E.B.R.O. 495

IN THE MATTER OF the Ontario Energy Board Act, R.S.O. 1990, c. O.13;

AND IN THE MATTER OF an Application by The Consumers' Gas Company Ltd. for an order or orders approving rates to be charged for the sale, distribution, transmission and storage of gas for its 1998 fiscal year.

BEFORE: P. Vlahos
Presiding Member

E.J. Robertson
Member

H.G. Morrison
Member

DECISION WITH REASONS

August 21, 1997

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APPENDICES

1. INTRODUCTION

1.1 THE APPLICATION AND PROCEEDING

1.1.1 On December 13, 1996, The Consumers' Gas Company Ltd. ("Consumers Gas" or "the Company") applied to the Ontario Energy Board ("the Board") pursuant to section 19 of the Ontario Energy Board Act (the "Act") for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas for the Company's 1998 fiscal year commencing October 1, 1997 (the "test year"). The Application was given Board File No. E.B.R.O. 495, and the related Notice of Application was issued December 19, 1996.

1.1.2 Pursuant to Procedural Order No. 1, a number of events occurred. A technical conference was held on February 3, 1997. On February 5, 1997, an issues conference was held for the purpose of developing an issues list. The proposed issues list was presented to the Board for its consideration on February 7, 1997. Under Procedural Order No. 1 dates were set for the filing of interrogatories and responses, and for the submission of intervenor and Board Staff evidence. The Order also made provision for the settlement conference which commenced on April 9, 1997.

1.1.3 On February 10, 1997, Procedural Order No. 2 was issued to finalize the Issues List.

1.1.4 On March 27, 1997, Procedural Order No. 3 was issued to direct parties to use the *Ontario Energy Board Draft Guidelines on a Formula-Based Return on Common Equity For Regulated Utilities*. This Procedural Order also provided for the inclusion on the issues list of certain issues arising from the creation of Consumers First Ltd. ("Consumersfirst") and expressed the Board's requirement for the full examination of certain other issues in the hearing. The purpose of this requirement was to exclude these issues from possible settlement in the Settlement Conference.

1.1.5 On April 17, 1997, Procedural Order No. 4 was issued to provide for the filing of interrogatories and responses relating to the Company's evidence by Dr. Cronin, pertaining to the issue of Comprehensive Cost Allocation.

1.1.6 The oral hearing commenced on May 7, 1997 and lasted 21 days ending on June 6, 1997. The argument phase was completed on July 11, 1997.

1.1.7 According to the Company's initial filing, an overall gross revenue deficiency of approximately $59.6 million would exist in fiscal 1998 based on current rates. Three updates were submitted with respect to the Company's initial filing.

1.1.8 The first update, Impact Statement No. 1, reduced the gross revenue deficiency by $61.7 million, resulting in a revenue sufficiency of $2.1 million. This change was primarily due to the implementation of the E.B.R.O. 492-02 rates, which incorporated higher gas costs.

1.1.9 The second update, Impact Statement No. 2, reduced the gross revenue sufficiency by $8.1 million, resulting in a gross revenue deficiency of $6.0 million. The change was attributed mainly to the removal of the Customer Information System ("CIS") expenditures from rate base for the test year. Due to its high Capital Cost Allowance for income tax purposes, removal of this item increased the Company's revenue requirement.

1.1.10 The third and final update, Impact Statement No. 3, increased the gross revenue deficiency by $54.7 million to $60.7 million. The change in gross deficiency resulted largely from updated gas commodity cost forecasts and updated storage and transportation charges and tolls.

1.2 THE SETTLEMENT PROPOSAL

1.2.1 A settlement conference was held by the parties commencing April 9, 1997. The final results of the Settlement Proposal were presented to the Board on April 29, 1997. Thirteen parties participated in the settlement conference. Board Staff, while present at the settlement conference, was not a party to the Settlement Proposal.

1.2.2 The Board reviewed the prefiled evidence as well as the rationale provided in the Settlement Proposal for settled issues. The Board advised the parties that it accepted the Settlement Proposal, subject to clarification of certain issues, and required that these issues come before the Board.

1.2.3 The Board reminded parties that it has the authority to take administrative notice of significant external events which may affect the settled issues. The Board also noted that there may be situations where, due to connectivity, a settled issue may be affected by the Board's findings on a non-settled issue.

1.2.4 The Settlement Proposal is attached as Appendix E to this Decision. The impact of the Settlement Proposal reduced the updated gross revenue deficiency by $2.1 million to $58.6 million, the details of which are shown in Appendices A to D.

1.3 EVIDENCE AND ARGUMENTS

1.3.1 Copies of all the evidence, exhibits and argument filed in the proceeding, together with a verbatim transcript of the hearing, are available for review at the Board's offices.

1.3.2 While the Board has considered all of the evidence and submissions presented in this hearing, the Board has chosen to summarize these only to the extent necessary to clarify specific issues on which it has made findings. Complete submissions of the parties are available for review at the Board's offices.

1.4 PRESENTATION OF ISSUES

1.4.1 The presentation of issues follows generally the Board's established practices. As a result, the issues presented do not necessarily follow the order on the Issues List. Also, some of the issues are subsumed by others; therefore, not every issue shown on the Issues List appears specifically in the Decision.

1.4.2 Where the Board's findings on certain issues are conclusive to the determination of other linked issues, the Board has presented and discussed these issues only to the extent necessary for completion of the discussion of any remaining matters. This is particularly pertinent in Chapter 2 where the Board's finding on the appropriate cost methodology to be applied to the Company's non-core activities obviates the need for a full discussion of, for example, the positions of the parties on the appropriate cost allocation method to be applied when individual ancillary programs are discussed. This is also evident in the discussion of deferral accounts in Chapter 8 where certain issues that impact the determinations on deferral accounts have been addressed and decided elsewhere in the Decision.

1.4.3 Although, with the exceptions noted above, the Board had accepted the settled issues at the opening of the hearing, for purposes of setting the background and for completeness, the settled issues are also set out in the Decision. Under each chapter, the settled issues are presented first. Generally, no Board findings follow the description of the settled issues, except where the Settlement Proposal requires the Board to deal with specific matters or where some commentary or explanation is warranted due to, for example, connectivity with other issues or due to updates. In no circumstances does the Board alter the letter or intent of the settled issues which the Board had accepted in its statement on the first day of the hearing.

1.4.4 In situations where there was partial agreement on an issue, i.e. some parties agreed to a specific settlement of that issue, the Board does set out the nature of the agreement along with the positions of parties who may have presented argument.

1.5 PARTIES TO THE PROCEEDING

1.5.1 The following is a list of parties who intervened in the proceeding and their representatives. Not all parties appeared or participated actively in the hearing. In addition to the Company, fourteen parties filed argument. Board Staff cross-examined but did not file argument. The Director of the Competition Bureau ("Competition Bureau") cross-examined, filed argument, but did not participate in the settlement conference.

Consumers Gas	Jerry Farrell Fred Cass
Board Staff	Jennifer Lea Kelly McKinnon
Consumers Association of Canada (“CAC”)	Robert Warren
Ontario Coalition Against Poverty ("OCAP")	Michael Janigan
Suncor Inc. ("Suncor")	Peter Budd George Vegh
PanEnergy Marketing Limited Partnership ("PanEnergy")	Peter Budd George Vegh
Pollution Probe Foundation ("Pollution Probe")	Murray Klippenstein
Green Energy Coalition (“GEC”)	David Poch
Canadian Industry Program for Energy Conservation ("CIPEC") replaced by the Alliance of Manufacturers and Exporters Canada ("Alliance")	Beth Symes
The Heating, Ventilation and Air Conditioning Contractors Coalition Inc. ("HVAC")	Ian Mondrow

Energy Probe Foundation ("Energy Probe")	Mark Mattson
NGC Canada Inc.	Glen Caughey
Enron Capital and Trade Resources Canada Corp. ("Enron")	Mahmud Jamal Aleck Dadson
Union Gas Limited/Centra Gas Ontario Inc. ("Union/Centra")	John Lucki
Ontario Association of Physical Plant Administrators ("OAPPA")	Michael Morrison
Industrial Gas Users Association ("IGUA")	Peter Thompson
Competition Bureau	Mark Ronayne
Association of Municipalities of Ontario ("AMO")/ECNG Inc. ("ECNG")	Peter Scully

1.6 WITNESSES

1.6.1 Consumers Gas called the following employees as witnesses:

L.A.E. Beattie	Vice President, Financial Services
J.M. Barton	Director, Retail Marketing
F. Botticella	Manager, Rental Business Development
M. Butler	Manager, Commercial/Apartment Sales and Marketing Energy Services
D.B. Charleson	Director, Accounting Systems
M.P. Duguay	Manager, Rate Research
J.P. Gould	Director, Budgets and Forecasts
J.B. Graham	Director, Customer Information Systems

J.C. Grant	Director, Rates and Regulatory Affairs
I. Gunel	Manager, DSM Monitoring and Evaluation
A.M. Hayward	Staff Assistant, Financial Reporting
J.A. Holder	Vice President, Energy Services
D.M.S. Kent	Vice President, Information Services
S.F. Kokotka	Manager, NGV Product Development
W.M. Laskaris	Director, Distribution Operations Marketing
T.E.M. Lawrence	Senior Analyst, Gas Supply Risk Management
M.P. Levac	Manager, Upstream Regulatory Proceedings
L.M. Luison	Manager, New Business Development
A.J. Maclure	Director, Transportation Contracting
W.G. Martin	Director, Information Technology Quality Assurance and Budgets
S.H. McGill	Manager, Customer Support Services, Planning and Analysis
C.J. McLorg	Manager, Rate Design
D.C. Morton	Director, Billing Services
S.D. Noble	Supervisor, Financial Statements
J.D. Oakley	Manager, Regulatory Accounting
J.A. Parr	Vice President, Human Resources
R.F. Riccio	Manager, Financial Statement Forecasts
L.F. Scavuzzo	Supervisor, Gas Costs Accounting
A.P. Skalski	Manager, System Expansion

D.R. Small	Manager, Gas Costs and Budgets
G.P. Stover	Director, Utility Ventures
W.B. Taylor	Director, Financial and Economic Studies
A. Wilson	Director, Market Planning and Evaluation
M.A. Wolnik	Director, Operations Work Management Systems
R.C. Wood	Vice President, Customer Support
L.W. Youell	Senior Vice President, Business Support

1.6.2 Consumers Gas called the following additional witnesses:

F.J. Cronin	Principal, Hagler Bailly Consulting, Inc.
K.C. McShane	Senior Consultant and Vice President, Foster Associates, Inc.
D. Nichols	Vice President, Tellus Institute

1.6.3 Suncor called the following witness:

S.L. Chown	Principal, Industrial Economics, Incorporated

1.6.4 GEC called the following witness:

P.L. Chernick	President, Resource Insight

1.6.5 OCAP called the following witnesses:

L.D. Booth	Professor of Finance, University of Toronto
J.D. Todd	President, Econalysis Consulting Services

1.6.6 CAC, Energy Probe, HVAC, IGUA, and OCAP called the following witness:

G.R. Edgar	Executive Director, Wisconsin Energy Conservation Corporation

1.6.7 HVAC called the following witness:

D.J. Effron	Berkshire Consulting Services

1.6.8 Board Staff called the following witness:

G.S. Roberts	Professor of Finance and Director, Financial Services Program, York University

Letters of Comment

1.6.9 The Board received a total of six letters of comment from organizations and individuals expressing concerns regarding the Company's request to increase rates.

2. COST ALLOCATION/ANCILLARY PROGRAMS/NON-UTILITY ELIMINATIONS/AFFILIATE TRANSACTIONS

2.0.1 Consumers Gas' core business activities are in the distribution, transmission, and storage of gas. These activities are regulated by the Board. Consumers Gas also provides a number of ancillary services which are viewed as complementary, but not essential, to the core business. The existing ancillary programs are:

- Rentals
- Merchandise Sales Program
- Heating Insurance Program ("HIP")
- Natural Gas Vehicle ("NGV") Program
- Agency Billing and Collection Transportation Service ("ABC T-Service")

2.0.2 These ancillary activities, with the explanation noted below regarding the NGV program, are not regulated; the Company sets the prices for these services. The Board includes the revenues and costs of these activities in the determination of the Company's revenue requirement for a test year. Currently, the cost allocation applied to these programs is on a marginal cost basis. The Board's review focusses on issues of cross subsidy of ancillary operations by the core business. The combination of the core and ancillary business are often referred to as the utility operations.

2.0.3 The NGV program involves the delivery and sale of gas to outlets for resale to the public; the program also involves the Company's investment in equipment and certain other activities aimed at promoting the program. Pursuant to the Act, the Board approves or sets the rate for the gas delivered and sold by the Company. The Board does not set any rates or charges associated with the Company's other activities in the NGV program, activities which may be viewed as the ancillary part of the program.

2.0.4 As part of the utility operations, the Company engages in certain other activities, such as furnace maintenance tune-up, home gas appliance inspection, and appliance repair and maintenance services. These activities have not been given the status of ancillary programs, i.e., revenues and costs are not separated for regulatory purposes.

2.0.5 The Company also engages in what are referred to as non-utility activities. These relate to the employment of the Company's competencies and resources outside the utility operations. Non-utility activities also involve the provision of services, known as affiliate transactions, to the Company's subsidiaries and affiliate companies. Examples are the management and other services associated with the York Region water project, and the provision of billing services to its affiliate, Gazifère Inc. Affiliate transactions also refer to the receipt of services by the regulated utility from the Company's affiliates. An example would be treasury services the Company receives from its ultimate parent, IPL Energy Inc. ("IPL").

2.0.6 In approving or setting rates for the Company's ratepayers, the regulatory review includes an assessment of the reasonableness of the Company's costing or pricing arrangements for such non-utility activities. Costs and revenues are eliminated from the utility cost of service because they relate to non-utility activities. This process is referred to as a non-utility elimination. In most instances the cost amounts, and in all cases the revenue amounts, can be segregated from the Company's accounts.

2.0.7 However, the costs associated with the Company's corporate departments' involvement in non-utility activities are included in the utility's Operating and Maintenance ("O&M") expenses. Such costs are identified through a cost allocation procedure. Currently, this allocation procedure is done on a fully allocated cost basis ("FAC"). A full cost allocation method attributes higher costs to these activities compared to marginal costing, where the common costs are distributed between the utility and non-utility activities by means of cost allocators.

2.0.8 In addition, the Company's Merchandise Finance Program ("MFP") is treated as an ancillary activity, in that costs to be eliminated are calculated on a marginal cost basis. However, unlike those of other ancillary programs, the revenues from MFP are not incorporated in the overall determination of the Company's revenue requirement.

2.0.9 The issues pertinent to this hearing and discussed in this Chapter are captured under: cost allocation; ancillary programs; non-utility eliminations; and affiliate transactions. There was no settlement of these issues.

2.1 COST ALLOCATION

2.1.1 As part of the E.B.R.O. 492 Alternate Dispute Resolution ("ADR"), Consumers Gas committed to undertake a Comprehensive Cost Allocation Study regarding the allocation of costs to ancillary and non-utility activities and the pricing of affiliate transactions. The Company submitted a concept paper ("White Paper") prepared by Foster Associates, and testified to by Ms. McShane of that firm. Prefiled evidence was also submitted by Mr. Edgar on behalf of the following group of sponsoring intervenors: CAC, Energy Probe, HVAC, IGUA, and OCAP. Mr. Edgar's evidence presented a review of the appropriateness of the Company's cost allocation proposals.

2.1.2 The Company engaged Dr. Cronin to rebut Mr. Edgar's evidence. Ms. McShane also co-authored additional evidence with Company employees in rebuttal to Mr Edgar's evidence. Pre-filed evidence on specific cost measurement issues was submitted by Mr. Effron on behalf of HVAC. A brief commentary on the Company's proposal was also presented by Ms. Chown on behalf of Suncor.

The Evidence

White Paper and Ms. McShane's Evidence

2.1.3 The White Paper recommended, and Consumers Gas proposed to adopt, a form of incremental costing referred to as the Uniquely Attributable Costs ("UAC") methodology.

2.1.4 Uniquely attributable costs were defined as those costs which would be eliminated in the forecastable future (a forecast horizon of 5 years was recommended) if all ancillary and non-utility activities were eliminated or removed at the current level of activity, all else being equal.

2.1.5 The White Paper noted that the introduction of a time horizon (5 years) allows the notional adjustment of the level of utility plant, equipment, labour and other expenses within the constraints imposed by the divisibility, economic replacement or redeployment of assets and the interchangeability and reorganization of labour. According to the White Paper, the time horizon distinguishes the approach from a short term incremental cost approach which measures only those out-of-pocket costs which would be eliminated in the test year. The White Paper also stated that the approach is distinguishable from a long term incremental cost approach which rests on the "unrealistic" assumption that all costs are variable.

Implementation of the Methodologies

2.1.6 The Company accepted the White Paper's costing methodology recommendation and filed evidence as to its implementation. However, the Company's filing for the test year reflects the existing methodology (marginal costing for ancillary activities and the MFP and full costing for non-utility eliminations).

2.1.7 According to the Company's evidence, to identify these uniquely attributable costs, it was necessary to determine the following:

- the impact on the Company's current employee structure and labour costs if the ancillary service and non-utility activities did not exist, i.e. the reduction in full time equivalents ("FTEs");
- the impact on the Company's non-salary O&M costs if the ancillary and non-utility activities did not exist;
- the impact on the Company's support departments given the impact of the FTEs and non-salary costs identified; and
- the impact on capital investments, space requirements and other infrastructure costs.

2.1.8 The Company categorized each of its departments as follows:

- Direct Service and Support. These departments provide a direct service or support to one of the ancillary and/or non-utility activities or their customers. Examples are: Systems Operations and Engineering, Gas Supply, Customer Accounting, Regional Customer Accounting and Marketing.
- Secondary Support. These departments, while they may provide direct support to an ancillary and/or non-utility activity, primarily support the other departments within the Company. Examples are: Training and Development, Information Services, Land and Facilities Management.

2.1.9 The Company conducted workshops with department managers and directors to determine the impact of the ancillary and non-utility activities on employee structure, labour costs and non-salary O&M costs. The workshops involved the presentation of a hypothetical department and activity analysis prepared for cost allocation purposes. According to the evidence, participants discussed the transferability of skill, department peaking requirements, etc. to determine future avoided costs under UAC. The results of the workshops were reviewed by various levels of management.

2.1.10 The Company requested that the Board accept the non-utility elimination determined by the UAC methodology in conjunction with a set of proposed affiliate transaction pricing guidelines. The guidelines specify as follows:

- if there is a market price for the specific service sold to the affiliate (i.e., the Company usually offers the service in the market), and the market price is greater than the costs to the utility, the transfer price would be market price;
- if there is a market price for the specific service sold to the affiliate, and the market price is lower than the costs to the utility, the transfer price would be cost; and
- if there is no market price for the specific service sold to the affiliate, the transfer price would be a negotiable price within the following limits: not less than causal costs, and not greater than the cost which the affiliate would incur to perform the service itself.

2.1.11 Where a market price is not available or reasonably determinable, the Company proposed that services be priced to recover:

- the direct labour costs and the associated fringe benefits of the employees providing the service;
- an appropriate share of other department specific overhead in support of providing these services; and
- the causal support and overhead costs identified through the determination of uniquely attributable costs.

2.1.12 In the E.B.R.O. 492 ADR Agreement, the Company agreed to provide the results of applying the FAC method to its ancillary activities in the manner recommended at that time by Mr. Edgar. The Company stated that these results were provided to Mr. Edgar who agreed the results were a reasonable representation of an FAC methodology. The results of the marginal and full costing methodologies are shown in Table 2.1 below. The results of the uniquely attributable approach are shown in Table 2.2. In both tables, the results do not include costs charged directly to the ancillary and non-utility programs. It is also noted in the table that fully allocated costs are the sum of the marginal and allocable costs.

Table 2.1:

COST ALLOCATION STUDY
1998 MARGINAL AND FULLY ALLOCATED COST ALLOCATIONS[1]

	Ancillary Programs ($000)		Non-Utility Programs ($000)	
	Marginal	**Fully Allocated[2]**	**Marginal**	**Fully Allocated[2]**
Primary Service and Support Departments				
Comptroller[3]	2,069.1	4,753.5	61.5	136.8
Corporate Services	877.7	1,190.1	28.8	228.3
Financial	148.8	303.0	330.3	642.5
Gas Supply	-	45.9	23.5	197.9
Marketing	1,587.3	1,782.8	187.2	254.6
Public Affairs and Communication	206.7	305.6	19.6	99.9
Regional				
Administration	1,260.5	4,132.3	-	20.0
Operations	823.0	1,473.5	35.8	494.9
Sales and Business Development	387.2	1,381.2	-	82.3
Regulatory Affairs	-	2.8	1.2	47.0
System Operations and Engineering	36.4	208.1	10.4	139.8
Other				
Executive and Area Administration	-	222.6	15.2	455.6
Internal Audit	29.8	37.7	32.4	37.1
IPL Treasury Fee	20.3	20.3	-	-
Business Dev. and Strategic Planning	-	-	75.1	136.3
Secondary Support Departments				
Comptroller[4]	488.6	2,094.8	4.1	226.0
Information Services	1,265.7	5,761.9	31.8	535.7
Human Resources	66.3	978.9	22.5	298.8
Fringe Benefits	1,826.3	2,795.1	172.4	377.4
Other areas				
Corporate Organization Sustaining Costs	-	1,042.4	-	51.1
Depreciation on Computer Equipment	697.1	4,145.4	20.7	401.0
SIM amortization	285.7	1,972.7	-	199.3
TOTAL	12,076.5	34,650.6	1,072.5	5,062.3

Note:
1. Study results do not include costs charged directly to the ancillary or non-utility programs.
2. Fully allocated costs are the sum of the marginal and allocable costs.
3. Includes Comptroller areas providing direct service or support to the programs
4. Includes Comptroller areas providing secondary support functions to the programs.

Source: Exhibit D2,T7,S8

2.1.13 The Company retained the services of Arthur Andersen Consulting to help it apply both the FAC and the UAC methodologies. Arthur Andersen did not testify at the hearing.

Table 2.2:

COST ALLOCATION STUDY 1998 COST ALLOCATIONS[1] BASED ON THE UNIQUELY ATTRIBUTABLE APPROACH		
	($000)	
	Ancillary Programs[2]	**Non-Utility Programs[2]**
Primary Service and Support Departments		
Comptroller[3]	2,200.1	132.0
Corporate Services	912.3	200.7
Financial	231.7	620.2
Gas Supply	26.4	193.2
Marketing	1,680.9	222.2
Public Affairs and Communication	208.9	77.3
Regional		
Administration	1,490.5	10.0
Operations	877.0	450.2
Sales and Business Development	669.9	82.5
Regulatory Affairs	-	46.9
System Operations and Engineering	97.1	273.4
Other		
Executive and Area Administration	307.8	624.1
Internal Audit	33.0	37.1
IPL Treasury Fee	20.3	-
Business Dev. and Strategic Planning	-	136.3
Secondary Support Departments		
Comptroller[4]	1,119.4	135.7
Information Services	1,600.4	174.6
Human Resources	350.6	124.0
Fringe Benefits	1,967.8	281.7
Other areas		
Corporate Organization Sustaining Costs	-	100.0
Depreciation on Computer Equipment	745.0	56.9
SIM amortization	285.6	-
TOTAL	14,824.7	3,979.0

Note:
1. Study results do not include costs charged directly to the ancillary or non-utility programs.
2. Fully allocated costs are the sum of the marginal and allocable costs.
3. Includes Comptroller areas providing direct service or support to the programs
4. Includes Comptroller areas providing secondary support functions to the programs.

Source: Exhibit D2,T7,S5&6

2.1.14 The Company calculated the impact of the different costing methodologies on the over/under earnings of the ancillary programs, on an aggregate basis, for the 1998 test year relative to the equivalent earnings resulting from the proposed overall rate of return on rate base. Relative to the proposed overall rate of return on a before-tax basis, the Marginal Cost approach yields overearnings of $13.7 million, and the FAC approach yields underearnings of $8.4 million. For comparison, the Company's proposed UAC approach would yield overearnings of $11.6 million.

2.1.15 The forecast fiscal 1998 rate of return on capital employed under the three methods for each of the existing ancillary programs and one proposed ancillary program, the St. Catharines Hydro Electric Commission ("SCHEC") project, are shown in Table 2.3 below.

Table 2.3:

RATE OF RETURN ON CAPITAL EMPLOYED			
Existing/Proposed Ancillary Program	**Marginal %**	**Fully Allocated %**	**Uniquely Attributable %**
ABC T-Service	184.4	(193.4)	58.8
Rentals	11.37	10.06	11.24
Merchandise Sales	(7.27)	(17.09)	(8.01)
HIP	1,065.02	190.54	883.76
NGV	9.62	4.54	8.88
SCHEC	14.9	(19.3)	4.6
Source: Exhibit D2,T7,S9			

2.1.16 With respect to the non-utility eliminations, the evidence was that the Company's UAC approach, in conjunction with the proposed transfer pricing methodology, reduced total eliminations by $0.7 million for the test year compared to the current FAC methodology.

2.1.17 With respect to the MFP, the UAC approach resulted in an elimination of $2.6 million compared to $2.2 million under marginal costing for this program. The application of the FAC approach on the MFP would result in an elimination of $3.6 million.

Mr. Edgar's Evidence

2.1.18 Mr. Edgar disagreed with the UAC approach on the basis that:

- the UAC methodology allocates all of the cost savings from shared use to competitive ancillary and non-utility functions, thereby understating the actual cost to provide services under these functions and overstating the actual cost to provide utility service;
- by focussing solely on costs rather than market value, the Company is pricing services and benefits to its ancillary and non-utility operations at levels that it would be unwilling to give to a third party; and
- using UAC results in the transfer of tangible and intangible benefits without charge or restriction to competitive services, thus creating an unfair competitive advantage for utility competitive services and non-utility affiliates.

2.1.19 Mr. Edgar suggested that, as a general rule, the transfer of goods and services "not for sale" or involving captive relationships should be priced on a fully allocated cost basis. The transfer of goods and services "for sale" should be priced asymmetrically. If the sale of the good or service is from the utility the value used should be the higher of cost or market price. According to Mr. Edgar, this assures that the utility does not provide a good or service below its cost. If the purchase is by the utility from the affiliate, the value should be the lower of market price or the cost to the affiliate. Mr. Edgar noted that this asymmetry ensures against self-dealing.

2.1.20 Mr. Edgar recommended that the Board should require that Consumers Gas adopt an FAC methodology and prepare and file a cost allocation manual based on this methodology. Mr. Edgar also suggested that the Board require Consumers Gas to file costing and pricing guidelines for the Board's review. He recommended the establishment of a schedule and a process for independent audit of the Company's application of its costing policies and procedures.

Dr. Cronin's Evidence

2.1.21 Dr. Cronin's evidence critiqued Mr. Edgar's evidence, focussing on two major areas: first, the competitive impacts of Consumers Gas' ancillary programs on the commercial market in which they operate; second, the effect of the cost allocation procedures on market competition and the limitations of the FAC approach.

2.1.22 On the competitive impacts, Dr. Cronin concluded that:

- the market for gas equipment and appliances is not competitive as suggested by Mr. Edgar; and
- the Company's ancillary programs have the potential to offer several important benefits, including:
  - providing products and services demanded by customers;
  - supplying quality and reliable services to customers;
  - creating high equipment standards;
  - providing better information to customers; and
  - improving business opportunities for area contractors and dealers.

2.1.23 On the limitations of the FAC approach, Dr. Cronin's evidence was that the arbitrary assignment of shares of costs that have little to do with ancillary services creates market signals that result in inefficient outcomes for society. An efficient producer may be excluded and customers would face higher prices, thereby hindering the maximization of consumer welfare.

The Company's and Ms. McShane's Additional Evidence

2.1.24 The Company, and Ms. McShane, filed additional combined evidence in rebuttal to the assumptions and conclusions reported in Mr. Edgar's evidence. The thrust of their rebuttal evidence was that:

- Mr. Edgar's conclusions are potentially incomplete and unfounded as he appears to erroneously assume that costing and pricing, as presented by the Company's evidence, are one and the same;

- ! Mr. Edgar wrongly alleges that the UAC approach allocates all of the cost savings from shared use to competitive ancillary or non-utility functions;
- ! Mr. Edgar is wrong in his assertion that the Company has proposed a costing methodology to justify price discrimination;
- ! Mr. Edgar has in certain circumstances misinterpreted the application of the UAC approach; and
- ! Mr. Edgar has failed to assess the FAC approach against the same criteria he uses to critique the UAC approach.

Mr. Effron's Evidence

2.1.25 According to Mr. Effron, his initial assignment was to review the Company's application of the allocation methods. He testified that he had not been able to obtain all necessary documentation from the Company and that the information presented by the Company was not adequate to verify whether the allocation methods were applied properly and captured all the costs that should be allocated. Mr. Effron's evidence then dealt with a description of the additional documentation and information that would, in his view, be necessary to verify the Company's application of the allocation methods.

Ms. Chown's Evidence

2.1.26 In her prefiled evidence, Ms. Chown contended that from an economic standpoint, it is desirable to have a regulated utility offer an ancillary service only if, due to market failure, unregulated companies are unwilling to offer a needed service or, due to the presence of significant economies of scope, it is more efficient for the regulated utility to offer the service. In Ms. Chown's view, neither of these conditions exist and therefore the Company should not be allowed to offer these services. In oral testimony, she noted a number of deficiencies of the FAC approach and maintained that economic efficiency is best achieved where companies are competing on an incremental cost basis.

Positions of the Parties

2.1.27 Pollution Probe submitted that the Board should adopt the uniquely attributable costing methodology for ancillary activities. According to Pollution Probe, uniquely attributable costing reveals whether the ancillary services are raising, lowering or having no impact on the Company's regulated gas distribution rates and it reveals whether or not the Company is engaged in unfair, predatory pricing.

2.1.28 GEC submitted that the Board's first duty is to ensure that ratepayers enjoy the economies of scale and scope made available by reason of the existence of the utility. However, there are other ratepayer benefits from ancillary programs to be considered beyond economies of scale and scope, such as overcoming market barriers to energy efficiency and least cost energy services. GEC noted that while incremental costing is the choice methodology for economic efficiency, this is not to say that some allocation of the common costs is inappropriate. The Board's decision should be primarily determined by regard to other matters, including fairness and market impact. GEC submitted that for ancillary activities inside the utility, uniquely attributable costing should be the preferred method. However, GEC rejected the Company's transfer pricing proposal for services outside the utility. GEC supported charges beyond incremental costing, primarily due to the concern that there is potential incompleteness of an allocation based upon incremental costing. GEC recommended that the Company continue to use full costing for non-utility eliminations and affiliate pricing until such time as an appropriate contribution is determined.

2.1.29 IGUA submitted that, by reason of the Company's proposals, marginal costing is no longer an option; the contest is between uniquely attributable and full costing for ancillary activities and uniquely attributable with the overlay of transfer pricing and full costing for non-utility eliminations. In choosing between the two methods, IGUA submitted that the Board's primary consideration should be whether the common costs ought to be shared. IGUA argued that full costing should be preferred as, on the evidence, it is the practice of most gas utility tribunals and of corporations. According to IGUA, full costing achieves common cost sharing on a fair and equitable basis and appears to be this Board's preference as signalled in E.B.R.O. 493/494. IGUA submitted that the Company's reasons for rejecting full costing lack merit. With respect to the uniquely attributable method, IGUA argued that, while advanced as cost causal, it has a pricing focus, is complicated to apply year after year, is very subjective, highly dependent on assumptions, and the required regulatory oversight exceeds that of full costing. Further, it proceeds from the unfair premise that the sharing of common costs is inappropriate.

2.1.30 OCAP asserted that the uniquely attributable method is nothing more than an expensive way for the Company to "tighten up" its traditional incremental costing methodology for the purpose of providing its competitive and potentially competitive activities with a price advantage. OCAP argued that the uniquely attributable method violates the most basic principle of long run incremental costing, in that it does not allocate 100% of the long run economic costs to an activity, will permit cross-subsidization if the relationship lasts for more than the assumed five year period, and illogically assumes that all costs that are not incrementally caused by ancillary, non-utility or affiliate activities are caused by utility activities. Further, OCAP argued that the UAC distorts pricing by over-pricing utility services which results in emitting the wrong price signals leading to economic inefficiencies and therefore to wrong business decisions. In consequence, OCAP supported the application of full costing.

2.1.31 HVAC submitted that the "common sense answer" to the cost allocation question is full costing. It argued that "neither the size nor the primacy in time of either the core or the non-core business is a determinative factor" as to which should enjoy incremental pricing. HVAC argued that the uniquely attributable approach erroneously assumes all costs not causally connected to the non-core business must be causally related to the core business. In rebutting the argument that full costing would be tantamount to a straight jacket on the ability of non-core businesses to compete, HVAC provided examples to argue that, if left to price non-core services on an incremental basis, a utility will eliminate the competition. This, HVAC argued, had happened in the water heater business in Ontario. HVAC noted that the overall unreasonableness of uniquely attributable costing as applied by the Company can be seen by the Company's evidence that elimination of the non-core businesses, which comprise some 21% of the total revenue, would result in only a few employee position reductions. In view of Mr. Effron's testimony, HVAC also suggested that, as a cross check, the Company's application of the FAC methodology should be independently audited.

2.1.32 CAC submitted that the basic goals of a cost allocation methodology are those identified by Mr. Edgar, namely to limit or prevent, to the extent practicable, the cross-subsidization of one service or entity by another, and to minimize the time and effort needed to implement and oversee the methodology. It noted that since the uniquely attributable methodology represents a departure from both Consumers Gas' past practice and from accepted practice for gas utilities, the onus is on the Company to prove that its proposed method is appropriate, an onus which, according to CAC, the Company failed to meet. CAC adopted Mr. Edgar's criticisms of the uniquely attributable method and submitted that the overriding objective of this method is to enable the Company to compete at the lowest possible cost in non-monopoly markets, which, in CAC's view, is not an appropriate objective for a cost allocation methodology. CAC submitted that full costing, which is practiced in other jurisdictions in North America and by unregulated firms, should be adopted by the Board.

2.1.33 AMO recommended that, other than NGV where there is a need to effectively promote its use and expansion, all other non-core activities should be fully costed because of the relative ease for the regulator to exercise oversight.

2.1.34 Energy Probe stated that the issue of assigning common costs is inherently judgemental; there are benefits and disbenefits in each approach. The uniquely attributable method is fairer and more efficient than the short run marginal cost method currently used. However, it is not reasonable, according to Energy Probe, to expect that maximization of efficient use of utility resources can be attained in the actual business and regulatory environments. Disbenefits of the uniquely attributable method, according to Energy Probe, are a) the method's uniqueness will not allow the Board to benefit from developments in other jurisdictions, b) it is judgemental and artificial in that it relies on utility managers for assessment and cost estimation, c) it wrongly assumes that all costs not causally connected to the non-core businesses must be causally connected to the core business, and d) it is difficult for the regulator to oversee. Energy Probe recommended that the Company be directed to adopt full costing. Further, it recommended that the Company be directed to file, in its next main rates case, plans for separating legally and physically all non-core businesses by the year 2000.

2.1.35 Suncor/PanEnergy submitted that the Board should ensure that the ratepayers not only do not subsidize the non-core services but actually receive some benefits from having these services provided by the regulated utility. To achieve this, the Board can either require the use of full costing or specify a contribution over the uniquely attributable costs. Suncor/PanEnergy noted that the contribution of the ancillary activities for the test year is estimated by the Company at $11.6 million at the proposed 11.5% rate of return on common equity and suggested that this contribution amount is reasonable.

2.1.36 The Competition Bureau submitted that, in the absence of economies of scope, to promote effective and efficient competition, cost allocation should be avoided in favour of structural separation between core and non-core activities. If it is necessary to choose a cost allocation method, the Bureau supported the use of long run incremental costing. If a contribution is required toward the common costs, a fixed charge was recommended rather than a per-unit mark-up. The Bureau also suggested that the respective jurisdictions of the Board and the Bureau over ancillary services and affiliate transactions should be clarified to ensure effective oversight. On matters where the Board has jurisdiction, it should provide avenues for potential competition issues to be addressed. As an example, the Bureau suggested that the Board might expressly forbear from some aspect of its regulation in order to allow the application of competition law. Alternatively, the Board might allow for ongoing changes to be made in the way in which the natural gas sector is regulated in order to mitigate related competition concerns.

2.1.37 In reply, the Company reiterated the "shortcomings" of full costing and noted that this costing approach will have negative operating implications for several of the ancillary programs, including:

! NGV Rate 9 rates would have to be increased by 8¢ a litre; this magnitude of increase would reduce the price differential with gasoline to an unacceptable level. The Company's evidence was that it requires a price advantage of at least 40% for NGV to be competitive.
! Charges per bill for ABC T-Service would have to more than double to 87¢; this level of increase would likely have an impact on the take-up of the program.

! The integrated utilities services initiative, of which SCHEC is the first project, could be affected with respect to whether to proceed with the initiative or in what manner. For fiscal 1998 ratepayers would be losing benefits of $104,000 with the additional loss of benefits of other similar arrangements in the future.

2.1.38 The Company rejected IGUA's assertion that the use of full costing was the only alternative and that marginal costing has been abandoned. The Company stated that at no point through the process was it suggested that all parties did not support a review of all costing philosophies, including those currently in practice.

2.1.39 The Company also rejected parties' assertions that the real focus of its proposal to implement the UAC is its desire to improve its competitive position. The Company argued that incremental costing was chosen on the basis that it represents the best method in meeting economic and other objectives.

2.1.40 With respect to the Board's "signals" in E.B.R.O. 493/494, the Company stated that the Board in that proceeding was not presented with a comprehensive cost allocation study on which to base its decision, nor did it have available to it the UAC methodology and an affiliate pricing policy as an alternative to full costing. The Company submitted that the UAC cannot be characterized as untested since it represents a practical application of the use of incremental costing.

2.1.41 The Company noted Dr. Cronin's evidence that incremental costing methodologies have a long history of application across many countries, regulatory bodies, and courts. On criticisms that Dr. Cronin drew many of his examples from the telecommunications industry, the Company stated that these criticisms ignore the evidence that incremental costing methodologies have been employed in the gas pipeline industry in the United States since 1992. Further, references to telecommunications provide examples of regulated businesses grappling with the transition to competition.

2.1.42 Noting that the difference of opinion on the appropriate cost methodology revolves around how best to measure and distribute economies of scale and scope, the Company stated that ancillary programs explicitly contribute to the common costs because the excess return over the allowed rate reduces the utility cost of service; non-utility activities explicitly contribute to the common costs because the application of the affiliate pricing policy will result in a price that is between the UAC and the stand-alone costs, the excess over the UAC reducing the utility cost of service. The Company stated that FAC, on the other hand, combines the cost allocation and pricing steps and thereby predetermines, in an arbitrary manner, the distribution of economies of scale and scope. The Company criticized intervenors who claimed that the FAC achieves a fair and equitable sharing of common costs, noting that these intervenors have not provided any basis nor explanation as to how the results that flow from FAC represent a fair and equitable sharing of common costs. The Company noted that even Mr. Edgar describes FAC as a proxy method for attributing common costs as a means of sharing economies of scope and that he conceded that, to the extent that there is an equitable sharing under fully allocated costs, it would only be by accident or by chance.

2.1.43 The Company submitted that there is adequate evidence in this case to conclude that full costing will fetter the Company's discretion or weaken its position in the competitive markets where prices will tend towards long term incremental costs. Noting the specific program exemptions recommended by some parties who argued in favour of full costing, the Company stated "these arguments hold their appeal for intervenors only as long as programs of interest to different intervenors are not adversely affected by FAC".

2.1.44 Noting that any costing methodology requires judgement, the Company submitted that it has implemented processes and procedures to ensure that there is completeness, accuracy and consistency in the results of the UAC. The Company argued that there was no reason to go beyond five years, as suggested by OCAP, to capture cost behaviour patterns.

2.1.45 In response to certain intervenors advocating structural separation as the optimal solution to avoid cost allocation issues, the Company viewed this recommendation as extreme and unnecessary given the "comprehensiveness" of the Company's proposed methodology. With respect to HVAC's suggestion for an independent audit and verification process for the next rates case and for each rates case following, the Company stated that this is excessive and unduly burdensome. The Company stated that Mr. Effron's inability to perform his review was due to his attempt to use the evidence for a purpose for which it was not designed, and for a need that was not expressed.

Board Findings

2.1.46 Re-consideration of the appropriate costing methodology is timely from several perspectives. First, this issue has not been before the Board for a considerable period of time. Second, the energy market has exhibited significant developments recently. Third, Consumers Gas has embarked on a number of additional non-core activities with the result that the common costs pool to be allocated in the test year is approximately $21 million. The evidence revealed that the Company plans to further increase non-core activities substantially in the future. Fourth, the repetition and intensity of some of the issues relating to non-core activities appear to have distracted attention from other issues that are equally fundamental to the setting of just and reasonable rates.

2.1.47 The Board has noted that certain parties have argued for the legal and physical separation of the Company's non-core activities from the regulated gas distribution business. The Board made it clear throughout the proceeding that the issue of separation in that context was not an issue for this proceeding. The Board appreciates that discussion of an appropriate costing methodology for the Company's non-core businesses inevitably invites discussion of separation. Given the Company's new business activities and strategic directions and the tangential relationship of these to the cost allocation issue, the Board found such discussion to be useful. However, the Board will not make any findings in that regard. Similarly, the Board will not comment on the appropriate pricing for asset transfers in the event of structural separation.

2.1.48 Issues related to separation were generally addressed by the Board in its May 15, 1996 *Advisory Report on Utility Diversification* ("*Diversification Report*") to the Government. The current Board sponsored Market Review also deals with the separation of the Company's gas merchandise function. Similarly, since the issue was not on the table in this proceeding, the Board has not commented on whether or not the Company's ancillary programs ought to be reclassified as non-utility which would mean that ratemaking considerations would be confined to cost allocation matters rather than cost allocation and revenue matters.

2.1.49 Discussion of separation or classification for certain activities was, however, appropriate. Specifically, in E.B.R.O. 492 the Board required that the Company justify the continuation of NGV as part of the utility. Also the Board allowed the issue of the appropriate classification of certain existing and new services. The Board deals with these matters later in this Chapter.

2.1.50 The Board concludes that a proper assessment of the merits of the alternative costing methodologies should be based not only on considerations of economic efficiency but also on considerations of fairness and the practicality of implementation. In its assessment the Board has not excluded marginal costing as an option, despite perceptions that this costing option had been abandoned by the Company. The Board has also considered its role as a regulator in its assessment of the alternatives. In that regard it has carefully considered parties' divergent arguments on the Board's role in the areas of policy, the environment, industry, and society at large.

2.1.51 What is also critical in choosing one methodology over the other, is a regulatory tribunal's explicit or implicit role in the workings of the marketplace and societal impacts at large. While the Board's mandate is not explicit in this regard, to the extent feasible and with deference to long standing arrangements and practices, the Board is generally guided by the belief that the Board should not needlessly impede competition.

2.1.52 Having given consideration to all the relevant criteria, the Board prefers, on balance, the FAC methodology to be applied to ancillary and non-affiliate programs and activities, including MFP.

2.1.53 On the basis of pure economic theory, marginal costing has certain attractions. Marginal costing satisfies a number of, but not all, economic criteria leading to the efficient allocation of resources. For example, marginal costing has a strong theoretical basis for allocating costs but since this Board does not regulate pricing of ancillary activities, marginal costing may not necessarily lead to pricing on the basis of marginal cost. Moreover, marginal costing falls short of fairly distributing the benefits of a common costs pool. Also, its application often generates controversy as to the identification of all costs to be considered as marginal.

2.1.54 It has been argued that a move from marginal costing would disadvantage the Company in its competitive activities. In the Board's view any advantage the Company presently has in these activities, by reason of its ability as a regulated monopoly to price its products or services at marginal cost, need not be preserved. The Company's concern that in this situation competitors would be advantaged by their ability to use incremental costing is unfounded, given that these companies ultimately must recover their total costs.

2.1.55 The Company's proposed Uniquely Attributable Costing methodology is a variant of marginal costing. Its longer-run time horizon attempts to address some of the criticisms attributed to short-run marginal costing in its application to a utility setting. The Board's comments regarding marginal costing apply equally to the UAC as a variant of marginal costing. Moreover, in the Board's view, the Company's proposal entails additional levels of judgement, internal effort, expense and regulatory complexity that place in question the pursuit of the benefits perceived by its proponents. Had the Board chosen not to require full costing, the results of marginal costing might have been used as the basis upon which a contribution to the pool of common costs was considered, rather than adopting a UAC approach. In addition, as negotiated transfer prices would not be readily verifiable without a review of an affiliate's cost structure, the Company could have an undue level of discretion in proposing these prices for ratemaking purposes.

2.1.56 As well as addressing the fairness criterion, full costing is attractive because of its relative simplicity in application for programs classified as either ancillary or non-utility. With respect to the ancillary programs, the relative simplicity of full costing may explain its wide use in gas utility regulation in other jurisdictions. With respect to non-utility eliminations, the Board concludes full costing is more reliable, less judgemental, and that it is easier to test its results compared to the application of the Company's Uniquely Attributable Cost approach overlaid by the Company's transfer pricing proposal.

2.1.57 The Board has noted the concern that full costing is arbitrary in its assignment of common costs to different activities. The Board has concluded that a degree of arbitrariness is acceptable given the preferability of other aspects of full costing. Moreover, the degree of arbitrariness is, in the Board's view, of no greater concern than the judgements required for the application of the UAC. Full costing also represents a less intrusive approach in the marketplace by a regulatory tribunal, because the price the affiliate pays is determined not by the Board but by management and shareholder decisions.

2.1.58 In reaching its conclusion on the appropriate costing method to be applied to all of the Company's ancillary programs, the Board considered whether any specific program or programs ought to be exempted from such treatment. It was the Board's conclusion that no general or special considerations justified exclusion for any of the Company's existing or proposed ancillary activities. It is possible, however, that exclusions from full costing may be warranted in special circumstances. The Board will make this assessment as these circumstances arise.

2.1.59 Deference for long standing arrangements and practices necessitates an assessment of the ramifications of a move to full costing on the Company's ancillary businesses. The Board estimates that on the basis of the weighted average cost of capital found appropriate by the Board in this Decision, the combined revenues from the ancillary programs, excluding the Merchandise Finance Program, will fall short by about $4.2 million on a pretax basis. In view of the size (approximately $220 million in revenues, excluding the revenues from the Merchandise Finance Program) and the range of the combined ancillary businesses, the Board considers such impact to be manageable by the Company. The Board does not consider that there are significant obstacles or competitive restrictions on the Company's ability to rearrange its affairs to deal with its revenues and costs in such a way as to bring the <u>combined</u> return for its ancillary programs to the overall rate of return allowed.

2.1.60 However, the Board recognizes that the Company needs sufficient time to implement any revenue enhancement or cost reduction measures it may consider necessary for its ancillary programs. For the 1998 test year, therefore, the Board will impute only 75% or $3.2 million of the revenue required from the bundle of ancillary programs to bring the combined rate of return to the same level as the overall rate of return. This reduction from the full revenue imputation allows for a three month transition period.

The $3.2 million revenue imputation excludes the cost of service reduction for the Company's Merchandise Finance Program, which is addressed later in this chapter.

2.1.61 In determining the appropriate revenue imputation amount, the Board did consider the argument by HVAC that revenue imputation ought to be on a program-by-program basis. The Board concluded that this approach would overcompensate ratepayers at the expense of the shareholder or customers of the Company's ancillary programs. Ratepayers would receive the benefits from the excess profitability of certain ancillary programs while at the same time they would be safeguarded from the profitability shortfalls of other ancillary programs. Any concerns about anti-competitive or non-competitive conduct by the Company for a specific program as a result of the Board's bundled ancillary program ratemaking treatment are, in the Board's view, in the domain of the Competition Bureau. It is the Board's expectation that the regulatory treatment of the Company's ancillary and non-utility activities in this Decision will assist the Bureau in its quest, as articulated in its submission, for clarification of the respective jurisdictions.

2.1.62 The Board has also noted that certain parties have dealt with specific cost matters on the various ancillary activities. The Board concluded that a move to full costing may alleviate the concerns expressed in regard to these matters. In any event, those parties may request at the next main rates case to re-introduce those matters should they remain outstanding or unresolved.

2.1.63 Full costing eliminates the need for any Board findings on the appropriate guidelines for transfer pricing for goods and services provided by the Company. Transfer pricing of goods and services received by the Company from its affiliates will be subject to existing review processes.

2.1.64 The move to full costing will necessitate the production of a costing manual. The Board directs the Company to prepare and submit such a manual for its next main rates case. The Board will defer until then its assessment of whether there will be a need to establish a schedule and a process for independent audit of the Company's application of costing policies and procedures.

2.2 ADDITIONAL MATTERS RELATING TO ANCILLARY PROGRAMS, NON-UTILITY ELIMINATIONS AND AFFILIATE TRANSACTIONS

2.2.1 The description of the issues in this section and the parties' positions thereon is confined to matters that require decisions additional to those matters that have been decided in the Cost Allocation section above.

Ancillary Programs

2.2.2 This section sets out the following four issues:

(a) the regulatory treatment of NGV;
(b) the Company's commitment in the E.B.R.O. 492 ADR with respect to the High Efficiency Home Heating Rental Program ("HEHHRP");
(c) the proposed classification of certain new programs; and
(d) the classification of certain other services.

2.2.3 The Board sets out its findings on all of these issues at the end of the section.

Regulatory Treatment of NGV

2.2.4 In E.B.R.O. 492, the Board stated as follows:

> *Although [the Board] has accepted for the 1997 test year the 6 percent return on the NGV program, the Board remains concerned about the continued poor performance of the NGV program; should this level of performance continue the Board will examine the possibility of removing this activity from the utility for the purposes of setting rates. The Board expects the Company to address this matter in detail in the 1998 test year.*

2.2.5 The Company noted that the Board's referenced rate of return did not reflect the Company's updated evidence in that rates case, but acknowledged that the Board's direction stood and that the Company has responded to it.

2.2.6 The NGV program is expected to achieve a rate of return in the test year of 4.54% on a fully allocated cost basis. An increase in revenues or reductions in costs of almost $1.4 million would be required to produce a rate of return equivalent to the overall cost of capital determined by the Board in this Decision. The Company stated that it could not generate this amount in additional revenues as it needs a 40% differential between the price of gasoline and the price of natural gas for the NGV program to attract customers.

2.2.7 The Company cited the following four reasons in support of its proposal to continue this program in the regulated utility:

- Utilities have an obligation to deliver natural gas to customers in a safe and usable form.
- The choice to use natural gas in vehicles instead of gasoline or diesel is no different than the customer's choice to use natural gas instead of fuel oil or electricity to heat buildings.
- NGV benefits customers through an improved system load factor and benefits society through environmental improvements.
- Gas utility leadership is crucial to successfully develop NGV markets.

Positions of the Parties

2.2.8 AMO urged the Board to provide positive encouragements to the Company in its NGV activities. It argued that this is one area where the Board should consider the application of incremental costing.

2.2.9 IGUA argued that if, in combination with all of the other ancillary programs, the pricing of NGV service remains uneconomic in a market place driven by economics, then the service should be discontinued. For rate setting purposes, the Board ought to take into account the extent to which the NGV program under-contributes on a fully allocated basis relative to the common equity return allowed to the Company.

2.2.10 OCAP argued that the Company's stated reasons provide "the flimsiest of justification" for continuing ratepayer support for the NGV program. OCAP viewed the Company's suggestions that NGV is part of the distribution system and that the resources it requires are comparable to the resources required to support heating customers as semantic; they could be equally applied to any ancillary product "and would be equally meaningless". On the environmental and societal benefits argument, OCAP submitted that if the Company is now justifying NGV as a Demand-side Management ("DSM") program, then the program should be subjected to the same cost-effectiveness screens as other DSM programs. As for the need of the utility's leadership role in NGV, OCAP submitted that this is no longer true given the increasing interest by large players in the energy markets. It noted that other fuel alternatives, such as electric fuel cells and propane, have developed without utility involvement. OCAP recommended that the Board direct the Company to spin NGV off to a non-utility affiliate at a deemed price which would include the cumulative ratepayer subsidy.

2.2.11 CAC questioned the need for NGV to continue to be developed within the utility operations. It stated that the Company has had ample opportunity to demonstrate that NGV is a commercially viable technology. CAC stated that it finds troubling the fact that, as anticipated results do not materialize, the program expenditures are scaled back to improve returns, which is counter to the Company's plan to expand the program. CAC recommended that the Company bring forward a proposal in its next main rates case to remove the program from utility operations.

2.2.12 Energy Probe urged the Board to reject the Company's characterization of refuelling appliances in the NGV program as similar to pipeline compressors, arguing that pipeline compressors are joint use facilities whereas refuelling appliances use dedicated equipment. Energy Probe also argued that the Company's evidence on the environmental benefits of NGV fails to account for environmental disbenefits that may result from NGV lowering costs for operating vehicles thereby increasing distance driven and resulting in additional noise, road hazard and emissions. Energy Probe recommended the removal of NGV from the regulated utility.

2.2.13 Suncor/PanEnergy argued that none of the reasons advanced by the Company for the inclusion of NGV are justified. Suncor/PanEnergy argued that the obligation to deliver natural gas in a safe and usable form does not extend to the obligation to own and operate NGV fuelling stations; rather, the Company's obligation is limited to delivering natural gas to the NGV station. Just as the customer's choice to use natural gas for heating does not obligate the Company to provide the furnace, the choice of natural gas as a transportation fuel does not obligate the Company to own and operate

NGV fuelling stations. Suncor/PanEnergy submitted that any improvement in the system load factor would result regardless of who owns and operates the NGV fuelling facilities. Further, as there is no specific mandate from government that the Company should engage in the NGV program, the Company should not provide this service as part of its regulated activities.

2.2.14 The Company contended that the program has performed well and reiterated the societal benefits of the program and the need for the Company to take the lead role. The Company pointed out that Energy Probe's discussion of compressors is mistaken. The Company had not likened refuelling appliances to pipeline compressors but rather compressors that supply compressed natural gas to retailers. The Company also noted that the Company does not own or operate the refuelling stations as Suncor/PanEnergy's argument states.

High Efficiency Home Heating Rental Program

2.2.15 In fiscal 1997 the Company proceeded with a full launch of the High Efficiency Home Heating Rental Program ("HEHHRP") and included the costs and revenues as part of the Company's general Rental Program. The Company testified that, in its view, the Board had approved the program as an ancillary program in E.B.R.O. 492.

Positions of the Parties

2.2.16 HVAC argued that, in proceeding with a full launch of the program, the Company has "flagrantly" breached the E.B.R.O. 492 ADR agreement and that the Board ought to "roll back" the status of HEHHRP from full program to pilot. HVAC also submitted that, given the pending determination by the Government of the status of the Board's *Diversification Report*, it would be inappropriate to allow the launching of new businesses within the regulated utility.

2.2.17 The Company argued that there were no substantive changes to the program but rather the changes are the "fine-tuning" the Company indicated in E.B.R.O. 492 it intended to do to enhance and improve the program's delivery.

Classification of New Programs

2.2.18 In addition to the inclusion of the HEHHRP program in the Company's ancillary Rental Program, the following two new programs were proposed by the Company to be classified as ancillary programs:

- Agency Billing and Collection Transportation Service or ABC T-Service
- St. Catharines Hydro Electric Commission or SCHEC

ABC T-Service

2.2.19 ABC T-Service is a process whereby a customer, who purchases gas through an Agent, Broker, or Marketer ("ABM"), receives his gas commodity cost billing through the utility's bill. The ABC T-Service was first introduced, as a concept, in E.B.R.O. 492, where the Board allowed its classification as an ancillary program on a temporary basis. In the present proceeding, the Company sought approval to classify the ABC T-Service as an ancillary program on a permanent basis.

SCHEC

2.2.20 The Company received interim Board approval on February 26, 1997 under E.B.O. 179-11 to enter into certain affiliate transactions related to the provision and acquisition of services to and from a joint venture comprised of its immediate parent, Consumers Gas Energy Inc. ("CGEI"), and TransAlta Energy Inc. ("TransAlta"). Specifically:

- the Company will be providing a billing and customer information service to SCHEC;
- SCHEC will provide the Company with cashiering services in downtown St. Catharines, enabling the Company to close one of its customer payment facilities; and
- the joint service will provide both the Company and SCHEC with meter reading services in the City of St. Catharines. (The joint venture will also provide SCHEC with energy management services designed to reduce electricity costs for SCHEC).

Positions of the Parties

2.2.21 Suncor/PanEnergy submitted that, as the ABC T-Service is in the introductory stages and in view of its recommendation that the Board remove all billing services from the utility by treating Customer Information System as a non-utility activity, it may be premature to determine the status of ABC T-Service and it should, therefore, remain for now as an ancillary service. With respect to SCHEC, Suncor/PanEnergy argued that similar services are provided to Gazifère, but as non-utility. Suncor/PanEnergy submitted that services provided to affiliates should be treated as non-utility.

2.2.22 Noting that a billing service is not a monopoly service, IGUA submitted that the ancillary classification ought to be phased out for services to competitive markets. It pointed out that the Company currently does not treat billing services in the same way for cost allocation purposes. The Company's service to Gazifère is classified as non-utility, whereas the proposed service to SCHEC has been proposed as ancillary service, although the Company initially classified it as non-utility in its cost allocation study.

2.2.23 CAC stated that there is no reason why the SCHEC project should be carried on as an ancillary activity. CAC suggested that the Company's proposal to include this program as part of the regulated utility is to limit the risks associated with the program.

2.2.24 Energy Probe stated that, ultimately, it would like to see the ABC T-Service out of the regulatory utility and as a model for spinning off CIS and other business activities that are not tied to the utility's monopoly on gas distribution. It recommended that the Company be directed to file, in its next main rates case, a plan to remove ABC T-Service from regulation including a plan to unbundle customer accounting costs.

2.2.25 The Company noted that the ABC T-Service program is not aimed at adding shareholder revenues but rather at introducing greater price transparency in the direct purchase market and disclosure to the customer and argued that it has been consistent in its position that this service be provided in the utility.

2.2.26 The Company noted that the provision of billing services represents only a part of the arrangement with SCHEC. It reiterated that the meter and cashiering services to be received through SCHEC are directly related to core utility functions and, as such, the program should be viewed as part of the regulated utility activities. The Company argued that the nature of each of the billing services under ABC T-Service, SCHEC, and Gazifère is "different, unique and incremental to the core utility billing function".

Other Services

2.2.27 The Company provides furnace/boiler tune-up and repair, maintenance of customer appliances, and home gas appliance inspection. The Company's evidence was that these are safety related programs and therefore are part of its core business, as opposed to ancillary. As such the Company does not provide separate costing for these services. The evidence was that each of these services is delivered either exclusively or primarily through HVAC contractors.

Positions of the Parties

2.2.28 HVAC stated that the Company's evidence is a "woefully inadequate basis" for assuring the Board that at least the costs of these activities are being recovered. HVAC submitted that the Company's contention that these programs are a core function is not tenable, that all of these services are offered by others in the marketplace, and that they are not different from other ancillary businesses that are run by the Company except that they are not required to make the allowed rate of return. HVAC submitted that the Company be directed in its next main rates case to file business case analyses, including costs and revenues, for each of these activities.

2.2.29 IGUA submitted that these services ought to be classified as an ancillary program as they are similar to the services which the Company provides under the HIP program.

2.2.30 Suncor/PanEnergy argued that there is no over-riding societal benefit to Consumers Gas providing these services since other firms provide similar services. Moreover, the Company's failure to treat these services as ancillary, provides no assurance to the Board that they are not being subsidized by the ratepayers.

2.2.31 In reply, the Company stated that there appears to be confusion of the Company's safety initiatives with emergency response. The Company noted that its safety responsibilities go "far beyond" the handling of emergency conditions. As such, these services should be in the Company's regulated activities. The Company further noted that the question of what should or should not be considered as "core" services is not relevant in these proceedings.

Board Findings

2.2.32 In the Board's assessment, controversies and arguments as to whether or not a non-core program should be structurally separated from the utility or how it should be classified within the utility are in the main driven by the cost treatment afforded to the program.

Regulatory Treatment of NGV

2.2.33 With respect to the NGV program, the Board has observed that parties arguing for its removal from the utility have not distinguished the part of the NGV service that must be regulated by the Board under the Act from the ancillary part of the program. Under the Act, the Board must approve or fix rates for the delivery and sale of any gas, including that sold to the NGV reseller under Rate 9. The Board therefore interprets the parties' arguments for removal to pertain to those portions of the NGV program that need not be regulated.

2.2.34 In view of the Board's decision to apply full costing to the NGV program, the issue remains as to the appropriate rates to be approved or fixed under Rate 9. The Board has concluded that the Company ought to be afforded a fair degree of flexibility in that regard, as long as the total revenue forecast to be generated from Rate 9 does not unreasonably exceed the fully allocated costs attributed to the NGV program. In filing its rate schedules with the Draft Rate Order, the Company is directed to identify any changes to Rate 9 occasioned by the Board's adoption of full cost allocation.

2.2.35 The Board has also concluded that, in the Company's next main rates filing, the Company must, for purposes of cost allocation and rate design, redefine the NGV program to distinguish that part of the program that requires rates to be set by the Board from the rest of the NGV activities.

2.2.36 The Board cannot assess to what extent its findings on the method of costing will alleviate the concerns expressed and whether calls for the removal of one specific program among many is warranted at this time. In view of its decision that full costing be applied to this program, notwithstanding any suggestions concerning the possible affinity of the NGV program with the Company's DSM Plan, the Board is not inclined at this time to direct any further action beyond cost allocation and rate design issues with respect to the NGV program.

Other Programs and Services

2.2.37 With respect to other programs or services, under full costing, their classification as ancillary or non-utility may not be significant. As revenue is imputed to deem profitability of the programs on a bundled basis, rather than on a program specific basis, concerns of shielding or protecting a specific program may be of limited consequence from a utility ratemaking perspective. As previously noted, concerns of non-competitive or anti-competitive nature are in the domain of the Competition Bureau.

2.2.38 However, there is the issue of consistency. The Board sees no reason why the new SCHEC service, which the Board views as primarily a billing service, should be classified differently from the service the Company provides to its affiliate, Gazifère. The Board directs the Company to classify this program for ratemaking purposes as non-utility in future filings.

2.2.39 On the other hand, the ABC T-Service, in the Board's view, is sufficiently linked to the Company's core business to warrant a classification of an ancillary nature.

2.2.40 The Board finds no evidence that the Company has violated the letter or spirit of the E.B.R.O. 492 ADR agreement as claimed by HVAC with respect to the launching of the HEHHRP program. Also, it would be, in the Board's view, unreasonable to expect the Company to delay implementation of all of its plans pending the outcome of deliberations on the *Diversification Report*. The Board accepts this program as part of the Company's overall ancillary rental program.

2.2.41 Finally, with respect to any new non-core activities in the future, whether under the Undertakings or otherwise, the Board expects the Company to be prepared to justify the need for classification as an ancillary program rather than as a non-utility activity.

2.2.42 During the proceeding, the Board had ruled that the classification of the Other Services identified and argued by HVAC was not an issue at this hearing. The Board expects the Company to address this issue at its next main rates case.

Non-Utility Eliminations

2.2.43 Currently, the cost allocation to derive the non-utility eliminations is performed on a fully allocated cost basis, except for that of the Merchandise Finance Program, which is on a marginal cost basis. For the 1998 test year, the Company proposed to eliminate $5.8 million from total O&M forecast expenses for ratemaking purposes.

2.2.44 The proposed eliminations include two new activities for the test year. The first is the provision of certain corporate services to Consumersfirst, an affiliate engaged in gas commodity sales, amounting to $79,000. These costs have been removed in the determination of the utility cost of service.

2.2.45 The second relates to the Company's involvement in the "Maritimes" project. By application dated May 2, 1997, the Company requested approval, pursuant to the Company's Undertakings, to provide services to Consumers Gas Energy Inc., Consumers Gas' immediate parent, related to its pursuit of business opportunities for natural gas distribution in the Maritimes. The Company anticipates providing support in the areas of engineering, market analysis and administrative services. Under the fully allocated cost methodology, the Company has identified utility resources that relate to these services of $179,200 and $202,200 for 1997 and 1998 respectively. The Company has determined that the incurrence of these costs would result in annual Management Fees and Direct Billings of $130,000 in 1997 and $120,000 in 1998. These costs have been included in the proposed non-utility elimination amount for the test year.

Positions of the Parties

2.2.46 CAC stated that unless the Company's budget is accurate, ratepayers are not compensated for the utility resources used in the non-utility activities. CAC noted that the nature and extent of non-utility activities is expanding rapidly and cannot be forecast with any accuracy. As examples, CAC noted the development and implementation of Consumersfirst and the need to update information on the Maritimes project during the hearing. It also noted the Company's evidence and press reports that Consumers Gas is actively exploring other ventures. CAC submitted that these developments underscore what was apparent in the evidence: that the Company is under internal and external pressure to enter into new areas outside its core business. CAC also submitted that the Company has consistently under-forecast the level of non-utility activity. In light of these two factors, i.e., consistency in under-forecasting and increased activity in non-utility projects, CAC recommended that the Board add a 30% premium to the forecast non-utility eliminations derived from full costing.

2.2.47 IGUA submitted that the non-utility elimination could reasonably be increased from the fully costed level in view of the Company's pursuit of non-utility business activities.

2.2.48 The Company submitted that the majority of the variances occurring in the period from 1991 to 1995 and a large portion in 1996 and 1997 related to amounts that were not included in the original Board approved cost of service and, therefore, were not recovered from ratepayers; variances relating to responses to Board directives and changes in methodology from one year to the next are not a reflection on the Company's forecasting accuracy. The Company argued that the activities referred to by intervenors are captured, in that the Company makes provision in the test year for future unspecified non-utility activities through forecasts of time allocation.

Board Findings

2.2.49 The Board approved the Company's application under the Undertakings for the Maritimes project on July 18, 1997 under E.B.O. 179-12, subject to the cost allocation methodology to be approved in this Decision. The proposed classification of the Maritimes project as non-utility is acceptable to the Board.

2.2.50 The Company's cost of service filing is based on full costing for non-utility eliminations but on marginal costing for the Merchandise Finance Program. Earlier in this Chapter, the Board found that full costing should continue to apply for non-utility eliminations and that full costing should also apply to the Merchandise Finance Program. Full costing of this program results in a cost of service reduction of $1.4 million. As in the ancillary programs, to allow sufficient time for the Company to adjust its business plans, the Board will reduce the Company's costs of service for the test year by 75% of this amount or by $1 million.

2.2.51 The Board is persuaded that the Company's proposed non-utility elimination amount of $5.8 million (exclusive of the MFP) is understated on three grounds.

- First, historically the Company has shown a consistent bias in underestimating the amount to be eliminated. In six of the last seven year periods, the Company has underestimated the actual amount. In the same seven year period, the average underestimation is in the order of 27% with a high of 58% in one particular year.
- Second, the Company's evidence was that the effort involved in overseeing the activity associated with the comprehensive cost allocation study was valued by the Company at $78,000, which is a large portion of the total $125,000 amount eliminated for non-utility eliminations. In the Board's view, the less than $50,000 remaining to be attributed to efforts of Company personnel and their related costs in administering non-utility eliminations is inadequate.
- Third, the evidence is compelling that the Company's activities in non-utility areas are on the increase.

2.2.52 The Board concludes that, on balance, a 20% increase is justified. The Board therefore increases the amount to be eliminated by $1.2 million to $7.0 million.

Affiliate Transactions

2.2.53 Under the current methodology, the direct billings and management fees are based on a review of fully allocated costs and, for the test year, were valued at $2.2 million. Included in this figure is an amount of $1.3 million in management fees from IPL Energy Inc., the indirect parent of Consumers Gas, an increase of $0.85 million from the Board approved level for fiscal 1997. The evidence was that this was an amount agreed upon by IPL and Consumers Gas. During the hearing and through an undertaking, the Company provided evidence in support of the proposed management fee.

Positions of the Parties

2.2.54 OCAP submitted that a claim of cost reductions should not be accepted as a basis for an increased payment to the parent. OCAP stated that it is not acceptable for identified savings of $850,000 to automatically translate into a corresponding increase in the management fee; that principle would imply that all benefits from economies of scale and scope should flow to the parent. OCAP recommended a reduction by $425,000, "unless the Company can demonstrate that IPL bears significant incremental cost in order to enable the Company to achieve this saving".

2.2.55 IGUA argued for disallowance of a portion of the IPL management fee. According to IGUA, the issue is not whether the payment of the fee to IPL is accounted for by reduced costs or savings; rather, it is whether IPL ought to be paid $1.3 million for activities which, in part, encompass actions of a parent minding its investments.

2.2.56 The Company submitted that the $850,000 increase in the fee represents reduced costs or savings for the Company of at least an equal amount.

Board Findings

2.2.57 The Board notes that, despite the Board's direction in E.B.O. 179-05 which approved the Company's application for an affiliate transaction relating to the management fee, in E.B.R.O. 492 the Company was not in a position to provide an absolute quantification of the benefits associated with the management fee. In this proceeding, the Company attempted to do so but only through an undertaking response. The Board would have expected that, given the size of the fee and the substantial increase, a justification would have formed part of the Company's pre-filed evidence and would not have been dealt with in the casual manner that it was in the proceeding. In any event, the Board now has sufficient information to make a determination on the reasonableness of the requested amount.

2.2.58 The Board notes that $686,000 of the $850,000 fee increase is largely based on the savings that were made possible by moving certain resources or activities to IPL. However, there is no reflection of the fact that certain resources or activities are either no longer required or are required at a reduced scope or are now shared with IPL and its other subsidiaries. Also, the Company's evidence speaks of increased support in such areas as corporate planning, corporate secretarial and investor relations. The Board is not persuaded that in view of the substantial resources residing in the Company and the removal of the Company's public float an increase is justified. In fact, the Board is particularly troubled with the Company's position that the $280,000 in savings achieved by removing the public float forms a justification for the increase in the management fee, when in fact this amount is simply an avoided expense for both corporations. The Company's evidence also speaks of other benefits and synergies which the Board finds to be either of little or questionable relevance to the Company's mainstream distribution business in Ontario. The Board finds no convincing evidence that the Company needs the full range of services provided by IPL, or the degree of use of any particular services that the Company alleges it requires.

2.2.59 The only incremental increase to the management fee that, in the Board's view, is valid, is the fee for corporate secretarial and pension advisory services. The two individuals now providing these services were transferred from the Company to IPL and it would appear that they serve IPL and its subsidiaries.

2.2.60 The Board approves a management fee from IPL of $500,000 for the test year, representing an increase of $75,000 over the level approved by the Board for fiscal 1997 in recognition of incremental services provided by the parent Company. The Board reduces the utility cost of service by $0.8 million on this account.

2.2.61 For the next rates filing, the Company is directed to provide its justification of, and to quantify to the degree possible and practical, the management fee to be paid by the Company in its prefiled material.

3. RATE BASE

3.0.1 The 1998 proposed rate base and its components are summarized in Appendix A. The proposed rate base amount of $3,066.8 million includes capital expenditures closed or expected to be closed to rate base for fiscal 1997 and includes proposed capital expenditures for the 1998 test year.

3.0.2 The fiscal 1998 capital expenditures were forecast at $379.1 million. The major components are: customer related plant ($212.5 million), system improvements ($73.2 million), general and other plant ($57.6 million), underground storage facilities ($19.3 million) and CIS ($16.5 million). The inclusion of the CIS expenditure in the test year rate base has been deferred. The sub-components of the capital budget are shown in Table 3.1. Capital expenditure projects exceeding $0.5 million are shown in Table 3.2.

Table 3.1:

UTILITY CAPITAL EXPENDITURES BUDGET FOR FISCAL 1998	
	Budget 1998 ($Millions)
Customer Related	
Sales Mains	40.8
Services	47.8
Meters and Regulation	24.1
Sub-total Customer Related Distribution Plant	112.7
Rental Equipment on Customers' Premises	99.8
TOTAL CUSTOMER RELATED CAPITAL	**212.5**
System Improvements and Upgrades	
Mains - Relocations	5.1
- Replacements	19.4
- Reinforcement	10.8
Sub-total Mains	35.3
Services - Relays	19.5
Regulators - Refits	5.2
Measurement and Regulation	7.7
Meters	5.5
TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	**73.2**
General and Other Plant	
Land, Structures and Improvements	5.6
Office Furniture and Equipment	1.9
Transp/Heavy Work/NGV Compressor Equip.	3.4
Tools and Work Equipment	1.5
Computers and Communication Equipment	45.2
TOTAL GENERAL AND OTHER PLANT	**57.6**
Customer Information System	16.5
Underground Storage	19.3
TOTAL CAPITAL EXPENDITURES	**379.1**

Table 3.2:

1998 BUDGETED CAPITAL EXPENDITURES (EXCEEDING $500,000)	
Description of Project	**($000)**
Danforth/Dawes - Replacement	1,319.4
Eglinton/Winnett - Replacement	1,836.9
Lakeshore/Sixth - Replacement	1,300.4
Hwy 9/Hwy 50 - Non-Rebillable Relocation	550.0
Brock Road - Reinforcement Main	550.0
Omemee - Residential Sales Main	852.7
Warkworth/Hastings/Norwood Community - Residential Sales Main	2,437.8
Wyevale/Parkinsfield/Balm Beach - Residential Sales Main	1,333.7
Cannington - Residential Sales Main	867.4
Lancaster/Williamstown - Residential Sales Main	717.3
East Valley - Reinforcement Main	3,000.0
Geographic Information Systems	2,500.0
Land Purchase from Ontario Hydro - Right of Way	3,500.0
Automatic Meter Reading	550.0
Customer Information System	16,478.6
Tecumseh - Coveny and Black Creek Storage Pools	12,603.9
Tecumseh - K-708 Lean Burn Conversion	650.0
Tecumseh - Dow Chemical Base Pressure Gas Volume	1,210.0
Osgoode - Residential Sales Main	1,714.2
Moonstone - Residential Sales Main	583.8

Source: Exhibit B3,T2,S3

3.1 SETTLED ISSUES

3.1.1 There was complete settlement of the following issues.

- E.B.O. 188 ADR Agreement Implications
- Periodic Contribution Charges ("PCC")
- Feasibility Guidelines
- Storage related matters
- Geographic Information System ("GIS")
- Amortization rate for CIS and Operation Work Management System ("OWMS")

3.1.2 A description of these issues is set out below. The parties accepted the Company's proposals. Details of the settlement on each issue are set out in Appendix E.

E.B.O. 188 ADR Agreement Implications

3.1.3 The Company's budget in fiscal 1998 for customer related capital expenditures was forecast to be $212.5 million, of which Customer Related Distribution Plant was $112.7 million and Rental Equipment on Customers' Premises was $99.8 million. Included in the Distribution Plant budget is an expenditure of $10.9 million to account for the effect of the ADR Agreement in the E.B.O. 188 proceeding. In the current Settlement Proposal, the parties noted that, should the Board not render a decision in E.B.O. 188 prior to the issuance of the E.B.R.O. 495 Decision, the impact of this expenditure should be removed by the Board.

Periodic Contribution Charge

3.1.4 When an expansion project is estimated to yield a profitability index less than one, the Company may proceed with the project if potential customers within the geographic boundaries are willing to make a contribution. For residential customers (Rate 1), the PCC contribution can be either a one-time sum or a series of $15 monthly payments for up to 60 months. The monthly contribution for commercial establishments (Rate

6) is a multiple of $15, the precise amount depending on the customer's estimated peak hour consumption compared to that of residential customers.

3.1.5 In an effort to attach more customers early, the Company instituted a policy of deferring collection of the PCC charge until the January following completion of construction. The Company's policy is aimed at (a) promoting a more efficient construction process (more individual service lines installed at the same time as the service mains) and (b) maximizing revenues. In the E.B.R.O. 492 ADR, the Company undertook to confirm public acceptance of this policy. To fulfil this undertaking, the Company presented the results of research from four focus groups (from three communities) undertaken by Schiappa Research Dynamics.

3.1.6 Under Board authorization in previous Consumers Gas rate cases, the Company is able to accept projects using what might be referred to as a general application principle. Under this principle, if projects arose from time to time that would normally be treated as Stage 2 projects (i.e., projects not feasible on solely financial considerations) and involve the application of the PCC, expenditures for these projects may be undertaken without these expenditures having been part of the Board approved budget.

3.1.7 For fiscal 1998, in addition to a $4.4 million amount included in its capital budget under the general application principle, the Company identified four projects involving $8.7 million in capital expenditures that would utilize the Company's PCC policy.

Feasibility Guidelines for System Expansion

3.1.8 The Company's original feasibility policy was adopted on January 9, 1980. The Company's proposal makes changes to that document. Feasibility calculations for residential and general service commercial customers are to continue to utilize all the applicable elements of the rate structure for full service revenues and the gas costs. Calculations for large volume customers are based on a direct purchase contract and are to utilize all applicable elements of the rate structure for revenues, and the gas costs. T-service calculations have been automated and where unbundled services are requested, revenue rates are to be calculated using the 300 series of rate schedules.

Also, the commodity component of "gas cost" has been removed as it is a pass-through cost and does not affect the determination of feasibility.

Storage Related Matters

3.1.9 The storage related matters include:

- the development of the Coveny/Black Creek Pools;
- the costs of the Dow Chemical base pressure gas; and
- the costs of the Lean Burn project.

Coveny/Black Creek Pools

3.1.10 The Company's evidence was that it had proposed development of the Coveny and Black Creek Pools, two Guelph formation reefs in Sombra Township, Lambton County, for storage service at a cost of $28.2 million. The two pools add storage space of 138 10^6m^3 and are to be integrated into the Company's storage system; 28.3 10^6m^3 of the space is being developed for Centra pursuant to the terms of the Black Creek Pool Ownership, Development and Operation Agreement.

3.1.11 Pursuant to earlier Company applications to develop the Coveny/Black Creek Pools as storage pools, the Board issued the following:

- a recommendation to the LGIC for designating the pools as gas storage areas;
- a recommendation to the Minister of Natural Resources for the drilling of a number of injection/withdrawal wells;
- approval of leave to inject gas, store gas in, and withdraw gas from the pools;
- approval for leave to construct pipelines and associated facilities for the operation of the pools;
- approval for a change in the designated manager of the Coveny Pool to Consumers Gas.

Dow Chemical Base Pressure Gas

3.1.12 The Dow Chemical Base Pressure Gas Volume represents the purchase of Base Pressure Gas in the Dow Moore Pool, previously owned by Dow Chemical Canada Inc. ("Dow Chemical"). Under agreement, Consumers Gas had the right to use this native gas in the pool until such time as Dow Chemical requested delivery of this gas. A volume of 42,160 10^3m^3 was specified in the purchase agreement.

3.1.13 Prior to 1996, the Company had delivered 10,051 10^3m^3 to Dow Chemical. In February 1996, Dow Chemical requested the delivery of the balance as soon as possible. In order to avert the need for replacement of this gas at critical periods of withdrawal and market demand, the Company negotiated the purchase of the remaining gas over three fiscal years.

3.1.14 In the E.B.R.O. 492 ADR Agreement, parties agreed with the Company's fiscal 1997 forecast of Dow Chemical Replacement Volume of 9,870 10^3m^3, at a cost of $0.980 million on the basis that, prior to the commencement of the hearing, the Company committed to providing written verification from Dow Chemical of the estimated volumes to be delivered from the Dow Moore Pool in fiscal 1997.

3.1.15 In April, 1996, Dow Chemical indicated it had been negotiating with Union to transfer all of its remaining volume to Union's storage account in the Dow Moore Pool. Union has 22% ownership of the Dow Moore Pool storage space. To secure the gas, Consumers Gas negotiated the purchase of Dow Chemical's gas. Terms of the purchase agreement call for the payment of equal monthly instalments over a 24 month period from July 1996 through June 1998. This results in the acquisition of 4,013.6 10^3m^3 in fiscal 1996, 16,054.5 10^3m^3 in fiscal 1997 and 12,040.9 10^3m^3 in fiscal 1998.

3.1.16 The price is based on the average monthly settlement price on the New York Mercantile Exchange ("NYMEX") for each respective month with no basis differential. All gas purchased from Dow Chemical under this agreement is to be treated as gas purchased for system supply and subject to PGVA treatment.

Lean Burn Project

3.1.17 The Company is continuing to install lean burn combustion systems on each of its reciprocating natural gas engines which provide the power for gas compression at the Tecumseh Gas Storage compressor station. This initiative will reduce nitrogen oxide and volatile organic compound emissions and bring the facility into compliance with proposed federal and provincial air quality guidelines. Two units have been converted with an additional unit being converted in 1997. The Company is proposing to convert one unit in 1998 at a cost of $0.650 million. The Company intends to convert the remaining six units in future years.

Geographic Information System

3.1.18 The Company proposes to continue its conversion from paper based records that map the location of the Company's distribution facilities to a computer based system known as the Geographic Information System ("GIS"). In E.B.R.O. 492 the Board approved a $2.0 million capital expenditure for implementation of GIS in Metro Region in fiscal 1997.

3.1.19 For fiscal 1998 the Company has requested a GIS capital expenditure of $2.482 million. The offsetting benefits in the test year are $0.612 million. Approximately $1.050 million of the capital expenditure is for the conversion of facilities data in the Niagara and Eastern Regions as well as the completion of the conversion of the Metro Region. The amount budgeted for land base acquisition is $0.480 million. The remaining $0.952 million is for computer hardware and software purchases, software enhancements and for the salaries and expenses of the Project Team. The project's overall Net Present Value was estimated at $1.4 million.

Amortization Period for CIS and OWMS

3.1.20 The Company proposed to extend the amortization period for CIS and OWMS (Operation Work Management System) software applications from five to seven years. The rationale for this proposal was based on changing industry practices, on life expectancy of the system applications, and on providing a better matching of benefits and capital recovery.

Board Findings

3.1.21 The details of the settlement on each of the issues appear in Appendix E. As the Board noted in Chapter 1, it accepted the Settlement Proposal subject to such matters as may arise due to connectivity of issues, due to updates, or where the Settlement Proposal requires that the Board make a finding. In that regard, the Board makes the following findings.

3.1.22 At the time of writing this Decision, the Board had not made any rulings with regard to the E.B.O. 188 ADR Agreement. In accordance with the Settlement Proposal therefore, the Board removes the impact of the additional activity associated with Board acceptance of the E.B.O. 188 ADR Agreement. Should the Board's E.B.O. 188 decision at a later time accept the corresponding ADR Agreement, the Company may seek the appropriate regulatory approvals.

3.1.23 The Board notes that the Company had not received all of the necessary approvals for its Coveny/Creek Pool storage development project at the time the parties filed the Settlement Proposal. However, at the time of writing this Decision the Board is aware that the Company has now received all necessary approvals for the commencement of this project.

3.1.24 As discussed later in this Chapter, the Company has withdrawn its proposal to include in rate base for fiscal 1998 any capital expenditures associated with its CIS initiative. While it appears to the Board that an extended amortization period for CIS expenditures is reasonable, given the delay in the implementation of CIS the issue of amortization for CIS should be deferred. The extended amortization period for OWMS was agreed to by the parties and was accepted by the Board.

Non-settled Issues

3.1.25 The rate base issues on which where there was either no settlement or there was partial settlement are set out below. These are:

! Variances in Fiscal 1997 Capital Budget (including adequacy of returns on prior distribution system expansion)

- Expenditures on Computer and Communication Equipment
- MarketLink
- CIS

3.2 VARIANCES IN FISCAL 1997 CAPITAL BUDGET

3.2.1 The variance between the 1997 capital expenditure estimate and the Board approved budget in E.B.R.O. 492 is $49.4 million. The variances are shown in Table 3.3. Due to the Board's deferred consideration of CIS expenditures in E.B.R.O. 492, the total variance is reduced by $22.6 million to $26.8 million. Of this $26.8 million variance, approximately $5 million is attributed to over-expenditures on System Information Management ("SIM"). This overage primarily results from delays in project completions, including an amount of almost $1 million for increased interest during construction. The Board deals with the SIM overage separately in this section.

3.2.2 An over-expenditure of $24.4 million is estimated in the area of Customer Related Distribution Plant. This over-expenditure is attributed to mains expenditures or major expansion projects as a result of increased customer additions and new community projects. These unbudgeted expansions are primarily a result of Consumers Gas' general application policy. At the time the budget was developed, many of these projects were close to being feasible but were not included in the capital budget for filing with the Board. Subsequently, under revised feasibility guidelines and the application of periodic contribution charges, the projects were found to be economic and were included in the Company's estimate of capital expenditures for fiscal 1997.

Table 3.3:

COMPARISON OF UTILITY CAPITAL EXPENDITURES
ESTIMATED 1997 AND BOARD APPROVED 1997

	($Millions)		
	Estimated 1997	**Board Approved Budget 1997**	**Est 1997 Over/(Under) Budget 1997**
Customer Related			
Sales Mains	45.9	27.2	18.7
Services	47.5	42.2	5.3
Meters & Regulation	21.8	21.4	0.4
Sub-total Customer Related Distribution Plant	115.2	90.8	24.4
Rental Equipment on Customers' Premises	93.9	104.3	(10.4)
TOTAL CUSTOMER RELATED CAPITAL	**209.1**	**195.1**	**14.0**
System Improvement and Upgrades			
Mains - Relocations	6.9	4.0	2.9
- Replacement	22.8	25.2	(2.4)
- Reinforcement	11.8	5.2	6.6
Sub-total Mains	41.5	34.4	7.1
Services - Relays	22.6	22.8	(0.2)
Regulators - Refits	4.6	5.6	(1.0)
Measurement and Regulation	7.4	7.4	0.0
Meters	5.3	6.8	(1.5)
TOTAL SYSTEM IMPROVEMENTS AND UPGRADES	**81.4**	**77.0**	**4.4**
General and Other Plant			
Land, Structures, and Improvements	7.9	8.5	(0.6)
Office Furniture and Equipment	2.0	2.0	0.0
Transp/Heavy Work/NGV Compressor Equip.	3.6	3.7	(0.1)
Tools and Work Equipment	1.7	1.6	0.1
Computer and Communication Equipment	41.7	39.1	2.6
TOTAL GENERAL AND OTHER PLANT	**56.9**	**54.9**	**2.0**
Strategic Information Management	38.3	10.7	27.6
Underground Storage	17.2	15.8	1.4
TOTAL CAPITAL EXPENDITURES	**402.9**	**353.5**	**49.4**

Source: Exhibits B4,T2,S2 and J1.1

3.2.3 Pursuant to the E.B.R.O. 492 ADR Agreement, the Company filed a study which reviewed the underlying variables causing capital budget variances. The Company described the main purpose of the study as presenting the conditions which give rise to capital expenditure variances and to assist the Board and other parties in assessing the reasonableness of variances in future rate cases.

3.2.4 The Company's evidence was that it does not view the approved capital budget as a spending constraint, but rather as a ratemaking device.

Settlement Proposal/Positions of the Parties

3.2.5 With the exception of OCAP, parties accepted the Company's evidence on the variances of customer related distribution capital expenditures, and with the exception of OCAP and IGUA, on capital expenditures, other than SIM. With respect to the Capital Variance Study, the parties, other than OCAP, agreed as follows:

> *The Company's Capital Budget Variance Study is accepted. As a result of this Study, the Company will take the following steps in order to reduce the variances between Board Approved and Actual expenditures:*
>
> > *co-ordinating the timing of new community projects with the planning and regulatory approval cycles;*
> >
> > *ensuring the new portfolio policy (per E.B.O. 188) is understood and applied in the budgeting process;*
> >
> > *taking into account, for budgeting purposes, the timelines of larger scale projects that span more than one fiscal year; and*
> >
> > *conducting an analysis that focuses on economic conditions in the various market sectors and the resulting impact on sales mains budgets.*

3.2.6 With the exception of IGUA, there was an agreement to settle the associated issue of adequacy of returns from prior distribution system expansion as follows:

> *The adequacy of returns on prior system distribution expansion is accepted, for the reasons given in the Company's evidence.*

There should be reasonable comparability between the System Expansion Study results and the feasibility standards of the Company. In this regard, the Company has filed a supplementary interrogatory response to I-1-73 that shows the benefit/cost ratio for the Basic Study on essentially the same basis as the parameters used for feasibility in the comparable year. The evidentiary support for the settlement will then be complete.

The Company will file information in the next main Rates Case in order to facilitate this type of comparison. Nevertheless, in the event that the E.B.O. 188 ADR Agreement is accepted by the Board, the information in relation to feasibility and monitoring will be comparable.

3.2.7 IGUA urged the Board to require the Company to treat the ADR and Board-approved capital budget as a constraint; not doing so, IGUA argued, tends to lead to continuous revenue deficiencies and rate increases, particularly in view of the E.B.O. 188 ADR Agreement. According to IGUA, this agreement, if implemented, will tend to lead to a larger expansion portfolio, an overstatement of the profitability, and an understatement of the short-term negative rate impact.

3.2.8 OCAP argued that it is increasingly important for a utility to operate like a competitive firm; competitive firms do not undertake all investments that are forecast to produce a favourable return. Unfettered capital spending is not in the ratepayers' best interest due to the inter-temporal inequities inherent in most capital projects. In this regard, OCAP had concerns in two areas. First, in view of developments in the gas market, there is an abnormally high risk that any investments that are made today will become stranded assets tomorrow. Second, as a consequence of industry restructuring, there is serious risk that ratepayers who made up the shortfall of investments in the early years for a future benefit will not reap those benefits; rather these longer term benefits will accrue to the shareholders. OCAP submitted that the best way to limit the impact on ratepayers is a strict enforcement of the Board approved capital budget. Strict enforcement should mean a disallowance of any overages. OCAP recommended that the aggregate over-spending in fiscal 1997 not be allowed in rate base. OCAP stated that the Capital Variance Study does not demonstrate a willingness on the part of the Company to reduce capital spending in the future, but rather it displays "an arrogant confidence that the Company will be able to explain any unapproved spending that it undertakes".

3.2.9 In reply, the Company stated that the OCAP and IGUA positions fail to take account of the "obvious" impacts to revenues and cost of service that would result from the disallowance of excess actual expenditures. The Company argued that it must respond to customer demands and it does so within the Board approved feasibility guidelines. It submitted that its evidence demonstrates a commitment to minimize capital budget variances where possible and appropriate. The Company noted that excess capital spending in fiscal 1997, net of the CIS amount, is 6% of the Board approved level and that the major driver is additional, revenue producing, distribution plant, driven significantly by the relatively new PCC program.

Board Findings

3.2.10 The Board deals with the overage related to SIM later in this section. The Board accepts the capital expenditure overages in the customer related distribution plant for fiscal 1997 for the purpose of setting rates in the 1998 test year.

3.2.11 The Board is, however, concerned with the Company's view that a Board-approved capital budget amount is nothing more than a rate setting device. It appears from the evidence that the main reason for overages in the past has been distribution system expansion. The Board recognizes that the Company's expenditures for distribution expansion must meet the Board-approved feasibility guidelines and are subject to scrutiny in subsequent rate reviews. However, the Board also considers that, generally, it takes many years for new distribution expansion projects to reach their break-even point. In a franchise system where maturity is not in sight, the break-even point for the Company's system expansion as a whole is forever pushed into the future. The result is a constant upward pressure on rates.

3.2.12 These upward pressures on rates must be better managed. Currently, there is no incentive for the Company to mitigate these pressures, whether they arise from customer related distribution expansion or from other capital expenditure activities, as it apparently sees its role as one of satisfying customer demands, forecastable or not. In the Board's view, the status quo embodies an incentive for the Company to grow to the degree possible without a balancing incentive to ensure that rate pressures are minimized.

3.2.13 The Board concludes that, for ratemaking purposes, any expenditures above the overall Board-approved levels in each of the main categories of the capital budget shall not automatically be included in the Company's proposed rate base for fiscal 1999.

3.2.14 Each category is to be treated by the Company as an expenditure envelope on its own. As shown in Table 3.1, the main categories are:

- customer related;
- system improvements and upgrades;
- general and other plant; and
- underground storage.

3.2.15 The expenditures shown in Table 3.1 are approved by the Board, except for reductions of $10.9 million relating to E.B.O. 188, $9 million relating to computer and communications equipment, and $0.366 million relating to MarketLink, as discussed elsewhere in this Decision. The proposed capital expenditures relating to CIS are not to be viewed as part of any of the above expenditure envelopes. The CIS related capital expenditures are dealt with in more detail later in this Chapter.

3.2.16 The Board cautions that this capping of capital expenditures will not absolve the Company from having to prove the reasonableness of its capital expenditures within each envelope, although such expenditures may be at or below the Board-approved level.

3.2.17 The Board recognizes that, for accounting purposes, the Company must record all expenditures. Should there be an overage within any envelope, the Company must present appropriate information for the Board to confirm the amounts for both regulatory and accounting purposes.

3.3 STRATEGIC INFORMATION PROJECTS (SIM)

3.3.1 During fiscal 1996, litigation support, regional field communications, internal audit, Materials Management (Accounts Payable), Materials Management (Central Logistics Facility) and Regulatory Process Management were completed and placed in service. The Company stated that it will complete its remaining SIM projects in fiscal 1997. The sole exception will be CIS. The reasons for the CIS delay are reviewed separately in this Chapter.

3.3.2 The six remaining SIM projects to be completed in fiscal 1997 are Rate Design/Revenue Forecasting, Operation Work Management System, Operations Records Management, Load Research, Fleet Management and the remaining portions of Materials Management.

Positions of the Parties

3.3.3 In regard to the Company's evidence on the costs and benefits of the remaining SIM projects to be completed in fiscal 1997, IGUA, CAC, Energy Probe and OCAP argued that, given that SIM costs will exceed E.B.R.O. 492 forecasts and benefits will decline, the Board should disallow all or part of the fiscal 1997 overage in SIM expenditures.

3.3.4 In reply, the Company noted that parties who took issue with SIM projects (other than CIS) were concerned only with the variation in cost and benefit estimates provided by Consumers Gas in E.B.R.O. 492 and the final estimates provided by the Company in the present proceeding.

3.3.5 Consumers Gas argued that it is difficult to estimate information technology costs with precision because of changing circumstances in the Information Services ("IS") field and that parties sought to impose on the Company unreasonable standards of estimates precision. Thus, in the Company's view, the parties' arguments suggesting that the Company be held to its E.B.R.O. 492 SIM estimates would not be in the interests of ratepayers.

3.3.6 The Company argued it has consistently followed the principle endorsed by the Board in previous decisions to the effect that it should achieve a positive NPV for the SIM project as a whole.

Board Findings

3.3.7 The Board notes that the parties' references to the amount of overexpenditure in SIM in fiscal 1997 vary. As the Board has noted previously, the overage is about $5 million, almost $1 million of which is interest during construction. A further $1 million is the expenditure associated with the EDS audit report. The remaining $3 million overage arises from delays in the in-service dates of SIM projects.

3.3.8 The Board also observes that the estimated benefits of SIM, excluding CIS, have declined by some $15 million. In its argument the Company stated that "It is through seeking a positive NPV rather than slavish adherence to a fixed capital expenditure number that the best possible outcome is achieved from the ratepayer's perspective".

3.3.9 In the E.B.R.O. 490 Final Decision with Reasons, the Board stated the following:

> *The Board cautions that the Company has an onus to optimize the returns on its SIM investments and to not merely generate the minimum acceptable financial threshold. In that context the achievement of a positive return at or beyond the ROR [Rate of Return], of itself, will not necessarily suffice.*

3.3.10 The Board is not satisfied that the Company has achieved the optimization that the Board required in the above Decision. The Board cannot accept increased costs and reduced benefits solely on the basis of the net present value remaining positive. In the circumstance, the Board reduces for ratemaking purposes the Company's SIM overage by $1 million. While this figure is not based on the reduction of any specific expenditure, it represents the Board's judgement as to the extent to which the Company's consistent over-expenditure on SIM projects closed to rate base should be shared with the shareholder. The Board directs the Company to treat this reduction as a permanent adjustment to its rate base.

3.4 COMPUTER AND COMMUNICATION EQUIPMENT

3.4.1 The test year capital expenditures in computer and communications equipment are $45.2 million. The major expenditures are in the areas of hardware ($17.0 million), software ($4.6 million), communications ($4.0 million), and NT technology ($7.5 million); an additional $12.1 million relates to other capital expenditures.

Positions of the Parties

3.4.2 HVAC argued that the budgeted unit costs for personal computers ("PCs") and laptops are out of line with market costs and recommended a decrease of $1.5 million.

3.4.3 OCAP argued that, on the basis of past expenditures, number of Company employees, type of equipment and the extent of its use, and because of the deferral of CIS, the Company's capital budget is unreasonably high. OCAP suggested a reduction equivalent to 200 PC units.

3.4.4 Energy Probe noted that, given the level of spending on computer and communications equipment, Consumers Gas is becoming a "major computer company." It suggested that the test year budget be reduced by $2.2 million.

3.4.5 CAC argued that several of the components of the hardware budget represent "an excessive, unnecessary and unsubstantiated expenditure". It submitted that:

- The number of desk-top PCs (3,600) exceeds the Company's number of full-time employees and questioned the need for state of the art technology in a gas distribution utility. CAC recommended deferral of the roll out of the 900 PCs on the basis of unsubstantiation of need and proposed configuration, and the delay of CIS.
- The Company has not provided adequate justification for the proposed expenditure for laptops and there is no formal policy for their allocation.
- The number of printers (750) is excessive in a company the size of Consumers Gas.

- The number of cell phones (1,177) is excessive and there is no formal policy for their allocation and use. It also noted that the O&M expense associated with cell phones exceeds $1 million.

3.4.6 IGUA submitted that the excessive spending in these areas is part of a larger problem, namely the "excessiveness and unreasonableness" of the Company's total capital and O&M budgets for Information Services. IGUA noted that the Company is planning to spend in the three year period ending in fiscal 1998 over $36,000 per permanent employee for computer equipment, excluding SIM capital expenditures, and $74,000 in O&M. IGUA recommended that $3.9 million be eliminated from the non-SIM capital expenditures for the test year.

3.4.7 In reply, the Company stated that information technology is costly but provides clear benefits to ratepayers; the capital expenditures budgeted in 1998 deliver real benefits and are either essential to the implementation of customer related systems like CIS or are important contributors to the efficiency and effectiveness of the computer system. With respect to the specific intervenor arguments, the Company submitted that:

- Computers are a productivity enhancement tool.
- The PCs to be acquired in the test year are almost entirely replacements of existing units; only 59 are added.
- CIS requires the full power of the new machines.
- Only 1,400 employees will require access to CIS and only these workstations will require NT units.
- The number of desktops assigned to full time employees in the test year will be 2,732, not 3,600; the balance will be used for part-time employees and contracted personnel, for home use and for the management of the network.
- The Company is not proposing state of the art technology for every employee.
- The justification for a laptop is derived from a business case and is approved by the senior management in the department.
- There are no additional cell phones budgeted in 1998 and cell phones are used as a productivity tool.
- The majority of the printers to be acquired in fiscal 1998 are for replacement of older units.

- Budgeted unit PC and laptop costs are the result of a tendering process.
- Cost per employee comparisons over time are not meaningful as fewer employees are needed due to productivity increases from computer technology.

Board Findings

3.4.8 On the basis of the Company's prefiled evidence, cross-examination, and argument, the Board has concluded that the Company's proposed expenditures in computer and communication equipment are excessive.

3.4.9 Of the total $17.0 million budget for hardware, the Board has calculated that approximately $8 million is for replacements, $3 million for upgrades, and $3.5 million for additions. Of the remainder, $2.3 million relates to roll-out of applications and to projects ($1.75 million), and for "Imaging Cold Technology" which relates to the ability to view images of customer bills and other correspondence ($0.6 million). The Board is persuaded by the evidence and the parties' arguments that:

- the Company's forecast unit costs for computer additions and replacements are excessive;
- on the basis of the Company's poor substantiation for its claims in this area, the Company's forecasts in unit costs for other hardware additions, replacements and upgrades are equally excessive;
- whatever the cost per unit, the combined number of desktops and laptops also appears to be excessive;
- in view of the delay of CIS, the Company may not want to undertake all of the hardware expenditures planned for the test year; and
- the delay in CIS may also lead the Company to delay or stagger its expenditures planned for the roll out of applications and for the "Imaging Cold Technology" Project.

3.4.10 The Board notes that a substantial portion of the Company's budget for software relates to licencing and the acquisition of new packages. With less equipment and fewer upgrades, additional licencing costs will be reduced. The Board also notes that a substantial portion of the budget is for the acquisition of new software packages.

3.4.11 Given the likely delay in the implementation of CIS, the Board is not convinced that all of the $7.5 million for the NT projects needs to be expended in the test year.

3.4.12 With respect to the communications capital budget of approximately $4 million, in the Board's view the number of cellular telephones currently in use has not been justified. The Board expects the Company to refrain not only from adding new cellular telephones but also from purchasing replacements in the test year. The Company may also consider deferring its plans for upgrading its voice-mail system and replacing fax machines.

3.4.13 The Board's findings above dealt with the Company's hardware, software, communications and network expenses totalling $33.1 million. In light of the above findings, the Board reduces this amount by 20%. A further $12.1 million of the budget could not be addressed in detail given the paucity of the evidence. This residual portion will be deemed by the Board to accommodate a similar percentage reduction. The Board therefore reduces the Company's total computer and communications equipment capital budget of $45.2 million by $9 million. The Board leaves to the Company's discretion the identification of specific areas of cost reduction, as the Company is in the best position to re-assess priorities.

3.4.14 The Board has noted that $2.5 million has been budgeted for the "Year 2000" problem. The Board cannot ascertain from the evidence whether this expenditure is included in the CIS project costs and, therefore, excluded with CIS from rate base inclusion in the test year. Further, the Board cannot ascertain from the evidence how the almost $1 million proposed expenditure characterized as "Internet/Intranet" relates to the capital expenditures identified for the MarketLink project. The Board's overall adjustment of $9 million does not reflect any adjustment in regard to either of these two items.

3.4.15 In the Company's next rates filing, the Board expects clear information setting out the Company's response to the Board's findings.

3.5 MARKETLINK

3.5.1 In its E.B.R.O. 492 application, Consumers Gas sought Board approval for an Internet-based gas commodity trading board (referred to generally as the MarketLink proposal). The initial phase of the MarketLink proposal was to be the development of an Electronic Gas Trading Board ("EGTB"). In its E.B.R.O. 492 Decision, the Board stated that it was sympathetic to the need of Consumers Gas to provide up-to-date facilities for communication with its customers, and to modernize electronic and telephone access for inquiries, billing information and so on. Nevertheless, the Board was not convinced of the benefit of EGTB as such. In consequence the E.B.R.O. 492 Decision stated that the cost of EGTB should not be borne by ratepayers; the Board thus excised the utility operating and maintenance costs associated with EGTB from the Company's application in respect of some $93,000 expended between November 1995 and November 1996. The Board did approve the balance of MarketLink O&M expenditures for the 1997 budget year; these were $130,000. Capital costs of $200,000 were also approved in E.B.R.O. 492.

3.5.2 The Company's evidence was that the EGTB had been run on a pilot basis from June to December 1996 at shareholder expense. The EGTB system failed to attract significant support and was completely dismantled in January 1997; the Company has no plans to revive this system. No costs are budgeted for fiscal 1998.

3.5.3 Consumers Gas' evidence was that its experience with the EGTB concept led to the development of the present MarketLink proposal. The Company stated that it drew upon the budget approved in E.B.R.O. 492 to develop a website for Consumers Gas using the same developer who was currently in the process of developing a website for Union. The total capital and O&M expenditures will be incurred by the end of fiscal 1997.

3.5.4 In fiscal 1998, the Company proposed additional expenditures on MarketLink of $366,000 capital and $200,000 O&M.

3.5.5 Consumer Gas' evidence was that the MarketLink project was planned in three phases.

- Phase I would involve a static website to provide customers with information on the Company's billing and service options as well as corporate, safety and environmental information. This phase was originally forecast to be completed by March 1997; that forecast was revised to July 1997.
- Phase II is intended to be completed at the end of fiscal 1998 and will enable customers to access their account information; review their gas consumption history, receive assistance in selecting energy saving choices and book service appointments.
- Phase III will increase the interactivity features, enabling customers, for example, to pay bills. The Company was unable to forecast the completion of this phase with any degree of certainty.

3.5.6 The Company further stated that it expected the MarketLink project to offer assistance to an Information Services planned project, the Intranet, which will be used for internal communication between employees.

3.5.7 The Company stated that it had prepared a 10 year forecast of the MarketLink project that showed a positive NPV of $1.8 million, with a positive cash flow occurring after four years. Savings were to be achieved by reduced O&M expenses in the Company's Call Centre assuming a customer adoption rate of MarketLink of 2% in 1998 and increasing to 24% at the end of the 10-year forecast period. In updated evidence the Company reduced the expected usage to 1% and reduced its NPV calculation to $590,000.

3.5.8 On the basis of its understanding that such analyses would not be required for projects involving capital expenditures of less than $500,000, the Company did not provide a cost benefit analysis for this project.

Positions of the Parties

3.5.9 IGUA argued that, in light of the EGTB experience, the Board "should be reluctant" to permit the Company to recover the costs of the Company's proposed Internet service without convincing evidence of a demand for such a service. IGUA submitted that no such objective evidence was made available in this hearing. IGUA further argued that even if the need for an Internet service had been established, the costs appeared to be excessive as, for example, the proposed cost of $70,000 for a website on the Internet. IGUA submitted that the costs claimed for this service should be disallowed for the test year without prejudice to the Company's right to seek to recover costs associated with such a service when the Company can better demonstrate that the service is likely to be used by a number of customers sufficient to justify its introduction.

3.5.10 CAC argued that while it was, as was the Board in E.B.R.O. 492, cognizant of the possible importance of electronic communications with customers of the Company, it had certain concerns about the present proposal. These were:

- Consumers Gas has not adequately assessed the economics of the project; the Company witness provided little detail about the MarketLink 1997 budget. In addition, no breakdown of the 1998 planned expenditure was provided other than some $70,000 to be spent on a website;
- Consumers Gas did not file an NPV analysis of the project; and
- the Company has relied upon an unsubstantiated assumption that 24% of its customers will be using the Internet service in 10 years.

3.5.11 CAC submitted that the Company has not adequately explored the potential use of the system by ratepayers and expressed surprise that no research has been undertaken on the extent to which customers of other utilities with websites make use of the system, such as using it to carry out banking or to pay bills.

3.5.12 CAC argued that the Company has not demonstrated to the Board that the development of this facility is being carried out cost effectively and that it is in the interest of ratepayers.

3.5.13 OAPPA submitted that the Board should approve the MarketLink services and the 1998 test year cost estimates. OAPPA, however, further submitted that the Board direct Consumers Gas to file, at its next mains rates case, a report which quantifies the reduction in Call Centre enquiries, bill inserts and other measurable savings which have resulted from customers' use of the MarketLink service.

3.5.14 OCAP submitted that the Company had failed to provide any assurance that MarketLink services are currently used, or will be used in the near future. It noted that the Company had projected a net benefit of $590,000 for MarketLink over the next 10 years. OCAP asserted that the Company had failed to provide evidence for its assumptions regarding customer use and noted that only 8.7% of Ontario households had Internet access last year. OCAP's conclusion was that the proportion of the 8.7% likely to be interested in accessing the Consumers Gas website was likely to be miniscule. OCAP noted that use of the Internet is four times higher in households in the highest income quartile than in households in the lowest quartile; lower quartile households with computers were also less likely to have a modem (and consequently Internet access) than upper income households.

3.5.15 OCAP further argued that the Company's short-term and long-term benefits projections are highly suspect given their evidence as to likely slippage in the anticipated completion of the interactive stage of the MarketLink website.

3.5.16 OCAP concluded that, in its view, the real drive behind MarketLink is not benefits that might be derived by core customers, but broadening the scope of the Company's competitive services. In that circumstance the benefits would flow to shareholders who should therefore bear the costs.

3.5.17 AMO/ECNG submitted that the expenditures planned by the Company for development of an Internet website should be looked at in the light of the Company's planned further expansions into non-regulated activities. AMO/ECNG suggested that the Board examine this connection and possibly impose some cost sharing formula (between shareholders and ratepayers) for this facet of the Company's planned business expansion.

3.5.18 The Company took issue with the submissions of IGUA and OCAP that Consumers Gas had not provided evidence of a clear desire by ratepayers for such a service. The Company pointed out its survey evidence which indicated that 11% of its current customer base would like to have an Internet connection with Consumers Gas and that those customers would use such a connection.

3.5.19 The Company conceded that the evidence indicated that higher income households are more likely than low income households to own personal computers. The Company argued, however, that a Statistics Canada report indicated that 22.7% of the lowest household income group (under $10,000 income) owned a personal computer; furthermore, OCAP itself operates a website, leading Consumers Gas to the submission that there are enough of OCAP's constituents who have Internet access to justify OCAP's website.

3.5.20 The arguments of AMO/ECNG and OCAP, that the purpose of the project, and the website in particular, is to broaden the scope of the Company's competitive services were dismissed by the Company as being speculative and indeed, in the case of OCAP, inconsistent with that intervenor's argument that the website would not be used by customers.

Board Findings

3.5.21 In its E.B.R.O. 492 Decision, the Board noted that, while it was prepared to approve certain costs for the 1997 fiscal year, it would require evidence on the extent to which the proposed service is used and is of benefit to ratepayers before approving ongoing expenditures for this project.

3.5.22 The Board is concerned that the Company's assumptions of use by customers in the 1997 test year appear to be based on evidence which is somewhat slender. This conclusion takes into account the Company's evidence that a survey of customers showed that 11% of customers would be interested in using such a service. No evidence was provided as to the details of the survey nor any indication of how the service was described to respondents. The Board does not consider the assumption of customer usage to be well supported.

3.5.23 Further, the Board is concerned that the evidence provided by the Company on expenditures made and planned for fiscal 1997 does not shed much light on whether these expenditures, such as the $70,000 cost of a website, have been prudently incurred. The Company offered no evidence as to comparable costs for such facilities elsewhere nor evidence as to tendering for this facility.

3.5.24 The Board is aware that the Company relied upon a general convention that its capital expenditures of less than $500,000 do not require supporting cost benefit analyses. The Board considers this assumption to be ill advised in the case of MarketLink, in which development would occur over several years at a substantially higher cost than the $500,000 "threshold".

3.5.25 In the Board's view, the Company has not justified the need for MarketLink and, therefore, the Board will not approve the estimates of $366,000 in capital and $200,000 in O&M expenses for the 1998 test year. The Company should be aware that, if it undertakes this expenditure, it will do so at the expense of the shareholder.

3.6 CUSTOMER INFORMATION SYSTEM

3.6.1 CIS constitutes the largest capital project in the Company's six-year SIM project. The Company's initial written evidence forecast completion of CIS in October 1997 and sought the Board's approval for inclusion of CIS capital costs in the 1998 fiscal year rate base. That initial evidence was, in the event, subject to several updates with the net effect of the Company withdrawing the proposal for inclusion of the project in 1998 rate base.

3.6.2 The Company stated that while CIS is composed of a number of projects, its largest task is the replacement of current Legacy systems which are crucial to the functions of billing, financial, customer service and sales and marketing. This project is the subject of a contract entered into by the Company with Price Waterhouse ("PW") by which the Company would obtain the use of PW's Service 2000 to replace these Legacy systems. Service 2000 is an integrated system by which, for example, the effect of an item on a customer's bill for a service call is reflected in the Company's financial records and its customer service records along with any changes to other records or files associated with the item.

3.6.3 In its E.B.R.O. 492 Decision with Reasons, the Board took issue with the Company's evidence on CIS in several respects, most notably in reference to Consumer Gas' statement that CIS was not being developed to accommodate future diversification and changing market conditions. In consequence the Board saw merit in the Company deferring its development of the CIS project until the Company could clearly demonstrate that it had effectively considered the ramifications of potential changes in its operating environment.

3.6.4 In the present proceeding Consumers Gas submitted, in prefiled evidence, an analysis of the impact of deferring CIS it had submitted in support of its Motion under E.B.R.O. 492-01. That Motion was an application by the Company for a rehearing pursuant to Section 30 of the Act to seek a review and redirection of the Board's E.B.R.O. 492 Decision. In its E.B.R.O. 490-01 Decision on the Motion, which denied the Company's application, the Board observed that Consumers Gas should lead evidence in the present proceeding to demonstrate that it had, despite its testimony to the contrary in E.B.R.O. 492, given effective consideration to CIS' ability to accommodate new business directions. A considerable portion of the Company's evidence in this proceeding addressed this issue.

3.6.5 Consumers Gas stated that the choice of the PW Service 2000 system was influenced by that system being flexible so as to accommodate, for example, possible future electric utility billing requirements, the unbundling of current services, the changing merchant role and diversification issues. The Company also commented that this flexibility had been obtained at no incremental cost to the ratepayer. The Company went on to stress, in the event that only the most basic distribution utility functions remained regulated, that the CIS costs would be appropriately allocated across regulated and unregulated businesses using the services of CIS.

3.6.6 The Company also provided evidence to address the Board's finding in E.B.R.O. 492 that the Company's attempt to negotiate the purchase of ownership rights in the PW contributions to the CIS system was "no more than a speculative venture". The Company stated that, although the system will not be owned by Consumers Gas, an irrevocable and perpetual licence had been negotiated with PW to also allow the Company to provide services using CIS to third parties in Canada and to provide for limited access to global markets for provision of these services.

3.6.7 This licence was to form part of a final comprehensive contract to be signed between Consumers Gas and PW. The Company originally expected this contract to be signed in January 1997; in the event, updated evidence stated that the contract was not signed until May 14, 1997. The Company declined, on grounds of commercial confidentiality, invoked by PW, to produce this contract in evidence.

3.6.8 The Company's amended evidence was that on March 11, 1997, PW notified Consumers Gas that their hesitation to finalize the Service 2000 contract - and the subsequent delay of the planned signing date of February 5, 1997 - was occasioned by PW concerns about certain code difficulties being experienced by another Service 2000 application at South Carolina Electricity and Gas ("SCE&G"). PW concluded that these problems at SCE&G could lead to substantial additional integration testing time prior to CIS going on line.

3.6.9 Consumers Gas stated that while there is, as a result of these difficulties, a high probability the project will be delayed and may not be completed in the 1998 fiscal year, until such time as more information leads to a new CIS schedule the Company would be aiming for the current project milestones. The evidence was that a delay of two months for additional integration testing of CIS could be accommodated within the present schedule; anything beyond that would make a late fall 1997 implementation of CIS, as presently planned, unlikely.

3.6.10 However, the Company later stated that the most prudent course of action would be to delay, for ratemaking purposes, the in-service date of CIS beyond the 1998 test year. The Company stated that the rate implication of the delay in the in-service date of CIS was an increase to its test year revenue requirement by $8.6 million.

3.6.11 The revised total cost of the CIS project is increased by $9.7 million to $69.5 million. This increase includes $3.0 million for interest during construction. The Company stated that full annual CIS project benefits remain unchanged by the delay, but emphasized that the Company would be at risk if those benefits were diminished because of the delay.

3.6.12 The Company testified that it would be paying PW during a six month delay period but that some of these costs might be mitigated since the contract with PW provides for a sharing of cost consequences of delay depending on the reasons for the delay.

3.6.13 In the hearing, a suggestion was put to the Company's witness that the Board should examine the PW contract and, at a minimum, decide that it represented a prudently incurred cost. The Company stated that the contract, on grounds of the commercial confidentiality concerns of PW, precluded outsiders from examining it. The witness acknowledged that any losses attendant on the contract would be the joint responsibility of both Consumers Gas and PW. The Company's testimony was that in earlier discussions with IBM and Andersen Consulting, in the context of studies those companies had made to assist Consumers Gas in the direction of CIS, it was clear every software company seeks a sharing of risks as in the Consumers Gas/PW contract.

3.6.14 The Company also confirmed that it considered that it was prudent for it to have signed the PW contract on May 14, 1997, even in the circumstance in which it knew, from a PW letter dated April 25, 1997, that integration problems were being experienced by PW at SCG&E.

3.6.15 The Company further testified that a continued delay in the completion of CIS would cause them "alarm" in regard to not dealing with the Year 2000 problem (billing systems for example depend on dates and arithmetic relationships; thus the year "00" causes many calculations to be in error or creates negative values). The Company stated that, while it has made Year 2000 modifications to some Legacy systems, other systems, such as billing systems, have not been so modified since the Company assumed that these and similar systems would be replaced by CIS in March 1998.

Positions of the Parties

3.6.16 Concerning the delay of CIS implementation, it was IGUA's view that:

- the PW induced delay and the consequent increases in cost amounting to $8.6 million should be for the account of the shareholder;
- the Company has not discharged the burden placed upon it in E.B.R.O. 492 wherein the Board's finding was that it had no evidence to determine whether the cost of CIS was used and useful. Thus the Board ought not to accept any CIS costs, including the additional costs attributable to the PW difficulties, for budgeting or ratemaking purposes;

- the total costs of CIS "are astronomical" and the Board should not make any decision on those costs until the first rate case following the project's implementation; and
- the Board should direct the Company to lead evidence showing a market value for the CIS project, limiting that valuation to the services CIS provides to the regulated utility.

3.6.17 It was CAC's view that, in signing the PW contract by which the Company would share the cost consequences of any delay with PW, in effect the Company is attempting to pass to the ratepayers the consequences of a delay caused by a third party. CAC argued that no regulated monopoly can responsibly enter into a contract which gives the other party a veto on disclosure of the contract to the regulator. In this circumstance CAC submitted that the $8.6 million increase in the Company's revenue requirement occasioned by the delay in implementing CIS should be disallowed by the Board.

3.6.18 CAC also submitted, given Consumers Gas' evidence that it had not compared the cost of its CIS system with similar information systems in other utilities, the Board has no benchmarks with which to assess the reasonableness of the CIS costs. CAC argued that the Company file, in its next main rates case, a comparison of its CIS system costs with those of other North American utilities.

3.6.19 Further, CAC submitted that given the magnitude of the present forecast costs and the decline in benefits, Consumers Gas should be required, in its next main rates case, to file an independent assessment of the worth of the CIS project. HVAC argued to the same effect.

3.6.20 Finally, CAC argued that the Board should not approve the 1998 capital expenditures related to CIS on the grounds that such approval might imply approval of the CIS project costs in total.

3.6.21 In view of the Board's refusal to approve the Company's CIS expenditure in E.B.R.O. 492, Energy Probe urged the Board to now order the Company to provide two options for the Board in the next rates case, namely:

- remove CIS from the Company's rate base; or
- plan to leave CIS in the rate base on the basis of its price at market valuation.

3.6.22 Energy Probe also argued that the Company's contract with PW has, in light of PW's difficulties with its client SCG&E on a similar CIS project, exposed the Company to significant risks. Energy Probe recognized that the CIS costs would not be closed to rate base because of the delay occasioned by PW. Energy Probe however submitted that the Board should indicate to the Company that CIS increased interest costs caused by this delay and the direct costs of the delay are not approved and should be borne by shareholders pending the Board's decision at the next rates hearing.

3.6.23 OCAP submitted that, because the Company had not undertaken indepth analysis of other CIS systems, the Board cannot be assured that lower cost alternatives could not have met the Company's needs. Further, OCAP argued that the real drive for choosing an "ambitious" CIS system was to provide a flexible platform, at the expense of utility ratepayers, to support the Company's extensive plans for entering competitive market activities.

3.6.24 OCAP argued that there must be no "regulatory bargain" concerning the inclusion of CIS expenditures in rate base. OCAP urged the Board to lay the ground work in this Decision for any future disallowance of CIS costs it may consider appropriate. Such a warning would be made on the understanding that it would not bind a future Board panel nor prejudge the merits of a future CIS case the Company might put forward.

3.6.25 Both Energy Probe and Suncor/PanEnergy argued that CIS should be operated outside the utility.

3.6.26 The Company submitted that the argument that CIS had been built not just for the basic business of Consumers Gas but primarily to provide a platform for the Company's present and future competitive activities, was "absurd", since it implied that CIS should be built for a hypothetical pipe company "rather than one to support the real business".

3.6.27 Consumers Gas submitted that in designing a CIS system to replace its old Legacy systems, it was necessary to support existing business (such as its ancillary businesses) as well as accommodate known or likely changes.

3.6.28 The Company argued that neither the proposals that CIS be operated outside the utility nor those that a market value assessment be made of CIS, were issues in this proceeding.

3.6.29 The Company noted CAC's submission that by signing the project contract for CIS with PW, Consumers Gas had been imprudent and increased risks for the ratepayer. The Company argued both it and PW had been honouring the contract prior to the formal signing and that by signing the contract the Company had reduced the risk of the project by sharing the risk with its lead contractor; in addition, execution of the contract implied that PW was obligated to finish the project and prevented it from giving notice and leaving the contract. The Company acknowledged however that the confidentiality of the contract did not absolve it from satisfying the Board that it had acted prudently in the matter. Consumers Gas stated that it was committed to finding an appropriate way to so satisfy the Board.

3.6.30 Referring to the argument that $8.6 million be reinstated in the revenue requirement for the test year, Consumers Gas submitted that this argument could only be attributed to a misunderstanding of the Company's evidence on this matter. Consumers Gas submitted that the $8.6 million reflects the ratemaking implications of a 1998 CIS delivery date and results primarily from an increased tax deduction to which the Company would have been entitled, had CIS been completed as planned.

Board Findings

3.6.31 The Board agrees with the Company that no further adjustments are required to the Company's test year revenue requirement by reason of the Company's removal of CIS from the 1998 rate base as originally proposed.

3.6.32 The Board has noted Consumers Gas' submission in its reply argument that the Board should accept the Company's management of the CIS project as reasonable and prudent and accept the capital expenditures associated with the project. The Board will make its findings on the prudency of the totality of expenditures of this (now seven year) project at the Company's first rates case after its completion.

3.6.33 The Board notes in this Decision certain issues emerging which lead the Board to require the Company to produce specific evidence at its next hearing.

3.6.34 The first issue concerns the contract which Consumers Gas signed on May 14, 1997 with Price Waterhouse for development of the CIS. The evidence was that Price Waterhouse had started work on that project in April 1995 and, in the original evidence, the parties had planned for completion of the work on March 31, 1998. The contract had thus been finalized some two years into the work and one year short of completion. Consumers Gas' testimony was that the contract is confidential and cannot be released to other parties without the consent of signatories. The evidence was that PW is unwilling to give that consent. The Board observes Consumers Gas' agreement that this provision was sought by PW for reasons of commercial confidentiality and precluded a regulatory agency, in this case the Board, from examining it in a public forum. Consumers Gas testified, however, that the contract specified that cost overruns were the joint responsibility of both PW and the Company. The Board has taken particular note of the Company's testimony that the PW contract was signed when the Company knew that:

- PW had a problem at SCG&E and substantial additional testing of CIS would thus be needed;
- the cost consequences of the delay were unknown;
- the fault was not of the Company's doing; and
- Consumers Gas might have to share the cost consequences of the delay.

3.6.35 Further, the Board notes the Company's testimony that it had signed the contract in the light of this circumstance and its liabilities because "our honour would certainly require us to stand by our word" in respect of its association with PW which predated the signing of the contract by some two years. The same witness also stated when asked why a regulated company would enter into a contract which incorporated both confidentiality and liability on the Company for non performance of the other party, that "I don't think we always act with a view to regulation".

3.6.36 The Board has noted the concerns of the parties as to this contract. It has also carefully noted the Company's reply argument in which it stated that "it will have to satisfy the Board that the deal negotiated with Price Waterhouse was prudent and, as a result, the Company is committed to finding an appropriate approach to do this." The Board notes that the onus is on the Company to provide the Board, at the next rates case, with sufficient information about the PW contract to enable the Board to decide whether or not the Company was prudent in entering into this contract.

3.6.37 The second issue concerns the capability, and the associated cost, of CIS to serve business interests of the Company which are not part of the regulated gas distribution monopoly. In the E.B.R.O. 492 proceedings the Company indicated that the CIS project was not being developed to accommodate diversification activities despite the evidence as to the Company's increasing interest in, and involvement with, such diversification activities at that time.

3.6.38 In its E.B.R.O. 492 Decision the Board found that it was not prudent for the Company to build CIS infrastructure "without analyzing the potential impact of changes in business strategy with regard to modification costs of the CIS system". Regardless of the merits of this justification, the Board considers the failure of the Company to put it forward in E.B.R.O. 492, to be a serious misjudgment by the management of the Company, which ultimately led to an unnecessary effort by all parties to consider the merits of a rehearing application in E.B.R.O. 492-01. The Board has noted the Company's present evidence that there are no additional CIS developmental costs to accommodate the use of CIS for the Company's activities beyond what is necessary to serve current gas ratepayers. The Board expects that parties will wish to be assured that this is indeed the case.

3.6.39 As to the arguments that a market assessment be made of CIS to ascertain whether the Company has been prudent in its expenditures, the Board is doubtful that such an approach is really practical. What the Board must do in the Company's next rate case is to make a finding on that prudency. To assist it in this task, the Board will require the Company to produce relevant comparisons with comparable utility systems.

3.6.40 The Board, in short, does not yet have the requisite evidence to make a finding as to the prudency of the Company's expenditure on CIS to date. The Company has already netted out for the test year the impact of delaying the implementation of CIS. Therefore, any capital expenditures to be undertaken in the test year are not "approved" in the sense that such expenditures are to form part of future rate base without an overall evaluation of the prudence of total CIS expenditures.

3.7 OVERALL ADJUSTMENTS TO RATE BASE

3.7.1 The Board has used the impact statement filed by the Company to reflect the adjustments necessary to exclude the E.B.O. 188 ADR Agreement. The impact statement indicated that the timing of the $10.9 million reduction in capital expenditures resulted in a $3.1 million reduction to net rate base.

3.7.2 As the adjustment for SIM overages occurred in 1997, the 1998 test year adjustment applies for the entire year. An adjustment of the opening balance of accumulated depreciation is also required to recognize the Board's reductions, deemed to have occurred uniformly throughout 1997. A depreciation rate of 20% is deemed appropriate for ratemaking purposes as SIM Software Applications are amortized over 60 months. The 1998 capital cost allowance adjustment reflects the 1997 capital cost allowance impact on unclaimed capital cost, and the Board deems that a rate of 30%, generally used for data systems, is reasonable as the adjustment is not made to specific capital items.

3.7.3 The $9 million reduction in the computer and communications budget are deemed to occur uniformly throughout the year. For the purpose of establishing related adjustments to capital cost allowance and depreciation expense, the Board has used the relative proportions of communications expenditures (approximately 10%) and computer expenditures (approximately 90%) indicated in the capital budget to determine the composite depreciation and capital cost allowance percentages. A CCA rate of 20% was applied for computer equipment, while 5% was applied for communications equipment. To determine depreciation expense, 25% was applied for computer equipment and 5.5% was applied for communications equipment.

3.7.4 The MarketLink project, originally forecast to enter rate base in mid-year, was not subject to adjustment in the Company's updates; therefore the Board has used a mid-year date to determine rate base and monthly depreciation impacts. The Board has used the same assumptions for capital cost allowance and depreciation expense rates as were deemed appropriate for SIM.

3.7.5 The Board has reduced the allowance for working capital by $0.05 million to account for other adjustments made by the Board in the areas of gas costs, as discussed above, and O&M expenses as discussed in Chapters 2 and 4.

3.7.6 As a result of the above findings, the Company's rate base proposal of $3,066.80 million has been reduced by $8.03 million. The Board approves a rate base of $3,058.77 million as summarized in Appendix A.

4. UTILITY INCOME

4.0.1 Utility Income is the result of subtracting costs from revenues. In the case of a regulated utility, the costs exclude any costs associated with the servicing of the utility's debt or the return associated with the utility's common equity. The Utility Income, when divided by total rate base, indicates the rate of return that is achieved. The derivation of Utility Income and its components are shown in Appendix B.

4.1 SETTLED ISSUES

4.1.1 There was complete or partial settlement on the following issues:

- Revenues from Gas Sales, Transmission and Storage
- Revenues from Transactional Services
- Forecast of Gas Costs
- Demand Side Management ("DSM") Plan

4.1.2 A description of these issues is set out below. Details of the settlement on each issue are set out in Appendix E. The Board's additional findings follow each of the issues below.

Revenues from Gas Sales, Transmission and Storage

4.1.3 The Company is forecasting a net increase of 44,274 Rate 1 and 3,636 Rate 6 customers in fiscal 1998 over fiscal 1997. Coincident with the growth in Rates 1 and 6 customers is a shift from system gas to T-Service for both rate classes which is attributable to the ABC T-Service initiative. Rate 1 T-Service for 1998 is forecast to increase by 378,232 customers over 1997 estimates. Rate 6 T-Service for 1998 is forecast to increase by 8,962 customers over 1997 estimates.

4.1.4 The Company forecast a total throughput volume of 11,710.0 10^6m^3 in 1998 which includes an increase of 102.4 10^6m^3 in Rate 1 due to customer growth of 134.4 10^6m^3, partially offset by lower average use per customer of 32.0 10^6m^3. Growth in Rate 6 is due to customer growth of 72.7 10^6m^3 and a slightly higher average use per customer of 3.6 10^6m^3. The total Contract Sales and T-Service increase of 162.1 10^6m^3 is primarily due to increases in the commercial sector of 55.0 10^6m^3, industrial sector of 60.4 10^6m^3 and Rate 200 sales of 51.7 10^6m^3, partially offset by lower apartment volumes of 5.0 10^6m^3.

Revenues from Transactional Services

4.1.5 Under Transactional Services, the Company provides: (i) Full Cycle and Short Cycle Storage from Released Capacity; (ii) Gas Loans; (iii) Exchanges; and (iv) Assignments. The Company's evidence was that it markets these services mainly to ex-franchise customers and only if the Company's physical assets and contractual transportation assets are in excess of the requirements of the Company's in-franchise and ex-franchise firm customers. A short description of the transactional services follows:

- Short Cycle Storage, both Peak and Off-Peak, applies to Released Capacity only and allows for injection and withdrawal over some portion of the year.
- A Gas Loan is a service under which the Company delivers a volume of gas to a third party during a defined period and the third party returns to the Company an equivalent volume of gas at a later pre-defined period.

- An Exchange is a service under which the Company receives gas from a third party at a receipt point and delivers the same amount of gas to the third party at a different point.
- An Assignment involves making some of the Company's transportation entitlements available to third parties.

The Market

4.1.6 In E.B.R.O. 492, the Board indicated that it would review in the present proceeding the status of the transactional services within the regulated utility and the degree of competition in storage markets in Ontario.

4.1.7 The Company provided an assessment of the competitiveness of the market in which the Company provides transactional services. It concluded that it provides these services in a competitive market on the basis that:

- in providing storage services the Company operates a relatively small share of the storage facilities and contracted transportation capacity in the geographic market of its services;
- the Company does not control any of its transportation paths to deliver its services to market;
- there are adequate alternatives available in the market; and
- there are no significant barriers to entry by competitors.

No Harm to Ratepayers

4.1.8 In E.B.R.O. 492 the Board stated that it has to be satisfied that the ratepayer is being kept harmless by the shareholder from potential increased gas costs due to the provision of transactional services.

4.1.9 In response, the Company's evidence outlined the interaction between the Transactional Services group and the Gas Supply group before the latter approves or rejects a Transactional Services request from the former. The Company also outlined the process followed by the Gas Supply group in rejecting or accepting a proposal. The guiding principles of the Gas Supply group were stated as follows:

- it will not rely on the curtailment of interruptible customers to satisfy a transactional service;
- it will assume the "worst case" scenario for injection and withdrawal patterns when reviewing off-peak and peak storage arrangements; and
- it will maintain storage inventory levels to meet the Company's multi-peak design criteria.

4.1.10 Recognizing the uncertainty surrounding several of the input parameters, the Company stated that, should there be a negative impact on ratepayers as a result of transactional service arrangements, alterations to the supply dispatch plan will be made, such as interrupting any of the non-firm transactional service arrangements or purchasing additional discretionary gas which will be charged to the Transactional Services group.

The Rate Treatment

4.1.11 For purposes of ratemaking, the Company defines Gross Margin as the revenues generated from transactional activities, minus direct costs, plus avoided costs, minus operating and maintenance costs. The Company also defines Net Revenue as the Gross Margin minus marginal operating and maintenance expenses.

4.1.12 In E.B.R.O. 492 the Board approved the Company's revenue and cost components that yielded a forecast Gross Margin of $772,000. The Company was directed to credit its 1997 cost of service by 90% of this amount or $694,000. The Board stated that the disposition of any variance will be subsequently determined by the Board.

4.1.13 For 1997, the Company projected a positive Gross Margin variance in the amount of $864,000 and a higher marginal O&M expense of $48,000. The Company proposed that 50% of the Gross Margin variance or $432,000 be credited to the customers. The remaining $432,000 and the operating and maintenance expense variance of $48,000 is to the account of the shareholder. According to the Company, the 50:50 disposition of the Gross Margin variance recognizes the fact that the customers are guaranteed the forecast level of Gross Margin regardless of actual results and is consistent with incentive mechanisms approved in other Canadian and U.S. jurisdictions.

4.1.14 The Company's fiscal 1998 forecast Net Revenue is $1,582,000 comprised of a Gross Margin of $2,081,000 less Marginal O&M expenses of $499,000. The Company proposed to continue to apply the current sharing approach. Of the $1,582,000 forecast Net Revenue, 90% or $1,423,800 is used to reduce the 1998 cost of service. The amount by which the actual Gross Margin exceeds the fiscal 1988 budget level of $2,081,000 will be recorded in the 1998 deferral account to be shared, according to the Company's proposal, also on a 50:50 basis between customers and shareholders - any deficiency in that variance or a positive variance in the marginal O&M expense will be to the account of the shareholder.

Intervenor Evidence

4.1.15 Mr. Todd's prefiled evidence on behalf of OCAP advocated that the Board adopt a sharing methodology similar to that adopted in British Columbia. Shareholders of BC Gas receive a "relatively large" 50% of the transactional services variance account balances for variances up to 40% and 50% in excess of the benchmark budget and a "relatively small" 20% of revenues in excess of the target range, and bear "little" relative responsibility for significant under-achievements.

4.1.16 Ms. Chown referred to the Board's E.B.R.O. 492 Decision which deferred the review of the status of the transactional services within the regulated utility to the next proceeding (the current proceeding). She stated that, although the competitive nature of the transactional services suggests that it would be appropriate to remove these services from the regulated utility, it is difficult to remove these services without removing all other storage services given the common facilities involved. For this reason, Ms. Chown recommended that the Board defer any decision on the removal of transactional services from the regulated utility until the Board determines the status of all storage services in the Market Review.

Settlement Proposal/Positions of the Parties

4.1.17 There was agreement to settle this issue as per the Company's proposal except that the closing balance in the deferral account be disposed of on a 75:25 customer:shareholder basis, rather than 50:50 proposed by the Company.

4.1.18 At the opening of the hearing, the Board invited parties to comment in argument whether this panel of the Board can accept the part of the agreement referring to the future disposition of any balance in that account.

4.1.19 The Company submitted that the Board panel in the Company's next main rates case is not necessarily required to come to its own conclusion in disposing of the actual balance; it would be obligated to do so only if the account does not contain a provision governing the disposition of the actual balance. IGUA stated that the disposition provision is appropriate and that it will support such disposition in the future. OCAP agreed with the position advanced by the Company.

Board Findings

4.1.20 The Board accepts that the Company has fully responded to the Board's requirement in E.B.R.O. 492 with respect to transactional services. The Board views the settlement of this issue to include transactional services as part of the regulated utility for the test year.

4.1.21 Having considered the Company's and the parties' comments, the Board approves in principle the agreed upon disposition of any future balances in this deferral account. The Board does not expect that the sharing proportions will, in the normal course, be reviewed in the near future.

Gas Costs

4.1.22 The Company's total gas supply costs to be recovered in the test year consist of:

- forecast costs of commodity purchases (including buy/sell purchases);
- forecast costs of transportation;
- positive or negative fluctuation in the forecast value of gas between the first and last day of the fiscal year;
- forecast storage and transportation costs;
- T-Service credits; and
- any regulatory adjustments.

4.1.23 The fiscal 1998 gas cost projections assume a mix of indexed and fixed price contracts. Approximately 50% of long-term supply is indexed to NYMEX, 33% to the Canadian Gas Price Reporter and 17% is fixed.

4.1.24 On April 14, 1997, an updated gas cost forecast was filed prior to the commencement of the settlement conference, which included a new forecast for volumes flowing under ABC T-Service, a new basis differential, exchange rate, and NYMEX strip forecast (US$2.0901/MMBtu) over the period from February 24, 1997 to March 24, 1997. In the Settlement Proposal, there was agreement to accept the Company's gas cost forecast.

4.1.25 On the last day of the hearing, however, the Company increased its gas cost forecast based on the average of the 12 month NYMEX strip as reported from April 29, 1997 to May 28, 1997. The Company projected the fiscal 1998 gas costs to be $1,093.5 million. The principal source of the increase was a revised NYMEX price of US $2.2265 per MMBtu. The basis differential and exchange rate components were also revised. In addition, the latest gas cost forecast reflected new NEB-approved TCPL tolls and new OEB-approved Union storage and transportation charges.

4.1.26 The updated forecast annual FT-WACOG is $\$109.384/10^3m^3$ which results in a Western Buy/Sell (without fuel) purchase price of $\$71.592/10^3m^3$.

Positions of the Parties

4.1.27 IGUA stated that there was no agreement authorizing the Company to file a further gas cost update and, technically, the Settlement Proposal may bind the Company to its agreement; any changes would be subject to the "trigger" mechanism, which is an option available to the Board. IGUA noted that this option will allow consideration of the Company's affiliate, Consumersfirst, being able to continue to offer "price capper" service at levels below the gas costs reflected in the Company's current rates. IGUA submitted that there is an apparent inability of the Company to manage its costs as effectively as its affiliate.

4.1.28 OCAP expressed concern about the "last minute" increase in the gas cost forecast because of the lack of sufficient opportunity to adequately test the Company's proposal. In OCAP's view, the Board should not set rates on the basis of the updated forecast given the volatility of NYMEX prices, and the possibility that gas costs may decline. OCAP suggested as an option that the Company provide a further update to the Board even after it issues its Decision but before the issuance of the Rate Order. Noting that this option would not resolve the problems of volatility or lack of adequate testing, OCAP recommended that the Board use the average of the gas cost forecast known to parties during the hearing and the updated forecast filed by the Company on the last day of the hearing.

4.1.29 CAC submitted that it is "effectively impossible" for the Board to assess the reasonableness or the effectiveness of the Company's risk management program. It noted that the Company refuses to provide certain information on grounds of commercial sensitivity and considers comparison with other utilities meaningless.

4.1.30 Energy Probe suggested that the risk management program should be phased out beginning in fiscal 1998 and customers should be notified accordingly. It noted that decisions made by the Company in gas cost management cannot be scrutinized by the Board. Energy Probe argued that customer choice, not the Company's judgement, should drive risk management. Customers seeking price security will be able to obtain that security through ABC T-Service arrangements. Energy Probe rejected any suggestions for an independent audit to compare the effectiveness of the Company's risk management program with those of other utilities on the basis that each utility has a distinct portfolio and faces different market conditions.

4.1.31 In reply, the Company stated that its gas cost updates follow a long standing practice of providing the latest information available. With respect to the risk management program, the Company stated that there is enough information filed for the Board to assess individual transactions and that no meaningful information about the program is sealed off from regulatory scrutiny. The Company submitted that a comparison of its program with those practiced by other utilities would be difficult to accomplish in view of the different objectives and methodologies applied by others as well as the different supply portfolios of each utility. Given the mechanical nature of its program, the Company stated that little subjectivity is applied and any allegations of bias in enhancing the attractiveness of its affiliate, Consumersfirst, are unsubstantiated. With respect to the suggestion that the risk management program is no longer required in the advent of ABC T-Service, the Company argued that the program is required until the situation changes to the point of only a "minority" of customers relying on system supply.

Board Findings

4.1.32 The Board accepts the Company's latest gas cost forecast as appropriate in setting rates for the test year. The Board appreciates the Company's position that it wishes to provide to the Board and the parties the latest available forecast before the evidentiary part of the hearing is completed. However, in the future, the Board expects the Company to provide any update early enough to ensure that there will be adequate time for consideration of any related issues that may arise from significant changes to gas costs.

4.1.33 With respect to the risk management program, the Board notes that there is a connection between the future success of ABC T-Service and the required level of effort and expense of the program. The Board expects the Company to continue to assess the appropriateness of its risk management program in view of the advent of ABC T-Service and other possibly related developments arising from the Market Review.

DSM Plan

4.1.34 The key objectives and principles developed by the company for its first DSM Plan and presented to the Board as part of its 1995 Test Year rate case (E.B.R.O 487) remain essentially unchanged in the present Plan. These objectives were summarized as part of the Company's prefiled evidence. In E.B.R.O. 492, the Board saw no basis upon which to interfere with the programs proposed for 1997, and encouraged the Company to continue its consultations with stakeholders, and to provide information in future cases on proposed improvements to its DSM efforts. The 1998 DSM Summary Report filed by the Company provided a status report on its current DSM activities, and outlined plans for new initiatives and directions. In addition, the Report quantified, in terms of volumes saved, participants, cost effectiveness and budget, the Company's current expectations compared to those presented in the 1997 Summary.

4.1.35 The Company also filed a proposal to implement a Lost Revenue Adjustment Mechanism ("LRAM") in fiscal 1998, and to introduce a Shared Savings Mechanism ("SSM"). These proposals are dealt with later in this section.

Program Performance

4.1.36 The Company was unable to achieve its overall targeted gas savings in fiscal 1996. It did, however, achieve 158.3% of its targeted residential volumes, with the overall result that annual effective volumes for the total DSM programs were 35.1% below the 1996 budget, with program specific costs down 57.5%. Changes to improve effectiveness are being introduced to all ten of the DSM programs introduced in fiscal 1995 as a result of experience gained by the Company to date.

Program Screening

4.1.37 The ten existing programs have been rescreened, incorporating current information at the time of filing. At the same high externality value used last year and a social discount rate of 9.14%, a cumulative impact of externality benefits of $234 million was forecast to be achieved, 7.8% higher than last year because of increased gas savings. Additional cumulative benefits of $67 million are expected due to avoided electricity and water supply costs. Updated gas costs as prefiled result in lower overall avoided gas costs than those used in screening results for E.B.R.O. 492, 7.5% lower for residential, and 12.8% lower for commercial and industrial programs. With the higher gas costs forecast at the conclusion of the hearing, avoided gas costs would increase. A Societal Cost Test ("SCT") with zero value of emissions was found to be more valuable than the Total Resource Costs Test ("TRC").

4.1.38 The results of the Company's screening indicate an overall increase in net societal benefits over those presented in E.B.R.O. 492, and a positive NPV for each program even at low externality values. As expected, all programs fail the Rate Impact Measure ("RIM") test. All programs pass the SCT at both high and low externality values, and one program fails the SCT with zero externalities. Using a 9.14% social discount rate, the total net social benefit arising from the DSM portfolio ranges from $362 million to $184 million using high and low externality values; with zero externalities, the SCT indicates an overall positive contribution of $128 million over the life of the programs.

Budget and Staffing

4.1.39 Total DSM O&M expenses increased from $2.9 million in 1996 to $5.1 million in 1997, mainly because of increased program participation. In 1998, total O&M is budgeted at $4.8 million, while capital expenditures are forecast at $3.3 million, up from $2.7 million in 1997.

Economic Potential Studies

4.1.40 In response to an intervenor interrogatory, the Company provided an update on the status of work on Economic Potential that was to be undertaken in part with Union. The Company noted that a Request for Proposal was issued in November 1996 to address the need to estimate the technical, economic, and achievable potential of natural gas DSM programs in the various sectors. Three proposals were received, a review of which indicated how costly such a broad based study would be. As a result, the research will be limited to the commercial sector only, with a focus on new construction, large offices, high-rise apartments and strip malls. Union will participate only in Phase 1 of the project (Data Collection and Baseline Establishment). Consumers Gas will undertake "more focused analyses of the potential in a number of high priority markets using alternate internal and external resources".

Settlement Proposal

4.1.41 Other than LRAM and SSM, there was complete agreement on all of the DSM related issues. Details of the agreement are shown in the appended Settlement Proposal.

Board Findings

4.1.42 On the request of the Board, the Company was questioned on the cost consequences of the Company's commitment to undertake an industry leadership role in the development of standards for energy efficiency and in promoting higher efficiency fireplace equipment. On the basis of the Company's testimony, the Board is satisfied with the Company's assurances that any additional costs in such activities would be minimal.

4.2 LOST REVENUE ADJUSTMENT MECHANISM AND SHARED SAVINGS MECHANISM

4.2.1 LRAM is a mechanism to adjust for margins the utility loses if its DSM program is more successful in the period after rates are set than was planned in setting the rates. SSM is intended to create a positive incentive for utility management to pursue DSM savings, in the face of "hidden costs" that are said to be experienced by the utility in promoting DSM, and a general historical and psychological antipathy of utility management towards DSM.

4.2.2 In the Board's E.B.O. 169-III proceedings on the DSM aspects of resource planning by distribution utilities, Consumers Gas argued that incentives were necessary to reward utilities for successful DSM performance. Following the introduction of evidence by Mr. Chernick on behalf of GEC in E.B.R.O. 490, the following commitment was included as part of the ADR Agreement in that rates case:

> *"Consumers Gas will most likely experience variations in actual DSM program participation and volumes from those forecast. A Lost Revenue Adjustment Mechanism (LRAM) adjusts for variances in DSM participation and volumes. (For discussion of these issues see the evidence of Paul Chernick, filed on behalf of the GEC in these proceedings)...*
>
> *The Company agrees in principle with an LRAM but wishes to study and consider the options and implications more fully before determining its recommendation to the Board.*
>
> *Consumers Gas will investigate the merits of adopting an LRAM for DSM and present its findings and recommendations to the Board in the next rate case. At that time, Consumers Gas will also provide an analysis of the impact an LRAM would have had, given actual fiscal 1995 and expected fiscal 1996 variations from previous rate case forecasts.*
>
> *Consumers Gas will consult with interested parties about its LRAM investigation and analysis as part of its DSM consultation process.*
>
> *All parties reserve the right to take any position on any proposal which may come forward." (E.B.R.O. 490, Exhibit K1.1, p. 28, s.7.1.8A)*

4.2.3 The Company's evidence in the present case was that, following its investigation of an LRAM in other jurisdictions and discussions with its DSM Consultative Group, in conjunction with the Tellus Institute, the Company proposed in this rate case both an LRAM and an SSM.

LRAM

4.2.4 Noting that the Board has already authorized a variance account for DSM O&M, the Company proposed an LRAM which would "put the margins from variations in volume savings on the same footing as DSM O&M expenses", by symmetrically adjusting for margins the utility either loses or gains that are in excess of prospective DSM impacts reflected in rates. According to the Company's evidence, applying the LRAM retrospectively in 1995 and 1996 would have resulted in reductions to before-tax earnings of $480,000 and $755,00 respectively.

SSM

4.2.5 The LRAM mechanism would compensate the Company for all lost sales directly attributable to DSM. But it is the Company's evidence that due to hidden costs the LRAM does not compensate it for the indirect impacts of DSM. The impacts identified by the Company included:

! adding DSM to the already "crowded plates" of senior managers requires that other priority business activities must compete for quality attention with the new DSM activity;
! assigning seasoned managers to developing and implementing DSM means that this "marketing talent" is not available to pursue marketing activities aimed at increasing market penetration of gas and other potentially profitable business services;
! in the short run, broad-based efforts to publicize the DSM effort have an incremental sales impact beyond that which is, or should be, captured through an LRAM; and

! DSM spending reduces the future level of earnings in the long run as capital investment in distribution is delayed due to the cumulative impact of DSM initiatives.

4.2.6 According to the Company and its expert witness Dr. Nichols of the Tellus Institute, the proposed SSM would provide a shareholder incentive that is tied to DSM performance and would help to offset the hidden costs of DSM. It was also suggested that the introduction of SSM would reduce regulatory costs.

4.2.7 The Company's original proposed SSM provides for an incentive to the Company based on a percentage of the net resource benefits that its DSM programs for any given year will produce over the life of the DSM measures. The percentage would vary non-linearly, depending on how much of the benefits from DSM budgeted at the beginning of a fiscal year are still likely to be realized, based on actual DSM activity through the end of that fiscal year.

4.2.8 The Company described the mechanism as follows: if actual DSM benefits are 100% of budgeted, the Company earns a 2% share of the benefits; if the budgeted levels are exceeded, the share of benefits will increase; if Company performance falls below 100%, the share of benefits decreases; below 50% performance a penalty would apply.

4.2.9 The proposed mechanism was modified to some extent by the ADR Agreement (see below). In oral evidence, the Company's witnesses confirmed the Company's view that LRAM and SSM were linked, and that neither alone would be acceptable.

4.2.10 Mr. Chernick of Resources Insight was retained by GEC to review the Company's LRAM proposal. He concluded that the Company's proposals are appropriate and should be adopted. In oral evidence, Mr. Chernick testified that the revisions to the proposed SSM resulting from the ADR Agreement were also in his view acceptable. As to the link between LRAM and SSM, he stated the following:

> "...As I see it, the SSM mechanism assumes that the LRAM is in place. The LRAM without the shared savings mechanism would be inadequate,

> although better than nothing, and a shared savings mechanism without an LRAM would have to be very much larger in order to be effective."

4.2.11 Mr. Todd of Econalysis Consulting Services was retained by OCAP to review the Company's SSM proposal. His prefiled evidence focussed on three rationales advanced by the Company in support of its proposal.

- Hidden Costs. Mr. Todd suggested that there is no evidence that an incentive over and above LRAM is necessary to compensate the Company for the hidden costs of DSM.
- Regulatory Costs. Mr. Todd did not accept the Company's reduced regulatory costs rationale for introducing SSM. He held that DSM program costs will still have to be reviewed and justified in the same manner and to the same extent as they would be in the absence of SSM. He suggested that regulatory costs may even increase since the sharing mechanism will have to be reviewed in tandem with the review of DSM.
- Improving DSM Performance. In Mr. Todd's view, the only legitimate purpose of a DSM incentive is to encourage managers to strive more diligently for exceptional performance.

4.2.12 In his oral evidence, Mr. Todd noted that the revisions to the proposed SSM agreed to in the ADR process, changing the slope of the incentive curve from exponential to three-part linear, and thereby reducing the strong incentives or penalties when results achieved were either much below or much above target, addressed his concerns about the design of the mechanism.

Settlement Proposal/Positions of the Parties

4.2.13 In Procedural Order No. 3, the Board directed that the issues of LRAM and SSM be addressed at the hearing. However, the parties also addressed this issue in the ADR process and agreed to the LRAM and SSM proposals. There was, however, disagreement as to the linkage of the two mechanisms. CIPEC/Alliance and IGUA disagreed that the two mechanisms are linked. CAC disagreed with the details of the SSM mechanism.

4.2.14 The Settlement Proposal goes on to describe the SSM mechanism, which would be based on the net present value of the Societal Cost Test (itself based on mid externality values) associated with the Company's budgeted DSM volume savings for the test year, have an incentive and penalty threshold equal to 65 percent of the targeted savings (the "crossover point"), and be symmetrical around the crossover point.

4.2.15 The Company urged the Board to approve the partial settlement in relation to both SSM and the linkage between the LRAM and the SSM, on the basis of the Company's evidence and the testimony of Dr. Nichols, Mr. Chernick, and Mr. Todd. With respect to the monetized externalities, the Company stated that their use is consistent with the Board's framework for selecting DSM programs as set forth in the Board's E.B.O. 169-III Report.

Board Findings

4.2.16 The Board has reviewed the proposed LRAM and SSM mechanism as partially agreed to by the parties to the ADR, and has considered the Company's view that there is a linkage between the two proposals such that the Board should approve both, but not one without the other.

4.2.17 The Board notes that there is no mathematical link between an LRAM and SSM. The Board is not persuaded that these proposals are linked for the reasons suggested by their proponents. The Board must, therefore, decide on each proposal on its own merits.

4.2.18 The Board agrees that an LRAM to compensate the Company for lost sales directly attributable to its DSM programs is appropriate, and directs that the Company implement the LRAM mechanism it has proposed and as agreed to in the Settlement Proposal.

4.2.19 The Board is not, however, prepared to approve the introduction of an SSM at this time. The Board is not persuaded that there are significant "hidden" costs to the Company indirectly attributable to its DSM initiatives. Furthermore, the proposed incentive mechanism is based on forecast benefits over a 30 year horizon, forecasts which are, in the Board's view, not sufficiently reliable to use as the basis of a present credit to the Company. The possible forecast error involved, and the uncertainty of the long-term validity of the calculations used to establish the level of the incentive payments lead the Board to be sceptical that the predicted savings can be assured.

4.2.20 The Board agrees with those parties who argue that an incentive mechanism such as the SSM is premature at this time. If and when a more general move is made toward performance-based regulation, such a mechanism may be part of that move, but in the present regulatory framework, the Board is not convinced that such a mechanism is required to encourage the Company to implement the Board's directions with respect to DSM initiatives.

4.3 O&M - GENERAL

4.3.1 In its original prefiled evidence, the Company proposed an O&M budget for 1998 of $259.5 million, an increase of $8.0 million or 3.2% over the 1997 Estimate of $251.5 million. In an update on April 7, 1997, this was increased to $260.0 million, and by update on May 6, 1997, decreased to $259.9 million. Included in the original proposed budget was a "general productivity credit" of $3.8 million, not initially "assigned" to any department. In the updated evidence filed on May 6, 1997, the $3.8 million was broken down by department.

4.3.2 The estimated expenses for O&M for 1997 were $3.4 million above the Board approved O&M budget for 1997 of $248.1 million, which had been reduced by the Board in the E.B.R.O. 492 Decision from the $248.3 million level agreed to in the E.B.R.O. 492 ADR.

Position of the Parties

4.3.3 A number of parties in their arguments addressed O&M expenses in general, the relationship of the proposed 1997 O&M expenses to amounts agreed to be reduced through the E.B.R.O. 492 ADR, and the nature of the "general productivity credit" proposed by the Company in the amount of $3.8 million.

4.3.4 In CAC's view, the "general productivity credit" did not appear to be empirically linked to productivity, and the sequence of budgeting events described by the Company’s witnesses "undermines the credibility of both the ADR process and the budgeting process". The subsequent allocation of the credit among departments led CAC to ask how the amounts that were identified for each department resulted in exactly $3.8 million to be allocated, and whether more savings could have been identified if required. CAC argued that there was no real incentive under cost of service regulation to keep O&M costs down, so long as recovery in rates was allowed. In fact, CAC opined, the prospect of the introduction of performance-based regulation may provide an incentive for the Company to maintain high O&M expenditures prior to the change, to ensure savings may be achieved in the early stages of its implementation.

4.3.5 CAC submitted that a reasonable approach to determining an appropriate O&M level for the test year is to provide an appropriate inflationary increase over the approved O&M figure for the bridge year. In its view, a budget of $253 million, or 2% over the Board approved 1997 level of O&M, would be appropriate.

4.3.6 IGUA argued that only three months after the beginning of the 1997 fiscal year, the Company's senior management accepted as reasonable an estimated actual O&M budget for fiscal 1997 more than $3 million higher than that agreed to in the E.B.R.O. 492 ADR process, and then used this higher figure as the starting point for setting the budget for the 1998 test year. In IGUA's view, such an approach calls into question the value of the ADR process and the decision-making process leading to a Board approved O&M budget. IGUA argued that the Board should follow the "envelope" approach utilized by some other regulators in determining the reasonableness of total O&M expenses claimed, whereby a previously approved or baseline O&M expense is adjusted by a percentage factor which takes in to account inflation, growth, and productivity. It also argued that the existence of the $3.8 million unassigned "productivity credit" and the process surrounding its development "evidences...a rather cavalier attitude to budgeting and accountability" on behalf of the Company's senior management. IGUA proposed that the total O&M allowed to the Company not exceed an increase of about 2% over the Board approved 1997 budget, and that any more than a $4 million increment would be unreasonable, given that, in IGUA's view, the Company has not discharged the onus upon it to demonstrate its claimed increment is reasonable. In summary, IGUA argued that the O&M allowance should be no more than $253 million, and that the Board should provide direction to the Company to confine its O&M spending within that limit.

4.3.7 OCAP expressed strong concerns over what it characterized as "the relentless upward trend" in the Company's O&M costs, and over the possible bearing by monopoly customers of staff and resource costs used by the Company in non-utility activities. In OCAP's view, it would be reasonable for the Board to approve an O&M budget that provides for no increase over the 1997 Board approved level.

4.3.8 Energy Probe urged the Board to approve 1998 O&M expenses at $253.1 million, basing its argument on its view that O&M spending per customer is a key indicator in assessing O&M spending, that this indicator should trend downward, and that to ignore the Board's decision in E.B.R.O. 492 and allow the Company to base its test year budget on its 1997 overspending of the limit set by the Board in that decision "would lock in future costs caused by the Company's failure to control spending in 1997". The Company should, Energy Probe suggested, be allowed to manage its own affairs within an overall O&M limit set by the Board. But the level of O&M spending should, Energy Probe contends, begin to show improvements from the productivity savings the Company has forecast to result from such major expenditures as CIS and the mains replacement program, savings which are not being realized at the Company's proposed level of O&M expenditure. As to the budgeting process, Energy Probe noted that the explanation for the "stretch item" provides little assurance to the Board that the Company has exhausted the savings available.

4.3.9 In the Company's view, the parties urged primary reliance on expected inflation in determining the utility's costs, ignoring the business drivers identified by the Company in its evidence. The disparagement of the Consumers' "grass roots" budgeting process by the parties, ignores, the Company contended, the "long history of reliability and acceptance by this Board" of this approach. According to the Company, the grass roots approach has served a dual purpose, utilizing the expertise of those in the Company responsible for service delivery, and assuring the Board that the proposed budget is linked to service and expansion plans, and incorporates system safety and reliability, productivity, employee compensation and utility plans for technology. Past ADR Agreements have, the Company argued, reflected these principles, and provided a reasonable basis for setting rates. The idea that an ADR Agreement on O&M represents a "cap" on O&M spending is, Consumers Gas submitted, unrealistic. If the Company overspends the O&M budget, it argued, neither specific parties nor “any other element of the public interest” is affected, since the shareholder must absorb the variance.

4.3.10 Furthermore, the Company submitted, these unrecoverable O&M amounts were shown in the Company’s evidence to have been expended for proper purposes relating to market factors, improvements in customer service, and one-time expenditures. To begin the estimates for the 1998 budget from the 1997 Board approved budget is, the Company argued, “a flawed approach”, since the 1997 budget did not reflect the market conditions and customer service requirements that were evident in the 1997 year, as identified through the grass roots process.

4.3.11 As to intervenors’ arguments that the O&M expenses should increase only by inflation from the previous Board approved budget, the Company pointed out that the utility customer base was forecast to grow by 3.7% in the test year, leading to an increase of $4.1 million in O&M expenses, but also generating volumes and revenues to offset these expenses. A similar argument is made concerning the increase of $1.3 million which will result from growth in the Rental Program. In addition, the Company reiterated that the fifty-third pay week in the test year results in a one-time impact of $1.4 million, and noted that the proposed $8.1 million increase related to Information Technology, an important element of the Company’s efforts to train its employees and generate appropriate customer service levels and productivity savings.

4.3.12 The Company contended that the “general productivity credit” which had been criticized by a number of the parties in fact demonstrated that the Company’s grass roots budgeting process worked well, allowing Senior Management to identify the budget implications of high level planning, in particular the organization redesign project, and to make a commitment to potential productivity savings, even before specific productivity reductions had been identified. The Company submitted that a review of overall O&M spending on a cost per customer basis indicates “continued progress in productivity and reductions in bottom line cost per customer”, with the 1998 Budget cost per customer representing a $17.5 million productivity achievement over the past five years, measured in nominal 1998 dollars, or a savings of $7.72 per customer compared to 1996 actual expenditures.

Board Findings

4.3.13 The Board shares the concerns of the parties who argued that O&M expenses are not subject to an appropriate level of control by the Company to ensure that ratepayers are not bearing unreasonable costs in this area. To overspend from an agreed-upon level of expenditure, and then base a new test year budget on the resulting estimated figure seems to the Board to build into each new budget a level of spending that would not have been approved by this Board. It is true, as the Company argues, that the shareholders absorb the original overspending, but when new budgets are based upon the higher amounts spent, ratepayers absorb the increase in all subsequent years.

4.3.14 The Company argues that customer demands for service must be met, and that increased customer numbers generate income, and cites decreasing per customer costs as indicating productivity gains. The Board agrees that customer additions will generate operating and maintenance expenses, but marginal expense per additional customer may be expected to decrease in a natural monopoly, however these reductions are characterized. As to the justification of ever-increasing costs because the Company believes customers demand improved service, the Board has noted elsewhere in this Decision that it is not persuaded that these demands exist, and if they do, that they need to be met at the level proposed by the Company.

4.3.15 There may be justification for a level of spending for a test year that is increased by more than the forecast inflation rate from that approved in the bridge year, but the Board would need to examine evidence as to exactly what increases were proposed, and what rationale supported them. Even if the proposed expenses were lower than those of the previous year, the Company would have to justify them to the satisfaction of the Board. In the present case, the Board is not persuaded that the proposed increase over the Board approved figure for the 1997 budget has been justified.

4.3.16 Although in any given rates case the Board may find specific O&M expense reductions, the Board concludes that it is also appropriate to review the Company's O&M expenses by means of an "envelope" approach - approving an overall O&M

figure, leaving the remaining allocation of the reduction in spending to the Company's discretion. Such an approach is consistent with that taken by the Company in requiring its departments to meet a "stretch target" reduction in spending.

4.3.17 In the present case, the Board has decided to approve an O&M budget 3% lower than that requested, in addition to the $1.7 million cost of service reduction associated with the Board's findings related to non-utility eliminations. In concluding that such an overall reduction is achievable, the Board has taken into account its suggested reductions in the areas of information services, regulatory expenses, and marketing/advertising expenses, as well as other O&M expense reductions identified elsewhere in this Decision.

4.3.18 In its discussion below on individual areas of O&M expenses, the Board makes certain suggestions which should be examined by the Company to reach the overall budget target reduction of $7.7 million.

4.4 O&M - MARKETING/ADVERTISING EXPENSES

4.4.1 Marketing and Sales expenses originally budgeted for 1998 were $16.4 million, up 3.1% from the 1997 estimate. Included in the $16.4 million amount are expenses of approximately $2.7 million relating to marketing and sales expenses associated with certain ancillary programs. Additional or new activities included which contributed to the variance are:

- residential initiatives including: cooperative promotional initiatives with builders to promote energy efficiency and the use of natural gas, direct mail programs for fireplaces in the existing customer market, promotion of expansion projects, and promotional programs for baseload products; and
- apartment market initiatives to increase penetration in this market, development of a comprehensive strategy to promote natural gas cooling, demonstration sites for industrial natural gas driven air compressors, and market research initiatives in all markets.

4.4.2 Updated evidence filed on May 6, 1997 indicated a reduction of $0.2 million in marketing costs as a result of reduced advertising expenses. The Company plans to replace general advertising campaigns with targeted communication vehicles, and to identify synergies among stand alone communications programs.

Position of the Parties

4.4.3 CAC argued that there was a consistent pattern of over-budgeting Sales and Marketing costs, with actual costs below Board approved costs on average by slightly more than $1 million per year for the 1992-1997 time period, and a resulting shareholder benefit of approximately $6.1 million in the same period. In CAC's view, expenditures in this area could be cut without adverse effects on customers or levels of customer service, and it therefore recommended a reduction of the budget for this department of $1 million to reflect consistent "overstating", and a further $200,000 to reflect potential cost reductions identified by Company witnesses.

4.4.4 Noting the overestimation of costs in this area in past years, IGUA suggested that this overestimation reinforces its view that the budgeting process is unreliable.

4.4.5 OCAP objected to the "significant spillover benefits" the Company's advertising and marketing expenditures may have on its non-utility affiliates, such as Consumersfirst. Given the Company's argument in the Code of Conduct proceeding concerning its ownership of the name, OCAP submitted that costs relating to enhancing the value of the name should be borne by shareholders.

4.4.6 AMO questioned, given the “very advantageous” competitive price of natural gas, and public awareness of its environmental advantages, the need for expenditures of the magnitude proposed to promote it. In any case, AMO submitted, customer loyalty is fostered by the favourable prices, and, once customers are attached, they are to a large extent captive. Given the existence of the Company’s affiliate, Consumersfirst, AMO argued that the Board should “take a very close look” at proposed marketing expenditures, questioning whether it “is aimed solely and entirely at the unselfish promotion of increased gas usage on behalf of all market participants”.

4.4.7 In reply, the Company relied on evidence it had provided stating that the proposed promotional activities would benefit customers and society, through lower gas rates and enhanced economic efficiency. It argued that these expenses are not entirely driven by Company initiatives, but are a result of "properly and professionally" addressing customer initiated contacts or needs. Of the $13.7 million budget (exclusive of expenses relating to ancillary programs), over $9.1 million is attributable to providing customer service.

4.4.8 With respect to CAC's contention that a reduction is justified to reflect past overstating of costs, the Company submitted that the proposed spending, at a level 2.8% below the 1996 actual level, is lower than the average actual expenditures for the last five years.

4.4.9 As to the argument that the price advantage enjoyed by natural gas obviates the need for advertising, the Company responded that customer purchases are not driven only by price, and that "the Company's marketing and sales efforts serve to show responsive concern to fulfilling [customer] needs and to establishing a sustainable, positive customer relationship." There is no evidence, according to the Company to substantiate intervenors' concerns that the direct advertising by the Company is associated with the presence of its affiliate, Consumersfirst, in the market.

Board Findings

4.4.10 As noted elsewhere in this Decision, the Board is concerned that "customer needs", as determined by the Company, may drive ever increasing expenditures, whether or not those needs are real. The Company emphasizes the extent to which marketing and sales expenditures are attributable to meeting customer service demands. The Board is not convinced that such expenditures are justified.

4.4.11 The Board also notes that the area of marketing and sales is one of chronic over-budgeting. Reasons provided by the Company for underspending in recent years are, in the Board's view, indicative of the optional nature of spending in this area. The Board is not convinced that customer service will be significantly affected by any reductions.

4.4.12 Overall, the Board finds that marketing and sales O&M expenses can be reduced substantially without seriously affecting the Company's ability to serve its customers. Furthermore, given the monopoly nature of the gas distribution business and the wide price advantage over alternative fuels, the Board would require identification of the precise portion of the budget devoted to advertising and strong justification for any Company expenses on generic advertising related to the promotion of natural gas, especially in view of the number of unregulated players in the commodity gas market.

4.5 O&M - EMPLOYEE EXPENSES

4.5.1 The 1998 Budget for salaries, wages and employee benefits charged to O&M expense accounts is $3.2 million higher than the 1997 estimate, according to updated information filed on May 6, 1997. The 1997 estimate is $6.9 million higher than the 1996 actual expenditure, and $1.7 million over the 1997 Board approved figure. The Company cites staff additions in areas such as the Call Centre, inflation, and the necessity to budget for an additional pay week in 1998 as responsible at least in part for the proposed increase, while noting that there will be a net reduction of 45 full-time positions in the 1998 budget year.

Positions of the Parties

4.5.2 CAC noted the evidence provided by the Company that considerable staff time and effort had been expended on reorganization of the Company, with approximately 400 staff involved in the process, including 16 senior managers who spent between 60% and 80% of their time for a period on this initiative. This reorganization effort was not foreseen by the Board when it approved the 1997 budget, a fact that CAC argued "indicates that the labour force at Consumers was larger than what was needed for the normal operation of the Company". CAC submitted that the Company's claims of productivity gains notwithstanding, labour costs continue to increase, and argued that the Company should be limited to a 2% increase over the 1997 budget.

4.5.3 OCAP argued that a 1.9% increase (the expected 1998 rate of inflation) over the Board approved budget for 1997 would be appropriate in this area, given that expenditures in SIM and other projects were forecast to improve productivity, and that the shareholders are benefitting in other ways from those expenditures.

4.5.4 IGUA also submitted that the amount of time utilized by staff in the reorganization effort suggests that "staff levels are much larger than what is required to serve the needs of the utility distribution customers".

4.5.5 The Company submitted that there were a number of factors besides inflation which needed to be taken into account in assessing the proposed labour budget. The Company argued that labour costs are affected by growth in customer base, and that on a cost per customer basis, in constant 1988 dollars, there is a reduction in salaries and wages of 2.45% for 1998 from the 1997 level, a reduction which, together with the increase in average number of customers per employee, demonstrates the productivity being achieved in the 1998 Budget. The significant staff time utilized in the reorganization does not, Consumers argued indicate a larger labour force that needed to operate the Company, since much of it involved time "far in excess of a regular workweek", excess hours which might be appropriate for a special project, but are not therefore an indicator of inappropriate staff levels.

Board Findings

4.5.6 As noted above, the Board is concerned about the overall level of O&M expenses and has set a level of expenditure which it believes to be reasonable. The Board believes the Company may be able to find substantial savings in this area to meet the Board's overall O&M expense reduction target. The Board notes, in particular, the possibilities of reductions to staff levels in the Call Centre due to the fact that ratepayers are provided with information on their bills about their agent or broker, and advised to call them for information about ABM service.

4.6 O&M - INFORMATION SERVICES

4.6.1 The Company in its evidence stresses that modern circumstances require information systems that are integrated over major business areas or whole enterprises. Such systems can provide integrated solutions and improved "one-stop" access to information and analysis, but require more sophisticated planning and management than earlier stand-alone systems. According to the Company, business areas are responding to changed customer expectations for access to information and technical convenience.

4.6.2 The Company's evidence states that the completion of SIM provides a foundation for its information systems, but further refinements and changes are needed to keep up with changing demands and technologies. Management of systems environments must include research, acquisition, support, monitoring, and failure prevention. The "Year 2000" problem must also be addressed, and new software implemented.

4.6.3 Information Services O&M expenses were forecast in updated evidence to be $46.3 million, an increase of almost 15% over the 1997 Estimate. Major increases are forecast in labour costs, computer services and communication costs.

4.6.4 O&M Information Services labour costs are forecast to increase by 22.2% over the 1997 estimate. During the hearing, the Company provided a clarification by way of undertaking of the causes for this increase. While no overall staff additions are forecast, staff that were developing SIM applications as contractors (capitalized cost) move into supporting these applications (O&M expenses) as SIM is completed during the year. A total of $2.963 million labour dollars move from Capital to O&M, but contractor costs in O&M are reduced by about $400,000 as a result. The total increase from 1997 forecast expenses to 1998 forecast expenses, if changes in both O&M and Capital spending are taken into account, is 15.1%; if work-in-progress labour is taken into account, the increase is approximately $713,000 or 3.3%. Salary increases and promotions account for $613,000 of the increase.

4.6.5 O&M Computer Services expenses, including those for leased and rental hardware and services relating to the mainframe, are forecast to increase by 24.3% in 1998 over 1997 estimates. Communications costs are forecast to increase by 20.8%. Updated evidence filed just prior to the hearing revealed that a $1 million dollar reduction in the Information Services O&M budget would be achieved through a Business Process Re-engineering project. One half of this savings is expected to be achieved through productivity savings resulting from the streamlining of business processes; the other half is anticipated to result from a redefinition of the Information Services Planning function.

Position of the Parties

4.6.6 CAC expressed concern over what it viewed as significant increases in O&M Information Services categories, and submitted that the Company should be required to provide detailed justification for these costs in the next rates hearing. In the meantime, CAC proposed a budget for 1998 of $42.3 million, based on an assumed inflationary increase of 2% and an appropriate transfer of labour from capital to O&M.

4.6.7 IGUA noted the significant increase of O&M Information Services expenses on a per-employee basis over the past few years, and submitted that the claim for 1998 is excessive, given the capital costs which are being incurred for Information Services in successive years. Citing the failure of the Company to provide comparisons with other Ontario and Canadian utilities in this type of expenditure, IGUA argued that the Company has not discharged the onus upon it to demonstrate the reasonableness of its proposed budget.

4.6.8 OCAP submitted that the growth in O&M for information services leads to an "alarmingly high" budget, with a significant rate impact. In its view, the fact that some of the proposed O&M costs result from transfers from capital to support new SIM applications does not justify them, and that "perpetual project maintenance costs" for the SIM projects should be eliminated from the Company’s total cost of service once these projects are completed. Furthermore, OCAP argued, the delay in CIS implementation should eliminate some of these costs for the budget year. Other O&M expenses related to the Company's IS capital expenditures on PCs and software should be reduced if OCAP's submissions on IS capital costs are accepted.

4.6.9 Energy Probe noted that the largest cause of the proposed O&M increase in 1998 over 1997 was in the area of Information Services. Energy Probe noted the Company’s evidence that rising data storage costs necessary to provide five years of billing history were a substantial part of these increases. In Energy Probe’s view, this information is important, and should be available to customers on their bills. It suggested that a more detailed analysis of the costs of providing this information should be undertaken before any decision to cut the program is made.

4.6.10 GEC submitted that the five year historical data “is a significant customer and DSM benefit”, but made it clear that it did not support “significant expenditure” on the provision of this data, and argued that the Company could not justify any significant portion of its budget on the need to provide this information.

4.6.11 In reply the Company noted "several uncontrollable or extraordinary and non-recurring items that drive the increase" in O&M Information Services expenses, such as a central processing unit replacement, the moving of expenditures from capital to O&M noted above, and increased software expenditures. When these "extraordinary items" are removed, the Information Services budget increases by less than 2% over the 1997 approved number. The Company argued that the budget recommended by CAC was unrealistic, and that the Company had provided ample information supporting its contention that it is managing the Information Services budget prudently.

4.6.12 The Company argued that the reductions in the Information Services budget through Business Process Reengineering and through strategic planning were not arbitrary, as argued by intervenors, but signalled productivity improvements from changed processes in the “new era” following the completion of the SIM plan. The calculation of O&M Information Services costs per permanent employee is not, the Company submitted a helpful comparison, since computer costs are driven by requirements to serve customers, and capital expenditures on information technology may reduce employee numbers, thereby increasing the ratio. It was stated that the Company had made a serious effort to draw comparisons of its IS expenditures with other Canadian utilities, but the comparisons could not be meaningfully completed. As to OCAP's argument that "perpetual project maintenance costs" were not included in the original approval for SIM, the Company submitted that all annual SIM Progress Reports have reported annual ongoing maintenance costs, and net present value and return on investment calculations for the SIM projects take these costs into account. In the Company's view, these maintenance costs are justified and should be approved. CIS delay could result in a reduction of $0.2 million, "if the Board deems it necessary to make this adjustment".

4.6.13 The argument made by OCAP that O&M Information Services expenses should be reduced in line with its proposed capital reductions does not, the Company argued, make logical sense, in that reductions in capital could in fact increase O&M expenses, to maintain service levels.

Board Findings

4.6.14 As in other areas, the Board is concerned that O&M spending increases are being justified on the basis of “customer demands” which are determined by the Company, and for which there is scant evidence. The Company proposed increases of more than 20% in several areas of the Information Services budget, and argued that “uncontrollable” or “extraordinary” or “non-recurring” items should be removed when considering the overall increase. The Board is not convinced that such items might not occur in every budget year, and is not prepared to evaluate the budgeted increase as if these items did not exist.

4.6.15 The delay in CIS must, in the Board’s view, result in reductions in the O&M expenses of this department.

4.6.16 Reductions of $9 million in capital expenditures for Information Services found by the Board in Chapter 3 must, in the Board's view, also lead to reduced O&M expenses. The Company has identified a $0.2 million reduction as a result of the delay in implementation of CIS. Given the Board's $9 million reduction, in part due to the delay in CIS, further O&M expense reductions are surely achievable. Reduced capital spending for hardware would lead to reduced O&M expenses for software, software maintenance, and materials.

4.6.17 In addition, capital cost reductions related to cellular telephone purchases should lead to proportional reductions in O&M expenses for maintenance, subscriber fees and usage costs. Further, the Board is confident that reductions are possible in other areas of this department to contribute to the overall reductions in O&M spending that the Board has found appropriate.

4.7 O&M - REGULATORY EXPENSES

4.7.1 The Company proposed a budget for total regulatory hearing expenses of $3,434,000. Included in this amount is a budget of $2,860,000 for the present hearing, and $574,000 for other hearings and interventions before this and other regulatory bodies. The Company provided details of its participation in upstream proceedings in the past few years, and noted that forecast costs for these interventions are somewhat lower than those approved by the Board in 1996 and 1997.

4.7.2 The estimates for fiscal 1998 were based on the assumption that the present rates case, inclusive of the ADR process, would be of a slightly longer length than E.B.R.O. 492. An update to these costs filed on May 7, 1997 reflected increased costs related to the Comprehensive Cost Allocation Study, but was still based on a fifteen day hearing, while the hearing in fact lasted 21 days.

4.7.3 No costs in respect to potential generic hearings were included in the 1998 budget, because the Company is proposing that a deferral account continue to record the cost of generic hearings initiated by the Board.

Positions of the Parties

4.7.4 CAC noted that the budget for the Company's legal costs seemed to be based "simply" on costs of past proceedings, adjusted for some expected changes. It also noted that the Company has agreed to obtain more detailed invoices relating to its legal costs, but has not agreed to make these available to the Board and other parties, on the basis of solicitor/client privilege. In CAC's view, the Company should be required to submit the details of its legal costs in the same way intervenors must.

4.7.5 Lacking any detailed invoices, CAC made a calculation of the hours of legal work which appear to be implied by the overall figures, and argued that these may be excessive. To ensure that a reasonable assessment can be made of the Company's legal costs, CAC argued that they should be captured in a deferral account, and reviewed and disposed of in the next rates case, assessed on the same basis as intervenors' costs. CAC also supported deferral account treatment of intervenors' costs claims, to ensure that forecast errors do not result in windfalls or unnecessary costs for either the shareholders or the ratepayers. If a deferral account is not acceptable to the Board, CAC argued, the Board should find the Company's forecast of costs for E.B.R.O. 495 to be excessive. It also submitted that costs forecast under "Other Interventions" were overstated, noting that they have been overestimated in the past two cases, and that the Board should reduce the budgeted costs for the Company's intervention in the Union rates case by $50,000.

4.7.6 As to the costs of the financial consultant used by the Company to provide a recommendation as to the appropriate return on equity, CAC argued that the Company's choice of a consultant who "traditionally" made recommendations higher than those accepted by the Board "was clearly driven in part with the interests of the shareholders in mind", so that shareholders should bear some of the costs for that consultant. CAC also submitted that costs of other consultants, Dr. Cronin, Mr. Edgar, and Mr. Effron, should be dealt with in the Comprehensive Cost Allocation Study Account, and not under regulatory costs.

4.7.7 Finally, CAC submitted that the costs of determining the appropriate level of non-utility eliminations should be borne by the shareholder who benefits from the non-utility activities, and urged the Board to reduce the E.B.R.O. 495 regulatory costs budget to reflect the time and effort spent on this issue by all involved. In CAC's view, if the increasing level of non-utility activities requires greater regulatory scrutiny, ratepayers should not bear the costs entailed.

4.7.8 IGUA supported the submissions made by CAC on this topic, and noted as well that inconsistencies among Company witnesses as to the hourly rate paid to their counsel symptomized the "rather cavalier attitude" prevailing in the budgeting process. IGUA also submitted that a non-utility elimination factor should be applied to regulatory costs given the amount of regulatory time spent on issues relating to ancillary and non-utility activities.

4.7.9 The Company replied that it had provided a detailed description of its budgeting process in an interrogatory response to CAC, and that the process was not the simple one assumed by CAC in its argument, but a careful attempt to develop an appropriate budget. As to its legal costs forecast for the present hearing, the Company argued that the Board could adequately assess the reasonableness of these costs "on the basis of the evidence before it, and based on the Board's knowledge of the various functions performed by the Company's counsel". It cited the relatively small difference in legal costs forecast for this proceeding compared to those for E.B.R.O. 492, even though that proceeding required only 12 hearing days compared to the 21 day E.B.R.O. 495 hearing, as additional support for the budgeted amount.

4.7.10 As to the different processes for determining the reasonability of intervenors' costs and the Company's costs, the Company submitted that intervenors' costs, which are allowed by the Board's rules to be recovered from the Company, must therefore be scrutinized and approved by the Board, separate from the Board's normal review of other utility expenditures. In the Company's view, submission of its legal counsel invoices would require the Company to place privileged information on the public record.

4.7.11 Consumers Gas noted that the traditional intervenors identified by CAC in its argument had claimed in E.B.R.O. 492 a total number of legal hours higher than that claimed by CAC to be excessive for the Company's counsel in the present case. The Company submitted that given the longer hearing this year, and the "far greater requirements" on Company counsel, these figures support the reasonableness of its forecast.

4.7.12 On CAC's argument that a deferral account should be created for regulatory costs, the Company submitted that revenue generated within a year should be matched with the cost of service incurred in the same year, and that a deferral account would result in either retroactivity in cost collection, or subsidization of this year's ratepayers by ratepayers next year. The risk of forecast error exists for regulatory costs as it does for the entire budget, and the Company accepts this risk. For the same reasons, the Company opposed the use of a deferral account to capture intervenor costs related to the present hearing.

4.7.13 The consultant fees for rate of return evidence, Consumers argued, are a normal cost of business for a regulated utility, incurred to assist the Board in its determination of a fair and reasonable rate of return on equity, and therefore their recovery should not be denied to the Company. As to other consultants' fees, the Company noted that Dr. Cronin's evidence was not part of the Comprehensive Cost Allocation Study, but was required to rebut the evidence of Mr. Edgar, and should therefore not be dealt with through the costs for that Study.

4.7.14 Noting that the budget for E.B.R.O. 495 provides for 15 hearing days, while the actual hearing extended for 21 days, the Company expressed surprise at the CAC contention that its budget is too high. IGUA and others had argued that the new role of Board's technical staff placed additional burden on active intervenors; the Company submitted that these observations support the maintenance of the budget it has proposed. In any case, the Company observed, the Board will have the intervenor cost claims prior to rendering its Decision, and may judge the reasonableness of the Company's forecast and adjust it as necessary. As to the proposed assignment of costs relating to the determination of non-utility eliminations to the shareholder, Consumers Gas argued that this determination is a regulatory requirement, and all related costs are appropriately included in the cost of service.

4.7.15 The Company's interventions in other matters, such as the Union rates application, result, the Company argued, in rulings which have ongoing value to the Company's ratepayers. In its view, the benefit or cost consequences of the issues pursued by the Company in such interventions in the interests of its ratepayers far exceed the costs involved.

Board Findings

4.7.16 In Chapter 9 the Board makes certain findings with respect to intervenor costs for this proceeding. The Board estimates the total reduction in intervenor costs to be no less than 20% from the $850,000 amount included in the Company's proposals and approximately the total amount requested by intervenors in their cost claims.

4.7.17 The Board is of the view that the costs for legal counsel for the Company should not necessarily, as argued by the Company, be of the same order of magnitude as the total legal costs of the traditional intervenors in the rates case.

4.7.18 Further, the Board is not persuaded by the Company's position that no portion of its regulatory costs should be attributed to the shareholder. In the Board's view, a significant portion of the main rates and other proceedings before the Board deal with issues relating to the Company's non-utility activities. Not all of the associated regulatory activities in this proceeding were for the benefit of the ratepayer. The Company's shareholders must also bear a portion of such costs in that, in the absence of these issues, the proceedings would likely be of lesser complexity and duration, and therefore less expensive. The $7.7 million O&M expense reduction reflects some sharing by the shareholders of the proposed $2.9 million regulatory expenses for this proceeding.

4.8 OVERALL ADJUSTMENTS TO UTILITY INCOME

4.8.1 The Board has made specific adjustments to the test year's Utility Income proposal of $260.3 million. Other Operating Revenue has been increased by $3.2 million to reflect an imputation of revenue relating to the Company's ancillary programs. In the area of Operating and Maintenance expenses, the Board has disallowed $0.8 million in management fees from IPL, imputed an expense reduction of $1 million relating to the Merchandise Finance Program, and increased non-utility eliminations by $0.9 million. The Board made a $7.7 million further reduction to O&M expense, and provided guidance as to how the Company may be able to achieve this reduction.

4.8.2 As noted in Chapter 3, the Board has used the impact statement filed by the Company to reflect the adjusments necessary to exclude the E.B.O. 188 ADR Agreement. Gas sales revenues and gas cost expenses are both reduced to reflect the reduction in sales volumes. These adjustments reflect the updated gas costs submitted by the Company. Other revenue has increased to reflect the additional income that will be earned from higher periodic contribution charge payments.

4.8.3 Utility Income has also been adjusted to reflect the revised depreciation expense. The Income Tax provision has been adjusted to reflect Capital Cost Allowance impacts of the capital reductions discussed in Chapter 3. The above adjustments, combined with those from the settlement process, result in a reduction of $8.87 million to Utility Income. The Board approves Utility Income of $269.17 million as summarized in Appendix B.

5. COST OF CAPITAL

5.0.1 The Company's test year proposed utility capitalization and cost of capital, as well as results agreed to in the Settlement Proposal, are set out in Appendix C.

5.0.2 The Company's evidence was that during fiscal 1997 it raised $300 million of debt. In addition, through its immediate parent, Consumers Gas Energy Inc., the Company plans to raise $36 million in common equity in the third calendar quarter of 1997 to maintain the common equity component close to 35% which is the level proposed by the Company to be continued for the 1998 test year.

5.0.3 For fiscal 1998, the Company plans to raise $425 million in long term debt. The Company indicated that it has no specific plans to redeem any of the outstanding long term debt in fiscal 1998. However, the Company requested authorization to establish a Debt Redemption Deferral Account to allow it to take advantage of redemption opportunities that may arise. This request was agreed to by the parties and accepted by the Board.

5.0.4 Forecasts of interest rates were provided by the Company and by Professor Dungan of the University of Toronto on behalf of Board Staff. The evidence on the cost of common equity is discussed later in this Chapter.

5.1 SETTLED ISSUES

5.1.1 Other than the cost of common equity, the parties agreed to the other cost of capital components. The Company's capitalization was not an issue at the hearing. Details of the settlement on each issue are set out in Appendix E.

Cost of Preference Shares

5.1.2 Preference share capital cost for the test year was proposed and agreed to at 6.48%.

Cost of Long Term Debt

5.1.3 The Company's forecast embedded cost of long term debt for the test year was 9.03%. The agreed upon cost rate was 8.99%.

Cost of Short Term Debt

5.1.4 The cost rate for short term debt was proposed at 3.99%. This cost rate was based on the Company's interest rate forecast for 90-day commercial paper, weighted by the borrowing pattern projected for fiscal 1998, plus a commitment fee of 0.06%. The agreed upon rate was 3.94%.

Adjustment Mechanism

5.1.5 The Settlement Proposal contained an adjustment mechanism for the agreed upon cost of short term debt if, upon evidence to be provided by any party, the average May 12-25 three-month Government of Canada T-Bill yield exceeded the April 1-14 yield by more than 50 basis points. The same mechanism applied to long term debt, with the benchmark being the ten year Government of Canada T-Bill yield.

Board Findings

5.1.6 No party filed updated evidence as a result of the adjustment mechanism. The Board therefore confirms its acceptance of the agreed upon cost of short term and long term debt for the test year.

5.2 COST OF COMMON EQUITY

The Evidence

5.2.1 Common equity makes up 35% of the Company's proposed capital structure. The Company proposed, in its original filing, a return on common equity of 11.5%. Ms. McShane, the Company's expert witness had recommended in her prefiled evidence a range of 12.0-12.25%.

5.2.2 Ms. McShane arrived at her estimation by applying two techniques, the risk premium test and the comparable earnings test with the following results.

Risk premium test	12.0 to 12.25%
Comparable earnings test	11.75 to 12.75%

5.2.3 The risk premium test measures the cost of attracting new capital, i.e. the cost per dollar of new capital, as the sum of prospective interest rates, plus a premium to compensate for the relatively higher risk of common equity capital. Return estimates based on the risk premium test are derived from the current market value of common equity of the firm, adjusted from the "bare bones" level for financing flexibility to cover flotation costs and a safety margin to allow for unexpected increases in capital costs. The margin above the "bare bones" cost suggested by Ms. McShane was in the range of 75 to 105 basis points.

5.2.4 The comparable earnings tests measures the returns expected to be earned on the depreciated book value of unregulated competitive enterprises having similar risk, appropriately adjusted for differences in risk between industrials and utilities.

5.2.5 Principal findings underlying Ms. McShane's rate of return recommendation relate to the business risks, the financial risks, the investment risk and the economic and capital market conditions. In her view, while Consumers Gas is exposed to a relatively lower level of business risk compared to other Canadian gas distributors, competitive risks are rising in the uncertain regulatory sphere, and the fair return for Consumers Gas is estimated to lie at the upper end of the range estimated for high grade utilities. With respect to financial risks, Ms. McShane stated that Consumers Gas "faces marginally higher financial risks than the typical gas/electric utility", and that Consumers Gas faces no less investment risk in comparison to this sample. Her analysis of the current economic capital market conditions resulted in a long Canada yield forecast of 7.0% to 7.5% for 1997 and 1998. Applying the risk premium test (70% weight) and the comparable earnings test (30% weight) yields a fair rate of return of 12.0% to 12.25% for Consumers Gas.

5.2.6 Ms. McShane's evidence set out the risk premium test using two types of studies. The first, the DCF-based Risk Premium study, was based on a regression analysis of the difference between historic discounted cash flow estimates for five high grade utilities and the corresponding long Canada yield. Results indicated an inverse relationship between interest rates and risk premiums, and produced a required risk premium for a high grade utility of no less than 350 basis points at a long Canada yield of 7.25%. The second method, based on an estimate of the required premium for the market as a whole, adjusted for the lower risk of the utility, suggested a premium of 425 basis points.

5.2.7 In the result, Ms. McShane recommended a risk premium of between 375 and 400 basis points at a long Canada yield of 7.25%, producing a "bare bones" cost of equity of 11.0% to 11.25% excluding the 75 to 105 basis points allowance for financing flexibility.

5.2.8 Dr. Peter Dungan provided evidence on behalf of Board staff concerning the economic forecast for Ontario and Canada for the coming fiscal year. His forecast of the long Canada yield was 7.20%.

5.2.9 Dr. Gordon Roberts filed evidence on behalf of Board Staff. He concluded that in all aspects, the Company's business and its risk are essentially the same as they were at the time of E.B.R.O. 492. Using the comparable earnings test with historical data (1), the comparable earnings test combining actual and forecasted data (2), two equity risk premium approaches, the first based on regression analysis (3), the second on a forward looking market rate of return (4), and the discounted cash flow method (5), Dr. Roberts determined the following rates of return:

Comparable earnings	1)	9.2 to 9.4%

	2)	8.6 to 9.6%
Equity risk premium 3)	10.4 to 10.58%	
	4)	9.75 to 10.55%
Discounted cash flow	5)	9.02 to 10.13%

5.2.10 Dr. Roberts' final recommendation was that Consumers Gas be allowed a rate of return on common equity in the range of 10.0% to 10.5% for the 1998 test year, based on a long Canada yield of 6.5% to 7.0%. Upon questioning in the hearing, Dr. Roberts declined to recommend a different rate of return based on the 7.25% long Canada yield agreed to in the Settlement Proposal, although he did accept that a premium of 331.25 basis points could be derived from his evidence, and that risk premiums between 330 and 356 basis points would result from the combination of a 7.25% long Canada yield and his adjustments for financing flexibility.

The Guidelines

5.2.11 By Procedural Order 3 dated March 27, 1997, the Board required the parties to use the *Ontario Energy Board Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities* in the Settlement Conference when addressing the return on common equity for Consumers Gas. If no agreement on rate of return based on the Board's Draft Guidelines were to be reached, the matter was to be reviewed during the hearing.

5.2.12 The Draft Guidelines advised the parties that the Board intends to move to a more formulaic approach using the Equity Risk Premium method for determining the fair rate of return on common equity for Ontario natural gas utilities. The Guidelines are intended to facilitate the implementation of a formulaic return on equity ("ROE") mechanism. The Guidelines provide for an initial setup phase, to establish a just and reasonable return on equity for each of the Ontario local distribution companies ("LDCs"), given a test year long Canada forecast. The reasonable return would then be the base against which subsequent adjustments to the ROE could be made. The initial setup phase requires that the forecast of the long Canada yield for the test year be established, taking an average of three and twelve months forward ten year Canada bond yield forecasts as stated in the most recent publication of Consensus Forecasts, and adding the average of the actual observed spreads between the ten and thirty year Canada bond yields as reported in the *Financial Post* for each business day of a month corresponding to the most recent Consensus Forecasts publication. Then the implied risk premium must be established to account for the utility's risk relative to the long Canada yield.

5.2.13 The Guidelines stated that the primary methodological approach to be used in evaluating the appropriate risk premium should be the equity risk premium test. Once the initial ROE has been set for each of the utilities through the initial setup phase, a procedure would be put in place to automatically adjust the allowed ROE for each utility to account for changes in long Canada yield expectations. The difference between the forecast long Canada yields calculated in step one of the initial setup phase, and the corresponding rate for the immediately preceding year would then be multiplied by an adjustment factor, which the Board suggested would be 0.75, to determine the adjustment allowed to ROE. The adjustment factor would then be added to the utility's previous test year ROE and the sum rounded to two (2) decimal places. It is the Board's intention that the rate of return formula be reviewed when conditions arise which may call into question its validity. Any adjustment to the utility risk premiums would be done only when there is a clear indication that relative risks have changed. The Guidelines stated that the capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals.

Additional Evidence

5.2.14 Following the issuance of the Guidelines, at the outset of the hearing OCAP was granted leave to introduce the evidence of Dr. Booth relating to the calculation of the "going in" equity risk premium for Consumers Gas. Dr. Booth recommended a risk premium of 200 basis points for Consumers Gas. In his opinion, the existence of an automatic adjustment mechanism for the risk premium reduces the overall risk of the Company.

5.2.15 Ms. McShane's rebuttal evidence stated that Dr. Booth's recommendation, which would produce an allowed return on common equity of 9.25%, is out of line with investor expectations, and that his suggested risk premium, implied or explicit, is lower than any other Canadian jurisdiction.

5.2.16 Ms. McShane set out the allowed return on common equity for Consumers Gas over the last five years, calculating an implicit risk premium for each. The implicit premium has averaged 360 basis points at an average long Canada yield of 8.20%. She also calculated the implied fiscal 1998 risk premiums at 7.25% long Canada yield had the Board instituted its proposed 0.75 automatic adjustment mechanism in any of the past five years. The resulting premiums ranged from 372 to 411 basis points.

Settlement Proposal/Positions of the Parties

5.2.17 There was no settlement on the value of the risk premium. There was agreement to use a forecast rate of 7.25% for the long Canada yield, which is within the range of the Company's forecast of 7.27% percent and Prof. Dungan's 7.20%. Parties also agreed to an adjustment mechanism as set out in the Guidelines, modified for an April to August time frame to arrive at the final ROE for the test year.

5.2.18 The Company noted that it is requesting a rate of return lower than that recommended by its expert, which requested rate is unchanged from that allowed for the 1997 test year. The Company pointed out that business risk, according to Dr. Roberts and Ms. McShane, is "at least no lower than in the previous case", and submitted that Dr. Booth's assertion that an automatic adjustment mechanism reduces the Company's business risk has not been demonstrated by his evidence.

5.2.19 The Company further argued that Dr. Roberts' evidence would support a higher risk premium than he recommended if it were based upon the agreed-upon long Canada yield of 7.25%. As to Dr. Booth's recommendation, the Company submitted that it was based upon evidence from past cases, that his evidence in other cases has often yielded low returns compared to those recommended by others, and that it is "clearly outside the zone of reasonableness" and, therefore, should be given no weight by the Board.

5.2.20 Energy Probe calculated that Dr. Roberts' recommendation results in an implied risk premium of 350 basis points (using the midpoints of his assumptions: 10% to 10.5%

return assuming a long Canada yield of 6.5 to 7%). It also noted that Ms. McShane agreed that Consumers Gas' risk premium might be 15 to 25 basis points below that appropriate for Union. Using an implied risk premium of 350 to 375 basis points for Union results in a lower range of 325 to 335 basis points, or a higher range of 350 to 360 basis points for Consumers Gas. The midpoint of these two approaches is a premium of 340 basis points, the risk premium which Energy Probe recommended for Board acceptance. Energy Probe also submitted that Ms. McShane's recommendation of 487.5 basis points is “out of line” with the Board's recent decision for Union.

5.2.21 OCAP, while questioning Ms. McShane's methodology, suggested that, nevertheless, her testimony and that of Dr. Roberts contain "substantial evidence" supporting the 200 basis points risk premium recommended by Dr. Booth. OCAP noted that all experts agreed that "the risk attached to regulated utilities has been consistently declining", and argued that no inverse relationship exists between long Canada yields and utility risk premiums. In OCAP's submission, spreads between long Canada bonds and utility bonds have decreased since the time of the British Columbia Utilities Commission ("BCUC") and National Energy Board ("NEB") hearings establishing risk premiums. Utilities should not therefore expect higher risk premiums than those set by the BCUC and the NEB. In any case, these earlier decisions were intended to be valid for a limited period which has now expired. Arguing that differences in tax treatment make estimates based on US data unreliable, OCAP submitted that risk premium estimates based on allowed returns do not provide an estimate of the fair return. In any case, OCAP relied on Dr. Booth's view that an automatic adjustment mechanism reduces a utility's risk of a "harsh" Board decision or a "penalty rate of return", and therefore reduces the risk overall.

5.2.22 OCAP noted that floating rate preferred shares are, according to Dr. Booth, very similar to utility common shares. A recent issue of Bell Canada Enterprises preferred shares with a yield of 5.28% implies a risk premium for Consumers Gas of 400 basis points, if one accepts Dr. Booth's recommended 9.25% ROE for the Company.

5.2.23 OCAP also argued that allowed ROEs for utilities across Canada are too high. As evidence of this, OCAP noted that IPL was prepared to pay a market to book ratio of 1.7 to buy out Consumers Gas' public float, a figure that results in an average ROE on those shares substantially lower than the allowed ROE. In addition, OCAP noted that its expert relied on evidence filed in E.B.R.O. 493/494 as quantitative and qualitative support for his recommended 200 basis points risk premium.

5.2.24 CAC argued that a risk premium of 325-350 basis points is appropriate for Consumers Gas, consistent with recent awards in other jurisdictions employing a formula-based ROE approach, and consistent with the Board's recent decision in the Union case. CAC noted that a premium of 15 to 25 basis points lower than the risk premium approved for Union was acknowledged by Ms. McShane to be appropriate, and should be accepted by this Board, given that Consumers Gas is less risky than Union, and "traditionally" the Board has recognized a 25 basis point spread between the two companies.

5.2.25 IGUA stressed that there is a need for the Board to reconcile the equity risk premium chosen for Consumers Gas with the views expressed by the Board panel which decided the Union case. In that case, the Board based its decision on long Canada yields in a range of 7.0% to 7.5%, and determined a rate of return on equity for Union of 11%, implying a risk premium of 375 basis points. The Board indicated in that case that a risk premium of 350 to 375 basis points for Union "may be high relative to the level of risk premiums found for similar utilities in other jurisdictions which rely solely on the [equity risk premium] methodology". IGUA noted that in the present hearing, all expert witnesses agreed that Consumers Gas is less risky than Union. Given that Ms. McShane suggested a premium 15 to 25 basis points lower for Consumers Gas than Union, one could calculate midpoints of 347.5 and 337.5 basis points respectively from the range approved for Union.

5.2.26 IGUA noted that the risk premium being considered is inclusive of financing flexibility costs and flotation costs. Formulas for this type of premium at the NEB, BCUC and Manitoba Public Utilities Board produce, at 7.25% long Canada yields, risk premiums of 350, 340 and 337 basis points respectively. IGUA submitted that Ms. McShane agreed that "the financial community could not complain" of a range between 337 and 350 basis points, and that "a finding within that range would be consistent with awards made by other regulatory jurisdictions in Canada". In IGUA's view, the lower number in the range is appropriate for Consumers Gas, given the Board's comments on the premium approved for Union.

Board Findings

5.2.27 The Board agrees with the Company’s submission that, while the Board must be cognizant of the findings relating to rate of return on common equity for other utilities and in other jurisdictions, the task before the Board in the present proceeding is to determine an appropriate ROE for Consumers Gas based upon the agreed upon long Canada yield, and the facts and evidence before the Board concerning the application of its Guidelines to arrive at the appropriate risk premium.

5.2.28 While the Board is not convinced that the existence of an automatic adjustment mechanism in itself reduces the Company’s risk, it is not persuaded by the Company’s argument that no change should be made to the rate of return granted the Company for fiscal 1997. Evidence before the Board in the present hearing, including the evidence of rates for other utilities and in other jurisdictions, the evidence of experts as to the historic rates of return for various types of investments and the relationship between risk premiums and interest rates, and the opinions of the expert witnesses on the relative risk of the Company and others, leads the Board to conclude that, at a long Canada yield of 7.25%, a risk premium of 340 basis points is appropriate for the Company.

5.2.29 This conclusion reflects the Board’s view of the appropriate difference between the risk of Consumers Gas and that determined by the Board for Union in E.B.R.O. 493/494. In particular, the Board notes that there is no disagreement among the experts that Consumers Gas is less risky than Union (as it then was), and takes into account the comments of the panel of the Board that set Union's rate of return.

5.2.30 The Board has identified a timing constraint with the implementation of the Settlement Proposal's application of the Board's Guidelines. The settlement specifies the use of the spreads between the 10 and 30 year Government of Canada bond rate for the month of August 1997, as published in the *Financial Post* which correspond to the selected month in which the *Consensus Forecasts* is published. In the case of Consumers Gas, the Board attempts to issue its Decision before the end of August. Consequently, the analysis of Government bond spreads must cover a period ending not later than the middle of August. Hence the Board has used a one month period ending August 15, 1997.

5.2.31 The average of the 10 year Government of Canada bond yield as calculated from the August *Consensus Forecasts* is 6.25%. The average spread between the 10 and 30 year Government of Canada bond yield, as reported in the *Financial Post* using the period from July 16 to August 15, 1997, is 54 basis points, thus producing a yield forecast of 6.79%. The difference between this figure and 7.25% (-0.46%) is multiplied by .75 factor to produce -0.35%, rounded to two decimal places. The settlement forecast (7.25%) is added to the equity risk premium (3.40%) producing a return of 10.65%, which is then adjusted downward by 35 basis points to produce a Board approved rate of return on common equity of 10.30%.

6. PHASE II COST ALLOCATION

6.0.1 There are three steps involved in allocating costs to the various rate classes: functionalization, classification, allocation.

6.0.2 The process of functionalization groups costs into similar operating functions. Classification groups the functionalized costs into three general groups: commodity, capacity, and customer specific. To provide for rate unbundling, these groups are further sub-classified. The allocation of the classified costs is the process of spreading similarly incurred costs to each rate class on a common factor that can be identified by each class (the allocators).

6.0.3 The Company proposed changes in its current cost allocation study in the following areas:

- allocation/recovery of compressor fuel costs;
- classification of gas costs to operations;
- classification and allocation of Transactional Services Net Revenues;
- functionalization of MarketLink costs;
- allocation of rate base and net investment costs associated with DSM; and
- functionalization of computer equipment costs in rate base.

None of these cost allocation issues was settled.

6.1 ALLOCATION/RECOVERY OF COMPRESSOR FUEL COSTS

6.1.1 Currently, compressor fuel costs are recovered in the Gas Supply Charge. The Company proposed to recover fuel costs (fuel used for the compressors required to transport gas from Western Canada to an Ontario delivery point) from the Gas Supply Load Balancing Charge on the basis that these costs can notionally be viewed as being transmission related.

6.1.2 The Company indicated that this transfer should be revenue neutral; consequently, the Company included a credit in the Transportation Service Rider (Rider A) to apply to Ontario and Western Bundled T-service customers who supply their own fuel.

Positions of the Parties

6.1.3 OAPPA submitted that the debit and then credit proposal is unnecessary and unwarranted.

6.1.4 IGUA submitted that the manner in which the Company proposes to achieve its objective is artificial and will not be readily understood by customers who provide their own fuel. IGUA suggested that the charge be identified as a separate charge such as "transportation fuel charge" and listed as such in the load balancing charges portion of the rate schedule, with the notification that it applies only to customers who have not opted to provide their own fuel.

6.1.5 In response, the Company claimed that customers are familiar with the process of debiting and then crediting as this is in essence similar to the treatment of TCPL transportation costs for Ontario Bundled T-service customers; the allocated demand and commodity tolls are recovered through the Gas Supply Load Balancing Charge, and credited back to the customers via the Transportation Service Credit. With respect to IGUA's suggestion for separate identification of a "transportation commodity charge" on the customer's bill, the Company stated that this would require a modification of the Company's Legacy Systems, which is "neither practical nor economical pending the implementation of CIS".

Board Findings

6.1.6 In the Board's view, given the size and relative sophistication of customers represented by IGUA, the submission by IGUA of possible customer confusion has little merit. The Board accepts the Company's proposal as it represents a better reflection of the transmission nature of these costs. The Board is satisfied that the Company's proposal, as it would apply to each individual customer supplying its own fuel, will be revenue neutral.

6.2 CLASSIFICATION OF GAS COSTS TO OPERATIONS

6.2.1 As a result of the Company's proposed change in allocation and recovery of fuel costs, the Company adjusted the variable unit rate for costing the commodity component of the purchases and receipts to exclude fuel costs.

6.2.2 In addition, the Company proposed the following changes to the classification of gas costs to operations:

- The classification of purchases and receipts was expanded.
- Discretionary supplies were unbundled into Western, Ontario, and U.S. and the latter two were re-classified as 100% pipeline seasonal, from a 100% pipeline annual.
- The storage fluctuation costs were separated into gas supply commodity and gas supply load balancing components.
- The TCPL delivery pressure charge has been re-classified 60/40 peak/annual demand from a 100% seasonal.
- The Union Gas-Interruptible Margin Rebate was reclassified from a 100% seasonal space to a 60/40 transmission delivery/winter classification.

Positions of the Parties

6.2.3 IGUA argued that the proposed change to the classification of discretionary purchases and the classification of storage fluctuation costs were inappropriate. IGUA claimed that it would be inappropriate to proceed as if the gas which the customer delivers to the Company has a value different from the load balancing gas which the Company temporarily provides to the customer for load balancing. IGUA also argued that these proposals cannot be fairly implemented until contractual arrangements between the Company and its bundled-T customers have been modified to specifically deal with the cost implications, if any, of the gas exchanges that take place with respect to the load balancing service which the Company has agreed to provide its bundled-T customers. With respect to the proposed changes in relation to the classification of gas costs pertaining to the delivery pressure charge and the Union interruptible rate, IGUA stated they these changes appear reasonable.

6.2.4 In reply, the Company maintained that its proposals are reasonable notwithstanding IGUA's objections. The Company also noted that cost allocation and rate design matters do not currently form part of the contract between the customers and the Company and, as a result, no amendments are required.

Board Findings

6.2.5 The Board accepts the Company's proposed revisions on the basis of the reasons advanced by the Company, namely:

- The expansion in the classification of purchase and receipts improves transparency.
- The unbundling proposal regarding discretionary supplies allows for a reasonable depiction of cost incurrence and the classification of Ontario and U.S. discretionary supplies into "pipeline seasonal", recognizes the reasons for the incurrence of such costs.
- The proposed classification of storage fluctuation costs is consistent with the classification of purchases and receipts.
- The reclassification of the TCPL delivery pressure charge is consistent with the treatment of transportation demand related costs.
- The proposed re-classification of Union's Interruptible Margin Rebate, arising from additional revenue by Union from utilization of available capacity on its transmission systems, mirrors the cost allocation treatment of Union's M12 transmission demand with compression charges (60/40 deliverability/winter).

6.2.6 In reaching its conclusions, the Board has accepted the Company's evidence that cost allocation and rate design matters do not currently form part of the contract between the affected customers and the Company. In any event, the Board is of the view that changes to cost allocation and rate design matters should not be hindered by contractual arrangements between the two parties.

6.3 CLASSIFICATION/ALLOCATION OF TRANSACTIONAL SERVICES NET REVENUE

6.3.1 Transactional Services include Full Cycle Storage, Short Cycle Storage, Exchanges and Assignments, and Gas Loans. Currently, the transactional services Net Revenue is allocated to in-franchise customers using the storage costs classifier and allocator. The Company proposed to:

- allocate the forecast revenue from Short Cycle Storage and additional revenue above the embedded cost based revenue under Rate 330 Full Cycle Storage to all customers, including ex-franchise customers. The Net Revenue allocated to in-franchise customers will offset the costs associated with Tecumseh Gas transmission and storage. The Net Revenue allocated to ex-franchise customers will be credited through the rate schedule for Rates 325, 330, and 331; and
- classify the forecast Net Revenue associated with Exchanges and Assignments on 60/40 peak/annual and allocate such revenue using the bundled peak deliveries and bundled annual deliveries allocators respectively.

6.3.2 The Company's proposal was to continue to classify and allocate the forecast Net Revenue associated with Gas Loans using the storage classifier and allocator.

6.3.3 The Net Revenues associated with Gas Loans, Exchanges and Assignments would not be subject to sharing with ex-franchise customers.

Board Findings

6.3.4 The Board notes that only IGUA commented on the Company's proposed changes which IGUA supported. The Board accepts the Company's cost classification proposals as reasonable. The proposed allocation of Net Revenue appears fair in that it recognizes that benefits are shared by all the customers who have been supporting the costs. Both in-franchise and ex-franchise customers support the costs to provide storage, transmission, and compression services. Therefore, any forecast revenue from Short Cycle Storage and any additional benefits above the embedded cost based revenue under Rate 330 Full Cycle Storage should be shared by both customer groups. On the other hand, ex-franchise customers have not been supporting the incurred costs that may give rise to revenue from Gas Loans, Exchanges, and Assignments.

6.4 FUNCTIONALIZATION OF MARKETLINK COSTS

6.4.1 Currently, the operating costs associated with MarketLink are functionalized, classified and allocated consistently with the treatment of the Gas Supply Department costs. The Company proposed to functionalize the Market Link costs as Customer Accounting - Enquiry.

Positions of the Parties

6.4.2 IGUA argued against the inclusion of these costs but noted that, in the event they are allowed, the proposed cost allocation treatment appears reasonable.

Board Findings

6.4.3 In Chapter 3 of this Decision, the Board has allowed the capital costs incurred in fiscal 1997 and has rejected the proposed capital costs for fiscal 1998. The Board accepts that the unamortized portion of the fiscal 1997 capital costs be allocated on the basis proposed by the Company.

6.5 DSM RATE BASE AND NET INVESTMENTS

6.5.1 Currently, DSM related capital costs are functionalized to the general service and large volume rate classes based on the specific market sectors that are being targeted by the DSM initiatives. The costs are then classified 60/40 peak/annual. The Company proposed to re-classify and allocate DSM capital using the rental equipment classifier and allocators.

Board Findings

6.5.2 Only IGUA commented on the Company's proposal which IGUA supported. The Board notes the Company's evidence that, in the test year, 98% of the DSM capital is in rental equipment and that the Company's proposal results in only inconsequential variation in allocated costs from the current method. The Board agrees with the Company that using the rental equipment classifier and allocator would simplify the process from currently tracking specific rate base for each DSM program. The Board therefore accepts the Company's proposal.

6.6 FUNCTIONALIZATION OF COMPUTER EQUIPMENT COSTS IN RATE BASE

6.6.1 Currently, functionalization of all of the capital costs associated with computer equipment follows the functionality of the information service charges included in O&M. In view of the large magnitude of the SIM and CIS capital costs in the test year, the Company proposed to isolate such capital costs from the total computer equipment account and it proposed specific functionalization factors for SIM and CIS computer costs.

Positions of the Parties

6.6.2 IGUA supported the Company's proposal.

6.6.3 OCAP took issue with some details of the Company's allocation methodology. It urged the Board to reject the Company's proposal on the basis that it goes into a level of precision that is not consistent with the overall level of precision of the Company's cost allocation methodology. Also, OCAP argued that there are related adjustments that should have been made but were not.

6.6.4 The Company responded that its proposal is a result of detailed studies periodically undertaken to ensure that costs are functionalized, classified, and allocated in a fair and equitable manner. With respect to the related adjustments, the Company noted that those amount to a total of \$0.16 million (\$0.13 per residential customer) and this amount would not change the proposed rate design.

Board Findings

6.6.5 The Board notes that many of the Company's cost allocation changes in this proceeding are the result of the Company having undertaken a more detailed review of its cost allocation practices. The Board accepts that a periodic detailed review may lead to changes that would appear to be beyond a level of precision that is customary for cost allocation purposes. However, to the extent that such detailed reviews are periodic the Board accepts that this is a useful approach to clean up or refine cost allocation matters.

6.6.6 The Board finds that the size of SIM and CIS computer related capital expenditures are large enough to justify the derivation of specific functionalization factors in allocating these costs. The Board accepts the Company's proposal in that it would lead to enhanced cost causality links.

6.6.7 The Board notes that the related adjustments that ought to be made are of relative insignificance in the test year and would not in themselves cause a change in rates. In any event, these adjustments will form part of the total rate recovery process the next time rates are reviewed.

7. RATE DESIGN

7.0.1 The revenue requirement to be generated from rates is separated into three components: distribution, gas supply load balancing, and gas supply commodity. The Company carries out the allocation of the deficiency/sufficiency in three stages. First, the allocated gas commodity and pipeline costs are taken from the cost allocation study and used for the development, for each rate class, of the new gas supply and gas supply load balancing unit rates respectively. Second, rate class responsibility for the distribution deficiency/sufficiency is apportioned pro rata on the basis of the allocated rate base. Third, adjustments to this allocation may be made to align class rates of return.

7.0.2 The Company's evidence addressed the rate design consequences of the proposed cost allocation changes as well as its proposals in the following areas:

- increases to Monthly Customer Charges for Rates 1 and 6;
- new firm seasonal Rate 135;
- new negotiable interruptible Rate 180;
- changes to the Transportation Service Rider A; and
- new overrun charges for Rates 330;

7.0.3 Suncor advanced the following issue:

> Identification of gas management and upstream transportation costs on customer bills

7.1 SETTLED ISSUES

Overrun Charges for Rate 330

7.1.1 Under Rate 330 a customer has a storage contract with Consumers Gas for delivery by the customer to Consumers Gas and re-delivery by Consumers Gas to the customer of a volume of gas owned by the customer.

7.1.2 The Company proposed adding a provision for authorized and unauthorized overrun charges for daily injection/withdrawal and Annual Turnover Volume ("ATV"). The rationale provided was that the Company needed a means to capture the value of service provided on an authorized overrun basis and place a greater onus on the users of services to nominate within contractual parameters so as not to jeopardize service to the Company's other in-franchise and ex-franchise customers.

7.1.3 The Company proposed that authorized daily overrun for contracted maximum daily injection and withdrawal volumes and authorized overrun of ATV be charged on a commodity basis within the Short Cycle range subject to negotiation or determination at the time at which the customer bids for service.

7.1.4 The Company proposed setting the unauthorized daily overrun rate at 10 times the maximum Short Cycle Rate. For unauthorized ATV overrun the Company proposed a rate that varied between the maximum Short Cycle Rate and ten times the maximum Short Cycle Rate depending upon the time of year when the unauthorized ATV overrun occurs. The Company's proposal to vary unauthorized overrun charges by period is related to the difference in the potential cost impact by time of year.

7.1.5 The parties agreed to the Company's proposals which were accepted by the Board.

Non-Settled Issues

7.2 INCREASES TO CUSTOMER MONTHLY CHARGES FOR RATES 1 AND 6

7.2.1 In E.B.R.O. 492, the Board directed the Company to:

> *... bring forward for the consideration of the Board ... a proposed timetable of increases to the customer charges, information as to the acceptability of proposed increases, and a proposed program to provide information to the customers who may perceive unfairness in such increases.*

7.2.2 In response, the Company filed the results of focus group research conducted by Schiappa Research Dynamics. The Company proposed to increase the Rate 1 current monthly charge of $7 by $2 in each of the next three test years which would bring the charge in the third year to approximately 50% of the customer allocated fixed costs. For Rate 6, the increase proposed is $4 from the current $12 for each of the next test years, that would also bring recovery of customer fixed costs to approximately 50%.

7.2.3 Mr. Todd's evidence, on behalf of OCAP, described the proposed increase to Rate 1 as inappropriate on the following grounds:

- only the costs directly associated with adding a customer should be recovered from the monthly charge (the overhead costs should be recovered from the delivery charge);
- an increase in the monthly charge will have a greater impact on lower income households; and
- increasing the monthly fixed charge and decreasing the per unit delivery charge will reduce the incentive to conserve and will have a negative impact on the economics of DSM programs.

7.2.4 Mr. Todd also suggested that increasing the monthly charge would reduce the Company's risk, and that therefore the return on common equity should be reduced.

Settlement Proposal/Positions of the Parties

7.2.5 There was a partial settlement of this issue; it provides for increases of $1 and $2 for Rates 1 and 6, respectively, for the test year. CENGAS and Energy Probe disagreed with the settlement; CENGAS neither cross-examined nor argued on this issue.

7.2.6 Energy Probe submitted that the partial settlement does not comply with the Board's directive in E.B.R.O. 492 as it rejects the introduction of a timetable of increases and it makes no progress toward improving the relationship between customer charges and the underlying costs. Claiming that the partial settlement is in part based on promoting the use of short run marginal costs as advocated by Mr. Todd, Energy Probe submitted that this amounts to a challenge of the Board's previous findings at E.B.R.O. 489 in which the Board found that, in setting customer monthly fixed charges, average costs better represent the measure of cost causality compared to incremental costs. Energy Probe supported the Company's original proposal.

7.2.7 Pollution Probe and GEC had agreed to the settlement proposal of this issue. They further commented in argument that they support the use of incremental rather than fully allocated costs to establish customer charges and warned of the impact of higher fixed charges and lower distribution charges on conservation.

7.2.8 The Company argued that the partial settlement fully meets the Board's directive and that it is the Company's intention to propose increased customer charges in future years.

Board Findings

7.2.9 Other than the recovery of the direct costs associated with adding a customer, the Board recognizes that there will always be controversy as to the appropriate level of recovery of the total fixed customer related costs in the monthly fixed charge.

7.2.10 Clearly there is no easy answer to this issue. It is largely a judgemental exercise of balancing economic efficiency considerations, perceived fairness and customer acceptance. The Board accepts the partial settlement of an increase of $1 and $2 for Rates 1 and 6, respectively, as reasonable. In accepting these increases, the Board does not necessarily accept that there is a demonstrable price elasticity of demand for these customer groups.

7.2.11 The Board finds the frequent visitation of this issue to be unproductive. The Board therefore will expect the Company to adhere to its three year timetable as proposed in its prefiled evidence, but with the same absolute amount increases in the monthly charges approved by the Board for the 1998 test year. The Board will not be inclined to accept revisitation of this issue during this time frame.

7.2.12 On the matter of the impact of higher revenue recovery on the rate of return on common equity, while directionally and theoretically correct, the Board does not consider the prescribed levels of increases in the monthly fixed charges to be of significant magnitude as to materially alter the Company's business risk.

7.2.13 The Board has noted the Company's plan to communicate to customers the higher increases it had proposed. In view of the lesser increases approved, the Board will leave it to the Company's judgement as to whether any modifications ought to be made to this plan.

7.3 NEW RATE 135

7.3.1 According to the Company, the proposed Rate 135, Seasonal Firm Service, is intended principally for gas cooling market development purposes in the large commercial and industrial markets. However, since it would be available year-round, the rate would be available to any customer who meets a minimum annual requirement of 340,000 m^3. Consumption during each of the billing months of December through March would be restricted to less than 5% of the contracted annual volume. Any excess would be subject to unauthorized overrun charges.

7.3.2 The design of Rate 135 is based on Rate 100, but modified to collect peak pipeline capacity and storage costs over the winter period only. Otherwise, the blocking structure and the level of the monthly customer charge match those of Rate 100.

7.3.3 The Company did not anticipate any sales under the new rate for gas cooling in fiscal 1998. However, the Company expected there would be a total migration of 48,025.9

10^3m^3 to the new rate from other existing rates, particularly from Rate 145, largely from operations exclusively conducted in non-winter periods.

7.3.4 In her evidence, Ms. Chown, on behalf of Suncor, stated the proposed new rate points out the deficiency in the design of the Company's rates in that the existing seasonal differentials are inadequate. Ms. Chown criticized the Company in choosing to offer a new rate rather than correct the deficiency. She also stated that the new rate will provide a discount to "some privileged" customers.

Positions of the Parties

7.3.5 OAPPA supported the introduction of the rate, noting that the need for this rate is demonstrated by the migration from other rates in the absence of demand for cooling in the test year.

7.3.6 IGUA supported the introduction of the rate on a trial basis.

7.3.7 Suncor/PanEnergy argued for the rejection of the proposed rate on the basis that there is no economic justification for its introduction since there will be losses in margin from customers migrating from firm rates. It also stated that the perceived need for this rate points out a deficiency in the design of the Company's rates and rather than fix a problem, the Company's approach will result in a "plethora of unnecessary rate schedules".

7.3.8 The Company argued that Suncor/PanEnergy have not recognized the distinctiveness of the load profile of the targeted customers.

Board Findings

7.3.9 The Board finds that there is a sufficiently distinctive load profile exhibited by the target customers of the proposed new rate that a specific and separate rate schedule is appropriate. The Board accepts the offering of Rate 135, as well its proposed structure. The Board expects the Company to highlight for the Board in the next rates case the level of activity and acceptance of this new rate.

7.4 NEW RATE 180

7.4.1 According to the Company, the proposed Rate 180, Negotiated Interruptible Service, is intended to address customer concerns of severe and protracted interruptions. The Company's evidence was that it had developed three conceptual alternatives for internal review which were subsequently presented to large interruptible customers through correspondence and through three meetings in different locations in the franchise area. The Company explained that the alternatives were "conceptual" in that the general mechanics were provided, but not specific rates. According to the Company's evidence, all three alternatives essentially involved a rebalancing of the basic distribution rate and the compensation paid to customers upon curtailment.

7.4.2 At the conclusion of the meetings customers were polled on a non-binding basis. In view of customers' requests at the first meeting, at the subsequent two meetings customers were also polled for their support of the status quo. According to the Company, "a significant majority" of customers supported retention of the status quo, as they viewed the weather and curtailment levels of the 1995/1996 winter as being abberations. In view of this, the Company did not propose the elimination or restructuring of the existing interruptible Rate 145 and 170. Rather, the Company proposed the introduction of the negotiable Rate 180 interruptible rate which, according to the Company, resembled one of the three proposed alternatives most favoured.

7.4.3 Although interruptible customers consuming over 2,000 10^3m^3 annually were invited to the meetings, eligibility for Rate 180 initially is proposed to be limited to customers contracted at a minimum annual level of 5,000 10^3m^3. This level is to be reduced as experience is gained with the operation of the new rate. According to the Company, the design objective for Rate 180 is to set a basic distribution rate comparable to a firm rate and to increase the Capacity Repurchase Credit ("CRC") to a level that, at the budgeted 15 days of curtailment, customers would be financially indifferent on an annual basis between Rate 180 and 170. The Company's evidence indicated that, initially, the level or right to curtail will not be for less than 15 days. Allowance would be made for the CRC to be negotiated at lower levels to reflect any limitations on the Company's right to curtail. The basic distribution rate is modelled on Rate 110, but with greater emphasis on demand charge components. Currently, Rate 110 fixed charges account for 40% of the revenue requirement. For Rate 180, fixed charges would recover approximately 60% of the revenue requirement.

7.4.4 In her evidence, Ms. Chown, on behalf of Suncor, stated the proposed negotiable features of this rate raises the potential for discriminatory rates, in that two "equally situated" customers would not necessarily receive the same CRC. She favoured "significant constraints" on the negotiable features of the Credit. She also claimed that it is not clear that the proposed rate represents the option preferred by customers. She suggested that a non-negotiable rate option should be investigated rather than implement the proposed rate.

Positions of the Parties

7.4.5 OAPPA supported the introduction of the new rate but with the following modifications:

- the wording in the proposed rate schedule be modified to reflect the Company's intent not to negotiate with customers for curtailment less than 15 days during the test year;
- to avoid pricing abuse, the negotiable nature of the rate be replaced with a sliding scale based on the number of days of curtailment;
- the excess commodity purchased by the Company from direct purchase interruptible customers (due to interruption over the contracted number of days) be purchased by the Company at the avoided cost, namely the peaking supply or discretionary purchase price, whichever is appropriate for the specific day(s); and
- the new rate should be available to all interruptible customers, not only those consuming over a certain volume of gas; alternatively, the Company could restrict the days of interruption for customers under 5,000 10^3m^3 to a specific number of days.

7.4.6 Suncor/PanEnergy asserted that since Consumers Gas will be the only party to know the negotiated rates of each of its customers, there is no assurance that discrimination will not occur, "perhaps unwittingly". It noted that, based on the Company's research, the majority of the Company's customers supported the existing arrangements and, therefore, there is no clearly demonstrated need to implement the proposed rate at this time. It submitted that since the exact financial implications of the various options presented at the meetings were not clear, a non-negotiated rate option may address customers' concerns more effectively. Suncor/PanEnergy recommended that the Board direct the Company to re-evaluate its interruptible rate offerings.

7.4.7 IGUA submitted that the proposed rate needs revision in the following areas:

- The Capacity Repurchase Credit amount should not be represented in the rate schedule as a ceiling, but rather as a fulcrum around which negotiations with respect to limited interruptibility can take place; for the 1998 test year, the rate schedule should specify that the Capacity Repurchase Credit amount at the budgeted 15 days of curtailment represents a ceiling.
- The rate schedule should interface with Rate 170. To assure fairness in negotiations for the 1998 test year, the rate schedule should specify that the credit amount will be payable for 15 days of interruption, the precise level to be negotiable.
- The commodity price payable by the Company should not be the reference price, but a price either fixed or negotiable. If negotiable, the price should take into account that curtailment may occur for gas supply reasons. If the commodity repurchase price is limited to the reference price, the rate schedule should specify that the customer will only be interrupted for capacity constraint reasons.

7.4.8 In its reply, the Company set out what it believed to be misunderstandings and confusion by IGUA and OAPPA regarding the Company's proposal by further explaining and supporting the derivation of the proposed rate.

Board Findings

7.4.9 The Board notes that there was substantial confusion in the hearing and in argument concerning the derivation of the new rate as well as its applicability. Also, the Board is concerned about the negotiable aspects of the proposed rate. In the Board's view, there may be less controversy if the applicable discounts were the result of more transparent criteria rather than the negotiable features that characterize the proposed rate.

7.4.10 The Board is not prepared to approve the proposed rate at this time. Should the Company wish to reintroduce this rate or a similar rate, the Board urges the Company to solicit further input from customers or their representatives.

7.5 TRANSPORTATION SERVICE CREDIT - RIDER A

7.5.1 Rider A applies to a customer who has a Gas Transportation Agreement with Consumers Gas under any rate other than Rates 300 and 305. The rider specifies the monthly direct purchase administration charges. It also specifies the Transportation Service Credit ("TSC") for gas owned by the customer and received by Consumers Gas at different acceptance points under Firm Transportation ("FT") and Firm Transportation Tendered.

7.5.2 The Company proposed two changes. The first is an accommodation of Western Bundled T arrangements with an intra-Alberta acceptance point by introducing a T-Service Debit. The Debit is equivalent to the 100% load factor Nova demand toll.

7.5.3 The second change stems from the Company's proposal to transfer recovery of fuel costs from the Gas Supply Charge to the Gas Supply Load Balancing Charge. Given that all T-service customers are required to provide their own fuel and given that they will pay for that fuel in the proposed Gas Supply Load Balance Charge, a credit will be stipulated in Rider A for these customers.

Board Findings

7.5.4 Elsewhere in this Decision the Board accepted the Company's proposed cost allocation treatment of fuel gas. The Board therefore accepts the Company's proposal that Rider A contain a credit for customers supplying their own gas. The Board also accepts as reasonable the Company's proposed introduction of a T-service Debit and the basis of its derivation.

7.6 BILLING IDENTIFICATION OF GAS MANAGEMENT AND UPSTREAM TRANSPORTATION COSTS

7.6.1 Ms. Chown recommended the introduction of a separate system gas administration fee, as approved by the Board for Union in E.B.R.O. 493/494. She suggested that a fee of \$0.50 per m^3 apply which is comparable to what Union has proposed.

7.6.2 The parties to the Settlement Proposal identified the following three components in relation to the billing identification issue:

(a) whether the upstream transportation costs should be separated for billing purposes;

(b) whether the applicable gas supply management costs should be separated as between system gas and buy-sell gas, and, if so, whether they should be separated for billing purposes, either individually or as part of a commodity charge; and

(c) whether such separated costs should be identified on the Company's bills.

Settlement Proposal/Positions of the Parties

7.6.3 With the exception of Suncor/PanEnergy, the parties agreed as follows:

> *Whether or not such costs should be separated for billing purposes, it is not practical for the Company to identify such separated costs on its bills during the 1998 Test Year, for the reasons given in the Company's evidence.*
>
> *Nevertheless, there should be a determination of whether the Company's applicable gas supply management costs should be separated to system gas customers and buy-sell customers, respectively, comparable to the charges approved by the Board for Union Gas Limited in the E.B.R.O. 493/494 Decision With Reasons.*

7.6.4 OAPPA, a party to the above settlement, submitted in argument that the Company should be directed to prepare to show upstream transportation cost on invoices starting in the 1999 fiscal year.

7.6.5 AMO, a party to the above settlement, urged the Board to approach this issue from the broad perspective of the public interest and with a view to maintaining regulatory consistency. In regard to the latter, AMO noted that, if there is no system supply charge in Consumers Gas' rates, there will be a discrepancy between Consumers Gas and Union.

7.6.6 IGUA, a party to the above settlement, submitted that the Company should be directed to bring the matter of gas supply administration cost separation and billing for determination to the next rates case with sufficient evidence to enable the establishment of a fee.

7.6.7 Suncor/PanEnergy stated that it disagreed with the settlement for the "plain and simple reason that [the Company's] proposal is a stalling tactic". They alleged that the Company has had adequate time to compute these costs but did not do so.

7.6.8 The Company replied that the issue with intervenors is one of interpretation. The Company's interpretation is that, if the Board decides that a similar treatment as in E.B.R.O. 493/494 is warranted, then the Company would comply in the next main rates case. The Company reviewed the history of this issue and argued that the determination of the specific level of this charge at this time would be arbitrary.

Board Findings

7.6.9 The Board can not ascertain from Suncor/PanEnergy's position whether they wish the Board to impose the same fee of $0.50 as Union. If so, the Board is not prepared to do that as such an amount would be arbitrary. There may be different cost considerations that apply to Consumers Gas. The Company has not provided the calculations because it was not required to do so. The Board expects the Company to adhere to the letter and intent of the partial settlement and to also address the quantification of the appropriate fee at its next main rates case. Further, the Board expects that any developments flowing from the Market Review in this connection will be reflected in the Company's proposals.

8. DEFERRAL ACCOUNTS

8.0.1 "Deferral" accounts capture the costs or revenues where no allowance has been made in the Company's rates. "Variance" accounts capture the variation in costs or revenues from amounts reflected in rates. For ease of reference, the Board will refer to both types of accounts as deferral accounts.

8.0.2 Simple interest is calculated on the monthly opening balances in deferral accounts at the short term interest rate last approved by the Board in the Company's main rates case.

8.0.3 The rates hearing process examines the accuracy and prudence of the deferral account balances and the appropriate disposition to customers or the shareholders.

Existing Accounts - Non-Gas Supply

8.0.4 In E.B.R.O. 492, the Board authorized five non-gas supply related deferral accounts for the 1997 fiscal year. These are:

> 1997 Deferred Rebate Account. This account records any amounts payable to or receivable from customers which will not be paid or collected due to inability to locate a customer. The account also records, for the non-gas supply deferral accounts, the difference between the actual closing balances and the estimated balances used for clearing purposes. Further, the account includes amounts arising from differences between actual and forecast

volumes used for the purposes of clearing deferral account balances, as the clearing of deferral accounts are based on eleven months actual, one month volumetric forecast, and may give rise to over/under clearing.

1997 DSM Variance Account - Operating. This account records the difference between the actual and budgeted DSM operating expenditures. The balance will not exceed 20% of the budgeted amount.

1997 Generic Regulatory Hearings Deferral Account. This account records the costs of any generic hearings not anticipated by the Company to take place in the test year.

1997 Class Action Suit Deferral Account. This account records the costs incurred for defending the Company's 5% late payment charge, excluding the amount of any judgement against the Company. Any award of costs made to the Company by the Court will be credited to this account.

1997 Comprehensive Cost Allocation Study Deferral Account. This account records the incremental costs incurred by the Company required to facilitate the completion of the Comprehensive Costs Allocation Study agreed to in the ADR.

8.0.5 By accounting order UA-108 dated February 14, 1997, the Board also authorized the creation of the following deferral account:

1997 Framework for Joint Action Deferral Account. This account records the Company's costs related to the failure of certain High Temperature Plastic Venting systems used to exhaust the products of combustion from mid-efficiency gas appliances, including furnaces, to the outdoors.

Existing Accounts - Gas Supply Related

8.0.6 In E.B.R.O. 492, the Board authorized the creation of four gas supply related deferral accounts for the 1997 fiscal year. These are:

> 1997 Purchase Gas Variance Account ("PGVA"). The PGVA accounts for the effect of price variances between actual and forecast gas purchase prices. Among other components, it includes the variances in commodity costs and TCPL tolls, amounts related to the Company's gas purchase risk management activities, any cost consequences associated with the under utilization of the Link Pipeline, and unforecast penalty revenues from interruptible customers who did not comply with the Company's curtailment requirements. The account also records the variation between the Company's estimated PGVA balance and the actual year end balance of the previous year, as the opening balance.
>
> 1997 Heat Value Differential Account. This account records the cost differences arising from the fluctuation in the forecast and actual heating value of gas volumes. It also includes energy-in-transit (the difference between the energy content of the Company supplied gas delivered to TCPL in Western Canada and the average value of the stream of gas delivered to Consumers Gas in Ontario by TCPL). Energy-in-transit also applies to Union's transmission and storage systems. The account also records the variance between forecast and actual balance of the previous year, as the opening balance.
>
> 1997 Union Gas Deferral Account. This account records the difference between the forecast and final rates for transportation and storage on the Union system. The account also records the variance between forecast and actual balance of the previous year, as the opening balance.
>
> 1997 Transactional Services Deferral Account. This account records the amount by which the actual Gross Margin varies from that forecast from the provision of Transactional Services (off-peak and peak storage from released capacity, Gas Loans, Exchanges, and Assignments).

8.1 BALANCES AND CLEARING

8.1.1 Consistent with previous practice, the Company proposed to clear balances through a one-time charge in the first billing month (usually October) following the issuing of the Board's Order.

8.1.2 Since the actual data for fiscal year-end (September 30) is not available at the time of the hearing or even at the time of issuing the Rate Order, the Company provides upper and lower boundaries on the forecasts for all deferral accounts. For gas supply related accounts, if the actual year end balances falls between the established boundaries, the remaining account balances are carried forward to the subsequent year in the respective accounts. Variances outside the boundaries would be dealt with through an accounting order. Balances remaining in the non-gas supply related accounts are carried forward in the following year's Deferred Rebate Account.

8.1.3 The forecast balances provided during the hearing, excluding interest, as determined on June 3, 1997 (utilizing mainly information up to April 1997) are shown in Table 8.1 below. The proposed clearing of the deferral accounts to the various rate classes reflect the principle of cost causality, as set out in the Company's cost allocation study.

Table 8.1:

DEFERRAL ACCOUNT BALANCES FORECAST			
Account Name	**April 1997 Forecast[4] Debit/(Credit)**		
Non-Gas Supply Deferral Accounts[1]	**Forecast to 1997-09-30 $**	**Upper Boundary $**	**Lower Boundary $**
1997 Deferred Rebate Account	250,000	298,000	240,000
1997 Demand-Side Management Variance Account - Operating	(2,092,000)	(1,892,000)	(2,292,000)
1997 Generic Regulatory Hearings Deferral Account[2]	450,000	475,000	337,000
1997 Class Action Suit Deferral Account	120,000	130,000	67,000
1997 Comprehensive Cost Allocation Study	710,000	715,000	674,000
1997 Framework for Joint Action Deferral Account	40,000	61,000	32,000
Sub-total	**(522,000)**	**(213,000)**	**(942,000)**
Gas Supply Related Deferral Accounts[1]			
1997 Purchased Gas Variance Account[3]	20,219,000	31,652,000	8,786,000
1997 Heating Value Differential Account	(179,000)	419,000	(777,000)
1997 Union Gas Deferral Account	(2,757,000)	(2,619,000)	(2,911,00)
1997 Transactional Services Deferral Account	(1,723,000)	(1,570,000)	(1,888,000)
Sub-total	**15,560,000**	**27,882,000**	**3,210,000**
Total for all Deferral Accounts	**15,038,000**	**27,669,000**	**2,268,000**

Notes:
1. All balances exclude interest.
2. Includes costs incurred to date for E.B.O. 188 and an estimate of costs to be incurred for the Ten Year Market Review up to May 31, 1997. No costs have been included for any generic hearings that may potentially be held subsequent to June 3, 1997, the date on which this estimate was produced.
3. The estimated cost consequences of Link pipeline underutilization is $830,000 or less, as compared to the E.B.R.O. 492 forecast cost consequences of $1,090,000.
4. The month associated with each forecast represents the last month for which an actual is available. For example, the April 1997 Forecast, prepared 1997-06-03, is based upon April actuals, May telemetered information, and a forecast for the balance of the fiscal year.

Source: Exhibit G3,T8,S3

8.1.4 Except for the 1997 Purchased Gas Variance Account, the 1997 Generic Hearings Deferral Account, and the Comprehensive Cost Allocation Study Deferral Account, the Company's proposals were accepted by the intervenors in the Settlement Proposal.

8.1.5 The Settlement Proposal noted that the Transactional Services Deferral Account is to be disposed on a 75:25 customer:shareholder basis instead of 50:50 originally proposed by the Company. The Board has set out a more detailed discussion of this item in Chapter 4.

8.2 1997 PURCHASE GAS VARIANCE ACCOUNT

8.2.1 There were two issues associated with the disposition of the forecast balances in the 1997 PGVA. The first relates to the under-utilization of the Link Pipeline. The second relates to the Company's proposed changes in disposing of the balances.

Link Pipeline

8.2.2 In November 1996, Niagara Gas Transmission Ltd. ("Niagara"), a Consumers Gas affiliate, commenced service of the Link Pipeline which connects Consumers Gas storage facilities with ANR facilities that connect with the Great Lakes Gas Transmission system and Michigan Consolidated Gas Company near its Columbus storage facility. Consumers Gas has a ten year contract with Niagara for 75 MMcfd of the total 150 MMcfd of capacity on the Link Pipeline.

8.2.3 In compliance with the E.B.R.O. 490 directives of the Board, the Company has recorded the cost consequences of any under-utilization of its contracted capacity on the Link Pipeline as a separate component in the PGVA. In the event that Consumers Gas markets any additional under-utilized capacity to third parties in fiscal 1997, the revenues received would offset these cost consequences. Consumers Gas estimated the net cost consequence of Link Pipeline under-utilization as $830,000. The Company requested authorization to collect 100% of these costs from customers.

Changes in Disposition Method

8.2.4 The Company's proposed disposition of the balance in this account represented a change from previous practice. Currently, the PGVA is separated into commodity related component and a toll related component. The commodity related component is cleared to systems and buy/sell customers only; it does not impact T-service customers. The toll related component is cleared to all customers except for Ontario

Bundled T-service customers. The proposed change relates to the clearing of the commodity component. The proposal is that T-service customers bear some responsibility for the seasonal load balancing variance. The seasonal component of the PGVA account consists of Ontario and U.S. discretionary and peaking supplies. The variances associated with peaking would be allocated to the customer rate classes based on bundled peak deliveries. The variances associated with discretionary variances would be classified and allocated to customer rate classes based on the seasonal space allocator.

Positions of the Parties

8.2.5 AMO argued that the most equitable way of disposing of the load balancing charges is to classify them in the distribution function. In the case of "extraordinary load balancing circumstances" AMO suggested that those circumstances should be dealt with on a "one off" basis.

8.2.6 IGUA took issue with the Company's proposal to classify some of the gas commodity charges as load balancing charges thereby proposing to recover a portion of these costs from bundled T-customers. It pointed out that these customers do not purchase gas from or sell gas to the Company. The load balancing provided by the Company for these customers represents, according to IGUA, a temporary exchange of molecules and, absent revised contractual arrangements, it would be inappropriate to assign in effect different values to these molecules.

8.2.7 With respect to the costs associated with the under-utilization of the Link Pipeline, IGUA argued that they should be excluded from the PGVA. According to IGUA, recovery of such costs would operate to provide a guaranteed return to Consumers Gas' affiliate, Niagara.

8.2.8 OCAP argued that the Company should not allocate any non-compliance revenues to interruptible customers unless it can demonstrate that secondary interruptions are in fact a common and necessary occurrence.

8.2.9 OCAP submitted that there is no good reason for allocating any of the costs associated with the net under-utilization of the Link Pipeline to ratepayers. For the test year, however, OCAP suggested that the Board should not allow more than 50% of these costs.

8.2.10 OAPPA agreed with the Company's proposal noting that since more heat sensitive customers will be served under ABC T-Service, the proposed disposition revision is appropriate.

8.2.11 With respect to the under-utilization of the Link Pipeline, the Company replied that it does not interpret the Board's findings in E.B.R.O. 490 that the Board would automatically burden the Company's shareholders with any costs of under-utilization. Rather, if the Board found that the Company acted in a prudent manner, these costs would be recoverable from ratepayers. The Company also argued that the value of the Link Pipeline should be assessed on its long term benefits, not the short term benefits as argued by intervenors.

8.2.12 The Company disagreed with the positions of the intervenors on the issue of the disposition of the load balancing variances and maintained that the variances should be refunded or collected from all customers. The Company did not view as practical IGUA's proposal that contracts specify deferral account disposition, as the prudence of any balances and the disposition method is a main rates case matter. The Company rejected OCAP's argument regarding the allocation of non-compliance revenue as either containing incorrect assertions or being unreasonable.

Board Findings

8.2.13 With respect to the costs associated with the under-utilization of the Link Pipeline, the Board observes that an amount of $180,000 was credited in the PGVA for revenues received from third-party assignments of the excess capacity. The Board is not convinced that all of the remaining Link Pipeline under-utilization costs should be borne by ratepayers. The Company's argument that the value of the Link Pipeline should not be assessed on the short term costs and benefits is contrary to the very purpose of the Board directing the establishment of the deferral account in the first place. The Board will allow recovery of half of the remaining costs, recognizing that the Link Pipeline provides some benefits to customers toward supply security and long term supply diversity. The Board expects the Company to provide to the Board the necessary details in support of the recovery amount as part of its Draft Rate Order.

8.2.14 With respect to the change in the clearing methodology, the Board accepts the Company's proposal as reasonable. Given the Company's forecast that the implementation of ABC T-Service will result in a substantial number of residential and other small volume customers choosing T-service, the Company's proposal will ensure that these heat sensitive load profile customers will bear the appropriate costs.

8.2.15 On the matter of the Company's risk management activities, the Board finds no evidence that any of such costs captured in the 1997 PGVA have been imprudently incurred.

8.3 1997 GENERIC HEARINGS DEFERRAL ACCOUNT

8.3.1 Based on updated evidence submitted during the hearing, the Company sought to recover from ratepayers the balance in this account, revised to $375,000, comprised of the following components:

- Natural Gas System Expansion (E.B.O. 188) ($240,000); and
- Market Review ($135,000).

8.3.2 The forecast balance for the Market Review excludes any cost for intervenors. The Consumers Gas portion will be invoiced by Union. Consumers Gas estimated its share of intervenor costs to be about $150,000 up to the time of the filing of the Working Group's report on May 31, 1997.

Positions of the Parties

8.3.3 IGUA submitted that the amounts that ought to be cleared are the actuals accumulated at the date that the account is cleared.

8.3.4 CAC submitted that, since the costs associated with the E.B.O. 188 proceeding have not been subjected to final assessment, they should not be cleared at this time. With respect to the amounts relating to the Market Review, CAC submitted that only the amount that was reviewed at the hearing ($63,889) should be cleared, not any amounts booked after that point.

8.3.5 The Company stated that it is appropriate to clear these balances since these costs were incurred in 1997 and the outcome of a generic hearing does not apply to a specific year. Moreover, the Company anticipates that the magnitude of the remaining balance in this account will be small and, as such, does not warrant the approach advocated by CAC. On IGUA's submission, the Company stated that the Board will have the actuals as of August 31 and the forecast as of September 30 for purposes of the Rate Order as has been the practice in the past.

Board Findings

8.3.6 In the Board's view, it would be reasonable to dispose of the amounts that have been recorded as a result of a previous Board assessment. However, disposing now of amounts that have yet to be reviewed by the Board may prejudice future activities.

8.3.7 The Board therefore defers the disposition of the amounts related to the Market Review. With respect to the amounts related to E.B.O. 188, the Board cannot determine from the evidence how much of the amount claimed represents intervenor and other costs that have been paid out as a result of the Board's Phase I Decision in E.B.O. 188 dated August 15, 1996. The Board directs the Company to include in its Draft Rate Order only those amounts that it paid pursuant to that Decision.

8.4 COMPREHENSIVE COST ALLOCATION STUDY DEFERRAL ACCOUNT

8.4.1 The forecast balance in this deferral account is $709,502 broken down into the following components:

- Arthur Andersen & Co. ($482,845)
- Foster Associates, Inc. ($119,697)
- Additional (labour) resources ($98,191)
- Wisconsin Energy Conservation Corp. ($6,892)
- Travel and employee expenses ($1,877)

8.4.2 These costs do not include the costs associated with the hearing process. Such costs, and the costs associated with retaining Dr. Cronin, formed part of the Company's O&M regulatory budget.

Positions of the Parties

8.4.3 IGUA argued that there was no need for the Company to retain three consultants, particularly Dr. Cronin who was asked to rebut Mr. Edgar's evidence although that evidence was substantially identical to the testimony Mr. Edgar presented last year. IGUA also contended that Dr. Cronin was "less than forthright".

8.4.4 IGUA also argued that the costs are higher due to the Company's support of a previously untested costing methodology. IGUA asserted that none of the parties to the E.B.R.O. 492 ADR process was aware of the Company's plan to abandon its reliance on marginal costing for ancillary programs and full costing for non-utility eliminations.

8.4.5 IGUA submitted that the costs are "grossly excessive" in comparison to Mr. Edgar's costs. It suggested that the Board disallow half of the costs, or $355,000, which when added to Mr. Edgar's costs, result in approximately $400,000. IGUA further suggested that ratepayers and shareholders share these costs equally, since non-utility eliminations and related transfer pricing are shareholder issues.

8.4.6 CAC argued that the Company has taken a restrictive view of what ought to have been captured in this account; the account ought to have captured all of the costs associated with the experts, not just costs up to a certain activity point. CAC also submitted that of the costs found by the Board to have been prudently incurred, 75% of these costs should be borne by the shareholders, since an appropriate cost allocation also deals with shareholders' interests. CAC argued that the costs associated with Arthur Andersen and Foster Associates are excessive, and that any costs associated with Dr. Cronin should be eliminated on the basis that he added "nothing of value".

8.4.7 OCAP submitted that a large share of the cost allocation study should be borne by the shareholders. It argued that the costs claimed for Foster Associates and Arthur

Andersen are excessive and that the Company exploited the E.B.R.O. 492 ADR commitment by undertaking an "activity costing analysis", whose real value is to "enable the Company to price unbundled services very effectively (from a profit maximization perspective) in a competitive environment."

8.4.8 In OCAP's view, the costs that should be allowed for Foster Associates should be comparable to those for Mr. Edgar. The fee for Arthur Andersen that is charged to ratepayers should be limited to the amount related to developing fully allocated costs.

8.4.9 OCAP also submitted that the costs to be recovered from ratepayers should not be on the basis of number of customers in each class as proposed by the Company, but rather on volume.

8.4.10 The Company submitted that whether a particular cost item is included in the deferral account or as a component of regulatory costs does not impede the Board's ability to review the prudence or the disposition of these amounts. The Company responded to the points raised by the intervenors regarding the prudence of the amounts and submitted that the costs incurred, when taken in conjunction with amounts eliminated in the non-utility elimination, are appropriately cleared to ratepayers.

8.4.11 The Company submitted that a volumetric allocation is "totally inappropriate" since the costs incurred are not volumetrically driven. The Company noted that the net revenues associated with ancillary programs are allocated to a customer rate class based on the customer count allocator or the rental allocator or are specifically allocated; in all cases the allocations are closely related or equal to those based on the customer count allocator.

Board Findings

8.4.12 In the Board's view, the issue of whether the costs associated with Dr. Cronin, Mr. Effron, and Ms. McShane's rebuttal evidence, as well as the preparation and hearing related costs associated with the review of the cost allocation issue, should or should not be captured in this deferral account is not of consequence. The Board has already considered these costs in its review of the Company's regulatory budget. The Board's findings herein deal with the reasonableness of costs captured by the Company in the deferral account and with the disposition of such amounts.

8.4.13 With respect to the $482,845 amount associated with Arthur Andersen, the Board finds this amount to be excessive. The Company's choice to engage the firm's Vancouver office resulted in additional costs of some $100,000. The Board also concludes that, with the Company's long experience in applying marginal and full costing, the Company has not justified the need to retain an outside firm for such work and for its retention of almost half a year. Further, the Board finds the Company's cost control efforts to be lacking. The amount recorded represents an increase of $120,000 or one-third from the amount forecast as late as at the time of the Technical Conference. For all of the above reasons, the Board finds an amount of $200,000 to be appropriate.

8.4.14 With respect to the $119,697 amount associated with Foster Associates' White Paper, the Board also finds this amount to be excessive. Given that firm's experience in regulatory matters, 500 claimed hours for its preparation appear particularly excessive, especially in comparison to the costs associated with Mr. Edgar's work. Further, the Board is not persuaded that any of the eight trips claimed by Foster Associates were required to produce a concept paper. For these reasons, the Board finds an amount of $40,000 to be appropriate.

8.4.15 With respect to the $98,191 for additional resources, the Board notes that about $87,000 of this amount was spent for the services of an external Chartered Accountant, and the balance for administrative services. The Board is not persuaded that, given the Company's resources in both the accounting and administrative areas, such costs are justified. The Board finds an amount of $10,000 to be appropriate.

8.4.16 The issue then is the appropriate allocation of the $259,000 amount that the Board finds to be an appropriate balance in the deferral account. The Board is not persuaded that all of these costs should be allocated to ratepayers. The nature of the cost allocation issue also encompasses the interests of the shareholders, especially given the non-utility proportion of the Company's total activities which necessitated the cost allocation study in the first place. The Board finds that one-third of the $259,000 is reasonably attributed to the shareholders.

Proposed 1998 Deferral Accounts

8.4.17 For fiscal 1998, the Company proposed the continuation of all of the non-gas supply related deferral accounts except the Comprehensive Cost Allocation Account and the Framework for Joint Action Deferral Account. In addition, the Company requested authorization to establish the following new deferral accounts:

1998 Debt Redemption Deferral Account. This account will record the net savings realized on any unforecast early debt redemption.

1998 Lost Revenue Adjustment Mechanism Variance Account. This account will capture margins the utility loses or gains if the results from DSM programs are more or less successful than results incorporated into the test year rate setting process.

1998 Shared Savings Mechanism Variance Account. The establishment of this account presupposes the establishment of the LRAM. The account will record the difference between the actual and budgeted shared services amounts incorporated in the Company's test year rate setting process.

1998 Agent Billing and Collection Transportation Variance Account. This account will record the differences between the 1998 ABC T-Service actual and budgeted revenues and budgeted variable costs.

8.4.18 The Company proposed the continuation of all the 1997 gas supply related deferral accounts. The Company indicated that the methodologies of the proposed accounts would be consistent with the existing methodologies, except for the following changes:

1998 Heating Value Differential Account. The description of the methodology has been modified to include *energy in transit* adjustments between the Company and Union Gas.

1998 Union Gas Deferral Account. The description of the methodology has been modified to include variances between the Union Gas rebates used to prepare the Company's budget and the final Union Gas rebates received by the Company, and to record amounts related to deferral account dispositions received or invoiced from Union Gas.

1998 Transactional Services Deferral Account. The treatment of O&M expenses has been modified and the account description has been expanded to include definitions of certain terms.

Settlement Proposal

8.4.19 There was complete settlement of these issues with the following exceptions: the introduction of the 1998 ABC T-Service Variance Account and the introduction of the 1998 Shared Savings Mechanism Variance Account. Other than Suncor/PanEnergy, there was agreement for the continuation of the Purchase Gas Variance Account; Suncor/PanEnergy agreed to deal with its concerns in argument only. Suncor/PanEnergy addressed this issue indirectly in the context of GCAM, discussed below.

8.4.20 The Settlement Proposal noted that the balance in the 1998 Transactional Services Deferral Account is to be disposed on a 75:25 customer:shareholder basis instead of 50:50 originally proposed by the Company.

Board Findings

8.4.21 While the Board, as part of its acceptance of the Settlement Proposal, accepted the proposed deferral account for transactional services, the Board wishes to observe that the operational aspects of this account need to be better explained. The Board expects the Company to include in its prefiled material for the next rates case clear evidence as to this account's operational characteristics, including the definitional aspects of all of its components.

8.5 ABC T-SERVICE VARIANCE ACCOUNT

8.5.1 IGUA argued that the Board ought to be reluctant to authorize the establishment of a deferral account related to a service for which the Board does not set the price.

8.5.2 OCAP submitted that any shortfall in the account should be recovered through increases in the ABC T-Service charge, not from ratepayers.

8.5.3 The Company reiterated that ABC T-Service is and should remain a revenue neutral service and that the deferral account would facilitate the development of the direct purchase option.

Board Findings

8.5.4 The Board notes the Company's forecast that some 400,000 customers will sign up for the ABC T-Service in the test year contributing $2.26 each (revenue minus variable costs). The evidence revealed that, under the most extreme assumptions for which information was requested by the Board, the potential variance in the Company's view ranges from a revenue deficiency of $790,000 if only 50,000 residential customers take up this service to a revenue excess of $1.85 million if all residential customers chose ABC T-Service.

8.5.5 The Board considers that the likely variance caused by customer uptake of the new service will not be as extreme as the above numbers suggest. Further, it would be unusual for the Board to authorize the creation of a deferral account for an ancillary activity over which the Board does not set rates or charges. For the above reasons, the Board rejects the Company's request.

8.6 LRAM/SSM DEFERRAL ACCOUNTS

8.6.1 As discussed in detail in Chapter 4, the Board has directed the Company to establish a deferral account for lost revenue resulting from the Company's DSM activities. The Board has, however, rejected the request for a shared savings mechanism and, consequently, the SSM deferral account is not required.

8.7 ALTERNATIVE CLEARING METHODOLOGIES

8.7.1 Following Board authorization in E.B.R.O. 492, the Company cleared its 1996 deferral accounts through a one-time adjustment to customers' October 1997 bills. According to the Company's evidence, for a typical residential customer the adjustment resulted in a one-time charge of about $25. This precipitated strong customer dissatisfaction - it was estimated that the Company received 110,000 calls.

8.7.2 In its E.B.R.O. 492-02 Oral Decision of February 6, 1997 dealing with gas cost changes, the Board stated as follows:

> *The Board has noted the Company's evidence that it is investigating alternative ways to deal with the disposition of PGVA balances. However, the Board is not satisfied that the Company's plans are definitive in addressing the use of prospective ratemaking.*
>
> *The Board directs the Company to include as part of its investigation of disposing of the PGVA balances the use of prospective ratemaking in recovering actual or forecast debit balances in all its deferral accounts, and to prefile evidence in this regard for consideration in the upcoming E.B.R.O. 495 main rates case.*

8.7.3 Based on its review of the range of past balances in its deferral accounts, the Company suggested that alternative methods could focus on the following two groupings: (a) the combination of the PGVA and the HVDA as one group and (b) the other deferral accounts as another group. The Company's examination of alternatives and conclusions are set out below:

> Prospective Clearing. Prospective clearing takes an accumulated balance and recovers or refunds it through a volumetric charge either in rates or by way of a unit rate adjustment over a defined time period. According to the Company, the main issues around prospective clearing are the following:
>
> Inter-generational inequity. Future customers pay or benefit from the costs or savings generated by past transactions.

Market impact. By building into rates the adjustment in the cost of gas for a prior period, market signals would be distorted leading possibly to back and forth migration between rates.

Multi-Payment Option

8.7.4 This option is the institution of a series of charges rather than a one-time charge. According to the Company, the main issues around the Multi-Payment Option are the following:

Perception of retroactivity. It does not address the customers' perception of retroactivity. Also, customers will be reminded of the charge more than one time.

Delaying the full refund. Should the application of this option be symmetrical, customers would expect to receive a refund right away. If they do not, a negative view of the Company would be created.

Immediate Method - Gas Costs Adjustment Mechanism

8.7.5 The Immediate Method takes the current month's opening deferral account balance and clears it to current month customers. The process of a monthly gas cost adjustment mechanism, or GCAM, would begin with the clearance of the variances between the past month's estimated monthly PGVA balance and the Board approved monthly PGVA forecast the month following the month that service was provided. The instrument would be a unit charge, differentiated by rate class and by type of sale. For example, the PGVA variance between the actual PGVA balance at the end of October and the forecast PGVA balance underpinning the approved budget would be cleared in the November bill based upon customers' November consumption.

8.7.6 Given that final costs for a month are not available until the middle of the following month, differences between the estimated fluctuation in the PGVA and the actual fluctuation that would occur would be cleared in the following month's GCAM.

8.7.7 The Company suggested the same treatment to the HVDA on the basis that it is the only other account in which a customer's type of service, i.e, sales or T-service, affects the customer's responsibility for the account balance. To include the HVDA with the Other Accounts for prospective clearing would require different unit rates for each rate for different types of service. The only difference from the PGVA treatment would be that the actual monthly HVDA balance would be cleared on a two month lag basis. For example, the actual October HVDA balance would be cleared to customers in the month of December. According to the Company, this treatment is necessitated by the fact that energy data from TransCanada and its suppliers is not available until the middle of the month following the month in which service it provided.

8.7.8 The Company proposed to adopt the GCAM methodology, noting that this proposal would still require:

- the preparation of a forecast year-end PGVA balance and associated boundaries for Board disposition approval;
- a one-time annual "true up" adjustment would be required after the fiscal year-end to deal with various other transactions in the PGVA, such as transactions carried forward from the prior year's PGVA, refunds, inventory adjustments, and non-compliance revenues;
- the calculation of carrying charges;
- the Company's responsibility for demonstrating prudence in its gas acquisition and risk management practices; and
- the maintenance of the "trigger" mechanism but only for purposes of guiding the Company in its risk management practices.

8.7.9 The Company proposed to utilize the PGVA to record the cleared amounts and not establish a new account.

8.7.10 The Company proposed that the monthly clearing through the GCAM be made without monthly Board approvals. The Company also proposed that the monthly variance be included in the Gas Supply Charge component of the customer's bill. In the case of General Service T-Service customers, the variance would be included in the Gas Supply Load Balancing component of the rate.

8.7.11 With respect to the variances in the other deferral accounts, the Company proposed a prospective clearing due to the limited magnitude of potential variances.

8.7.12 In its original evidence, the Company proposed to introduce its new proposals in fiscal 1998. In later evidence, the Company indicated that implementation would have to be deferred to fiscal 1999 to avoid the expense of making immediate changes to CIS now, in order to accommodate GCAM, which would mean a reallocation of personnel and a delay in the full implementation of CIS.

8.7.13 The Company, therefore, requested that the Board approve in principle the GCAM proposal for introduction in November 1998; approval in principle now would allow the Company to undertake the appropriate customer communication initiatives prior to that time.

Ms. Chown's Evidence

8.7.14 Ms. Chown indicated that the result of the GCAM proposal is a series of smaller monthly adjustments; the proposal is still a retroactive mechanism. She expressed concern that the proposed approach will not reflect current market conditions. She favoured an approach where the utility would act as a competitor to an ABM with no final reconciliation at year-end.

Settlement Proposal/Positions of the Parties

8.7.15 CAC, CENGAS and Energy Probe agreed to the Company's proposal. IGUA, OCAP and Suncor/PanEnergy did not.

8.7.16 Energy Probe supported the Company's GCAM proposal. It argued that Ms. Chown's proposal would leave the utility at risk for unforecast price changes that may give the Company an incentive to over-forecast.

8.7.17 Suncor/PanEnergy argued against the requested approval "in principle" noting that:

- Such approval is not binding upon a future panel of the Board.
- The Board does not have any results of customer research.

! The mechanism is still retroactive and the Board should be provided with other prospective options to consider.

8.7.18 Suncor/PanEnergy submitted that the Company should be subjected to the discipline of the marketplace and, therefore, retroactive recovery of gas costs should be eliminated. Suncor/PanEnergy supported Ms. Chown's suggestion that the Company, as any other gas marketer, should establish a price for its system gas supply to be adjusted as needed without a true up.

8.7.19 IGUA stated that since this proposal lies outside the parameters of the test year it ought not to be considered at this time. It also disagreed with the Company that it can impose periodic charges in advance of a Board Order.

8.7.20 AMO submitted that this is not the appropriate proceeding to introduce GCAM and questioned whether this mechanism is needed or is desirable.

8.7.21 OAPPA submitted that the Company proposal is not an improvement from the status quo and is unduly complicated and confusing for the average customer. On Ms. Chown's proposal, OAPPA argued that the Company, as a regulated utility and a supplier of last resort, should not compete or be perceived to be competing with unregulated competitors. OAPPA also argued that both proposals are premature in view of the subsequent changes that may result from the Market Review. Instead, OAPPA suggested that the trigger mechanism should be lowered to $20 from the current $35.

8.7.22 The Company stated that approval in principle, sooner rather than later, would allow it integrate the GCAM customer communications and education projects with other projects and would allow the Company to prefile evidence of its efforts in the next main rates case. The Company argued that IGUA is not correct that there is a legal impediment to the implementation of GCAM. The Company noted that the true-up mechanism now exists in the Company's Equal Billing Plan. Further it noted that GCAM is in response to the Board's direction for the Company to investigate a prospective ratemaking means of clearing deferral account balances which is what GCAM is designed to be.

8.7.23 The Company argued that Suncor/PanEnergy's proposal is a radical departure from the status quo and that there is insufficient evidence before the Board to properly assess this issue. Similarly, the Company submitted that there is no evidence in this case to suggest that lowering the trigger amount to $20 would be appropriate, as suggested by OAPPA.

Board Findings

8.7.24 The Board is appreciative of the Company's quick and thorough response to the Board's request. The Board found the review of the alternatives a very useful step towards the eventual resolution of the problems associated with retroactive one-time customer charges.

8.7.25 Given that the Company is unable to implement its proposals earlier than the beginning of its 1999 fiscal year, the Board has concluded that it would be advisable to await the results of the Market Review process. The Company's proposal presupposes that the Company will play essentially the same role in the gas commodity market as it does currently. This may or may not be the case. There are certain scenarios where the GCAM may not be applicable or warranted. The Company's desire for early customer education is laudable but it may confuse rather than help should any changes to the Company's current gas commodity functions come about in the near future.

8.7.26 In view of this finding, the Board will not comment on the specifics of the Company's proposal.

8.7.27 In addition, in a future review of this issue the Board directs the Company to also address the prudence of wishing to continue to clear forecast balances in its deferral accounts rather than the actual balances that are subject to review and scrutiny during the hearing.

8.7.28 In light of the Board's deferral of the GCAM issue, the Company's communication budget could be reduced by $110,000 which, according to the evidence, would have been spent on investigating appropriate customer communication through customer focus groups. This has been reflected in the Board's overall O&M expense target reduction discussed in Chapter 4.

9. COST AWARDS AND COMPLETION OF THE PROCEEDINGS

9.1 COST AWARDS

9.1.1 Section 28 of the Ontario Energy Board Act authorizes the Board, at its discretion, to fix or tax the costs of, and incidental to, any proceeding before it. The Board addresses the awarding of costs in its Rules of Practice and Procedure ("new Rules") recently updated (February 1, 1997). Given the timing of the Company's application, the Board decided to apply the former rules ("old Rules") for purposes of this proceeding.

9.1.2 The following parties applied for an award of costs:

- OAPPA
- CAESCO
- Pollution Probe
- HVAC
- Suncor/PanEnergy
- GEC
- AMO/ECNG
- CAC
- Energy Probe
- IGUA
- OCAP
- CIPEC/Alliance

The Company's Submissions in Argument-in-Chief

9.1.3 The Company reiterated submissions made in previous proceedings that responsible interventions, either by intervenors directly representing customers, or by public interest groups who do not have a pecuniary interest in the outcome of the proceeding, should justify awards representing 100% of reasonably incurred costs. However, any interested party that pursued an issue in a manner which served only, or principally, a private interest should not be eligible for costs. In cases where issues are substantially related to commercial transactions or the environment in which these take place, and in which an intervenor's participation is principally guided by its economic interests in the outcome, a portion of the intervenor's reasonably incurred costs should be absorbed by the intervenor as a "cost of doing business".

9.1.4 The Company noted that while this proceeding is not subject to the cost provisions of the new Rules, the Board is not precluded from applying such criteria if it chooses to do so. The Company added as follows: "However, it is recognized that the Board may prefer to await the next rate case before applying these criteria, and the Company is making specific submissions in respect to certain individual intervenors, whether or not they may be viewed as having commercial interests, where it deems it appropriate to do so".

9.1.5 While not requesting cost disallowance on the following specific grounds, the Company noted that certain intervenors attended the hearing even when their issues were not being discussed. The Company singled out HVAC. The Company also named CAC for having both Counsel and its consultant attend, at numerous times, when CAC was not cross-examining.

9.1.6 The Company requested that the Board disallow HVAC's costs in pursuing the computer cost issues which, according to the Company, are beyond HVAC's obvious interest. The Company also argued that HVAC's costs related to Mr. Effron be disallowed on the basis that his evidence provided no value to the Board, particularly in light of the review conducted by Mr. Edgar who also acted on behalf of HVAC.

9.1.7 The Company argued that one-third of Ms. Chown's costs should be denied as her evidence presented opinions on a "smorgasbord" of issues which she wished to address rather than issues that her client asked her to address. In particular, the Company noted that Suncor's interest in Rates 135 and 180 is not apparent and the issue of separation of ancillary services was not an issue for this hearing.

9.1.8 With respect to Dr. Booth, the Company noted that despite the Board's stated intent not to entertain any discussion of its rate of return methodology and adjustment mechanism, both contained in the Board's guidelines, his original evidence expanded into those areas. Only after editing and removal of sections was his evidence allowed into the hearing. The Company also noted that Dr. Booth failed to restrict himself from commenting in those same areas when he appeared as a witness.

The Parties' Responses

9.1.9 IGUA submitted that the Company's criticism of intervenors who attended the hearing with counsel and their consultant is inappropriate. The process is heavily weighted in favour of the Company and if intervenors are penalized for having both counsel and consultants present, the ability of intervenors to mount any serious resistance to the Company would be seriously compromised, especially in view of Board Staff's new role.

9.1.10 ECNG/AMO submitted that there is a need to allow a fair degree of latitude in the judgement areas of a) co-attendance of counsel and consultants and b) expert evidence on areas for which the client's interest is not apparent to Consumers Gas.

9.1.11 Suncor submitted that it is entirely appropriate for Ms. Chown to make recommendations related to the range of competition issues that are of interest to her client. With the possible exception of the new Rates 135 and 180, all of the issues included in Ms. Chown's evidence are directly relevant to the clients' interests. It was stated that Ms. Chown's evidence was prepared with careful attention to the issues list and dealt with issues that are relevant for the client's concerns and to the decisions that need to be addressed by the Board in this proceeding.

9.1.12 HVAC submitted that expenditures on infrastructure other than the pipes in the ground potentially represent subsidies to the ancillary services and non-utility activities. With respect to Mr. Effron, HVAC submitted that he was specifically instructed to limit his work to review the detailed allocations, as Mr. Edgar's work would deal with the broader policy and philosophical issues.

9.1.13 As for Consumers Gas' objection to the presence of counsel other than the person conducting lead cross examination on a joint issue, HVAC submitted that each party still retains an individual intervention with its own individual interest.

9.1.14 OCAP stated that it does not intend to claim costs for the preparation of Dr. Booth's original evidence dealing with the adjustment mechanism. However, OCAP submitted that Dr. Booth's oral testimony provided important considerations to be examined and tested by the Board in determining the "going in" risk premium and was not the same evidence as the excised section of Dr. Booth's initial prefiled evidence.

Board Findings

9.1.15 The Board's comments and findings below have considered the Company's position in its argument-in-chief, the parties' responses, the Company's comments on the parties' cost statements, and the responses by certain parties to the Company's comments related to costs. The ultimate determination of cost awards will be the result of the Board's consideration of its Cost Assessment Officer's recommendations. However, in light of its review of all these submissions and its assessment of the parties' contributions to the hearing, the Board is providing certain directions to the Cost Assessment Officer as set out below.

9.1.16 The Board wishes to commend those intervenors who coordinated cross-examination which resulted in efficiencies with no perceived compromise in effectiveness. The Board encourages intervenors to continue this practice in the future.

9.1.17 The Board has noted the Company's concerns about unnecessary joint counsel/consultant attendance. In this connection, the Board is also concerned about the overall costs associated with unnecessary joint attendance by counsel and consultants or case managers, especially when the party in question is not cross-examining. The Board wishes to remind the parties that they have an obligation to schedule their attendance at the hearing responsibly. The Board expects the Company to be alert to obvious violations of this expectation and to draw those to the attention of the Board for cost award purposes.

9.1.18 Since cost awards in this proceeding are pursuant to the old Rules, the Board awards parties 100% of their reasonably incurred costs, except in the circumstances noted below.

9.1.19 The Board agrees with the Company's criticisms of HVAC's expansion of its intervention into areas which have no direct or obvious interest to this intervenor. The Board also finds that Mr. Effron's evidence was of no value to the Board, especially in view of HVAC being a co-sponsor of Mr. Edgar. The Board therefore will not accept the $14,755 direct cost claims for Mr. Effron. In recognition of time spent by HVAC's counsel and case manager for preparation, cross-examination, attendance, and argument in this area, and in respect of costs that have been incurred by others in addressing Mr. Effron's evidence, the Board directs the Cost Assessment Officer to deduct $5,000 from the ultimate cost award.

9.1.20 In the Board's view, ratepayers should not in general be burdened with an intervenor's cost in pursuing issues that are clearly beyond that intervenor's direct interest, especially given the presence of "broad interest" intervenors, such as CAC and IGUA. In the present case, the Board will not disallow cost claims associated with HVAC's counsel and case manager for the preparation, cross-examination, attendance, and argument relating to the issue of PC unit costs. The Board cautions HVAC that in future cases it should restrict its intervention to issues which are directly relevant to its membership.

9.1.21 However, the Board observes that the number of hours spent by HVAC's counsel, at 539.8 hours, is by far the highest of all intervenors despite the limited direct interest of HVAC's intervention compared with those spent by a broad interest intervenor, such as IGUA. The Board directs the Cost Assessment Officer to deduct 60% of the hours claimed by HVAC's counsel.

9.1.22 With respect to Ms. Chown, appearing on behalf of Suncor, the Board agrees with the Company's assessment. Further, Ms. Chown's prefiled material deals with issues that were not on the Issues List. While her approach to the issues of the Company's ancillary activities was clearly beyond the scope of this hearing, the Board found her oral testimony on the cost allocation issues to be of some assistance. The Board also finds that Ms. Chown's filed material was largely commentary in nature. The Board directs the Cost Assessment Officer to deduct 40% of Ms. Chown's reasonably incurred costs.

9.1.23 The Board also reduces the total claim of Suncor by an amount of $5,000 for time spent by the Company, the Board, the parties, and Suncor's counsel on the less than relevant issues raised by Ms. Chown. Further, the Board finds that the number of hours claimed by counsel for Suncor and PanEnergy, at 325.4 hours, appear particularly high in light of the settlement of the gas cost related issues which are of direct interest to these intervenors. The Board directs the Cost Assessment Officer to deduct 40% of the hours claimed by counsel for Suncor\PanEnergy.

9.1.24 The Board also agrees with the Company's assessment of Dr. Booth's participation. His original evidence dealt with issues which were not to be addressed in this proceeding. Also, the line of direct examination, and argument, by OCAP's counsel delved into these same issues. The Board noted OCAP's statement that it did not intend to claim any costs for the rejected portion of Dr. Booth's evidence; the Board, however, does not believe the submitted reduction of four hours in the 174 hours claimed, sufficiently accounts for these costs. The Board directs a further reduction of 20 hours in Dr. Booth's claimed hours. The Board also reduces this intervenor's claim by an amount of $5,000 in respect of the effort required by the Company, the Board, and the parties to deal with the rejected portion of Dr. Booth's evidence.

9.1.25 With respect to Mr. Todd's participation, the Board has difficulty appreciating how all of the issues he commented upon could not have been canvassed by OCAP's counsel with the Company's witnesses and addressed in argument. The Board therefore denies 20% of Mr. Todd's reasonably incurred costs and cautions OCAP that this level of disallowance may be higher in the future, should such a practice persist.

9.1.26 Finally, the Board finds that it received limited assistance from OCAP's counsel in clarifying a number of issues. In this connection, the Board directs the Cost Assessment Officer to deduct 10% of the hours claimed by OCAP's counsel.

9.1.27 The Board also finds that the costs claimed by GEC, OAPPA, AMO/ECNG, and CIPEC/Alliance are high in view of their single issue or limited issues interventions. The Board directs the Cost Assessment Officer to deduct 20% of the hours claimed by counsel to GEC, AMO/ECNG and CIPEC/Alliance, and 20% of the hours claimed by consultants to OAPPA.

9.1.28 The Board directs the Cost Assessment Officer not to apply the above reductions to the parties' out-of-pocket expenses. Such expenses should be scrutinized in the normal manner.

9.1.29 The Board expects the Cost Assessment Officer to confirm that the individuals characterized as case managers by certain intervenors are not employees of the intervening organization.

9.1.30 The Board has also noted that certain parties' claimed legal fees and certain other disbursements exceed the Board's guidelines. The Board anticipates that these will be adjusted accordingly by the Cost Assessment Officer.

9.1.31 The Board directs the Company to pay the amounts of the intervenor cost awards immediately upon receipt of the Board's Cost Orders.

9.1.32 The Board further directs the Company to pay the Board's costs of, and incidental to, this proceeding, immediately upon receipt of the Board's invoice.

9.1.33 In Chapter 4 of this Decision, the Board noted that the total costs claimed by intervenors are about the same as costs included in the Company's budget. The Board estimates that its findings will result in a reduction of not less than 20% from the requested amount.

9.2 COMPLETION OF THE PROCEEDINGS

General Matters

9.2.1 The comments below are directed towards the Company and are intended to assist the Board and the participants in future proceedings.

9.2.2 To the extent possible and practical, the Company should include in its direct (textual) evidence the quantification of the impact on customer classes of significant proposed cost allocation and rate design changes.

9.2.3 The Company should date any evidence it files after its original prefiled evidence.

9.2.4 Where impact statements are filed to indicate necessary adjustments to rate base or Utility Income, the Board would be assisted if such adjustments corresponded to the presentation of the financial schedules normally appended by the Board to its Decision. For example, the rate base adjustments provided in the Settlement Proposal in regard to the possible removal of the $10.9 million capital expenditures relating to the E.B.O. 188 ADR Agreement, were provided on a net basis rather than shown as gross plant and accumulated depreciation.

Revenue Requirement and Draft Rate Order

9.2.5 The rates currently in effect are those approved by the Board in its E.B.R.O. 492-02 Order. Based on these rates, the Board finds an overall revenue deficiency of $20 million, as shown in Appendix D [Determination of Revenue Excess/(Deficiency)] and supported by Appendix A [Rate Base], Appendix B [Utility Income], and Appendix C [Capitalization/Cost of Capital].

9.2.6 Shifts of revenue responsibility were not specifically mentioned on the Issues List. However, revenue shifts are part of allocating revenue deficiencies or excesses, aimed at arriving at reasonable revenue to cost ratios for rate classes. Based on the Company's final proposals, the amounts of $1.5 million, $2.5 million, and $3.0 million were removed from the revenue responsibility of Rates 6, 110, and 115 respectively. The revenue responsibility of Rate 01 was increased by the corresponding amount of

$7.0 million. The Company is directed to identify in its Draft Rate Order any revenue shifts as a result of the Board's adjusted revenue requirement.

9.2.7 The Board directs that the new rates be effective October 1, 1997. The Board expects the Company to implement the new rates on the same date.

9.2.8 The Company is directed to submit to the Board, within 15 business days of the date of release of this Decision, a Draft Rate Order to be accompanied by the following:

i) proposed final rate schedules with appropriate supporting documentation, incorporating the Board's findings;
ii) updated deferral account balances and interest calculations;
iii) draft accounting orders and entries for the new and continuing Board-authorized deferral accounts, along with accounting entries for interest;
iv) a summary of the Board's directives found in this Decision pertaining to future rate filings; and
v) drafts of the proposed notices to customers which shall accompany the first customer bill following the implementation date of the new rates.

DATED AT Toronto August 21, 1997.

P. Vlahos
Presiding Member

E.J. Robertson
Member

H.G. Morrison
Member