E.B.R.O. 499

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

AND IN THE MATTER OF an Application by Union Gas Limited for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution and transmission and storage of gas for its 1999 fiscal year.

BEFORE: R.M.R. Higgin
Presiding Member

H.G. Morrison
Member

P. Vlahos
Member

DECISION WITH REASONS

January 20, 1999

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APPENDICES TO THE BOARD'S DECISION

1. THE APPLICATION AND THE PROCEEDING

1.1 THE APPLICATION

1.1.1 Union Gas Limited ("Union" or "the Company" or "the Utility") filed an application with the Ontario Energy Board ("OEB" or "the Board") on May 8, 1998 for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, storage and transmission of gas ("the Application"). The proposed rates and other charges are based on projected results for the test year commencing January 1, 1999 and ending December 31, 1999. The Board assigned file number E.B.R.O. 499 to the Application.

1.1.2 In E.B.O. 177-17, Union had applied to the Board for approval of an affiliate transaction to transfer its sales, financing, rental and servicing of natural gas appliances to a non-subsidiary affiliate, Union Energy Inc. ("Union Energy"). The E.B.O. 177-17 Decision was issued on May 28, 1998.

1.1.3 In the Application Union also sought a number of other approvals including:

- Approval of the capital structure of the Utility after the separation of the ancillary program assets.
- Certain transactions with affiliated companies under the provisions of Article 6.1 of the Undertakings of the Company and its shareholders to

the Lieutenant Governor in Council ("the Undertakings") dated December 16, 1992, as amended in 1995 and 1996.

- The use of the shared services allocation methodology proposed by Union in E.B.O. 177-17 for non-utility transactions and services provided to affiliated companies.

- A sharing mechanism for margins from Union's storage and transportation transactional services.

- Treatment of the premium earned from long-term storage contracts sold under market based rates.

- The disposition of Deferral Account balances.

1.1.4 The former Union and Centra Gas Ontario Inc. ("Centra") were amalgamated effective January 1, 1998 and continue operations under the 'Union' name. In the evidence regarding the bridge and test years, the former Union franchise area is referred to as the Southern operations area and the former Centra franchise area is referred to as the Northern and Eastern operations area.

1.2 THE PROCEEDING

1.2.1 The Board issued a Notice of Application dated June 12, 1998 and Procedural Order No. 1 on July 31, 1998. An Issues Day was held on August 12, 1998, and the Board subsequently approved the Issues List and set out various directions relating to the proceeding in Procedural Order No. 2 dated August 14, 1998. A Technical Conference was held on September 22, 1998.

1.2.2 A Settlement Conference was held by the parties from October 26, 1998 to November 6, 1998. The proposed Settlement Agreement was filed with the Board on November 16, 1998 and is included as Appendix B to this Decision (due to printing limitations certain appendices are not included). An errata sheet to the Settlement Agreement is shown as Appendix C to this Decision.

1.2.3 At the commencement of the oral hearing the Board informed parties that it accepted the Settlement Agreement as a package subject to updates, changes necessary as a result of the Board's decision on unsettled matters, or as a result of significant external events.

1.2.4 The oral hearing of the remaining issues commenced on November 30, 1998 and lasted until December 3, 1998. Union's argument in chief was delivered orally on December 4, 1998 and intervenor arguments were filed by December 15, 1998. Reply argument was filed on December 21, 1998.

Participants

1.2.5 Below is a list of parties, including the Company, and their representatives who participated actively in the Settlement Conference and/or by cross-examining or filing argument.

Union	Michael Penny Glen Leslie
Board Technical Staff	Jennifer Lea
Alliance of Manufacturers and Exporters Canada ("AMEC")	Beth Symes
The Corporation of the City of Kitchener ("Kitchener")	Alick Ryder
Consumers' Association of Canada ("CAC")	Robert Warren
Industrial Gas Users Association ("IGUA")	Peter Thompson
Ontario Association of Physical Plant Administrators ("OAPPA")	Michael Morrison
Alliance Gas Management Inc. ("Alliance")	Brian Dingwall
CENGAS	Richard Perdue
Coalition for Efficient Energy Distribution ("CEED")	George Vegh

Comsatec Inc. (“Comsatec”)	David Waque
NOVA Chemicals (Canada) Ltd. ("NOVA")	Michael Peterson
Pollution Probe Foundation (“Pollution Probe”)	Murray Klippenstein
Green Energy Coalition (“GEC”)	David Poch
HVAC Coalition ("HVAC")	Ian Mondrow
Ontario Coalition Against Poverty ("OCAP")	Michael Janigan
Ontario Hydro	William Harper
Enbridge Consumers Gas Ltd. ("Enbridge Consumers Gas")	Fred Cass
TransCanada PipeLines Limited ("TCPL") and TransCanada Power (“TCP”)	Paul Jeffrey
The London Board of Education Gas Purchase Consortium and the Ontario Association of School Business Officials (the “Consortium")	Tom Brett
Canadian Association of Energy Service Companies of Ontario ("CAESCO")	Mark Anshan
Energy Probe Foundation (“Energy Probe”)	Mark Mattson
Natural Resource Gas Limited (“NRG”) Northland Power ("Northland"), The Wholesale Gas Service Purchasers Group ("WGSPG") and Tractebel Power Inc.	Peter Budd
Société en Commandite Gaz Métropolitain ("Gaz Metropolitain”)	Michael Peterson
The Association of Municipalities of Ontario ("AMO"), ECNG Inc. ("ECNG")	Peter Scully
Consumersfirst Ltd. ("Consumersfirst")	David Purdy

Witnesses

1.2.6 The following Union employees appeared on behalf of the Applicant:

Richard Birmingham	Vice-President, Regulatory Affairs
James Brown	Manager, Control Systems
Lynn Galbraith	Manager, Marketing Sales
William James	Manager, Storage Development
Mark Kitchen	Manager, Cost of Service
Michael Packer	Manager, Rates and Cost of Service
Harold Pankrac	Manager, Rate Design
Steve Poredos	Manager, Integrated Supply and Transportation Planning
Paul Shervill	Director, Distribution Marketing
Dave Simpson	Manager, Industrial Market Planning

1.2.7 In addition, Union called the following witnesses:

Matthew R. Harrison	Business Unit Manager Radian International LLC
Jeffry L. Fink	Harrington & Hrehor Energy Consulting Group, LP

1.2.8 TransCanada Power called the following witness:

Steven Jakymiw	Principal, Steven Jakymiw and Associates

1.2.9 Other evidence was filed on behalf of the Company and other parties, but it was not necessary for the witnesses for these parties to appear at the oral hearing. This evidence was attested to by written affidavits.

1.2.10 Letters of comment were received from twelve parties. Some of these letters expressed general concerns about a possible rate increase, while others dealt with specific Company policies and practices.

1.2.11 The Board has considered all the evidence and argument in the proceeding, but has referenced these only to the extent necessary to provide background to its specific findings. The full record of the proceeding is available for review at the Board's offices.

2. REVENUE REQUIREMENT AND OTHER MATTERS

2.0.1 In the Settlement Agreement, which was accepted by the Board, all matters related to the Company's revenue requirement for the 1999 test year were settled, except for two issues advanced by Pollution Probe. One other non-settled Phase I issue, which does not affect the 1999 revenue requirement, was approval of an appropriate code of conduct for the Company's new distribution business.

2.0.2 The Settlement Agreement included the disposition of 1998 balances in the Company's deferral/variance accounts including some new accounts for which separate applications were made to the Board, but for which accounting orders were not issued by the completion of the oral hearing. Also contained in the Settlement Agreement was the acceptance of Company requests for affiliate transactions.

2.0.3 During the hearing the Company filed an application, under Board file E.B.R.O. 499-01, for a gas cost adjustment effective January 1, 1999 under its Quarterly Rate Adjustment Mechanism ("QRAM"). This application was approved and a Board Rate Order issued on December 10, 1998.

2.0.4 This Chapter addresses the non-settled matters described above as well as the implications of the E.B.R.O. 499-01 Rate Order for the 1999 revenue requirement. requested gas costs adjustment.

2.1 THIRD PARTY ON-BILL FINANCING AND FIREPLACE EFFICIENCY

2.1.1 Pollution Probe contended that the Company had not lived up to agreements made by its predecessor companies in previous Alternative Dispute Resolution ("ADR") Settlement Agreements with respect to facilitating the provision of on-bill financing for purchases of natural gas appliances and equipment by end use customers. Pollution Probe also contended that the Company had failed to adequately implement Board directions in E.B.R.O. 493/494 to develop and implement a consumer information and marketing plan for "higher efficiency" fireplaces. Pollution Probe, supported by GEC, proposed that the Company be subject to a sanction in the form of a Board imposed financial penalty for its alleged failures in these respects.

Third Party On-Bill Financing

2.1.2 In E.B.R.O. 483/484, Centra agreed to make a "best efforts attempt to enter into a cooperative arrangement with a third party financial institution to facilitate the financing, in 1994, of natural gas appliances and/or equipment by its end use customers at interest rates as low as possible". Centra's Request for Tender for the financing was to be provided to parties in the Demand Side Management ("DSM") consultative process, and any final proposal was to be reviewed with the consultative group.

2.1.3 In E.B.R.O. 489, Centra argued that while it had devoted considerable effort to pursuing third party financing, technical problems relating to the inclusion of finance charges on customers' gas bills had not been resolved. A year later, in E.B.R.O. 493/494, the Companies' evidence indicated a lack of interest on the part of third party financial institutions to undertake the proposed service, and continuing technical problems relating to billing. The Board was unconvinced that there were major technical obstacles, and directed the Companies to "file complete evidence on their ability to provide on bill invoicing for third parties and the costs to upgrade the Customer Information System ("CIS") to provide this capability, in the next rates case".

2.1.4 The Company noted that it had tendered evidence in E.B.O. 177-17 in which it stated that, since billing was not a service which the utility could offer competitively in the longer term, and as incremental investment in infrastructure would be required to attain the billing capability, the Utility did not plan to pursue this line of business. The Company further noted that none of the Board's conditions of approval of the separation of ancillary businesses in that case dealt with the issue of third party financing. It was the Company's position that it had complied with the Board's directive by filing evidence on the matter in E.B.O. 177-17 and, in any event, given the fact that Union will no longer carry on the business of merchandise sales or financing, it makes no sense for it to offer third party billing services for such activities. Further, Union agreed with the position advanced by AMEC that the Board does not possess the jurisdiction to impose a penalty of the nature requested by Pollution Probe and GEC.

2.1.5 The Board finds that the Company has adequately responded to the Board's directives on this issue since the Company will no longer be in the business of merchandise sales and financing. The Board accepts the Company's plan not to pursue on-bill third party financing and billing services.

Fireplace Efficiency Information Program

2.1.6 In its E.B.R.O. 493/494 Decision, the Board directed the Companies to "develop and implement a consumer information and marketing plan for 'higher efficiency' fireplaces and to report on this in their next rates cases". Costs of the plan were to be part of the budget for fireplace sales and promotion for 1997. The Company filed evidence that it had developed such a customer information and marketing plan and that information was sent to customers in August 1997. Additional information would be circulated again in 1998 and 1999.

2.1.7 The Company's witnesses were questioned by Pollution Probe about the content of the 1997 customer information brochure on fireplaces. The focus of cross examination was whether the messages in the brochure promoted fireplace purchases, rather than fireplace efficiency and, in particular, why customers had to mail in requests for efficiency information and wait up to four weeks for a reply, when they could contact the Company and arrange for immediate fireplace purchase and installation. Union defended its approach and also provided information which indicated that higher efficiency fireplaces were not cost effective from a societal cost perspective and hence did not meet the criteria for promotion under the Company's DSM program.

2.1.8 The Company also submitted that it has been participating with government and other industry members in the development of efficiency measures under the Energuide labeling program. Union is also participating in the development of fireplace efficiency test protocols by a Canadian Gas Association committee, which will form the basis of the final P4(1) efficiency standard. Once the [federal] government regulation establishing an efficiency standard for fireplaces has been promulgated, the labeling process will be implemented, likely within 18 months. In the Company's view, it has responded adequately to the Board's directive and no further action is required.

2.1.9 Pollution Probe submitted that the Company's 1997 fireplace information program and its plans for 1998 and 1999 were inadequate, pointing to the Company's own estimate that out of 15,000 fireplace sales, only 100 customers would purchase a higher efficiency fireplace as a result of the program. Pollution Probe urged the Board to direct the Company to develop a more aggressive program for 1999.

2.1.10 GEC supported Pollution Probe. Some other parties provided brief submissions that supported the Company's position.

2.1.11 The Board's expanded mandate under the *Ontario Energy Board Act, 1998* ("the OEB Act 1998" or "the new Act") as indicated in the Purpose section, includes facilitation of energy efficiency. The Board finds that the accessability of gas appliance efficiency information needs to be improved and as long as the Company includes promotion of gas appliances in its advertising paid for out of the cost of service, it must play a direct role in disseminating information on, and promoting, energy efficient choices. The alternative is to disallow the recovery of the cost of such Company promotions and leave it to governments, manufacturers, Union Energy and other energy service providers to bear these costs.

2.1.12 Given that the Company proposes a new brochure on fireplaces in 1999, the Board expects this to contain greater promotion of fireplace efficiency and reference to the recent regulation under the [Ontario] *Energy Efficiency Act* and the future Energuide labeling program. In addition the Company's Call Centre should be able to respond directly to requests for efficiency information resulting from the promotion. The Board requests the Company to file a copy of the information program plan with the Board as soon as it is available.

2.2 INTERIM LDC CODE OF CONDUCT

2.2.1 Union's Interim LDC Code of Conduct ("Code") was adopted following a hearing in conjunction with Enbridge Consumers Gas under Board file E.B.R.O. 492-03/493-03/494-04. The Code was designed to govern the Company's conduct in providing utility services to parties, including affiliates, engaged in commodity gas marketing activities. In E.B.O. 177-17 the Company proposed new Standards of Business Practice designed to govern its practices in dealing with retail energy service providers who are not direct customers of utility services. Having concluded that there is potential confusion from having two different documents, the Board directed Union to file an Interim LDC Code of Conduct ("amended Code") incorporating in two sections the original Code related to gas marketers and the new standards of business practice related to affiliate and non-affiliate service providers.

2.2.2 In the E.B.O. 177-17 Decision, dated May 28, 1998, the Board approved Union's application to separate and sell the assets of its ancillary business to Union Energy, an affiliate, effective January 1, 1999. As part of its approval of the affiliate transaction, the Board set out certain conditions to be satisfied by the Company, including the filing of an amended Code.

2.2.3 Union filed an amended Code in this proceeding but, other than certain revisions agreed to and reflected in a revised amended Code which was filed as Appendix K to the Settlement Agreement, there was no agreement to settle this matter in its entirety. It was agreed at the outset of the hearing that the issue would be dealt with through argument only. The Board also requested parties to make submissions as to whether the revised amended Code in Appendix K to the Settlement Agreement should be adopted, pending development of new codes under the Board's rulemaking powers set out in section 44 of the new Act or, alternatively, what regime should prevail in the interregnum.

2.2.4 Having reviewed parties' arguments, the Board notes the prime concern is one of "urgency" to put in place a "strict" code of conduct pending exercise of the Board's new rulemaking powers under the new Act. The perceived urgency arose from the Board's authorization for Union to transfer its ancillary businesses to its affiliate as of January 1, 1999. The question of a strict standard relates to whether the stricter standards of separation and relationship advertising, which are part of the LDC Code relating to gas marketers, would apply to Union Energy which is both a gas marketer and retail energy service provider.

2.2.5 The Board finds that the proper regulatory approach is to develop a new code or codes under the rulemaking provisions of section 44 of the new Act to cover the matters dealt with in the amended Code, which now incorporates proposed standards of business practice. The Board notes that the original Code governing relationships with gas marketers was developed by a comprehensive process involving an ADR settlement conference and hearing, whereas the Standards of Business Practice occupied only a small part of the E.B.O. 177-17 separation hearing and hence have had a much more cursory review. In addition, Enbridge Consumers Gas was not prepared to make submissions on the content of an amended Code in this proceeding, since it is an issue for the E.B.O. 179-14/15 proceeding which deals with an application by Enbridge Consumers Gas to separate certain ancillary activities from the regulated utility.

2.2.6 The Board also notes that the Company's Undertakings have recently been amended to become effective on April 1, 1999 and therefore the status of both the original Code and amended Code after that date is unclear. The new undertakings prohibit the regulated utility from carrying on businesses, other than the utility business, without prior approval of the Board, except through affiliates as defined in the *Business Corporations Act.* These undertakings imply a certain standard of separation.

2.2.7 The Board finds that these matters need careful consideration and a common approach with Enbridge Consumers Gas. The Board therefore approves the Interim LDC Code of Conduct, incorporating standards of business practice as set out in Appendix K of the Settlement Agreement, with the revisions agreed to and shown in that Appendix. In doing so, the Board relies on the Company's statements in argument in this proceeding to the effect that the Company's relationship with Union Energy or with any other entity that is <u>both</u> a gas marketer and an energy service provider will be governed by the standards in the gas marketers section (Section 1) where applicable, and not parsed according to the discrete activities within that entity. The Board expects the Company to adhere to the revised amended Code in satisfying the Board's condition of approval of the separation transaction in E.B.O. 177-17, unless and until it is superceded by rules made pursuant to section 44 of the new Act.

2.3 DEFERRAL/VARIANCE ACCOUNTS

2.3.1 As part of the Settlement Agreement the parties settled all of the issues pertaining to the Company's deferral/variance accounts. In Appendix H of the Settlement Agreement (Appendix B to this Decision), the deferral/variance account summary includes a number of accounts which had yet to be established at the time the Settlement Agreement was filed. The Company's requests for establishing these accounts were made in separate applications. Some of these requests were referred to the E.B.R.O. 499 proceeding, others were still outstanding at the time of filing of the Settlement Agreement. By accepting the disposition of the forecast balances in these accounts as set out in the Settlement Agreement, the Board in effect has authorized the establishment of these accounts. The Board understands that separate authorization letters have now been issued for all of the outstanding applications.

2.3.2 Appendix H to the Settlement Agreement showed a net credit balance of all deferral/variance accounts in the amount of $78 million. The Board notes that the Company updated the forecast balances in its gas related deferral accounts during the hearing. This update, together with a change to the balance associated with storage cost accounting, resulted in a revised total net credit balance of $61 million. The Board expects the Company to further update the balances in the deferral/variance accounts to reflect the December 31, 1998 actual balances for disposition through a one-time adjustment to customer bills. This information should be provided as part of the Company's Draft Rate Order.

Tax Assessment Change

2.3.3 By letter dated November 27, 1998, Union notified the Board of a change in Revenue Canada's assessment in respect of the tax treatment of Administrative and General Overheads effective January 1, 1997. Union is now able to claim a current deduction for these costs whereas previously these costs were capitalized. The 1999 impact (tax savings of $11.3 million on a pre-tax basis) of this change was reflected by the Company in its updated revenue requirement. With respect to the impact on the Utility's cost of service, excluding ancillary activities, for fiscal years 1997 and 1998, Union requested that a deferral account be established. Upon Board questioning regarding the disposition of such amounts during the hearing, the Company requested that the disposition of these amounts be deferred to a future proceeding.

2.3.4 The Board notes that Union's request for approval to capture the 1997 and 1998 utility tax rebate savings, with interest, in a deferral account has been authorized by the Board by letter dated January 19, 1999. The Board finds that the disposition of the balance in the account shall be deferred until the parties have the opportunity to review this matter in a future proceeding.

2.4 AFFILIATE TRANSACTIONS

2.4.1 Affiliate transactions are governed by the Undertakings given by the Company to the Ontario Government. The Company has entered into arrangements for the provision of services to and from certain affiliates which will continue into, or commence in, the test year. In response to a Board request regarding the affiliate transactions agreed to in the Settlement Agreement, the Company provided a list of the affiliate transactions requiring specific Board approval under the Undertakings. This list and the associated amounts are appended to the Company's response document and included as Appendix D to this Decision.

2.4.2 Specifically, with respect to the $6.9 million proposed payment to Enlogix CIS Inc., pursuant to the Board's direction in E.B.O. 177-15, the Board received a letter dated December 4, 1998 from the Board's Energy Returns Officer. The letter confirms that the CIS activities forecast for 1999 totals $6.9 million as submitted in evidence in the E.B.R.O. 499 proceeding.

2.4.3 By accepting the revenue requirement aspects of the Settlement Agreement, the Board has in effect authorized the relevant affiliate transactions.

2.4.4 As noted earlier, on December 9, 1998, after the close of the hearing, the Company's Undertakings were amended to become effective on April 1, 1999. The new undertakings do not require the Company to obtain prior Board approval for most affiliate transactions. Under the new Act, the Board may make rules governing the conduct of gas distributors as such conduct relates to affiliates. As requested in the Application, the Board grants approval for all affiliate transactions resulting from the Settlement Agreement, as set out in Appendix D to this Decision, for the period January 1, 1999 to March 31, 1999 during which the current Undertakings apply.

2.4.5 The Board directs the Company to formally request, in accordance with the new undertakings, the Board's approval to carry on any business activity other than the transmission, distribution or storage of gas from April 1, 1999 to the end of fiscal 1999. The Board also directs the Company to seek the Board's direction regarding the longer term operation of non core businesses prior to fiscal year 2000.

2.5 REVENUE REQUIREMENT

2.5.1 Subsequent to filing the Settlement Agreement, the Company updated the Utility's revenue requirement calculations appended to the Settlement Agreement to reflect a number of changes as shown in the financial schedules in Appendix A. These changes are: a lower final cost of common equity; a lower cost of preference capital; lower costs due to a different treatment of storage accounting; and lower income taxes payable due to changes to Revenue Canada's assessment of capitalized Administrative & General Overheads.

2.5.2 The Board confirms its acceptance of the 1999 test year cost consequences of settled issues and subsequent changes as they are reflected in the revenue requirement encompassed in the financial schedules presented in Appendix A in this Decision. The Board finds a rate base of $2,705.848 million for the 1999 test year and a revenue sufficiency of $85.076 million as shown in Appendix A. The above sufficiency is based on the final calculation of the rate of return on common equity as agreed in the Settlement Agreement. This yielded a return of 9.61% (395 basis points over the forecast 5.66% yield for 30 year long Canada bonds) which was determined on the basis of the Board's *Draft Guidelines on a Formula Based Return on Common Equity for Regulated Utilities*.

2.5.3 However, the revenue sufficiency of $85.076 million will be reduced as a result of the Board's E.B.R.O. 499-01 Rate Order issued on December 10, 1998 that approved new rates effective January 1, 1999 to reflect higher forecast gas costs pursuant to the Company's Quarterly Rate Adjustment Mechanism ("QRAM"). The cost of gas forecast approved by the Board in the E.B.R.O. 499-01 Rate Order reflected an Alberta border Weighted Average Cost of Gas ("WACOG") of $2.50/GJ compared to $2.28/GJ in the Company's filing in E.B.R.O. 499. This resulted in a cost of gas expense increase of $38.9 million. However, the forecast 1999 gas sales revenue increase accepted by the Board is lower than the gas expense increase. This is because the rate changes approved in E.B.R.O. 499-01 were based on the then current rate schedules which reflected a WACOG of $2.33/GJ. The Board estimates that after incorporating the financial consequences of the E.B.R.O. 499-01 Rate Order, the overall revenue sufficiency for 1999 will be approximately $71 million.

2.5.4 The Board directs the Company to file as part of its Draft Rate Order the precise calculation, with supporting schedules, of the revenue sufficiency to be applied to the E.B.R.O. 499-01 rates.

3. COST ALLOCATION AND RATE DESIGN

3.0.1 A significant number of cost allocation and rate design issues were the subject of a complete settlement as reflected in the Settlement Agreement. Other issues were the subject of a partial settlement and ongoing discussions between the parties during the hearing. The remaining issues were unsettled and were heard in full in the oral hearing phase and were also the subject of argument.

3.0.2 This Chapter addresses cost allocation and rate design issues which were not settled.

3.1 COST ALLOCATION

3.1.1 The following cost allocation issues were the subject of a complete settlement among the parties to the Settlement Agreement:

- separation of merged costs by operational area:
  - O&M expense allocation,
  - merger of cost allocation studies;
- allocation of Winter Peaking Service costs to storage;
- proposed changes to the delivery commitment credit;
- proposed deferred tax draw down;
- the impact of the separation of ancillary businesses;
- the allocation of DSM costs for the southern operations area;
- northern and eastern operations area storage and transmission costs;

- allocation of storage costs to northern and eastern operations area;
- allocation of unaccounted for gas in the northern and eastern operations area; and
- functionalization of heavy equipment and capital leases.

Descriptions of the settlement of these issues can be found in Appendix B.

3.1.2 The non-settled issues discussed below include certain issues upon which the Company and involved parties continued their discussions and agreed either to a process for resolution without resort to the hearing and Board decision, or that the Company's evidence was adequate and they would proceed to argue their positions and have the Board make a determination.

Allocation of Dawn Compressor Carrying Costs

3.1.3 In accordance with the Board's directive in the E.B.R.O. 493/494 Decision, Union examined the allocation of Dawn Compressor carrying costs to define the design day compression requirements for storage and transmission services including those for Tecumseh Gas Storage. Subsequent to this study, Union proposed to continue its current methodology of functionalizing compressor carrying costs to storage based on the horsepower required to raise the pressure of gas up to 700 psi on design day and to transmission based on the horsepower required to raise the pressure of gas from 700 psi to 895 psi on design day. The proposed allocation of Dawn Compressor carrying costs for the 1999 test year is shown in the Table below.

Customer Group	Storage %	D-T Transmission %	Ojibway/St Clair %	Total %
In-Franchise Southern	27.2	8.0	3.3	38.5
In-Franchise N&E	1.2	1.3	0.3	2.8
M12 Rate Class	13.6	39.7	0.0	53.3
M16 [CanEnerco]	0.0	0.0	0.1	0.1
C1 Rate Class	3.5	0.0	1.8	5.3
Total	**45.5**	**49.0**	**5.5**	**100.0**

3.1.4 Union's conclusion that the existing methodology is appropriate is based on the following:

- the separation point of 700 psi used to determine whether compression is storage related or transmission related is consistent with the pressure of gas received from connected pipelines; and

- it is not possible to specifically assign compressors to storage or transmission services due to the interchangeability of compressors at Dawn, and the use of compressors at Dawn for both transmission and storage purposes.

3.1.5 TCPL asked extensive interrogatories of the Company on this matter and, pending a response to these, declined to accept the proposed settlement of this issue. In the oral hearing Union and TCPL advised the Board that they had agreed to pursue the matter outside of the E.B.R.O. 499 proceeding.

3.1.6 The Board accepts the Company's evidence on this issue and finds that there shall be no change in the proposed allocation of the Dawn Compressor carrying costs for the test year.

Rate M9 and Rate T3 Matters

Rate M9 Advertising Costs

3.1.7 Union incurs advertising costs to develop new business and to promote the use of natural gas. Union's (Southern operations area) existing cost allocation methodology classifies 50% of the forecast advertising expenditures as customer-related and 50% as commodity-related. In recognition of the fact that the utilities being served under Rate M9 incur their own advertising costs, no customer-related advertising costs are allocated to the Rate M9 class for 1999. However, the M9 rate class has been allocated $20,000 in commodity-related advertising costs in recognition of the generic benefit provided to M9 customers resulting from Union's natural gas promotion.

3.1.8 WGSPG and NRG opposed the allocation of advertising costs and related sales promotion supervision costs to Rate M9 as proposed by Union. They submitted that advertising costs and related sales promotion supervision costs should all be classified as customer-related and hence should not be allocated to Rate M9. In support of their position they pointed out that it was the practice in the Northern and Eastern operations area to classify advertising costs as customer-related.

3.1.9 Union in reply noted that NRG had made similar submissions in E.B.R.O. 493/494 and that the Board had found that distribution-related (commodity) sales promotion costs should be allocated to Rate M9. Union submitted that there has been no change in the service provided to Rate M9 customers and a portion of advertising and sales promotion costs should continue to be allocated to the M9 rate class.

3.1.10 The Board finds no new evidence that would justify changing its decision on this matter from that taken in E.B.R.O. 493/494. Accordingly, the cost allocation proposed by Union shall continue for the 1999 test year. The Board notes the different approach used to classify advertising costs for the Northern and Eastern operations area and directs the Company to address this matter as part of its rate harmonization initiative.

Access and Costs of Rate T3

3.1.11 Rate T3 is the companion unbundled service to Rate M9. There are currently no customers taking service under the T3 rate schedule.

3.1.12 The matter at issue involved the principles to be followed when customers receiving Rate M9 bundled service move to unbundled service under Rate T3 and also the allocation of costs to Rate T3 which are reflected in the customer charge.

3.1.13 Although there was no settlement of this issue, Kitchener and Union continued discussions and agreed to make submissions on any outstanding aspects in the argument phase of the hearing.

3.1.14 The Board notes Kitchener's argument that Union's costs would be reduced if a customer moved to unbundled T-service and, accordingly, the customer charge for unbundled service under Rate T3 is too high. Union's position is that the costs of serving a customer do not necessarily diminish if a customer elects to take unbundled services and thus the Rate T3 customer charge is appropriate.

3.1.15 Kitchener observed that the issue of access to T3 service may be the subject of a section 39(2) application under the new Act. The Board does not understand Kitchener's request for direction on this matter and agrees with Union's position that the current rates case, rather than a section 39(2) proceeding, is the correct forum for a review.

3.1.16 It is unfortunate that Kitchener and Union did not reach a clear understanding on these matters. The Board has no evidentiary basis on which to modify the customer charge. Accordingly the cost allocation and rate design for Rate T3 as proposed by Union is approved for the test year.

Southern Operations Area Distribution Capacity Cost Allocation

3.1.17 Union proposes to change the allocation of capacity-related distribution costs in the Southern operations area from an allocation to rate classes based on the peak demand of all customers, including those customers who are served directly from transmission facilities, to an allocation to rate classes in proportion to the demands of only those customers served using distribution facilities. The proposed change would result in a shift of approximately $6.8 million of costs from contract customers to Rate M2 customers.

3.1.18 The Company noted that:

- customers in a rate class who are served directly off transmission lines do not cause Union to incur any distribution capacity related costs, and the cost allocation study should reflect this lack of causation;
- the proposal is consistent with the allocation of sole use main costs to rate classes in the Northern and Eastern operations area; and

- the allocation has "good" cost causality.

3.1.19 The Board rejected an identical proposal in its decision in E.B.R.O. 493/494 on the grounds that, to the extent that a rate class is predominantly served through transmission capacity, the proposal could result in an inappropriate level of avoidance of distribution capacity costs. The Board also noted in E.B.R.O. 493/494 Union's evidence that the reversal of the proposed cost allocation change would have no impact on 1997 rates.

3.1.20 Union's evidence in this proceeding was that although it reversed the distribution capacity cost allocation as a result of the Board's rejection of the Company's proposal, it allowed revenue to cost ratios to change rather than adjusting rates. In this regard the Company's witness stated that although the Board's decision was reflected in the final cost allocation for 1997, rates for M2 and M4 customers did not decrease and rates for classes served predominantly by transmission capacity did not increase.

3.1.21 According to Union, the reason a rate adjustment was not deemed necessary related in part to a coincident change in the bypass rate for Terra International Canada Inc. ("Terra") which occurred in 1997 and to the fact that the Company interpreted another Board finding as allowing no rate adjustment as a result of the rejected distribution capacity cost allocation change.

3.1.22 Union's evidence was that in the last rates case it had identified that, prior to 1997, while Terra was on a special bypass rate, there were capacity costs allocated to Terra that were not being recovered and as a result revenue for other classes was increased. When Terra moved onto Rate T1 for 1997, these costs were now being recovered and not charged to other classes. This change was coincident with the (rejected) cost allocation which therefore, in the Company's submission, did not require a further rate adjustment.

3.1.23 At paragraph 9.15.11 of the Board's E.B.R.O. 493/494 Decision, the Board found that "... to the extent that the Company's proposed cost allocation changes were not reflected in the Company's proposed 1997 rates and these changes were approved by the Board, the Board understands that the Company will not reflect these cost allocation changes in 1997 rates". The Company stated in this proceeding that it had interpreted this finding as supporting a decision not to adjust rates on account of the Board's rejection of the distribution capacity cost allocation proposal.

3.1.24 A significant issue for OCAP and CAC was whether rates for small volume customers were too high because the reduction in allocated distribution capacity costs was not reflected in lower rates during 1997 and 1998. The Company explained that the 1997 revenue to cost ratios were in accordance with the Board's directions and since rates would not have increased if the cost allocation proposal was accepted, the decision to maintain rate levels was appropriate.

3.1.25 The Board notes that intervenors representing small volume customers opposed the change in distribution capacity cost allocation. They noted that if the Company's proposed change is rejected again, revenue to cost ratios should be adjusted; otherwise rates may be too high. Opposition was also based on perceived differences between the configuration of the service mains in Union's Northern and Southern operations areas respectively and the contention that Union cannot clearly separate transmission from distribution facilities on its system. There was also concern that the main beneficiary of the proposed change would be the Rate T1 class that already has a revenue to cost ratio of 0.93.

3.1.26 As in E.B.R.O. 493/494, submissions by intervenors representing the interests of large volume customers supported the change on cost causality and harmonization grounds.

3.1.27 The Board notes Union's arguments that: its proposal was consistent with the methodology used to allocate mains costs in the Northern and Eastern operations area; the proportion of industrial demand served directly from transmission is similar for the Southern operations area; there will be no rate change if the allocation is approved; and rates for industrial customers will increase if the proposal is rejected.

3.1.28 The Board is unconvinced that there are not underlying fundamental differences between the configuration of the infrastructure serving customers in Union's Southern and Northern and Eastern operations areas, particularly the Northern area. In the Board's view Union's attempt at harmonization using only the cost allocation step is incomplete.

3.1.29 In particular, Union has not satisfied the Board that separation of transmission and distribution service is identical for the two service areas. In the Board's view a complete approach to harmonization would first involve functionalization of Southern operations area pipe costs as either grid, joint or sole use main (or conversely to re-functionalize Northern operations area costs), followed by classification as capacity or commodity related costs. The Company's own witness indicated that the proposed cost allocation change was in the right direction, but stated " when we [have] completed our analysis as far as integrating cost allocation methodologies that will be something that we look at and evaluate whether we can do it".

3.1.30 The Board considered whether the Company's proposal could be accepted on an interim basis. However based on the Company's responses there is no certainty that a more rigorous analysis will be presented in the next rates case.

3.1.31 The Board therefore declines to approve any change in the allocation of Southern operations area distribution capacity costs for 1999 and directs the Company to better justify any change in the allocation of distribution capacity costs as part of the overall harmonization of cost allocation and rate design for its service areas. The Board expects that 1999 revenue to cost ratios for general service customer classes will recognize the reversal of this cost allocation change.

Allocation of Unaccounted for Gas (UFG)

3.1.32 In the Settlement Agreement for E.B.R.O. 493/494, Union agreed to undertake a study which would "examine alternate methodologies to allocate UFG separately for the storage, Dawn-Trafalgar transmission, other transmission and distribution functions". Union subsequently retained Harrington & Hrehor Energy

Consulting Group LP and Radian International LLC ("the Consultants") to undertake the study.

3.1.33 In the present proceeding Union filed the Consultants' report which recommended no change to the existing allocation methodology. Although intervenors representing in-franchise customers endorsed the report, Enbridge Consumers Gas as a large M12 customer did not accept the current methodology.

3.1.34 The Consultants' evidence was that they attempted to segregate, for the purposes of UFG allocation, Union's system into four envelopes; storage, Dawn-Trafalgar transmission, other transmission and distribution. The criteria they defined for a methodology to be found acceptable were technical completeness, causality, cost effectiveness, accuracy/bias, predictability/stability, and objectivity.

3.1.35 The Consultants first applied mass balance techniques to the envelopes, but found that the other transmission and distribution categories could not be separated due to data constraints, so these envelopes were combined yielding a three envelope approach. The analysis based on three envelopes (storage, transmission, distribution and other transmission) showed large volumetric fluctuations in the Dawn-Trafalgar and other transmission and distribution envelopes over the four year analysis period. In the Consultants' opinion, the methodology failed the stability/predictability criterion.

3.1.36 Union stated that installation of custodial transfer quality meters on the Dawn-Trafalgar transmission system would improve data quality, but would cost over $2 million. The Company therefore proposed to continue with the existing allocation methodology based on throughput.

3.1.37 Enbridge Consumers Gas challenged the Consultants' findings and proposed an increase in total allocation units due to addition of a distinct component for distribution that recognizes that distribution volumes travel on the storage transmission and distribution systems. Under Union's methodology, distribution volumes were included only with storage and transmission volumes.

3.1.38 Union and the Consultants disagreed with Enbridge Consumers Gas' proposition and stated that adding another volume allocator for distribution would be double counting, especially if the underlying causality for UFG was metering inaccuracies.

3.1.39 The Consultants conceded that for the lost gas (leakage) component, current studies of system emissions had provided a theoretical basis to allocate lost gas between storage, compression, transmission and distribution.

3.1.40 The Consultants provided an estimate from the Company's emissions model, based on 1995 data, of the percentage of emissions from the transmission, storage and distribution components of the Company's facilities and the relationship of these to the 1997 estimate of total UFG. This showed that unaccounted for emissions were about 33 $10^6 m^3$ per year or about 41% of total UFG. The sources of emissions (relative to total UFG) broken down by component are: 11% transmission, 2.6% storage and 28% distribution. The Consultants noted that metering and accounting differences went into the derivation of total UFG and cautioned that the use of emissions estimates was not appropriate and mass balances were the proper and accepted way of allocating UFG costs.

3.1.41 Intervenors representing the interests of large volume customers supported Union's proposal to maintain the status quo noting that the Consultants recommended the current approach as more appropriate than the considered alternatives.

3.1.42 Intervenors representing customers served under Rate M12 disagreed with the current methodology contending it does not attribute distribution system losses solely to in-franchise customers. They argued that Union's current methodology allocates system wide losses to storage and transmission only, resulting in a claimed cross-subsidization by ex-franchise customers.

3.1.43 These intervenors also advocated that Union install custodial transfer quality meters at all delivery points on the Dawn-Trafalgar system (which they noted may be required in the event of gas market deregulation towards burner tip sales) and that the Board direct Union in future rates cases to allocate distribution system losses to in-franchise customers only.

3.1.44 The Board notes that the Company's current allocation methodology is based on an assumption that UFG is caused solely by metering and accounting differences and, if one accepts this assumption, the current allocation methodology is appropriate and in line with historic industry-wide practice. However, the Board is of the view that there is a significant body of recent industry experience and Company-specific data that indicates that UFG has two primary underlying causes: lost gas-uncontrolled leakage and metering and accounting differences. Both are related to volumetric throughput.

3.1.45 In the Board's view, the approximately $2 million cost of new meters to create a separate UFG envelope for improving the mass balances for the Dawn-Trafalgar transmission system is not warranted on the single ground that a hoped-for improvement in the accuracy of UFG allocation may result. However, the Board expects that the recent removal of legislative restrictions on title transfers and the development of an active wholesale gas commodity market will require custodial metering upgrades at additional delivery points on the Dawn-Trafalgar system. According to the Company's evidence, 20 receipt/delivery points do not have custody transfer meters. The Board expects Union to utilize the opportunity presented by market developments to ensure that its future UFG allocation methodology can appropriately reflect the operation of the Dawn-Trafalgar system.

3.1.46 Further, the Company's emissions inventory model provides new information and a basis for reconsidering the overall methodology for allocation of UFG to storage, transmission, compression and distribution. The Board directs the Company to consider a new allocation methodology and report its findings in the next rates case.

Allocation of Storage Deliverability Costs

3.1.47 The Bentpath/Rosedale Storage Project, approved by the Board in E.B.L.O. 257/E.B.R.M 107, lowered the pressure required for design day deliverability from the Bentpath and Rosedale pools, thereby reducing design day inventory requirements and creating both additional space and additional storage deliverability. Although all of the space in excess of requirements for in-franchise and Rates C1/M12 requirements has been sold for the winter of 1999/2000, there is excess deliverability of 2,572 10^3m^3/day.

3.1.48 Union proposed to allocate the excess storage deliverability related costs using a methodology which allocates such costs in proportion to forecast storage deliverability demands. This would result in all customer classes receiving an allocation of "excess" storage deliverability costs. The approximate split is 60% to in-franchise and 40% to Rates C1/M12 customers respectively. Union stated that it did not propose to allocate all of the costs associated with deliverability in excess of the forecast deliverability demand to in-franchise customers only because:

- ex-franchise (M12) customers have benefitted from the Bentpath/Rosedale Storage Project through lower storage rates; according to Union's evidence the 1997 Rate M12 storage deliverability rate was about $14/$10^3m^3$/day per month less than without the Project; and

- any margin earned from the sale of short-term storage deliverability will be allocated to both in-franchise and ex-franchise customers in proportion to the allocation of storage deliverability costs.

3.1.49 In the Board's E.B.R.O. 493/494 Decision at paragraph 9.7.20 the Board stated "... recognizing that the [Bentpath/Rosedale] Project is to be completed late in the 1997 fiscal year and will then be allowed into Union's Rate Base as an asset considered to be used and useful, the functionality of that asset should be reflected in the cost allocation methodology. The Board therefore agrees with [Enbridge] Consumers Gas and finds that the allocation units for 1998 should reflect the increased deliverability generated from the Project".

3.1.50 The Board notes that Enbridge Consumers Gas questioned Union's interpretation of the Board's decision in E.B.R.O. 493/494 and contended that the <u>total</u> deliverability, not only the sold portion of the deliverability, should be the denominator of the allocation factor. The result of this interpretation would be to allocate about $458,000 less storage deliverability costs to Rate M12 and correspondingly increase the allocation to in-franchise customers, particularly to Rate M2.

3.1.51 Union's position is that it had not incurred costs to increase storage deliverability and, while some deliverability is not contracted, it is appropriate to continue allocating storage deliverability costs in proportion to storage deliverability demand. Union also claimed that Enbridge Consumers Gas is trying to counterbalance the fact that revenue associated with the storage space premium is allocated entirely to the account of in-franchise customers.

3.1.52 The Board finds that although the average storage deliverability costs and rates will, in the long term, reflect the increased deliverability of the Bentpath/Rosedale pools, the allocation of storage deliverability costs to rate classes and rates should be based on the test year forecast of class design day storage deliverability demand, relative to the total forecast design day storage deliverability demand. Accordingly Union's methodology is appropriate for a period such as the 1999 test year, in which the total forecast deliverability requirement is less than the total design day capability.

Allocation of Gas Supply Load Balancing Costs

3.1.53 In E.B.R.O 494-06, the Board approved a methodology for the allocation of load balancing and flexibility related costs in the then Union franchise area. It is the Company's proposal in the present application to continue to use that methodology, and to offer a two point balancing option to those direct purchase customers in its Southern operations area who wish to avail themselves of it.

3.1.54 The purpose of the methodology approved by the Board was to allocate load balancing costs to those who cause the Company to incur them. The cost of short term and balancing supplies, forecast to be $7.561 million in the test year, were determined by comparing the 1999 updated forecast cost of gas supply with what the forecast cost of gas would be under a scenario in which it is assumed the total supply is entirely underpinned with Alberta sourced commodity and TCPL Firm

Transportation ("FT") capacity. These costs were then split into two components. The first component, $5.931 million of commodity gas supply related load balancing costs attributable to direct purchase customers, is calculated by multiplying the winter/summer spot price differential by the forecast winter spot volume. Those costs were allocated to each rate class in proportion to the forecast supply/demand direct purchase imbalance on March 31, 1999. The remaining $1.630 million of short-term supply costs, designated as flexibility costs by the Company, were assigned to the M2 general service rate class, the only rate class which presently contains system supply customers.

3.1.55 To the extent that actual load balancing costs differ from those forecast, the differences are captured in a deferral account. It was agreed by the parties in this proceeding that the existing deferral account balance be disposed of on the same basis as the 1999 forecast. The deferral account balance resulting from test year differences, however, need not be disposed of in the same way and will be considered in a future proceeding.

3.1.56 Submissions by intervenors representing the interests of large volume customers supported continuing the interim methodology approved by the Board in E.B.R.O. 494-06, subject to a review of the methodology in the context of the Company's planned unbundling of delivery services. They also noted Union's evidence that it had reviewed alternative cost allocations and no superior alternative was proposed by any intervenor.

3.1.57 The Board notes the position of some intervenors that Union, by its failure to present alternative load balancing cost allocation methodologies, has not met the requirements expressed by the Board in E.B.R.O. 493-04/494-06. There was also a concern expressed that this issue would remain contentious even after rates have been unbundled, since many customers will still choose to take bundled service. A further concern of intervenors was that, since Union may not completely exit the commodity gas supply function for the foreseeable future, the Company may have to provide load balancing for some time.

3.1.58 Union's position was that it was not reasonable for intervenors to demand another methodology in this case. Given the new legislation, the continuing efforts of the

Board's Market Design Task Force (" MDTF") to address various issues including unbundling and load balancing, and the potential for the Local Distribution Companies ("LDCs") to develop a Standard Service Offering ("SSO"), the Company has devoted its resources to these initiatives rather than to investigating another short-term proposal that could be significantly affected by the outcome of these initiatives. The current interim methodology is a balanced and reasonable approach and should be approved.

3.1.59 The Board finds that although there are good reasons to continue the current methodology for the test year, the Board's approval is a temporary measure. The Board expects that a new load balancing service will be brought forward as soon as the Company has completed its work on the unbundling of its services. The Company is directed to report to the Board as soon as it is in a position to present a new load balancing proposal.

Allocation of Taxes

3.1.60 Union proposes to change the manner in which income taxes are allocated in the Northern and Eastern operations area to the methodology currently utilized for allocating taxes in the Southern operations area. Union proposes that income taxes for both areas be allocated in proportion to rate base on the basis that it is the return on rate base that gives rise to the tax. The former allocation method for the Northern and Eastern operations area used an income statement approach, with certain items on the income statement allocated according to specific allocators. The effect of the proposed change is to allocate $1.086 million fewer costs to Rate 01; $1.296 million more to Rate 10, $0.755 million more to Rate 20, $0.444 million less to Rate 100, $0.479 million less to Rate 25 and $0.041 million less to Rate 16.

3.1.61 It is the Company's evidence that not only does the proposal provide consistency between the two operations areas, it is also less complicated than the existing allocation methodology under which any change to other allocation factors has a corresponding income tax allocation impact. In the Company's view, such income tax allocation impacts should arise only as a result of changes to the allocation of rate base.

3.1.62 The Board notes that the Consortium was the only party opposed to Union's proposed tax allocation change. The Board recognizes the link between return on rate base and income tax cited by Union, but the Board is not persuaded that Union's proposal is necessarily superior to the existing allocator. However, the Board does agree that simplicity and uniformity across the utility with respect to allocation of taxes is desirable. Noting that the impact of the proposed change on any one rate class is not substantial, the Board accepts the Company's proposed change.

Treatment of Distribution Structures Costs

3.1.63 As a result of the merger between Centra and Union, plant accounting records were combined. In this process, \$21.837 million in gross plant related to field offices has been reclassified from general plant structures and improvements to distribution plant structures and improvements. As a result, Union is proposing to treat distribution plant structures and improvements in a manner consistent with distribution land for cost allocation purposes. The effect of Union's proposed treatment is to allocate \$0.924 million more costs to Rate 01. In the absence of a cost allocation change, the costs allocated to Rate 01 customers would decrease by \$2.680 million, as historically distribution structures and improvements for the Northern and Eastern operations area have included costs relating to structures and fences associated with sales meter and town border stations. These costs have been allocated using average number of customers, excluding Rate 01.

3.1.64 Intervenors representing the interests of small volume customers contended that there was no convincing evidence that the principles of cost causality and fairness were well met in this proposal and they were concerned that this allocation change shifts costs, which include more than just the cost of field offices, to Rate 01 customers, whereas if only field office costs were involved, then the cost allocation change combined with other changes would be neutral for Rate 01 customers. They requested that the Board deny Union's proposed change.

3.1.65 Some intervenors supported the Company's proposed change and linked the rate impacts of this proposal with the change in the basis for allocating income taxes, noting that while this proposal increases costs to Rate 01 customers by $924,000 and decreases costs to Rate 10 customers by $1.98 million, the income tax allocation change will reduce costs to Rate 01 customers by $1.086 million and increase costs allocated to Rate 10 by $1.296 million.

3.1.66 Other intervenors provided partial support for Union's proposal, but also indicated that the Company should be directed to scrutinize the plant accounts to differentiate between the structure-related costs of sales meter stations and town border stations and to make necessary adjustment to rates in the next rates case.

3.1.67 In reply Union reiterated that it was not practical to separate the costs of structures related to town border stations from those related to sales meters.

3.1.68 The Board finds that the Company's original evidence is not entirely clear on why additional costs (besides the costs of the field offices) are being transferred to the Rate 01 class. However, the Company indicated that a further consideration in proposing this change was whether the Rate 01 customers should have been paying more of the structure-related sales meter and town border station costs in the past. The Company did not provide any support for this assertion and was unaware of the rationale for Rate 01 customers escaping these costs in the past.

3.1.69 In the Board's view the Company has adequately justified the allocation of field office costs to Rate 01 following the accounting change, but it has not fully justified the additional allocation of the structure-related costs of town border stations using the same allocator as land and has inadequately explained why Rate 01 customers should be allocated any of the costs of structures associated with sales meters. The Board is particularly concerned with the change in allocation of any sales meter related costs to Rate 01.

3.1.70 The Board will accept the cost allocation change as proposed, on a temporary basis for the test year, since this will allow the Company to allocate field office costs to Rate 01. The Company is directed to provide greater support and justification for its allocation of the costs of structures related to town border stations and of sales meters to Rate 01 customers in the Northern and Eastern operation areas in the next rates case.

3.2 RATE DESIGN

3.2.1 The following rate design issues on the approved Issues List were the subject of a complete settlement among the parties to the Settlement Agreement:

- deferral of final harmonization of Fort Frances rates;
- increase in Rate 25 delivery range rate to $27.00/10^{3}m^3;
- revenue to cost ratios (subject to an opportunity to review final ratios in the Draft Rate Order);
- harmonization of rate schedules, terms and conditions;
- Rate 25 applicability to Lennox Generating Station;
- M9, C1 and M12 rate changes;
- storage service entitlements;
- account opening charges;
- transacting in energy units;
- true up for Rates M2 and M4;
- optional two point load balancing; and
- harmonization of direct purchase administration fee.

Descriptions of the settlement of these issues can be found in Appendix B.

3.2.2 The rate design issues below were not settled as part of the Settlement Agreement and require a Board decision.

Rate Seasonalization

3.2.3 Rate 01 is applicable to residential customers in the Northern and Eastern Operations Area. The rate is seasonalized with the result that delivery rates are 1 cent per 10^{3}m^3 higher during the months October to March inclusive. There is no seasonalization of Rate M2 (general service) in the Southern operations area. In E.B.R.O. 493/494 the Board accepted Union's position that Rate M2 seasonalization should be examined as part of Union's review or rate harmonization following the proposed amalgamation of the former Union and Centra. In the present proceeding, Energy Probe and Pollution Probe reiterated their argument that Rate M2 ought to be seasonalized. Union maintained its position that seasonalization should await the outcome of the overall rate harmonization exercise for the two operations areas which is currently being undertaken by the Company.

3.2.4 The Board agrees with Union's position. It would be premature for the Board to order seasonalization of Rate M2 prior to Union having an opportunity to present evidence on its conclusions regarding rate harmonization. The Board expects Union to make a proposal with respect to rate seasonalization in the context of rate harmonization at its next main rates case.

Removal of the Rate 25 Buy/Sell Option

3.2.5 Rate 25 large volume interruptible service is available to customers in the Company's Northern and Eastern operations area who have a total interruptible demand of at least 14,000 $10^3m^3/d$ or, for the interruptible portion of combined firm and interruptible demand of at least 14,000 $10^3m^3/d$. The gas supply options currently available with the interruptible delivery service are: bundled sales, buy/sell service and customer-owned gas commodity supply (T-service).

3.2.6 In the past, customers using Rate 25 interruptible service have been curtailed for both capacity and price reasons. The issue of price curtailment and the link to Rate 30 supply service was extensively canvassed in E.B.R.O. 493/494. The Board in its Decision, requested Union to examine ways to reduce the chance of Rate 25 customers being forced onto Rate 30 for price reasons to the customer's disadvantage.

3.2.7 In the present proceeding Union indicated that it was now offering a "Rate 25A" option under which a customer can, by contracting with Union for supplies under pre-arranged pricing terms, avoid curtailment if the price of spot supply exceeds the commodity sales rate.

3.2.8 Union's evidence indicated that, historically, under a buy/sell contract the customer would supply gas at Empress in an amount equal to their total annual consumption (firm and interruptible) at their facility. These supplies and the customers' consumption are targeted to be equal on an annual (contract term) basis, such that the customer is not an overall net supplier to the system. Union's evidence is that the Rate 25 buy/sell supplies at Empress are, in essence, simply part of the overall gas supply portfolio utilized to serve firm customers. In Union's view, there is no link between the supply of Rate 25 buy/sell volumes at Empress and the molecules acquired and used to support the Rate 25 service at the customer's facility. Union does not contract for firm transportation capacity specifically to serve Rate 25 or other interruptible demands.

3.2.9 Union stated that, over time, increased demand on both its Northern and Eastern operations area system and TCPL's total system have resulted in an increasing reliance on Union acquiring delivered spot gas supplies to support the Rate 25 service. As future direct purchase will have to be facilitated, Union's remaining TCPL capacity will continue to be utilized for new firm direct purchase customers. Given these conditions, Union proposes to delink the Rate 25 service from a customer's gas supply arrangement effective November 1, 1999 in order to ensure adequate TCPL capacity remains to accommodate the requirements of the remaining firm customers electing direct purchase.

3.2.10 Union's proposal to discontinue the buy/sell option under Rate 25 was opposed by ECNG/AMO and the Consortium on fairness grounds, since this option continues to be available to other interruptible customers served under Rates 16, M5 and M7. Union replied that the purchase of gas from Rate 25 customers is not part of a normal buy/sell arrangement. It noted that supply is not matched with deliveries, and the price paid for supply is not the reciprocal of the commodity price paid by the customer, a condition that underpins a true buy/sell arrangement. It further reiterated that there is no firm transportation capacity associated with buy/sell service for Rate 25 as there is for the other rate classes referred to by the intervenors.

3.2.11 Union submitted that Rate 25 sales service was underpinned mainly by spot and delivered gas and the Rate 25 buy/sell transaction which allowed the customer to supply gas at Empress with no associated transportation, was artificially grafted onto an interruptible delivery service. Given the reduced amount of transportation capacity to accommodate direct purchase, it did not make sense to perpetuate this option.

3.2.12 The Board agrees with Union's position. The relationship between Rate 25 interruptible delivery service and buy/sell commodity supply is artificial and the buy/sell option can only exist if firm transportation capacity in excess of firm requirements on TCPL is available for a significant part of the winter period. The Company's unchallenged evidence is that as sales service is reduced and capacity is assigned to direct purchase, firm transportation will no longer be available to supply interruptible customers. The Board therefore finds that the options available to Rate 25 interruptible customers should be bundled sales service or T-service only. The Rate 25 bundled sales service customer, if interrupted for other than capacity constraints, can now arrange the pricing terms for their alternative gas supply or switch to alternative fuels. The Board accordingly approves the removal of the buy/sell supply option from Rate 25.

3.2.13 The Board notes that the Company has not proposed a similar treatment with respect to the buy/sell service of Rate 16. Should the Company wish to continue the provision of buy/sell service for Rate 16, the Board expects the Company to justify the retention of this service at the next rates case.

Design of Rate 100

3.2.14 Rate 100 is a high load factor firm service available to customers in the Company's Northern and Eastern operations area with a maximum firm demand greater than 100,000 10^3m^3/d and an annual load factor of at least 70%.

3.2.15 Union is not proposing any changes with respect to the design of Rate 100. All customers receiving service, irrespective of the customer-specific facilities in place to serve them, are charged the same customer charge and delivery rate. The delivery rate includes an allocation of distribution costs based on Rate 100 being served on sole and joint use mains only.

3.2.16 TCP opposed the structure of Rate 100 delivery rates as it applies to it. In TCP's view, its cogeneration plants in Kapuskasing and North Bay are served directly from TCPL with no main and only a meter connection owned by Union. TCP therefore considers that it is receiving only a "metering and invoicing service" and, therefore, bearing distribution costs that are inappropriately allocated, given the service they receive.

3.2.17 TCP argued that the design for Rate 100 should be further unbundled to reflect a component for metering and invoicing services currently included in the customer charge and delivery charge. In the alternative, TCP suggested that the Rate 100 cost allocation be changed to separate delivery services to customers served by sole use main from those served by joint use main. None of the intervenors who commented on this issue supported either of TCP's proposals.

3.2.18 Union disagreed with TCP's views regarding the structure and design of Rate 100, or that special circumstances should apply to TCP. In Union's submission TCP wants a new rate which is limited to the use of metering equipment only and TCP was therefore seeking a new rate, but attempting to present it as a change to Rate 100 because of the Board's ruling on Issues Day that it would not consider a new rate for cogeneration facilities in this proceeding. Union submitted that this issue was fully dealt with by the Board in E.B.R.O. 493/494 and there is no change of circumstances since that time and therefore Union's current design of Rate 100 should be adopted.

3.2.19 The Board finds that there is no change in circumstances and no special circumstances exist that would require the further unbundling of Rate 100. The Board agrees with Union that TCP is seeking either a new service rate for metering and billing only, or a customer-specific rate within Rate 100. Therefore the Board accepts the current design of Rate 100 as appropriate for the test year.

Supplemental Gas Supply Service

3.2.20 The Company requested approval, at least on a trial basis, to provide a supplemental gas supply service for the sale of gas to ex-franchise customers at negotiated prices under the C1 rate schedule. It was the Company's evidence that ex-franchise customers seeking to meet their incremental gas supply needs have, on some occasions, requested storage and transportation services from the Company which include the supply of commodity as well. The Company argued that the flexibility to combine the sale of gas with the sale of short-term storage and transportation services as a supplemental service would improve the range of its transactional services offerings. The Company noted that it does not intend to market gas independently under this service, and that the number of transactions involved is expected to be small, perhaps a dozen per year. The proposal was opposed by intervenors largely because it would involve the Company selling commodity gas in a competitive market.

3.2.21 The Board finds two fundamental difficulties with the Company's proposal. As a gas distributor Union requires a rate for the 'sale' of gas (commodity). The "rate" proposed is nothing more or less than an open ended market commodity price. In addition, the Company's declared business strategy for its distribution business is to exit the gas merchant function. Although Union's proposal is linked to an unbundled commercial S&T business serving wholesale customers, the Board clearly distinguishes the Company's sale of transactional services using surplus capacity associated with utility assets from the type of gas commodity transactions envisioned in the proposed supplemental gas supply service. Union's proposal for supplemental gas supply service is therefore denied.

4. COSTS AND COMPLETION OF THE PROCEEDING

4.1 COST AWARDS

4.1.1 At the time of writing this Decision the Cost Award process was not completed. In the interest of expediting the issuance of this Decision the Board will issue a supplemental Decision on intervenors' Cost Awards as soon as possible.

4.1.2 The Board directs Union to pay the Board's costs of, and incidental to, the proceeding upon receipt of the Board's cost invoice.

4.2 COMPLETION OF THE PROCEEDING

4.2.1 As noted in Chapter 2, the Board finds an overall revenue sufficiency for the 1999 test year of $85.076 million, as shown in Appendix A page 5 of 5 [Determination of Revenue Excess/(Deficiency)] and supported by the other schedules in that Appendix. As also noted in Chapter 2, this revenue sufficiency amount will be reduced to about $71 million to reflect the E.B.R.O. 499-01 Rate Order.

4.2.2 The Company is directed to adjust its delivery rates by the delivery sufficiency amount while giving effect to the Board's other findings on cost allocation or rate design matters found herein. Since the rate schedules were recently changed to reflect a forecast increase in gas costs, the forecast sufficiency relating to gas costs shall not be used to lower rates at this time; any difference between the actual and forecast gas costs shall be recorded in the Company's Purchased Gas Variance Account ("PGVA") in the normal course for future disposition.

4.2.3 While the Board finds that the new rates shall be effective January 1, 1999, the implementation of the new rates shall be as soon as possible but no later than April 1, 1999.

4.2.4 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, including revised financial schedules corresponding to Appendix A herein reflecting the Board's E.B.R.O. 499-01 Rate Order and the Board's findings in this Decision;

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;

v) drafts of the proposed notices to customers which shall accompany the first customer bill following the implementation date of the new rates; and

vi) information outlining the Company's plans to effect a one-time bill adjustment to cover the rate changes for the period from the effective date of January 1, 1999 to the date of implementation of rates.

4.2.5 The draft rate schedules and supporting documentation will be available at the Board's offices. Parties wishing to comment on proposed final rates may do so no later than 5 business days following the date on which the Board receives the draft material. To facilitate this process the Company shall provide all intervenors of record in E.B.R.O. 499 with a facsimile copy of its transmittal letter.

DATED AT Toronto January 20, 1999.

R.M.R. Higgin
Presiding Member

H.G. Morrison
Member

P. Vlahos
Member