previously approved by the Board. The most contentious issue, and the issue with the greatest impact on cost of service results, was the allocation of net export revenues between customer classes. In this Order, the Board did not accept Hydro's proposed cost of service methodology. The Board directed Hydro to file an actual cost of service study for the year ended March 31, 2003 by no later than September 30, 2003 and a prospective cost of service study for the year ended March 31, 2004 by no later than September 30, 2003 which reflected a number of specific directives as set out in the Order including the cost treatment of export classes.

Although Hydro was not seeking any change to firm rates currently charged to customers, the Board noted that certain customer classes have consistently paid rates higher than their allocated costs. Therefore, the Board directed Hydro to file for Board approval a revised schedule of rates to be effective April 1, 2003 that reflects:

(a) A 1% rate decrease for General Service Small customers;
(b) A 2% rate decrease for General Service Large ("GSL") customers greater than 30 kV; and
(c) A decrease in the winter ratchet to 70% and the subsequent elimination of the winter ratchet effective April 1, 2004.

The Board understood that this change will likely bring the General Service Medium class and the GSL <30 kV class closer to unity. Therefore, no further rate adjustments were ordered for this class.

Given that uniform rates have provided recent rate decreases to some residential customers and the residential class revenue to cost coverage ratio has been consistently below unity (i.e., subsidized by other classes), no further rate changes were ordered for the residential rate class at this time.

The Board directed Hydro to file a separate application for approval of an open access transmission tariff by no later than June 30, 2003.

The Board approved the Curtailable Rate Program, confirmed as final a number of interim ex parte Orders, and approved extending the Limited Use Billing Demand Rate option to March 31, 2004.

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

Subject to these and other specific rate directives contained in this Order, the Board confirmed Hydro's remaining existing rate schedules to be in effect until March 31, 2006, or until otherwise amended by a further Order of the Board.

AN APPLICATION BY MANITOBA HYDRO TO VARY BOARD ORDER 7/03 – Board Order No. 154/03 – October 31, 2003

On March 19, 2003, Hydro filed an application with the Board pursuant to subsection 44(3) of The Public Utilities Board Act, to review and vary certain directives contained in Order 7/03. On March 31, 2003, the Board issued Order 51/03 which deferred the operation and implementation of the Board's directives in Order 7/03 until a further order of the Board.

Subsection 44(3) of The Public Utilities Board Act does not set out specific circumstances when actions to rescind, change, alter or vary a Board Order may be taken. The Board, in considering any review and vary application, must apply some standard of review to determine whether a directive is to be varied and whether the onus of proof has been met. In this application, the Board applied the following standards in considering whether a specific directive should be varied:

(a) Is there an error of law?
(b) Is there an error of fact?
(c) Is there a material change in circumstances? and
(d) Has further evidence been adduced?

In addition to these standards, the Board must balance the interests of the utility with the interests of all ratepayers. As with any application, the onus of proof remains with the Applicant.

This Order contained the Board's decisions with respect to Hydro's request to review and vary certain directives in Order 7/03.

General Small and General Service Large Rates

Directives 3(a) and 3(b) of Order 7/03 directed Hydro to file, for Board approval, a revised schedule of rates to be effective April 1, 2003 including revenue impacts that reflect:

(a) A 1% rate decrease for General Service Small ("GSS") customers; and
(b) A 2% rate decrease for General Service Large ("GSL") customers in subclasses greater than 30 kV.

Hydro's Application requested that the implementation of Directives 3(a) and 3(b) be delayed until such time as Hydro and the Board considered the results of the 2003 Integrated Financial Forecast ("IFF") to be finalized in late 2003, together with the results of the report on the impact of decreasing the demand and increasing the run-off block of energy charge (tail block rate).

Hydro filed no new evidence that would suggest that the inequities related to the zone of reasonableness had been addressed for the GSS and GSL customer classes. The Board remained of the view that directional rate adjustments were required and appropriate to address these inequities. This was the primary reason for the decision in Order 7/03 and Hydro provided no evidence to alter that rationale. Even with these adjustments, the GSL sub-classes greater than 30 kV were still significantly outside the zone of reasonableness using the Board's approved methodology.

Accordingly, the Board did not vary its directive for a 1% decrease in rates for GSS customers and a 2% decrease in rates for GSL customers in sub-classes greater than 30 kV. These rate changes were to be effective April 1, 2003. In making this decision the Board wanted to ensure all customers receive the full benefits Order 7/03 was to confer on them.

Elimination of the Winter Ratchet

Directive 3(c) of Order 7/03 directed Hydro to file for Board approval a revised schedule of rates to be effective April 1, 2003 including revenue impacts that reflect a decrease in the winter ratchet to 70% and the subsequent elimination of the winter ratchet effective April 1, 2004.

Hydro requested that the implementation of Directive 3(c) be delayed until such time as Hydro and the Board considered the results of the 2003 Integrated Financial Forecast together with the results of the report on the impact of decreasing the demand rate and increasing the run-off block of energy charge.

The Board indicated it continued to believe that the winter ratchet was problematic, and did not vary the directive in Order 7/03 to reduce the winter ratchet to 70% effective April 1, 2003. However, the Board agreed that there was merit in more fully understanding the impacts of eliminating the winter ratchet completely. The Board therefore approved Hydro's request to delay the elimination of the winter ratchet until the impacts of the elimination can be studied further. The Board directed Hydro to complete a study by no later than February 28, 2004.

Elimination of the Limited Use Billing Demand ("LUBD") Program

Directive 4 of Order 7/03 directed Hydro to eliminate the Limited Use Billing Demand Rate option on April 1, 2004 and inform all affected customers of the changes to the winter ratchet and the Limited Use Billing Demand Rate option.

Hydro requested that the implementation of Directive 4 be delayed until such time as Hydro and the Board considered the results of the 2003 Integrated Financial Forecast together with the results of the report on the impact of decreasing the demand and increasing the run-off block of energy charge.

The Board approved Hydro's request to vary Directive 4 in Order 7/03 to permit further consideration of the LUBD program in greater depth. The Board directed Hydro to submit, for Board review by no later than February 28, 2004, a study including an analysis of the LUBD program. The LUBD will remain a regular rate offering until the Board considered this study.

Transmission Tariff

Directive 5 of Order 7/03 directed Hydro to file an application by no later than June 30, 2003, for approval of Hydro's Open Access Transmission Tariff ("the Tariff").

Hydro requested time to consider further its position on jurisdictional issues related to the Tariff and requested that Directive 5 of Order 7/03 and be varied to defer the requirement to file an application seeking approval of the Tariff.

The Board stated it remained of the view that its jurisdiction and obligations for Hydro rates arise from The Crown Corporation Public Review and Accountability Act. As a rate for service for the provision of electrical power, the Board believed that Hydro was obligated to have such a tariff approved by the Board. Therefore, the Board denied the request to vary Directive 5 in Order 7/03, subject to amending the filing date from June 30, 2003 to December 31, 2003.

Filing Time for Reports on Inverted Rates, Time of Use and Wind Power

Directives 6(d), 6(f), and 6(i) of Order 7/03 directed Hydro to file the following information with the Board by no later than December 31, 2003:

6(d) A study on the merits of implementing an inverted rate structure for all customer classes;

6(f) A study which considers time of use rates for general service classes based on a season, weekly, daily, and hourly basis; and

6(i) Consider the use of wind power in remote diesel electric communities and file a report with the Board.

Hydro requested that Directives 6(d), 6(f), and 6(i) be varied to allow an extension of the submission date for the studies on Inverted Rates, Time of Use Rates, and Wind Power from December 31, 2003 to December 31, 2004. Hydro provided new evidence suggesting the quality of the studies would be improved by the Board extending the filing dates to December 31, 2004, due to Hydro's ability to gather more extensive data.

The Board approved Hydro's request to vary Directives 6(d), 6(f) and 6(i) of Order 7/03 by amending the filing date for the Inverted Rate

Study, the Time of Use Rate Study and the Wind Power Study from December 31, 2003 to December 31, 2004.

Cost of Service Studies

Directive 8 of Order 7/03 directed Hydro to file actual and prospective cost of service studies by September 30, 2003.

Hydro requested that Directive 8 be varied by extending the deadline for filing the cost of service studies from September 30, 2003 to December 31, 2003.

The Board approved Hydro's request to vary Order 7/03 by amending the filing date for the actual and prospective cost of service studies from September 30, 2003 to December 31, 2003. This additional time would permit Hydro to utilize actual data for 2002/03. The additional time would also permit Hydro to utilize its most current IFF and data from the former Winnipeg Hydro service territory.

Allocation Methodology for Net Export Revenues

Directive 7 of Order 7/03 denied Hydro's proposed cost of service study methodology, which included allocating net export revenues to customer classes on the basis of total allocated costs including distribution costs, and continued to support the allocation methodology set out in Order 51/96, which allocated net export revenues on the basis of only generation and transmission costs.

Hydro requested that the Board vary Directive 7 in Order 7/03 to permit Hydro to further explore options for the allocation of net export revenues and to present these options to the Board for consideration.

The Board approved Hydro's request, and directed Hydro to file a study that examines options and impacts to customer classes for the allocation of net export revenue. The study was to be filed for Board review by December 31, 2003 in conjunction with the filing of the requested cost of service studies.

Determination of Net Export Revenue

Directives 8(c) and 8(d) of Order 7/03 directed Hydro file cost of service studies which reflected the creation of a Firm Export Class and the creation of an Opportunity Export Class.

Hydro requested that the Board vary Directives 8(c) and (d) and defer implementing the directive relating to the creation of an export class or classes until Hydro can further review this issue and file the results of such review with the Board for further direction. Hydro stated that the expected completion date for this review was December 31, 2003.

The Board was of the view that there was insufficient information on the public record regarding the impact of export revenues and costs to customer classes. Given the magnitude of the export revenues and costs, the Board continued to be concerned there may be direct and indirect costs related to export power inappropriately being allocated to other customers. The Board saw no new evidence to alleviate these concerns.

The Board noted CAC/MSOS' comments that "in theory, the creation of an export class would help to answer the question of whether the investments Hydro has made to support exports truly benefit customers." As identified by MIPUG, the Board also was interested in continuing the examination of, "… whether there is merit in implementing an export class of customer". The Board heard evidence in the hearing from Hydro that the creation of an export class was practical and possible. The Board recognized, of course, this was not the preferred option of these parties.

The Board understands the concerns of Hydro that allocating export benefits to customer classes can result in rates falling below short-run marginal costs. The Board was confident Hydro can devise a methodology to adequately identify and assign costs related to the export revenues earned.

The Board clarified that the purpose of the request in Order 7/03 for the cost of service studies to include firm and opportunity export classes was not to establish a new rate class, but rather to examine alternate approaches by which export power costs and revenues may be determined, and ultimately, to assist in ratemaking that is fair and equitable for domestic customers.

The Board approved Hydro's request such that Hydro can further review the issue of the creation of an export customer class or classes, and file the results of such review with the Board, including recommendations, financial impacts, and supporting cost of service information, by no later than December 31, 2003.

Filing Dates

Throughout this Order, the Board directed various filing dates for studies and other matters. Many of these dates were requested by Hydro. The Board recognized that as a result of the passage of time dealing with the Application, some of these filing dates may no longer be achievable. The Board also recognized that Hydro has a number of other matters on its regulatory agenda. The Board expected Hydro to advise the Board if the filing dates set out in this Order are achievable and, if not, to recommend achievable filing dates.

Curtailable Rates Program

Hydro applied for approval of a new Curtailable Rate Program ("CRP") to supercede the existing Curtailable Service Program ("CSP"). The existing program, originally set to expire November 30, 2001, was extended to February 28, 2002 by Order 150/01 and then again by ex parte Order 55/02. Hydro proposed the new CRP have a relatively short duration of until November 30, 2003 because the unknown impact of MISO's requirement for and value of reserves.

The CRP allows Hydro to curtail a portion of a large industrial customer's peak load in exchange for reduced rates on that same portion of the load when it was not curtailed. The objective of the CRP is to cut back on the electrical loads during specific periods when the overall electrical system was being taxed to its maximum capacity. As part of the Demand Side Management Program, the CRP reduces Hydro's peak load and assists in maintaining the essential power capacity reserves required for domestic and export operations.

At the time, nine curtailable rate options existed for customers, based on duration and notice for curtailment, in addition to price. Three customers then subscribed to the program, with a total subscribed load of approximately 100 MW. In 2001, the two customers who subscribed to the curtailable rates program saved $1.96 million and $380,000 respectively. Under the proposed CRP, five curtailable rates options would be offered to customers.

Under the proposed CRP, the rationale for curtailments were altered to only instances required to meet reliability of the system and obligations to maintain operating reserves. There was to be no curtailments to enable Hydro to make a high value opportunity sale; curtailments were, however, permissible to be made for firm export sales. Additionally, curtailments could occur for forecast errors, loss of facility, and restoring the operating reserve. Curtailments would not be conducted for peak shaving. In 2001, the overwhelming majority of curtailments (26 of 29) were for peak shaving and reducing imports. Since neither of those were reasons for curtailment in the future, Hydro expected only two to three curtailments per year under the new program, although there would be a maximum ceiling of 3 to 18 curtailments per year depending upon the option chosen.

The financial case for the CRP was based upon an expectation of 150 MW subscribed annually, for a $4.3 million revenue savings to customers. With approximately $1 million attributable to benefits easily quantifiable, the remaining $3.3 million was attributable to reliability benefits not easily quantifiable according to Hydro witnesses. In 1998 (Order 153/98) Hydro presented an application to the Board to alter and extend the Curtailable Service Program. At that time, Hydro indicated there would be $10.4 million in savings to ratepayers if the CRP were extended for a decade. With compounding effects, this would increase to $26 million over that 10 year period. At the update proceeding Hydro was unable to provide any tangible evidence whether part of this benefit had been achieved since 1998, noting that by their very nature, the benefits were difficult to quantify and reconstructing decisions made based upon existing circumstances at that time was nearly impossible with intervening events.

The proposed CRP had a reference discount which varied by percentage for each program option. Previously, the benefits had been calculated using the marginal cost values of capacity. The benefit of capacity curtailed over the winter peak was estimated to result from the ability to improve reliability and thus defer the timing of resource requirements. For summer, the benefit of capacity curtailed was estimated to result in increased revenues corresponding to short-term firm capacity sales. Previously the reference discount varied monthly, based on the US – Canadian dollar exchange rate.

In the update proceeding, Hydro applied for a fixed reference discount of $2.75/kW per month, to be adjusted annually for the Consumer Price Index. Hydro changed the calculation of the reference discount since Hydro now believes marginal costs are commercially sensitive information and the determination of a value was difficult. Now, Hydro attempted to use reasonable judgment to balance the lowest value Hydro judges to be necessary to attract sufficient curtailable load to make the CRP work, with the expectation that the load would be available in the long term where the capacity values to Hydro were expected to be higher. Accordingly, Hydro proposed the reference discount be ascribed a value of a reasonable relationship to an alternative least cost resource of capacity, namely a natural gas combustion turbine. In this instance, at $2.75/kW, it was approximately 42% of the levelized cost of the combustion turbine.

Order No. 159/03 dated October 31, 2003 approved the Terms and Conditions of Service for the CRP.

Surplus Energy Program

On October 25, 1999 Manitoba Hydro applied to the Board for the establishment of the Surplus Energy Program (SEP) to supersede the Industrial Surplus Energy, Dual Fuel Heating and Surplus Energy Services to Self-Generators programs. The SEP is designed to allow eligible customers to have access to surplus energy on terms relatively similar to those available to export customers. SEP reasonably addresses the key rate design issues of fairness and cost recovery.

Throughout 2002, the Board issued interim ex parte Orders approving weekly spot market rates pursuant to the Surplus Energy Program.

On December 2, 2002 Manitoba Hydro applied to the Board to increase certain rates applying in communities served by diesel generation. Manitoba Hydro applied to increase the rates applying to consumption in the tail block for General Service and Residential customers (full cost rate) and to all consumption by Government customers. The communities affected included Brochet, Lac Brochet, Shamattawa and Tadoule Lake.

This matter is scheduled to be heard in 2004.

MANITOBA PUBLIC INSURANCE

The Manitoba Public Insurance Corporation, a provincial Crown Corporation, commenced operations in 1971. The objectives of the Corporation from its commencement have remained: operate as a financially self-sufficient agency; offer compulsory, universal insurance; return at least 86% of premium revenues in the form of benefits; operate at a lower cost than private insurers; offer lower rates than private insurers; provide coverage comparable or superior to that in other provinces; make insurance services readily available to Manitobans; invest significantly in Manitoba, and earn a yield comparable to that earned by private insurers; and pursue traffic safety programs.

Approximately 1,000 claims a day are reported to the Corporation, which has in excess of 800,000 policies in force. The Corporation provides no fault accident benefits to its policyholders and victims of motor vehicle accidents, and approximately 15,000 bodily injury claims are made each year. As of March 31, 2003, the Corporation reported total assets of $1.5 billon, including $1.26 billon of investments.

The Manitoba Public Insurance Corporation ("MPI") filed an application with The Public Utilities Board ("the Board") on June 18, 2003 for approval of premiums to be charged for compulsory driver and vehicle insurance ("Basic insurance") for the insurance year commencing March 1, 2004 and ending February 28, 2005 ("fiscal 2005").

MPI requested an increase in overall vehicle premium revenue of 2.5%. The application reflected a revised forecasted net loss of $1.3 million for the year ending February 29, 2004 ("fiscal 2004") and projected a net loss of $13.8 million for fiscal 2005. MPI's forecast showed that the actuarially indicated rate increases required are 4.3% in fiscal 2005, 1.2% in fiscal 2006, and 0.4% in fiscal 2007. Given the fluctuation in the indicated rate changes for each of those three years, MPI proposed smoothing the rate increase by applying for a 2.5% increase in this application with the future intention of seeking similar increases in each of the next two years assuming current forecasts hold. MPI contended such an approach was possible because of its monopoly position and its long term commitment to rate stability.

MPI did not request any changes for driver licence premiums, service and transaction fees, and permit and certificate fees.

Premium revenues for fiscal 2004 were forecast to be $523.4 million. With the applied for rate increase in fiscal 2005 of 2.5%, premium revenues were projected to increase by $32.1 million to $555.5 million. MPI assumed a 3.5% vehicle upgrade factor and a 1% increase in the size of the vehicle population. The Board found these assumptions to be reasonable.

MPI's claims forecasting methodology remained unchanged from last year. In MPI's Financial Forecast approach, the cost of claims incurred for fiscal 2004 were forecast to be $470.8 million, with a projected increase in costs of $41.5 million for a total claims forecast for fiscal 2005 of $512.2 million. Physical damage claims were projected to increase by $19.1 million, of which $13.7 million was attributable to increased collision claims costs. Personal Injury Protection Plan accident benefits and weekly indemnity payments were expected to increase by approximately $21.1 million to $210.5 million for fiscal 2005. Claims expenses, operating and other expenses, commissions and premium taxes were expected to increase by approximately 6.9%.

The Board found that MPI continues to show a reasonable degree of forecasting accuracy, over the long-term. However, the Board was concerned with the large variances between projected and actual claims incurred in fiscal 2002 when the claims experience was

$45.4 million or 10.5% higher than projected. In fiscal 2003, the claims experience was $26.9 million or 5.8% greater than forecast. The Board noted that while the experience over this two year period may not be sufficient to indicate a permanent change in trends, nonetheless some emerging factors could be adversely impacting future claims costs. As well, investment income which is used to offset underwriting loss from insurance operations declined from an estimated $62.2 million to $44.1 million in fiscal 2003. MPI forecasted investment income to be $61.5 million in fiscal 2004, increasing to $67.3 million in fiscal 2005.

Depending on the assumed frequency of serious loss counts, the Board was concerned that an updated fiscal 2004 Statement of Operations filed during the hearing may be indicating further adverse claims development ranging from $23.3 million to $43.6 million. The Board noted that any adverse development would have a direct and negative impact on the $1.3 million net loss currently forecast for fiscal 2004.

With MPI budgeting for a net loss in its GRA of $13.8 million for fiscal 2005, the Board reiterated its earlier position that MPI should, at a minimum, budget for a break-even position for the year of the application. Given the uncertainty inherent in forecasting, a break-even position does not necessarily mean achieving a zero net income. However, the Board considered the projected net loss of $13.8 million for fiscal 2005 to exceed the limits of a break-even position.

The Board considered MPI's proposal to smooth rates over future years to be inappropriate in that costs of current claims experience would be paid by future ratepayers. Given the recent adverse experience in claims incurred and the current volatility in investment income and in forecasting, the Board viewed MPI's application for a 2.5% increase as unduly exposing Manitoba motorists to larger increases in the future to cover ever escalating claims costs and a further depleted Rate Stabilization Reserve ("RSR"). As stated by the Board in previous GRAs, the appropriate RSR target range for rate setting purposes is between $50 million and $80 million. MPI's Board of Directors maintained the range ought to be $80 million to $100 million while it was committed to transferring to the Basic RSR funds in excess of certain levels of retained earnings in MPI's Special Risk Extension ("SRE") and Extension divisions. The transfer from SRE for fiscal 2004 was $4.0 million, and was projected to be $1.6 million in fiscal 2005, although in last year's GRA, MPI had forecasted an SRE transfer of $3.0 million. If the applied for rates were approved, the forecast for the RSR level was $38.2 million for fiscal 2004, and down to $25.9 million for fiscal 2005, with both amounts well below the Board's minimum RSR target of $50 million.

MPI indicated the actuarially indicated rate for fiscal 2005 was 4.3% assuming a consumer price index ("CPI") of 3.0%. Although reasonable at the time of submitting its GRA, the Board considers that CPI figure to be excessive. The Board noted that recent forecasts by the Governor of the Bank of Canada and various consensus forecasts indicate a CPI of 2% as being more likely.

Bearing in mind a CPI of 2%, the Board estimated a premium revenue increase of 3.7% affords MPI with a better opportunity of achieving a break-even net income in fiscal 2005. It will also ward off any further deterioration in the current RSR level. The Board ordered MPI to refile its rate schedules and related documents including Major Vehicle Class impacts to reflect the increase of 3.7% in overall vehicle premium revenue in fiscal 2005.

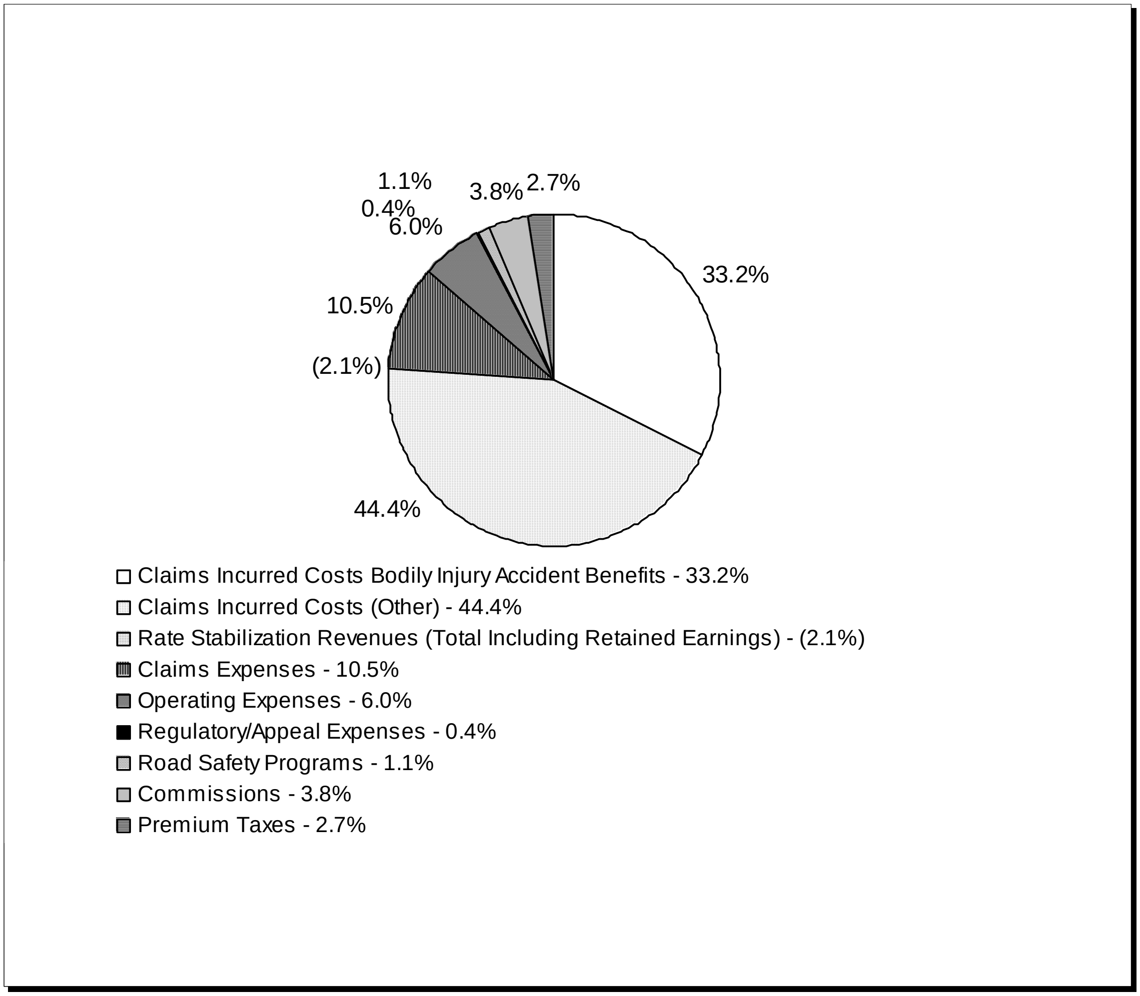
At the hearing, evidence was presented relative to the possible adoption of a loss transfer mechanism as an alternative to MPI's current method of calculating premium levels based on costs attributed to Major Vehicle Classes, regardless of fault. Upon review of the issues surrounding the adoption of a loss transfer model, the Board determined that there was no compelling reason to abandon the current system of assigning costs on a first party basis in favour of a loss transfer model.

The Board was concerned with the magnitude of required motorcycle rate increases experienced over the past decade. Notwithstanding annual increases of approximately 15% to the Motorcycle Class over that period, current motorcycle rates still remain well below the actuarially indicated rate. This was primarily due to serious losses in that class. The Board was not persuaded that claims costs and expenses paid to or on behalf of members of any Major Class should be borne by members other than from that class. MPI and the Board wish to halt the cross-subsidization of the Motorcycle Class by other classes.

Rather than applying experience-based adjustments to the Motorcycle Class in fiscal 2005, MPI opted to combine rate increases in accordance with the actuarially indicated requirements, while capping individual rate group increases at 30%. The Board, however, limited the capping to 20% which will result in a 14.91% average overall increase in motorcycle premiums rather than the 19.93% which MPI originally proposed.

A report on MPI's road safety program as well as recommendations by various stakeholders in response to that report was reviewed by the Board. The Board was encouraged with the responses received and stated that it would like to see all stakeholders taking an active role in advancing their respective areas of expertise with respect to road safety and thus eventually reducing insurance costs for Manitoba motorists.

FIGURE 3

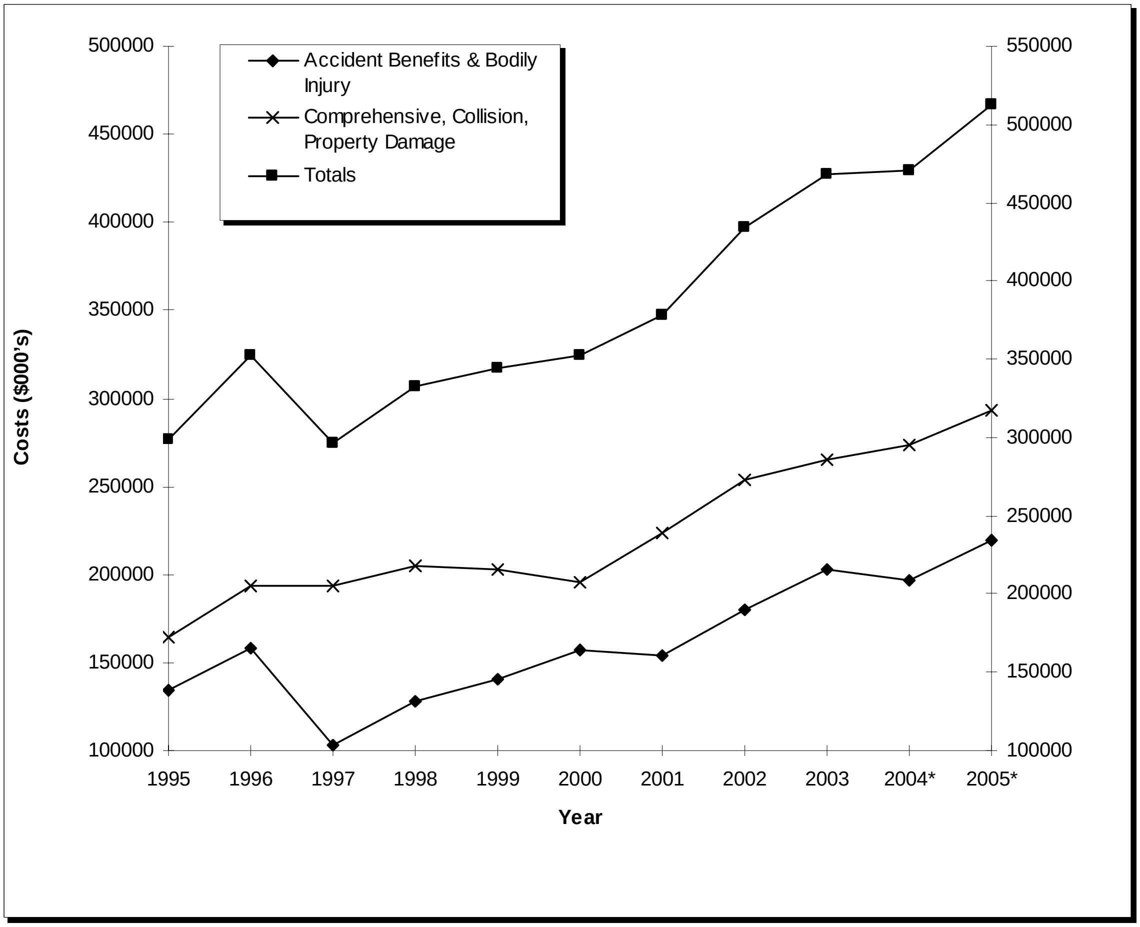


2004/2005 INSURANCE YEAR
(Estimated by Financial Forecast Method)

DISTRIBUTION OF NET REVENUES
BASIC DIVISION

Manitoba Public Insurance

FIGURE 4



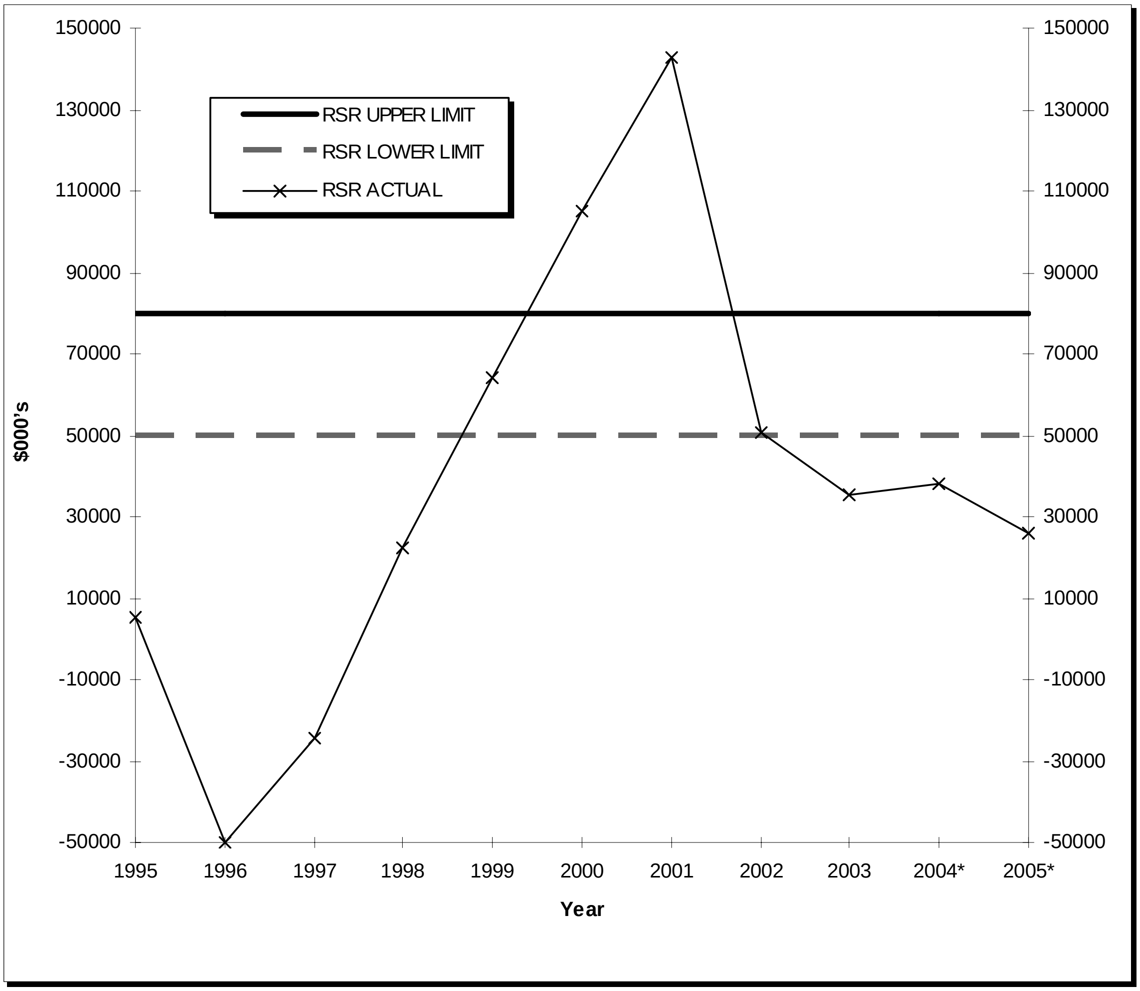
MANITOBA PUBLIC INSURANCE
CLAIMS INCURRED COSTS

Basic Division

Insurance Year Ending February 28

FIGURE 5

MANITOBA PUBLIC INSURANCE
BASIC RATE STABILIZATION RESERVE



Upper RSR limit of $80,000 and Lower RSR limit of $50,000 as Approved by The Public Utilities Board

Insurance Year Ending February 28

THE MUNICIPAL ACT

WATER AND SEWER UTILITIES

The Board issued a total of 63 Orders respecting applications filed with the Board by local municipal authorities, as set out below:

(i) 42 Orders were issued respecting applications for approval and authorization for methods of recovery pertaining to operating deficits.

(ii) 21 applications for revisions, amendments to or establishment of rates were processed and Orders were issued authorizing same. Board guidelines which have been prepared and distributed to local authorities were applied wherever possible to assist with rate design and to ensure that sufficient revenue would be provided to cover normally anticipated operating expenses plus an adequate contingency allowance. Applications were handled by public hearing or returnable date notice. In all cases the municipalities and affected water and sewer customers were served appropriate notice.

Board staff assisted applicant municipalities and others contemplating changes and seeking guidance in the preparation of their applications thus reducing the cost to the municipalities in preparing a report. Board staff met with municipal representatives to ensure that applications were filed in the form prescribed by the Board, pursuant to statute. In most instances, these applications required the preparation of rate studies, and when necessary, public hearings were held in the applicant municipalities.

THE HIGHWAYS PROTECTION ACT

Pursuant to Section 21 of The Highways Protection Act the Board is the appeal body to decisions of The Highway Traffic Board (HTB) respecting applications for permits for the change in use of an access driveway, the relocation of an access driveway, or the construction of an access driveway onto a Limited Access Highway (LAH) and also, the building of structures within the control limits of LAH.

The Board conducted six hearings in 2003. Four of the applicants had been denied access to a Provincial Trunk Highway by the HTB and were also denied an appeal by the Board. A fifth applicant was granted access by the HTB but upon appeal by the Department of Transportation access was denied. The sixth appeal concerned the introduction of a frequently changing electronic sign on an existing sign structure. This was denied by the Board as it was deemed to be a safety risk to all motorists.

THE PREARRANGED FUNERAL SERVICES ACT

Pursuant to The Prearranged Funeral Services Act, the Board is responsible for licensing companies selling prearranged funeral plans and for reviewing the operations of these firms as to conformity with statutory requirements.

In 2003, the Board issued 23 renewal licences. Sixteen applications for revisions in fees for services were acknowledged.

The Board continued to review and monitor the annual reports filed by the licensees and their trustees in respect of the prearranged funeral plans being sold and the contracted funds maintained in trust.

THE CEMETERIES ACT

Pursuant to Part III of The Cemeteries Act, the Board reviews applications and issues licences to the owners of cemeteries, columbariums and mausoleums that are owned and operated for gain and if not owned and operated for gain, where more than 15 sales of plots occur in any year. Cemeteries related to religious denominations or owned by municipalities are not required to be licensed by the Board.

Pursuant to Part II of the Act, the Board approves the plans of and issues licences for the operation of crematories.

During the year the Board issued renewal licences for the operation of 11 cemeteries, 31 columbariums and 1 initial, 5 mausoleums and 13 crematories and 2 initial.

83 licences and 1 transfer licence to sell cemetery services were issued either to owners or to their sales personnel. In addition, 10 applications for revisions in schedules of fees for spaces, materials and services were authorized and 3 applications for initial fees.

The Board continues to monitor the licensee's compliance for the passing of accounts in respect of perpetual care funds collected and deposited in trust funds with authorized trustees pursuant to The Cemeteries Act.